Electrical Distribution Fundamentals Design Guide

Data Bulletin

0100DB2301
03/2025

www.se.com

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Introduction and Basic Fundamentals

Introduction

With the increasing sophistication of modern power systems, it is easy to overlook the fact that the basic function of a power distribution system has been the same for over 100 years: the safe, reliable distribution of power from a source to the connected loads. Although this basic function has not changed, the complexity of the loads themselves, along with today's reliability and efficiency requirements, makes its realization more complex.

This guide discusses the main considerations that must be taken into account to obtain an optimal system design. Because the characteristics of each load, process, or other issue, are unique, each design is unique to match the requirements imposed.

Purpose of this Guide

This guide is intended to present the fundamentals of power system design for commercial and industrial power systems. It is not designed as a substitute for educational background and experience in this area, nor is it designed to replace the multitude of detailed literature available about this subject. It does, however, bring into one volume much material or standards which has previously been available only by referencing several different sources with different formats and terminologies.

This guide is also intended to present the state of the art about power system design for commercial and industrial facilities, in a consistent format along with traditionally available material.

For the new college graduate from a four-year electrical engineering curriculum working in the field of commercial and industrial power systems, this guide can serve as a starting point for learning the different aspects of the profession. For the licensed design professional, this guide presents several guidelines in a handy and convenient reference.

This guide is not intended to substitute for the services of a licensed design professional, but can aid when working with such professionals on commercial and industrial power system design.

Applications of Electrical Power in Industrial and Commercial Facilities

In both industrial and commercial environments, electric power is used for a wide number of applications. The following is a brief list of the most common uses for electric power, taken in part from *Standard Handbook for Electrical Engineers*[1], which provides an expanded treatment of this subject:

Illumination: Whether for providing light for an office environment or a manufacturing shop floor, illumination is one of the most important applications of electric power.

Environmental systems: Electric heating, ventilation, and air conditioning are a large application for electric power, and an area in which electric power receives direct competition from other energy sources such as natural gas.

1. New York: McGraw-Hill, 2001, pp. 21-1 – 21-99.

Industrial processes: Industrial processes account for a large percentage of the global use of electric power. Typical process applications listed below, are not all-inclusive, but do cover the majority of process applications:

- Pumping
- Motors
- Chemical processes
- Semiconductor preparation processes
- Furnaces
- Smelting
- Rolling mills
- Pulp-and-paper preparation processes
- Welding
- Refrigeration
- Drying
- Well drilling
- Materials handling
- Water treatment processes

Computers and Data Centers: With the advent of large computer networks, there is a need to reliably power these.

Health Care: Reliable power has always been a requirement of the health care industry but added to this is the need for power quality due to the nature of the equipment used.

Safety Systems: Systems such as fire alarm and smoke detection systems, sprinkler systems and fire pumps are vital to any commercial or industrial facility.

Communication Systems: Systems such as telephone and intrusion detection and monitoring are critically important.

Basic Design Philosophy

The following basic considerations are fundamental to any power system design:

- **Basic safety:** The power system must be able to perform all of its basic functions, and withstand basic abnormal conditions, without damage to the system or to personnel.
- **Basic functionality:** The power system must be able to distribute power from the source to the connected loads in a reliable manner under normal conditions.
- **Reasonable cost:** The power system cost to obtain basic safety and functionality should be reasonable.
- **Code compliance:** All applicable codes must be complied with.

Above and beyond the basics are a multitude of considerations, some of which apply to each system design:

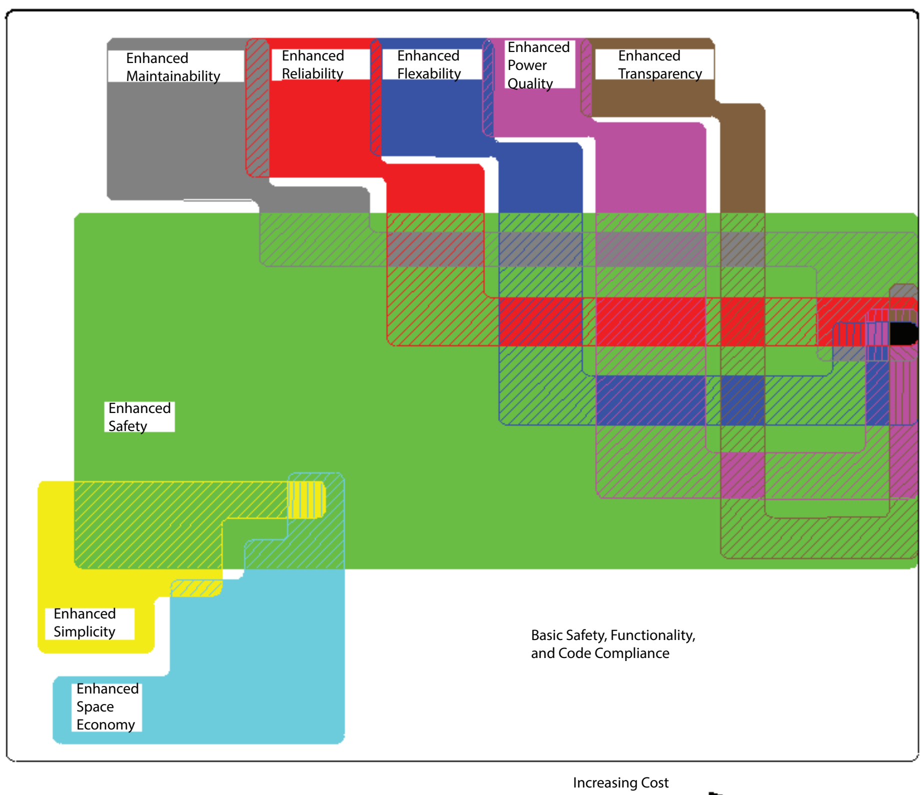
- **Enhanced safety:** The ability to withstand extremely abnormal conditions with a minimum of risk to personnel.
- **Enhanced reliability:** The ability to maintain service continuity during abnormal system conditions.
- **Enhanced maintainability:** The system can be maintained with minimum interruption to service and with minimum personnel protective equipment.
- **Enhanced flexibility:** The ability to add future loads to the system, and with loads of a different nature than currently exist on the system.

- **Enhanced space economy:** The power system footprint is optimized for the available space.
- **Enhanced simplicity:** The power system is easy to understand and operate for a qualified person.
- **Reduced cost:** The power system costs; both first cost and operating cost, are low.
- **Enhanced power quality:** The power system currents and voltages are sinusoidal, without large harmonics present. System voltage magnitudes do not change appreciably.
- **Enhanced transparency:** The power system data at all levels is simply acquired and interpreted, and the power system is simply interfaced with other building systems. Enhanced control of the system is also possible.

While it is the goal of every power system design to meet the above basic considerations, no system design can yield all the enhanced characteristics listed. The relationship between the considerations listed is shown in Power System Design Consideration Heuristics, page 9.

Some of the enhanced characteristics mentioned are mutually exclusive, and to obtain a combination of several enhanced characteristics requires a significant increase in cost. The design engineer, therefore, must consider the balance between the performance requirements of the system and the cost, while not compromising the basic safety elements, functionality, and code compliance.

Figure 1 - Power System Design Consideration Heuristics



Electric Power Fundamentals

Abstract: The fundamentals of electric power and electrical systems have remained unchanged for many years though technologies employed in electrical power systems have advanced greatly. Anyone responsible for any part of an electrical system relies on the fundamental relationships presented.

Introduction

The fundamentals of electric power and electrical systems have remained unchanged for many years, though technologies employed in electrical power systems have advanced greatly. Anyone responsible for any part of an electrical system relies on the fundamental relationships presented. An understanding of the fundamentals of electric power is vital to successful power system design. It is assumed that the reader has a degree in electrical power engineering or electrical power engineering technology, however the following discussion is presented as a review and reference material for completeness.

Basic Concepts

Commercial electric power in the United States is generated and delivered as alternating current, abbreviated as "AC". AC power consists of sinusoidal voltages and currents. Mathematically, an AC voltage or current can be expressed as follows:

$$v(t) = V_{max}\cos(360f \cdot t+\Phi_v) \qquad (2–1)$$

$$i(t) = I_{max}\cos(360f \cdot t+\Phi_I) \qquad (2–2)$$

Where:

- $v(t)$ is an AC voltage
- $i(t)$ is an AC current
- V_{max} is the voltage amplitude
- I_{max} is the current amplitude
- f is the system frequency
- Φ_v is the voltage phase shift in degrees
- Φ_t is the current phase shift in degrees
- t is the time in ms

All angles are measured in degrees.

AC currents and voltages are economical to generate and, further, the magnitudes of the currents or voltages can be stepped up or down using transformers.

Three-phase AC power is the standard in the United States due to its convenience of generation. Three-phase (abbreviated “3Φ “) power is characterized by three different phases, each with a phase shift 120° from the other two phases. The three phases are typically referred to as “A”, “B”, and “C”. Further, the standard frequency for the United States is 60 Hz. Therefore, three-phase voltages in the United States can be mathematically described as follows:

$$v_a(t) = V_{max}\cos(360x60xt) = V_{max}\cos(21600t) \quad (2–3)$$

$$v_b(t) = V_{max}\cos(360x60xt – 120°) = V_{max}\cos(21600t – 120°) \quad (2–4)$$

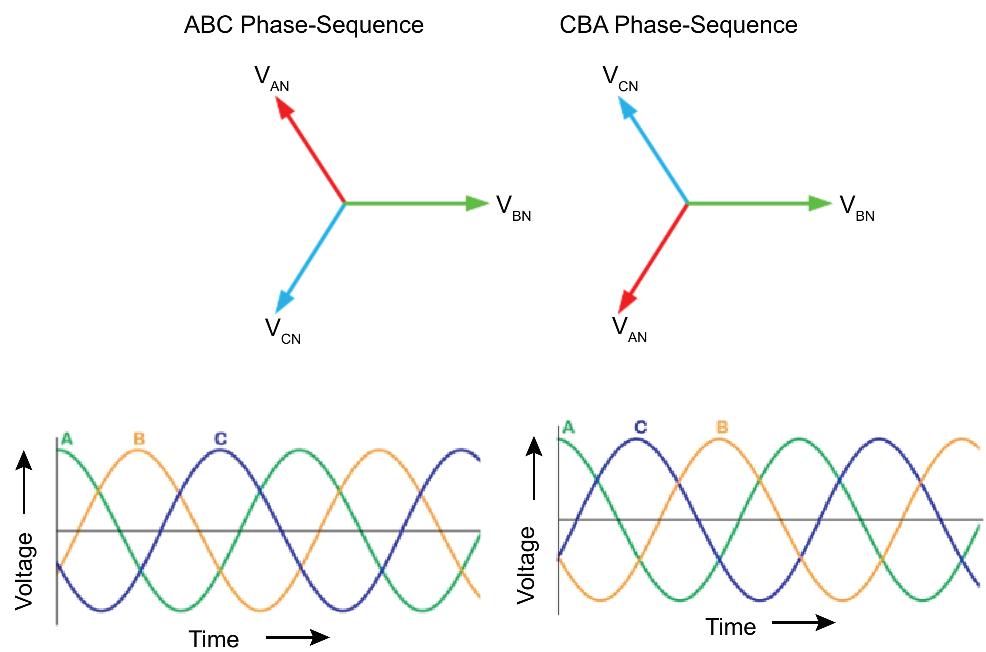
$$v_c(t) = V_{max}\cos(360x60xt +120°) = V_{max}\cos(21600t + 120°) \quad (2–5)$$

Where:

- $v_a(t)$ is the A-phase voltage
- $v_b(t)$ is the B-phase voltage
- $v_c(t)$ is the C-phase voltage

The voltages from (2-3) – (2-5) are shown graphically in Graphical Representation of 3Φ Voltages, page 11.

Figure 2 - Graphical Representation of 3Φ Voltages



The peaks of the voltage waveforms are 120° (5.5 ms at 60 Hz) apart. The peak of phase A occurs before the peak of phase B, which in turn occurs before the peak of phase C. This is referred to as an ABC phase sequence or ABC phase rotation. If any two-phase labels are swapped, the result is a CBA phase rotation. Both are encountered in practice. Also, the definition of time = 0 is arbitrary due to the periodic nature of the waveforms.

Because the full mathematical representation of AC voltages and currents is not practical, a shorthand notation is usually used. This shorthand notation treats the sinusoids as complex quantities based upon the following mathematical relationship:

$$\cos(\theta) = Re\{e^{j\theta}\} \quad (2–6)$$

Where:

- R_e is the real part of the complex quantities

The voltage quantities from (2-3) – (2-5) can therefore be rewritten as follows:

$$v_a(t) = R_e\{V_{max}e^{j21600t}\} \qquad (2–7)$$

$$v_b(t) = R_e\{V_{max}e^{j(21600t-120°)}\} \qquad (2–8)$$

$$v_c(t) = R_e\{V_{max}e^{j(21600t+120°)}\} \qquad (2–9)$$

To further develop this shorthand notation, it must be recognized that the use of the RMS (root-mean-square) quantity, rather than the amplitude, is advantageous in power calculations (discussed below). The RMS quantity for a periodic function f(t) is defined as follows:

$$F_{rms} = \sqrt{\frac{1}{T}\int_0^T f^2(t)dt} \qquad (2–10)$$

Where:

- F_{rms} is the RMS value of the periodic function f(t)
- T is the period of $f(t)$

Using (2-10), the RMS value of each of the sinusoidal voltages from (2-3) – (2-5) are calculated as:

$$V_{rms} = V_{max}/\sqrt{2} \qquad (2–11)$$

Because the RMS value is so useful in the calculation of power-related quantities, any time an AC voltage or current value is given it is assumed to be an RMS value unless otherwise stated.

Assuming only the real part of $e^{j\theta}$ is kept, the voltages from (2-7) – (2-9) can be written as complex quantities known as phasors:

$$\bar{V}_a = V_{max}e^{j21600t} \qquad (2–12)$$

$$\bar{V}_b = V_{max}e^{j(21600t-120°)} \qquad (2–13)$$

$$\bar{V}_c = V_{max}e^{j(21600t+120°)} \qquad (2–14)$$

Assuming a frequency of 60 Hz, the commonly-used shorthand notation for (2-12) – (2-14) is:

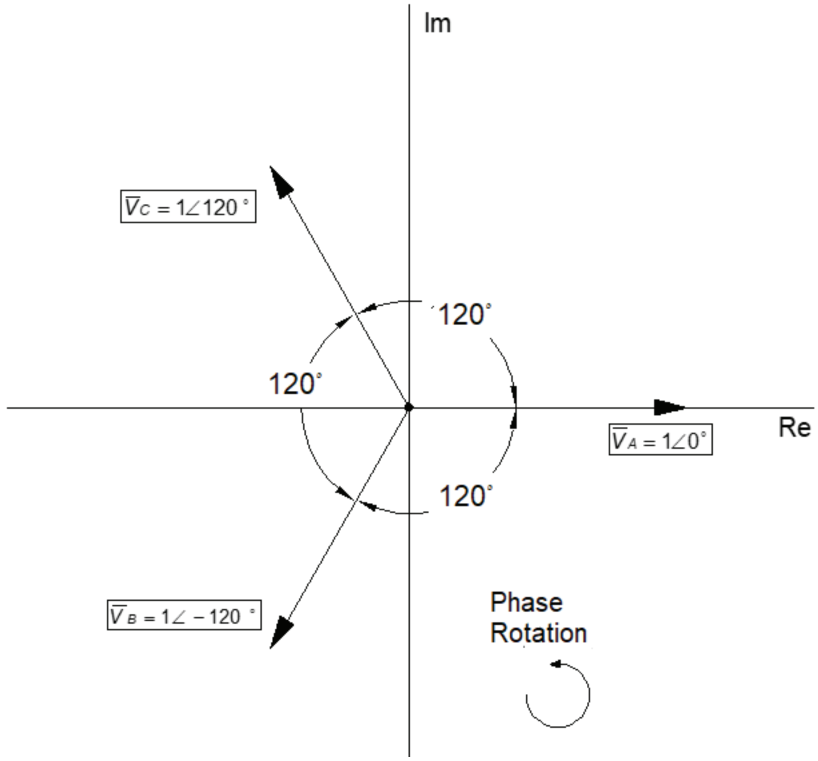
$$\bar{V}_a = V_{max}\angle 0° \qquad (2–15)$$

$$\bar{V}_b = V_{max}\angle -120° \qquad (2–16)$$

$$\bar{V}_c = V_{max}\angle 120° \qquad (2–17)$$

The phasor quantities in (2-15) – (2-17) can be treated as complex quantities for the purposes of manipulation and calculation, but with the understanding that, if required, the basic time-domain voltage relationships of (2-3) – (2-5) can easily be obtained. The phasors can be plotted, as shown in Plot for Phasors per (2-15) – (2-17), page 13.

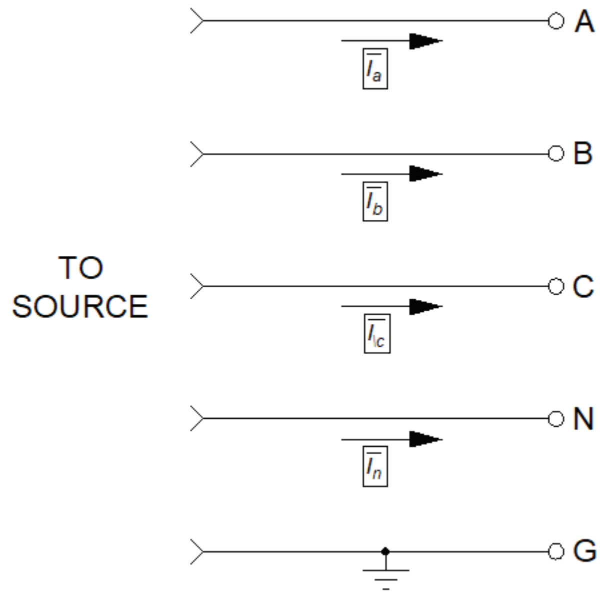
Figure 3 - Plot for Phasors per (2-15) – (2-17)



In most instances the R_e and I_m axes are omitted since the definition of time zero (and thus angle zero) is arbitrary; the important information conveyed is the angular relationships between the phasors themselves. The real part of a phasor is its projection on the R_e axis; if the phasors are imagined to rotate in a counter-clockwise direction about the 0,0 point it can be seen that the peak of $v_a(t)$, represented by the tip of phasor $\bar{V}_a$ crossing the R_e axis, occurs first, followed by the peak of $v_b(t)$, followed in turn by the peak of $v_c(t)$. Thus, for angles defined as positive in the counter-clockwise direction the ABC phase sequence is indicated by a counter-clockwise phasor rotation. If angles are defined as positive in the clockwise direction a clockwise phasor rotation indicates an ABC phase sequence. Both are encountered in practice. In this guide all angles in phasor diagrams are assumed to be positive in the counterclockwise direction.

A very general representation of a 3Φ system is shown in General 3Φ System Representation, page 14.

Figure 4 - General 3Φ System Representation



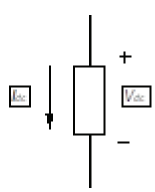
In Figure 4 the three phases A, B, and C have been labeled, along with the neutral (N) and ground (G). The neutral is optional, however the ground always exists. The AC voltages $\bar{V}_{a1}$, $\bar{V}_{b1}$, and $\bar{V}_{c1}$ per the discussion above could represent phase-to-phase voltages ($\bar{V}_{ab1}$, $\bar{V}_{bc1}$, $\bar{V}_{ca1}$), phase-to-neutral voltage. ($\bar{V}_{an1}$, $\bar{V}_{bn1}$, $\bar{V}_{cn1}$), or phase-to-ground voltages ($\bar{V}_{ag1}$, $\bar{V}_{bg1}$, $\bar{V}_{cg1}$). The existence of the neutral, and the relationship between the phases and ground, is dependent upon the system grounding and is discussed in System Grounding, page 51. A ground current is not defined; this is because the ground is not intended to carry load current, only ground fault current as discussed in subsequent sections of this guide. In practice, when 3Φ voltages are discussed, they are assumed to be phase-to-phase voltages unless otherwise noted.

AC Power

With the basic concepts per above, AC electrical power can be described.

Consider the following DC circuit element:

Figure 5 - DC Circuit Element for Power Calculation



For the circuit element of DC Circuit Element for Power Calculation, page 14 the following is true:

$$P = V_{dc} \cdot I_{dc} \qquad (2\text{–}18)$$

Where:

- V_{dc} is the DC voltage across the circuit element under consideration, with polarity as shown.
- I_{dc} is the DC current through the circuit element under consideration, considered positive for the direction shown.
- P is the power generated by, or dissipated through, the circuit element under consideration.

The sign of P in (2-18) depends on the direction of current flow with respect to the DC voltage. A positive value for P indicates power dissipated, while a negative value for P indicates power generated. DC power is measured in Watts, where one Watt is 1 V x 1 A.

With AC voltages and currents the expression for power is more complex. Assume that one phase is taken under consideration, with an AC current and voltage as defined by (1-1) and (1-2) respectively. The expression for the instantaneous power, after some manipulation, is:

$$p(t) = v(t)\, i(t) = V_{max} I_{max}/2[\cos(\Phi_v - \Phi_i) + \cos(2\pi ft + \Phi_v + \Phi_i)] \qquad (2–19)$$

Thus, the instantaneous power consists of two parts: A DC component and an AC component with a frequency twice that of the system frequency. The quantity $(\Phi_v - \Phi_I)$ is defined as the power angle or power factor angle and is the angle by which the current peak lags behind the voltage peak on their respective waveforms. The quantity $P= \cos(\Phi_v- \Phi_I)$ is known as the power factor of the circuit.

The average value of p(t) is of concern in AC circuits. The average value of p(t) is:

$$P = V_{max} I_{max}/2 \cos(\Phi_v - \Phi_i) \qquad (2–20)$$

Recall that V_{max}can be expressed in terms of V_{rms} per (2-11); substituting V_{rms}per (2-11) into (2-20) yields:

$$P = V_{rms} I_{rms} \cos(\Phi_v - \Phi_i) \qquad (2–21)$$

However, the absolute value of the product $V_{rms} I_{rms} \cos(\Phi_v - \Phi_I)$ is always less than $V_{rms} I_{rms}$ unless $(\phi_v - \Phi_I) = 0$. Further, if $(\phi_v - \phi_I) = \pm 90°$, as is the case with a purely inductive or capacitive load. $V_{rms} I_{rms} \cos(\phi_v - \Phi_I) = 0$. Because energy is required to force current to flow, and energy is always conserved, AC power must have another component. This component is most easily defined if AC power is treated as a complex quantity. To do this, Complex Power $\bar{S}$ is defined as follows:

$$\bar{S} = \bar{V} \cdot \bar{I}^* \qquad (2–22)$$

The quantities $\bar{V}$ and $\bar{I}$ are the AC current and voltage in their complex forms per (2-15) above, with the * operator denoting the complex conjugate, or angle negation, of the current. This conjugation of the current is done to yield the correct value for the power angle as described below. Real Power P and Reactive Power Q are defined as follows:

$$\bar{S} = P + jQ \qquad (2–23)$$

$$P = \mathrm{Re}\{\bar{S}\} = V_{rms} I_{rms} \cos(\Phi_v - \Phi_i) \qquad (2–24)$$

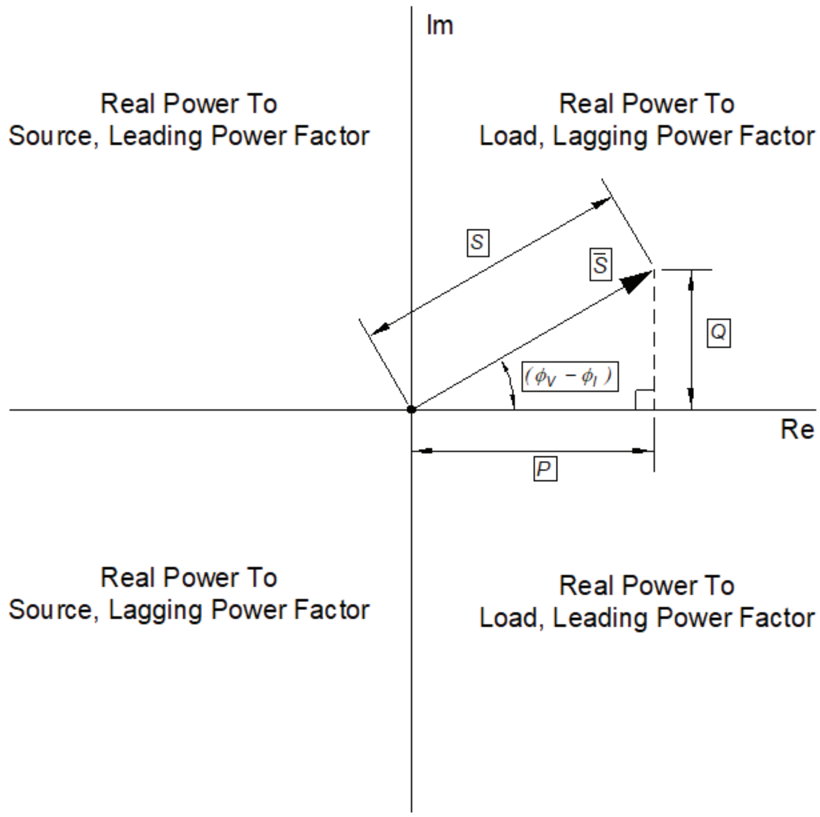
$$Q = \mathrm{Im}\{\bar{S}\} = V_{rms} I_{rms} \sin(\Phi_v - \Phi_i) \qquad (2–25)$$

$$S = |\bar{S}| = \sqrt{P^2+Q^2} \qquad (2–26)$$

P is expressed in Watts. Q has the same units but to differentiate it from P it is expressed in Vars. rather than Watts. S is the Apparent Power and is also expressed in Volt-amperes.

The relationship between P, Q, S, $\bar{S}$, and (Φ_V - Φ_I). can be shown graphically:

Figure 6 - Graphical Depiction of AC Power



The depiction in Graphical Depiction of AC Power, page 16 is referred to as the power triangle since P, Q, and $\bar{S}$ form a right triangle. It is also important to note that the power factor angle is the same as the load impedance angle of the circuit. The power factor is referred to as a lagging power factor if the current lags the voltage (that is, (Φ_V - Φ_I) is positive up to 90°) and as a leading power factor if the current leads the voltage (that is, (Φ_V - Φ_I) is negative down to -90°). For a lagging power factor, the real and reactive power flow is in the same direction; for a lagging power factor they flow in opposite directions. Of the passive circuit elements, resistors exhibit a unity power factor, inductors exhibit a 0 power factor lagging, and capacitors exhibit a 0 power factor leading.

The foregoing discussion considers only single-phase circuits. For 3Φ circuits the power quantities for all three phases must be added together, that is,

$$\bar{S}_{3\Phi} = \bar{S}_A + \bar{S}_B + \bar{S}_C \qquad (2–27)$$

$$P_{3\Phi} = P_A + P_B + P_C \qquad (2–28)$$

$$Q_{3\Phi} = Q_A + Q_B + Q_C \qquad (2–29)$$

$$S_{3\varnothing} = \sqrt{P_{3\varnothing}^2 + Q_{3\varnothing}^2} \qquad (2–30)$$

If the voltage magnitudes and power factor angles for each phase are equal, the power quantities per phase can be represented as $\bar{S}_{1\Phi}$, $S_{1\Phi}$, $P_{1\Phi}$, $Q_{1\Phi}$; equations (2-27) – (2-30) can then be simplified as:

$$\bar{S}_{3\Phi} = 3\bar{S}_{1\Phi} \qquad (2\text{–}31)$$

$$\bar{P}_{3\Phi} = 3\bar{\bar{P}}_{1\Phi} \qquad (2\text{–}32)$$

$$Q_{3\Phi} = 3Q_{1\Phi} \qquad (2\text{–}33)$$

$$S_{3\Phi} = 3S_{1\Phi} \qquad (2\text{–}34)$$

Transformers

Transformers are vital components for AC power systems. They are used to change the voltage and current magnitudes to suit the application.

The Ideal Transformer

Transformers are relatively simple devices that utilize Faraday's law of electromagnetic induction. In its simplest form, this law can be written:

$$\xi = -N\, d\psi/dt \qquad (2\text{–}35)$$

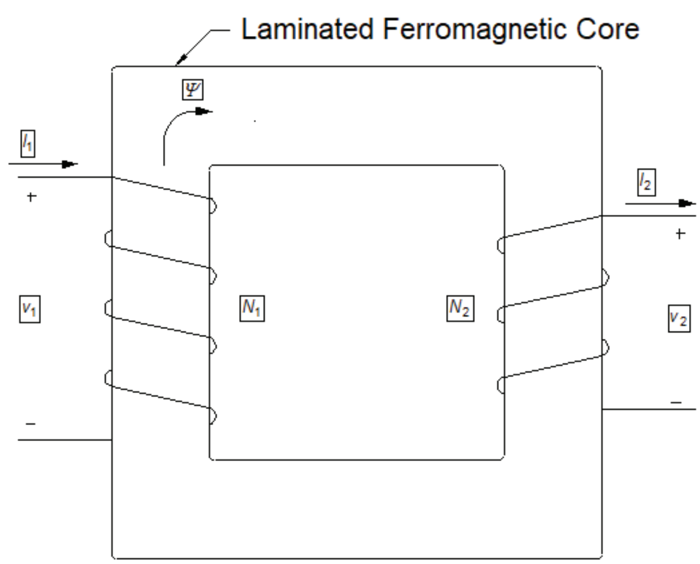
Where ξ is the voltage induced in a coil of N turns that is linked by a magnetic flux Ψ.

In turn, the magnetic flux Ψ for a coil of N turns through which a current I passes and linked by a magnetic path with reluctance $\Re$ can be expressed as:

$$\Psi = NI/\Re \qquad (2\text{–}36)$$

Consider the simple transformer shown in Basic Transformer Model, page 17:

Figure 7 - Basic Transformer Model



From (2-35) and (2-36):

$\Psi=(N_1 I_1)/\Re = (N_2 I_2)/\Re$ (2–37)

$\Rightarrow N_1 I_1 = N_2 I_2$ (2–38)

$\Rightarrow I_1 = N_2/NI_1I_2$ (2–39)

$V_1 = -N_1 d\Psi/dt = -(N_1{}^2/\Re)dI_1/dt = -(N_1N_2/\Re)dI_2/dt$ (2–40)

$V_2 = -N_2 d\Psi/dt = -(N_2{}^2/\Re)dI_2/dt$ (2–41)

Dividing (2-40) by (2-41),

$V_1/V_2 = N_1/N_2$ (2–42)

Equations (2-38) and (2-42) are the basic equations for a single-phase transformer. The voltage ratio (V_1/V_2) is equal to the turns ratio (N_1/ N_2), and the current ratio is equal to the inverse of the turns ratio. By re-writing (2-38) in terms of the turns ratio (N_1/N_2) and substituting into (2-42), the following is obtained:

$V_1I_1 = V_2/I_2$ (2–43)

This is to be expected, since the apparent flowing into the transformer should ideally equal the apparent power flowing out of the transformer.

The usefulness of the transformer lies in the fact that it can adjust the voltage and current to the application. For example, on a transmission line it is advantageous to keep the voltage high to be able to transmit the power with as small a current as possible, to minimize line losses and voltage drop. At utilization equipment, it is advantageous to work with low voltages that are more conducive to equipment design and personnel safety.

Another important aspect of the transformer is that it changes the impedance of the circuit. For example, if an impedance $\bar{Z}_2$ is connected to winding 2 of the ideal transformer in Practical Transformer Model, page 19 it can be stated that:

$\bar{Z}_2 = I_1 = \bar{V}_2/I_2$ (2–44)

Using (2-38) and (2-42), (2-44) can be written in terms $\bar{V}_1$ and $\bar{I}_1$:

$\bar{Z}_2 = (N_2/N_1)\bar{V}_1/(N_1/N_2)/\bar{I}_1 = (N_2/N_1)^2(\bar{V}_1/\bar{I}_1$ (2–45)

By definition:

$\bar{Z}_1 = \bar{V}_1/(N_1$ (2–46)

Therefore, (2-45) can be re-written as:

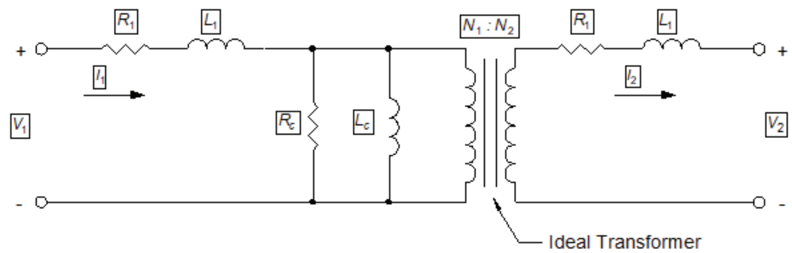
$\bar{Z}_2 = (N_2/(N_1)^2\bar{Z}_1$ (2–47)

The impedance through the transformer is the load impedance at the transformer output winding multiplied by the square of the turns ratio.

A Practical Transformer Model

The idealized transformer model just presented is not sufficient for practical electric power applications since the core is not lossless and not all the magnetic flux links both sets of windings. To take this into account, a more realistic model is used:

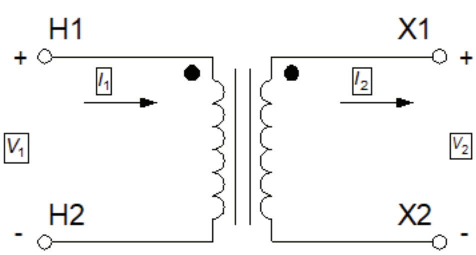
Figure 8 - Practical Transformer Model



The resistance R_c represents the core losses due to hysteresis, and inductance L_c represents the magnetizing inductance. Resistances R_1 and R_2 represent the winding resistances of winding 1 and winding 2, respectively. Inductances L_1 and L_2 represent the leakage inductances of windings 1 and 2, respectively. For quick calculations, the core losses and magnetizing inductance are often ignored, and the model is treated as an impedance in series with an ideal transformer.

To denote the proper polarity, the circuit representation for a transformer includes polarity marks as shown in Standard Transformer Symbolic Representation, page 19. If the current for one winding flows into its terminal with the polarity mark, the current for the other winding flow out of its terminal with the polarity mark. In addition, the ANSI polarity markings per *IEEE Standard Terminal Markings and Connections for Distribution and Power Transformers*[2] are shown; "H" denotes the higher voltage winding, and "X" denotes the lower voltage winding.

Figure 9 - Standard Transformer Symbolic Representation



3Φ Transformer Connections

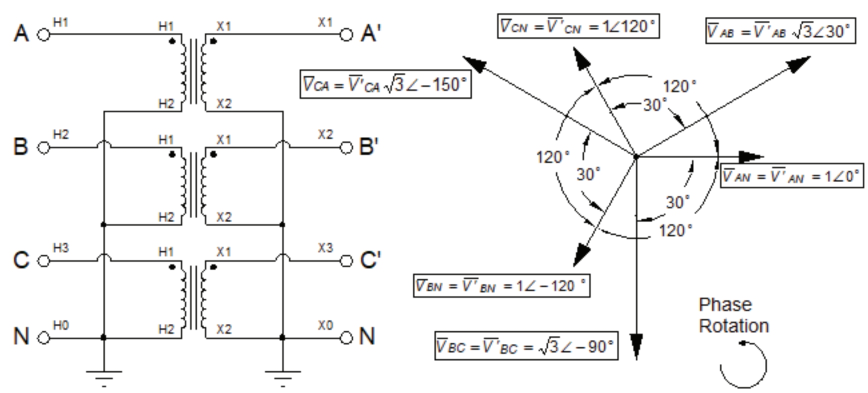
To be useful in 3Φ systems transformers must be connected for use with 3Φ voltage. This is accomplished using 3Φ transformer connections.

The wye-wye connection is shown in Wye-Wye Transformer Connection, page 20. This could be a bank of three single-phase transformers or one 3Φ transformer which consists of all three sets of windings on a common ferromagnetic core. Polarity markings for three single-phase transformer connections are shown at the individual transformers, and polarity markings for a 3Φ transformer are shown next to the A, B, C, and N terminals.

2. IEEE Std. C57.12.70-2000.

For both the primary and secondary windings the magnitude of the line-to-line voltage is equal to the magnitude of the line-to-neutral voltage multiplied by √3. For convenience, the transformer turns ratio is taken as 1:1 on the phasor diagram.

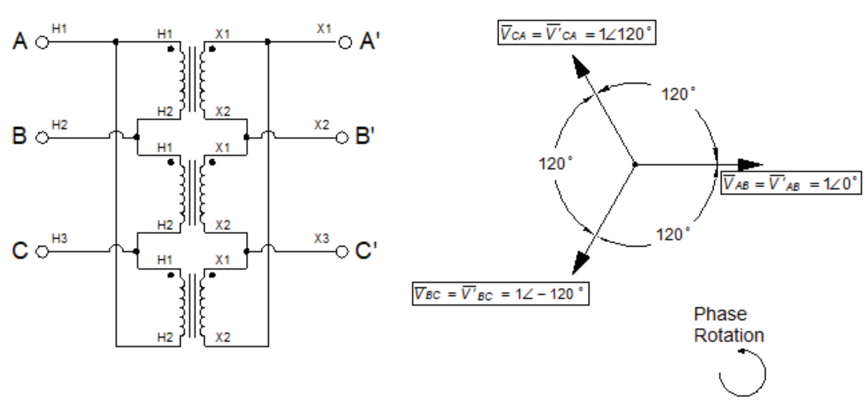
Figure 10 - Wye-Wye Transformer Connection



If a three-phase transformer is used, the wye-wye connection has the disadvantage of requiring a four-legged core to allow for a magnetic flux imbalance. Further, the solidly-grounded neutrals allow for ground currents to flow that can create interference in communications circuits (see *Electric Power Distribution System Design, New York*[3] Both the primary and secondary neutrals terminals must be solidly grounded to allow for triple-harmonic currents to flow; if the neutrals are allowed to float, harmonic overvoltages are developed from phase to neutral on each winding. These overvoltages can damage the transformer insulation. Wye-wye transformers are often used on systems above 25 kV to minimize a problem known as ferroresonance. Ferroresonance is a condition which results from the transformer magnetizing impedance resonating with the upstream cable charging capacitance, resulting in destructive overvoltages as the transformer core moves into and out of saturation in a non-linear manner. Single-phase switching is usually the cause of ferroresonance.

The delta-delta connection is shown in Delta-Delta Transformer Connection, page 20. There is no neutral on the delta-delta connection. A unique feature of this connection is that if one transformer is taken out of service, the two remaining transformers still provide three-phase service at a reduced capacity (57.7% of the capacity with all three transformers in service).

Figure 11 - Delta-Delta Transformer Connection



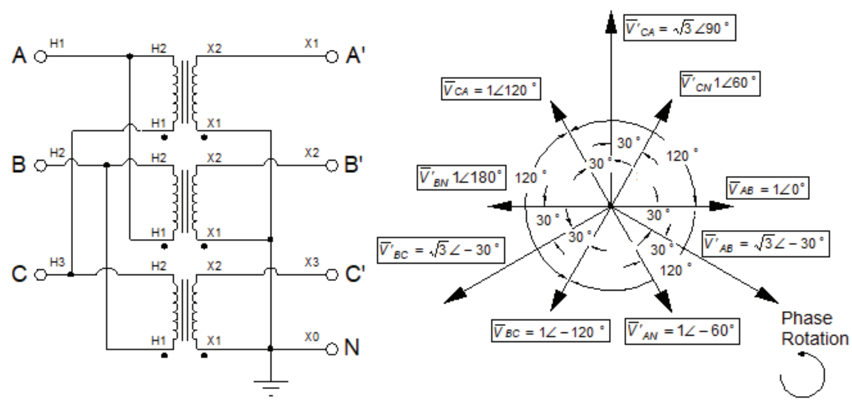
The delta-wye connection is shown in Delta-Wye Transformer Connection, page 21. Note that for the given turns ratios of 1:1 that the magnitude of the phase-to-phase

3. Turan Gonen, : McGraw-Hill, 1986, p. 137.

output voltage is equal to the magnitude of the phase-to-phase input voltage multiplied by √3. The input and output voltages of 3Φ transformers and 3Φ banks of single-phase transformers are always referenced as the phase-to-phase magnitude. Therefore, for a delta-wye transformer the winding turns ratios for each set of windings must be compensated by (1/√3) to produce the desired input-to-output voltage ratio. The phase-to-phase voltages on the lower voltage side of the transformer lag the phase-to-phase voltages on the high voltage side by 30˚. This is dictated by *IEEE Standard Terminal Markings and Connections for Distribution and Power Transformers*[4].

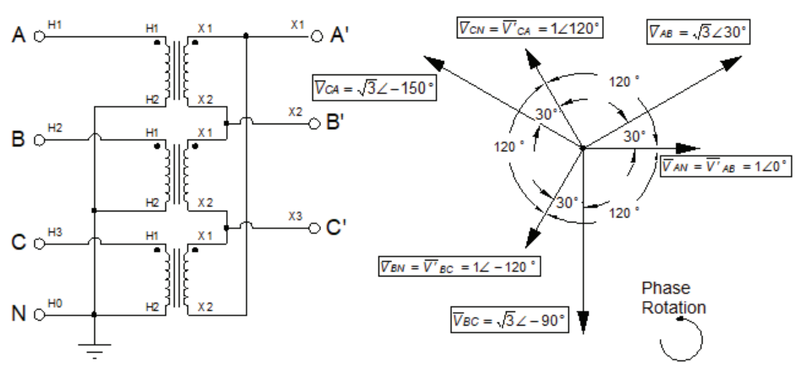
The delta-wye transformer connection is by far the most popular choice for commercial and industrial applications. 3Φ transformers do not require a four-legged core like the wye-wye connection, but the advantages of a wye secondary winding (elaborated on in System Grounding, page 51) are obtained. Further, the secondary neutral can be left unconnected in this arrangement, unlike the wye-wye arrangement.

Figure 12 - Delta-Wye Transformer Connection



The wye-delta connection is shown in Wye-Delta Transformer Connection, page 21. This connection is seldom used in commercial and industrial applications. The delta is arranged differently from the delta-wye connection, to satisfy the requirement from *IEEE Standard Terminal Markings and Connections for Distribution and Power Transformers*[4] to have the phase-to-phase voltages on the low-voltage side of the transformer lag the corresponding voltages on the primary side by 30˚.

Figure 13 - Wye-Delta Transformer Connection



4. IEEE Std. C57.12.70-2000.

Parallel Operation of Transformers

For supplying a load in excess of the rating of an existing transformer, two or more transformers may be connected in parallel with the existing transformer. The transformers are connected in parallel when the load on one of the transformers is more than its capacity. The reliability is increased with parallel operation than to have single larger unit. The cost associated with maintaining the spares is less when two transformers are connected in parallel. The most essential condition for successful parallel operation of transformers are:

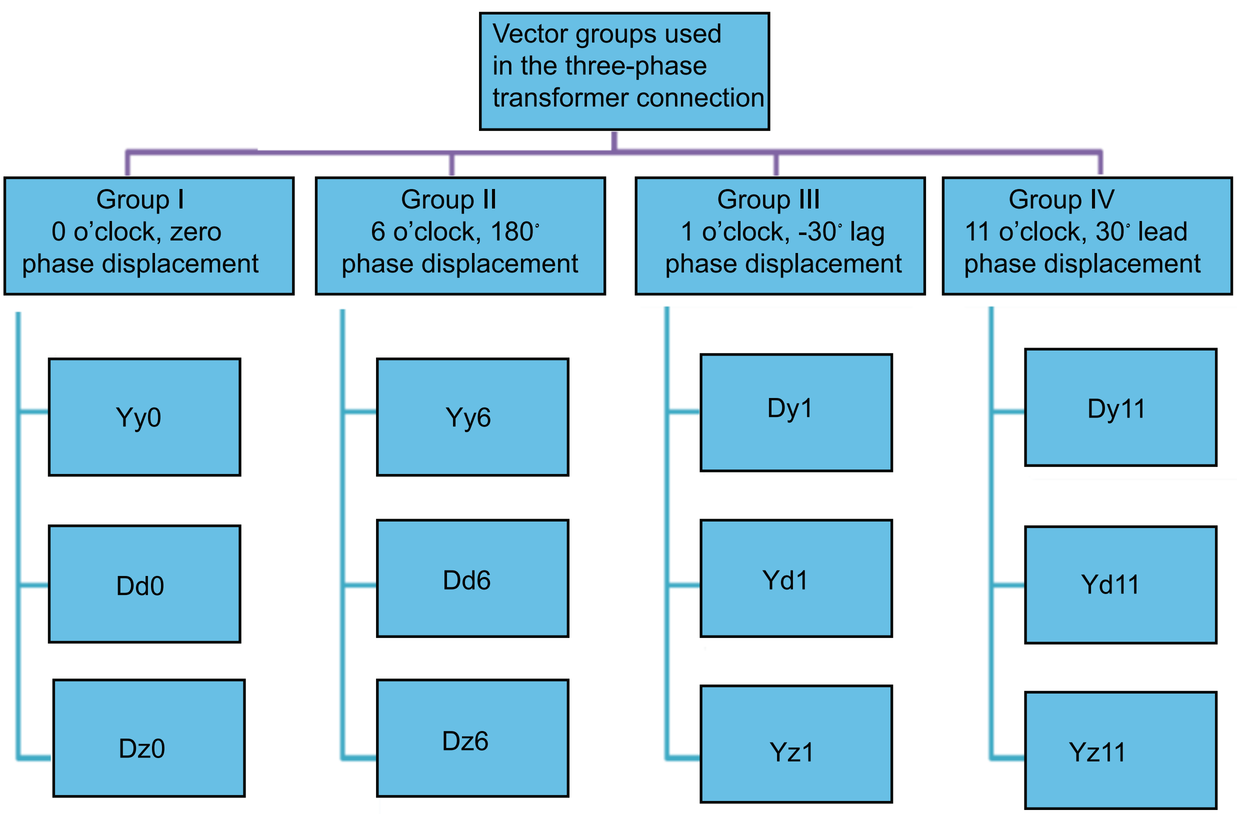
- The voltage rating of both primaries and secondaries should be identical, for example, the transformers should have the same turn ratio.
- The percentage impedances should be equal in magnitude and have the same X/R ratio to avoid circulating currents and operation in different power factor.
- The polarity of the two transformers should be the same.
- Phase sequences and phase angle shifts must be the same (for three-phase transformer).

Transformer Vector Group

The vector group is used to identify the phase shift between the primary and secondary windings. In the vector group, the secondary voltage may have the phase shift of 30° lagging or leading, 0° for example, no phase shift or 180° reversal with respect to the primary voltage.

The transformer vector group is labeled by capital and small letters plus numbers from 1 to 12 in a typical clock-like manner; the capital letter indicates primary winding and small letter represents secondary winding as shown in Transformer Vector Group Label, page 22:

Figure 14 - Transformer Vector Group Label



Basic Electrical Formulae

The following formulae are given as a convenient reference for the reader. These formulae include both formulae derived in this section and those basic formulae which are derived from basic circuit theory.

DC Circuits

$V_{dc} = I_{dc}R_{dc}$ (2–48)

$P = V_{dc} = I_{dc}I_{dc}$ (2–49)

$P = I_{dc}^2R_{dc} = V_{dc}^2/R_{dc}$ (2–50)

Where:

- V_{dc} is the DC voltage across the circuit element under consideration.
- $I_{dc}$is the current through the circuit element under consideration. $I_{dc}$is considered positive if it flows from the circuit element terminal at the higher voltage to the terminal at the lower voltage.
- $R_{dc}$is the DC resistance of the circuit element under consideration, measured in Ohms.
- P is the power dissipated or generated by the circuit element.

P is the power dissipated or generated by the circuit element. A positive power from (2-49) indicates power dissipated by the circuit element, and a negative value indicates power generated by the circuit element. The sign of P in (2-50) is lost due to the squaring of the current or voltage.

Passive Energy Storage Elements

Capacitors store energy in the form of voltage, with governing equations:

$i_c = Cdv_c/dt$ (2–51)

$E = i/2Cv_c^2$ (2–52)

Where:

- v_c is the voltage across the capacitor.
- I_c is the current through the capacitor, considered positive if it flows toward the terminal from which v_c is referenced.
- C is the capacitance value of the capacitor, measured in Farads.
- E is the energy stored in the capacitor.

Inductors store energy in the form of current, with governing equations:

$v_i = Ldi_l/dt$ (2–53)

$E = 1/2L_i^2$ (2–54)

Where:

- v_l is the voltage across the inductor.
- I_l is the current through the inductor, considered positive if it flows toward the terminal from which v_l is referenced.
- L is the inductance value of the inductor, measured in Henries.
- E is the energy stored in the inductor.

AC Voltages and Currents, Time-domain Form

Single-phase AC voltage and current can be expressed as follows:

$v(t) = V_{max}\cos(360f\bullet t + \Phi_v$ (2–55)

$i(t) = I_{max}\cos(360f\bullet t + \Phi_I$ (2–56)

Where:

- $v_t$is an AC voltage.
- I_I is an AC current.
- V_{max} is the voltage amplitude.
- I_{max} is the current amplitude.
- f is the system frequency.
- $\Phi_v$is the voltage phase shift in degrees.
- Φ_i is the current phase shift in degrees.
- t is the time in milliseconds.

All angles are measured in degrees.

If the frequency is 60 Hz, 3Φ voltages can be written as:

$$v_a(t) = V_{max}\cos(360x60xt) = V_{max}\cos(21600t) \quad (2–57)$$
$$v_b(t) = V_{max}\cos(360x60xt – 120°) = V_{max}\cos(21600t – 120°) \quad (2–58)$$
$$v_c(t) = V_{max}\cos(360x60xt +120°) = V_{max}\cos(21600t + 120°) \quad (2–59)$$

Where:

- $V_a(t)$ is the A-phase voltage.
- $V_b(t)$ is the B-phase voltage.
- $V_c(t)$ is the C-phase voltage.

The RMS value of a perfectly sinusoidal AC voltage or current is:

$$V_{rms} = V_{max}/\sqrt{2} \quad (2–60)$$
$$I_{rms} = I_{max}/\sqrt{2} \quad (2–61)$$

AC Power, Time-domain Form

The instantaneous single-phase AC power resulting from a current per (2-56) flowing through a circuit element with voltage (2-55) across it is:

$$p(t) = v(t)i(t) = V_{max}I_{max}/2[\cos(\Phi_v - \Phi_i) + co(2\pi ft + \Phi_v + \Phi_I)] \quad (2–62)$$

Where all terms are as defined for (2-54) and (2-55).

The average power in this case is:

$$P = V_{max}I_{max}/2 \cos(\Phi_v - \Phi_i) \quad (2–63)$$
$$P = V_{rms}I_{rms}\cos(\Phi_v - \Phi_i) \quad (2–64)$$

Where P is the average power.

AC Currents, Voltages and Circuit Elements, Frequency-domain Form

Assuming only the real part is kept when converting to time-domain and that the same frequency applies throughout, AC currents and voltages can be written in the frequency domain as:

$$\bar{V} = V_{rms}\angle \Phi_v \quad (2–65)$$
$$\bar{\bar{I}} = \bar{I}_{rms}\angle \Phi_I \quad (2–66)$$

Where:

- $\bar{V}$ is the AC voltage in frequency-domain form.
- $\bar{I}$ is the AC current in frequency-domain form
- Φ_v is the voltage phase shift.
- Φ_I is the current phase shift.

Capacitor and Inductor impedances in frequency domain form are:

$\bar{Z}_c = 1/j2\pi fC$ (2–67)

$\bar{Z}_l = j2\pi fL$ (2–68)

Where:

- $\bar{Z}_c$ is the impedance of the capacitor.
- $\bar{Z}_l$ is the impedance of the inductor.
- $j = \sqrt{(-1)}$.
- f is the system frequency.
- C is the capacitance of the capacitor .
- L is the inductance of the inductor.

AC voltage and current for an impedance $\bar{Z}$ are related as follows:

$\bar{V} = \bar{I} \cdot \bar{Z}$ (2–69)

Average single-phase power in AC form can be expressed as:

$\bar{S} = \bar{V} \cdot \bar{I}^*$ (2–70)

Where $\bar{S}$ is the complex power.

Complex power $\bar{S}$ can be separated into real power P and reactive power Q:

$\bar{S} = P + jQ$ (2–71)

$P = R_e\{\bar{S}\} = V_{rms}I_{rms}\cos(\Phi_v - \Phi_i)$ (2–72)

$Q = I_m\{\bar{S}\} = V_{rms}I_{rms}\sin(\Phi_v - \Phi_i)$ (2–73)

$S = |\bar{S}| = \sqrt{(P^2 + Q^2)}$ (2–74)

For 3Φ circuits the total power is the sum of the power in each phase, that is,

$\bar{S}_{3\Phi} = \bar{S}_A + \bar{S}_B + \bar{S}_C$ (2–75)

$P_{3\Phi} = P_A + P_B + P_C$ (2–76)

$Q_{3\Phi} = Q_A + Q_B + Q_C$ (2–77)

$S_{3ø} = \sqrt{P_{3ø}^2 + Q_{3ø}^2}$ (2–78)

If the current and voltage magnitudes and angles are equal for each phase, (2-76) – (2-78) can be simplified as follows by considering the power quantities per phase to be $\bar{S}_{1\Phi}$,$S_{1\Phi}$, $P_{1\Phi}$, and $Q_{1\Phi}$:

$\bar{S}_{3\Phi} = 3\bar{S}_{1\Phi}$ (2–79)

$P_{3\Phi} = 3P_{1\Phi}$ (2–80)

$Q_{3\Phi} = 3Q_{1\Phi}$ (2–81)

$S_{3\Phi} = 3S_{1\Phi}$ (2–82)

Basic Transformers

The input voltage and current V_1 and I_1 and the output voltage and current V_2 and I_2 for an ideal single-phase transformer are related as follows:

$$N_1 I_1 = N_2 I_2 \quad (2–83)$$

$$V_1/V_2 = N_1/N_2 \quad (2–84)$$

The impedance $\bar{Z}_1$at the input terminals of a transformer is related to the load impedance $\bar{Z}_2$connected to the transformer output terminals by the following equation:

$$\bar{Z}_1 = (N_1/N_2)_2\bar{Z}_2 \quad (2–85)$$

References

Because the subject matter for this section is basic and general to the subject of electrical engineering, it is included in most undergraduate textbooks on basic circuit analysis and electric machines. Where material is considered so basic as to be axiomatic no attempt has been made to cite a particular source for it.

Load Planning

Abstract: Understanding the loads connected to an electrical system is an essential consideration when designing or operating said system. Determining the size of the equipment required, including fault interrupting devices, bus bars, conductors, and similar, is not just a summation of connected load nameplates. Herein, considerations and practices are presented to facilitate load planning to ensure adequate sizing is accomplished while not over-sizing and increasing electrical system infrastructure costs. Additional information on motor characteristics, motor load, sizing requirements and motor protection are found in the *Fundamentals of Motor Control Design Guide*.

Basic Principles

The most vital, but often the last to be acquired, pieces of information for power system design are the load details. An important concept in load planning is that due to non-coincident timing, some equipment operating at less than rated load, and some equipment operating intermittently rather than continuously, the total demand upon the power source is always less than the total connected load (see *IEEE Standard Terminal Markings and Connections for Distribution and Power Transformers*[5]). This concept is known as load diversity. The following standard definitions are given in *IEEE Standard Terminal Markings and Connections for Distribution and Power Transformers*[5] and *Electric Power Distribution System Design, New York*[6]and are tools to quantify it:

Demand: The electric load at the receiving terminals averaged over a specified demand interval. of time, usually 15 min., 30 min., or one hour based upon the particular utility's demand interval. Demand may be expressed in amperes, kiloamperes, kilowatts, kilovars, or kilovolt amperes.

Demand Interval: The period over which the load is averaged, usually 15 minutes, 30 minutes, or one hour.

Peak Load: The maximum load consumed or produced by a group of units in a stated period of time. It may be the maximum instantaneous load or the maximum average load over a designated period of time.

5. IEEE Std. C57.12.70-2000.
6. Turan Gonen, : McGraw-Hill, 1986, p. 137.

Maximum Demand: The greatest of all demands that have occurred during a specified period of time such as one-quarter, one-half, or one hour. For utility billing purposes the period of time is generally one month.

Coincident Demand: Any demand that occurs simultaneously with any other demand.

Demand Factor: The ratio of the maximum coincident demand of a system, or part of a system, to the total connected load of the system, or part of the system, under consideration, that is:

Demand Factor (DF) = Maximum coincident demand/Total connected load. (3–1)

Diversity Factor: The ratio of the sum of the individual maximum demands of the various subdivisions of a system to the maximum demand of the whole system, that is:

$$\text{Diversity Factor } F_D = \frac{\sum_{i=1}^{n} D_i}{D_G} \quad (3\text{–}2)$$

Where:

- D_i = maximum demand of load i, regardless of time of occurrence.
- D_g = coincident maximum demand of the group of n loads.

Using (1), the relationship between the diversity factor and the demand factor is:

$$F_D = \frac{\sum_{i=1}^{n} (TCL_i \times DF_i)}{D_G} \quad (3\text{–}3)$$

Where:

- TCL_i = total connected load of load group i.
- DF_i = the demand factor of load group i.

Load Factor: The ratio of the average load over a designated period of time to the peak load occurring in that period, that is:

Load Factor (LF) = Average load/Peak load (3–4)

If T is the designated period of time, an alternate formula for the load factor may be obtained by manipulating (3-4) as follows:

Load Factor (LF) = Average load x T/ Peak load x T = Average energy/Peak load x T (3–5)

These quantities must be used with each type of load to develop a realistic picture of the actual load requirements if the economical sizing of equipment is to be achieved. Further, they are important to the utility rate structure (and thus the utility bill).

As stated in *Electric Power Distribution System Design, New York*[7], the following must be considered in this process:

- Load Development/Build-up Schedule: Peak load requirements, temporary/ construction power requirements, and timing.
- Load Profile: Load magnitude and power factor variations expected during low-load, average load, and peak load conditions.
- Expected Daily and Annual Load Factor.
- Large motor starting requirements.
- Special or unusual loads such as resistance welding, arc welding, induction melting, induction heating.
- Harmonic-generating loads such as variable-frequency drives, arc discharge lighting.
- Forecasted load growth over time.

Reference *IEEE Recommended Practice for Electric Power Systems in Commercial Buildings*[8]: and individual engineering experience on previous projects are both useful in determining demand factors for different types of loads. In addition, the *National Electrical Code*® [9] gives minimum requirements for the computation of branch circuit, feeder, and service loads.

NEC Basic Branch Circuit Requirements

NEC *National Electrical Code*® [9] Article 220 gives the basic requirements for load calculations for branch circuits, feeders, and services. To understand these requirements, the basic NEC definitions of branch circuit, feeder, and service must be understood, along with several other key terms:

Branch Circuit: The means to carry electric power from the final overcurrent device protecting the circuit to the outlets and equipment in residential, commercial, and industrial locations.

Feeder: All circuit conductors between the service equipment, the source of a separately derived system, or other power supply source and the final branch-circuit overcurrent device.

Service: The conductors and equipment for delivering electric energy from the serving utility to the wiring system of the premises served.

Outlet: The point on the wiring system at which current is taken to supply utilization equipment.

Receptacle: A receptacle is a contact device installed at the outlet for the connection of an attachment plug. A single receptacle is a single contact device with no other contact device on the same yoke. A multiple receptacle is two or more contact devices on the same yoke.

Continuous Load: A load where the maximum current is expected to continue for three hours or more. For example, a single-phase 120 V circuit feeding an open-office lighting load (continuous) of 1,000 VA and a small cooling unit's condensate pump load (non-continuous) of 100 VA.

The NEC definition of Demand Factor is essentially the same as given above, so the points below must be considered when calculating the Demand Factor.

Minimum lighting load (Article 220.12): Minimum lighting load must not be less than as specified in Table 1 (NEC Table 220.12). Motors rated less than 1/8 HP and connected to a lighting circuit shall be considered general lighting load.

7. Turan Gonen, : McGraw-Hill, 1986, p. 137.
8. IEEE Standard 241-1990, December 1990.
9. NFPA 70, The National Fire Protection Association, Inc., 2020 Edition.

Table 1 - General Lighting Loads by Non-dwelling Occupancy

Type of Occupancy	Unit Load	
	VA/ m^2	VA/ $ft.^2$
Automotive facility	16	1.5
Convention center	15	1.4
Courthouse	15	1.4
Dormitory	16	1.5
Exercise center	15	1.4
Fire station	14	1.3
Gymnasium[10]	18	1.7
Health care clinic	17	1.6
Hospital	17	1.6
Hotels and motels, including apartment houses without provisions for cooking by tenants[11]	18	1.7
Library	16	1.5
Manufacturing facility[12]	24	2.2
Motion picture theater	17	1.6
Museum	17	1.6
Office[13]	14	1.3
Parking garage[14]	3	0.3
Penitentiary	13	1.2
Performing arts theater	16	1.5
Police station	14	1.3
Post office	17	1.6
Religious facility	24	2.2
Restaurant[15]	16	1.5
Retail[16, 17]	20	1.9
School/university	33	3
Sports arena	33	3
Town hall	15	1.4
Transportation	13	1.2
Warehouse	13	1.2
Workshop	18	1.7

NOTE: The 125% multiplier for a continuous load as specified in 210.20(A) is included when using the unit loads in this table for calculating the minimum lighting load for a specified occupancy.

Motor Loads (Article 220.14(C)): Motor loads must be calculated in accordance with Articles 430.22, 430.24, and 440.6, summarized as follows:

- The full load current rating for a single motor used in a continuous duty application is 125% of the motor's full-load current rating as determined by Article 430.6, which refers to horsepower/ ampacity Tables 430.247, 430.248, 430.249, or 430.250 as appropriate (Article 430.22).

10. Armories and auditoriums are considered gymnasium-type occupancies.
11. Lodge rooms are similar to hotels and motels.
12. Industrial commercial loft buildings are considered manufacturing-type occupancies.
13. Banks are office-type occupancies.
14. Garages — commercial (storage) are considered parking garage occupancies.
15. Clubs are considered restaurant occupancies.
16. Barber shops and beauty parlors are considered retail occupancies.
17. Stores are considered retail occupancies.

- The load calculation for several motors, or a motor(s) and other loads, is 125% of the full load current rating of the highest rated motor per a.) in Table 1 plus the sum of the full-load current ratings of all the other motors in the group, plus the ampacity required for the other loads (Article 430.24).
- For hermetic refrigerant motor compressors or multi-motor equipment employed as part of air conditioning or refrigerating equipment, use the equipment nameplate rated load current instead of the motor horsepower rating (Article 440.6).

Luminaires (lighting fixtures) (Article 220.14(D)): Calculate an outlet supplying luminaire(s) based on the maximum VA rating of the equipment and lamps for which the luminaire(s) is rated.

Heavy-duty Lampholders (Article 220.14(E)): Calculate loads for heavy-duty lampholders at a minimum of 600 VA.

Sign and Outline Lighting (Article 220.14(F)): Calculate sign and outline lighting loads at a minimum of 1200 VA for each required branch circuit specified in article 600.5(A).

Show Windows (Article 220.14(G)): Calculate show windows in accordance with either:

- The unit load per outlet as required in other provisions of article 220.14.
- 200 VA per 300 millimeters (one foot) of show window.

Loads for Fixed Multi-outlet Assemblies: Calculate these in other than dwelling units or the guest rooms and guest suites of hotels or motels as follows (Article 220.14 (H)):

- Where simultaneous use of appliances is unlikely, each 1.5 meters (five feet.) or fraction thereof of each separate and continuous length, must be considered as one outlet of 180 VA.
- Where simultaneous use of appliances is unlikely, each 300 millimeters (1 foot) or fraction thereof must be considered as an outlet of 180 VA.

Receptacle Outlets (Articles 220.14(I), 220.14(J), 220.14(K), 220.14(L)): Loads for these are calculated as follows:

- Dwelling occupancies (Article 220.14(J)): In one-family, two-family, and multifamily dwellings, the minimum unit load shall be not less than 33 VA/m^2 (3 VA/ft^2). The lighting and receptacle outlets specified in 220.14(J)(1), (J)(2), and (J)(3) are included in the minimum unit load. No additional load calculations are required for such outlets. The minimum lighting load is determined using the minimum unit load and the floor area as determined in 220.11 for dwelling occupancies. Motors rated less than 1⁄8 hp and connected to a lighting circuit are considered part of the minimum lighting load.

  (1) All general-use receptacle outlets of 20 A rating or less, including receptacles connected to the circuits in 210.11(C)(3) and 210.11(C)(4).

  (2) The receptacle outlets specified in 210.52(E) and (G).

  (3) The lighting outlets specified in 210.70.
- Office buildings (Article 220.14(K)): Calculate receptacle outlets to be the larger of either the calculated value per c.) below or 11 VA/m^2 (one VA/per square foot).
- All other receptacle outlets (Article 220.14(I)): Calculate each receptacle on one yoke as 180 VA. Calculate a multiple receptacle consisting of four or more receptacles at 90 VA per receptacle.

Sufficient Branch Circuits: Incorporate sufficient branch circuits into the system design to serve the loads per Article 220.10 (summarized 1.) – 8.) above), along with branch circuits for any specific loads not covered in Article 220.10. Determine the total number of branch circuits from the calculated load and the size or rating of the branch circuits used. Evenly proportion the load among the branch circuits (Article 210.11(C)). In addition, Article 210.11(C) requires several dedicated branch circuits as follows for dwelling units:

- Two or more 20 A small-appliance branch circuits (Article 210.11(C)(1)).

- One or more 20 A laundry branch circuits (Article 210.11(C)(2)).
- One or more bathroom branch circuits (Article 210.11(C)(3)).

Continuous Loads (Article 210.20): The branch circuit overcurrent protection must be at least the sum of the non-continuous load + 125% of the continuous load, unless the overcurrent device is 100%-rated. Because the overcurrent protection rating determines the rating of the branch circuit (Article 210.3), the branch circuit must be sized for the non-continuous load + 125% of the continuous load. In load calculations, continuous loads should therefore be multiplied by 1.25 unless the circuit overcurrent device is 100% rated. Motor loads are not included in this calculation as the 125% factor is already included in the applicable sizing per above.

NEC Basic Feeder Circuit Sizing Requirements

Once the branch circuit loads are calculated, the feeder circuit loads may be calculated by applying demand factors to the branch circuit loads, so the points below must be considered when calculating the Demand Factor.

General Lighting Loads (Article 220.42): Calculate the feeder general lighting load by multiplying the branch circuit general lighting load calculated per the first bullet of **Motor Loads (Article 220.14(C))** in NEC Basic Branch Circuit Requirements, page 28, for those branch circuits supplied by the feeder, by a demand factor per Table 2 (NEC Table 220.42). The demand factors specified in Table 220.42 apply to that portion of the total branch-circuit load calculated for general illumination. They do not be applied in determining the number of branch circuits for general illumination.

Table 2 - Lighting Load Feeder Demand Factors

Type of Occupancy	Portion of Lighting Load to Which Demand Factor Applies VA/	Demand Factor (%)
Dwelling units	First 3000 at From 3001 to 120,000 at Remainder over 120,000 at	100 35 25
Hotels and motels, including apartment houses without provision for cooking by tenants[18]	First 20,000 or less at From 20,001 to 100,000 at Remainder over 100,000 at	60 50 35
Warehouses (storage)	First 12,500 or less at Remainder over 12,500 at	100 50
All others	Total VA	100

The National Electrical Code.[19]

- **Show Window or Track Lighting (Article 220.43):** Show windows must use a calculated value of 660 VA per linear meter (200 VA per linear foot), measured horizontally along its base. Track lighting in other than dwelling units must be calculated at an 150 VA per 660 millimeters (two feet) of lighting track or fraction thereof. Where multi-circuit track is installed, the load is divided equally between the track circuits.
- **Receptacles in Other than Dwelling Units (Article 220.44):** Demand factors for non-dwelling receptacle loads are given in Table 3 (NEC Table 220.44) and Table 2 (NEC Table 220.42).

18. The demand factors of this table shall not apply to the calculated load of feeders or services supplying areas in hotels and motels where the entire lighting is likely to be used at one time, as in ballrooms or dining rooms.
19. The National Fire Protection Association, Inc., 2020 Edition.

Table 3 - Demand Factors for Non-dwelling Receptacle Loads

Portion of Lighting Load to Which Demand Factor Applies VA	Demand Factor (%)
First 10 kVA or less at	100
Remainder over 10 kVA at	50

The National Electrical Code[20]

Motors (Article 220.50): Motor loads shall be calculated in accordance with 430.24, 430.25, and 430.26. The feeder demands for these are calculated as follows:

- The load calculation for several motors, or a motor(s) and other loads, is 125% of the full load current rating of the highest rated motor per the second bullet of **Motor Loads (Article 220.14(C))** in NEC Basic Branch Circuit Requirements, page 28 plus the sum of the full-load current ratings of all the other motors in the group, plus the ampacity required for the other loads (Article 430.24).
- Base the load calculation for factory-wired multimotor and combination-load equipment on the minimum circuit ampacity marked on the equipment (Article 430.25) instead of the motor horsepower rating.
- Where allowed by the authority having jurisdiction, feeder demand factors may be applied based on the duty cycles of the motors. No demand factors are given in the NEC for this situation.

Fixed Electric Space Heating (Article 220.51): Calculate the feeder loads for these at 100% of the connected load. However, in no case shall a feeder or service load current rating be less than the rating of the largest branch circuit supplied.

Noncoincident Loads (Article 220.60): While unlikely that two or more non-coincident loads will be in use simultaneously, it is permissible to use only the largest loads for use at one time in calculating the feeder demand.

Feeder neutral load (Article 220.61): The feeder neutral load is defined as the maximum load imbalance on the feeder. The maximum load imbalance for three-phase four-wire systems is the maximum net calculated load between the neutral and any one ungrounded conductor. A service or feeder supplying the following loads such as a feeder or service supplying household electric ranges, wall-mounted ovens, counter-mounted cooking units, and electric dryers and the unbalanced load in excess of 200 A shall be permitted to have an additional demand factor of 70%. Refer to NEC article 220.61 for neutral reductions in systems other than three-phase, four-wire systems. This demand factor does not apply to non-linear loads; in fact, it may be necessary to oversize the neutral due to the current flow from non-linear load triple harmonics.

Continuous Loads (Article 215.3): The rating of the overcurrent protection for a feeder circuit must be at least the sum of the non-continuous load + 125% of the continuous load, unless the overcurrent device is 100%-rated. Because the rating of the overcurrent protection determines the rating of the branch circuit (Article 210.3), size the branch circuit for the non-continuous load + 125% of the continuous load. In the final feeder circuit load calculation, the continuous portion of the load should therefore be multiplied by 1.25, unless the overcurrent device for the circuit is 100%-rated. Motor loads are not included in this calculation as the 125% factor is already included in the applicable sizing per above.

Additional calculation data is given in *NEC Article 220* for dwelling units, restaurants, schools, and farms. This data is not repeated here.

As this guide only presents the basic NEC requirements for load calculations, it is imperative to refer to the NEC itself when in doubt about a specific load sizing application. Computer programs are commercially available to automate the calculation of feeder and branch circuit loads per the NEC methodology described above.

20. The National Fire Protection Association, Inc., 2020 Edition.

System Voltage Considerations

Abstract: In addition to factors such as load planning, system voltage selection is a fundamental aspect of electrical system design. The utilization voltage of equipment can be accomplished with various distribution system voltages. Typical considerations include utility connections, rate tariffs, distances to loads, costs and others. Selecting the appropriate system voltage allows efficiencies while managing the capital and maintenance expenditures.

Basic Principles

The selection of system voltages is crucial to successful power system design. Reference *American National Standard Preferred Voltage Ratings for Electric Power Systems and Equipment (60Hz)*[21] lists the standard voltages for the United States and their ranges. The nominal voltages from *American National Standard Preferred Voltage Ratings for Electric Power Systems and Equipment (60Hz)*[21] are given in Standard Nominal Three-phase System Voltages per ANSI C84.1-1989, page 33.

ANSI C84.1-1989 divides system voltages into “voltage classes”. Voltages 600 V and below are referred to as “low voltage”, voltages from 600 V - 69 kV are referred to as “medium voltage”, voltages from 69 kV - 230 kV are referred to as “high voltage”, and voltages 230 kV - 1,100 kV are referred to as “extra high voltage”, with 1,100 kV also referred to as “ultra-high voltage”. The emphasis of this guide is on low- and medium-voltage distribution systems.

Table 4 - Standard Nominal Three-phase System Voltages per ANSI C84.1-1989

Volatge Class	Three-Wire	Four-Wire
Low Voltage	240 480 600	208Y/120 240/120 480Y/277
Medium Voltage	2,400 4,160 4,800 13,800 23,000 34,500 46,000 69,000	4,160Y/2400 8,320Y/4800 12,000Y/6,930 12,470Y/7,200 13,200Y/7,620 13,800Y/7,970 20,780Y/12,000 22,860Y/13,200 24,940Y/14,400 34,500Y/19,920
High Voltage	115,000 138,000 161,000 230,000	—
Extra-High Voltage Ultra-High Voltage	345,000 500,000 765,000 1,100,000	—

The choice of service voltage is limited to those voltages that the serving utility provides. In most cases, only one choice of electrical utility is available, and thus only one choice of service voltage. As the power requirements increase, so to does the likelihood that the utility will require a higher service voltage for a given installation. In some cases, a choice may be given by the utility as to the service voltage desired, in which case an analysis of the various options is required to arrive at the correct choice. In general, the higher the service voltage the more expensive the equipment required to accommodate it is. Maintenance and installation costs also increase with increasing service voltage. However, equipment such as large motors may require a

21. ANSI C84.1-1989.

service voltage of 4160 V or higher, and, further, service reliability tends to increase at higher service voltages.

Another factor to consider regarding service voltage, is the voltage regulation of the utility system. Voltages defined by the utility as “distribution” should, in most cases, have adequate voltage regulation for the loads served. Voltages defined as “subtransmission” or “transmission”, however, often require the use of voltage regulators or load-tap changing transformers at the service equipment to give adequate voltage regulation. This situation typically only occurs for service voltages above 34.5 kV, however it can occur on voltages between 20 kV and 34.5 kV. When in doubt, consult the serving utility.

The utilization voltage is determined by the requirements of the served loads. For most industrial and commercial facilities this is 480Y/277 V, although 208Y/120 V is also required for convenience receptacles and small machinery. Large motors may require 4160 V or higher. Distribution within a facility may be 480Y/277 V or, for large distribution systems, medium-voltage distribution may be required. Medium-voltage distribution implies a medium-voltage (or higher) service voltage, and results in higher costs of equipment, installation, and maintenance than low-voltage distribution. However, this must be considered along with the fact that medium-voltage distribution generally results in smaller conductor sizes and makes control of voltage drop easier.

Power equipment ampacity limitations impose practical limits on the available service voltage to serve a given load requirement for a single service, as shown in Equipment Design Limits to Service Voltage vs. Load Requirements, for a Single Service, page 35.

Voltage Drop Considerations

Because all conductors exhibit an impedance to the flow of electric current, the voltage is constant throughout the system, but tends to drop closer to the load. Ohm’s Law, expressed in phasor form for AC circuits, gives the basic relationship for voltage drop vs. the load current:

$$\bar{V}_{drop} = \bar{I}_l \times \bar{Z}_{cond} \tag{4–1}$$

Where:

- $\bar{V}_{drop}$ is the voltage drop along a length of conductor or across a piece of equipment in V,
- $\bar{I}_l$ is the load current in A, and
- $\bar{Z}_{cond}$ is the conductor or equipment impedance, in Ohms.

Thus, the larger the load current and larger the conductor impedance, the larger the voltage drop. Unbalanced loads, of course, give an unbalanced voltage drop, which leads to an unbalanced voltage at the utilization equipment.

Section 210.19(A) – branch circuits – Informational Note N° 3 recommends the voltage drop at the farthest outlet of power, heating, and lighting, or combination of such loads, to three percent of the applied voltage. Alternatively, the maximum combined voltage drop on the feeder and branch circuits to the farthest outlet should be five percent.

Section 215.2(A)(1) – feeders – Informational Note N° 2 has the same recommendations for feeders.

Those statements mean that the feeder could have a one percent voltage drop if the branch circuit had no more than four percent. Also, limiting the branch circuit voltage drop to three percent allows a two percent drop in the feeder. These or any other combinations of feeder and branch circuit voltage drops not exceeding a total of five percent are adequate.

A voltage drop of five percent or less from the utility service to the most remotely-located load is recommended by NEC article 210.19(A)(1), FPN No. 4. Because this is a note only, it is not a requirement per se but is the commonly accepted guideline.

Table 5 - Equipment Design Limits to Service Voltage vs. Load Requirements, for a Single Service

Voltage (V)	Equipment Type	Maximum Equipment Ampacity (A)	Maximum Load (kVA)
208 480 600	Switchboard or Low-Voltage Power Switchgear	5000	1,800 4,157 5,196
2,400 4,160 4,800	Metal-Enclosed Switchgear, w/Fuses	1080	4,489 7,782 8,979
6,900 8,320 12,000 12,470 13,200 13,800		720	8,605 10,376 14,965 15,551 16,461 17,210
20,780 22,860 23,000 24,940		175	6,299 6,929 6,972 7,560
34,500		115	6,872
2,400 4,160 4,800 6,900 8,320 12,000 12,470 13,200 13,800	Metal-Clad Switchgear	3000	12,471 21,616 24,942 38,853 43,232 62,354 64,796 68,589 71,707
20,780 22,860 23,000 24,940		2000	71,984 79,189 79,674 86,395

Because conductor impedance increases with the length of the conductor, unless the power source is close to the center of the load, the voltage varies across the system, and, further, it can be more costly to maintain the maximum voltage drop across the system to within five percent of the service voltage since larger conductors must be used to offset longer conductor lengths.

Also, from equation (4-1) as load changes, so does the voltage drop. For a given maximum load, a measure of this change at a given point is the voltage regulation, defined as:

$$\text{Voltage Regulation} = |\bar{V}_{no\ load}| - |\bar{V}_{load}| / |\bar{V}_{load}| \times 100\% \qquad (4\text{–}2)$$

Where:

- $\bar{V}_{no\ load}$ is the voltage, at a given point in the system, with no load current flowing from that point to the load.
- $\bar{V}_{load}$ is the voltage, at the same point in the system, with full load current flowing from that point to the load.

Another source of concern when planning for voltage drop is the use of power-factor correction capacitors. Because these serve to reduce the reactive component of the load current, they also reduce the voltage drop per equation (4-1).

Both low and high voltage conditions, and voltage imbalance, have an adverse effect on utilization equipment (see *IEEE Recommended Practice for Electric Power Distribution for Industrial Plants*[22] for additional information). Voltage drop must therefore be considered during power system design to avoid future problems.

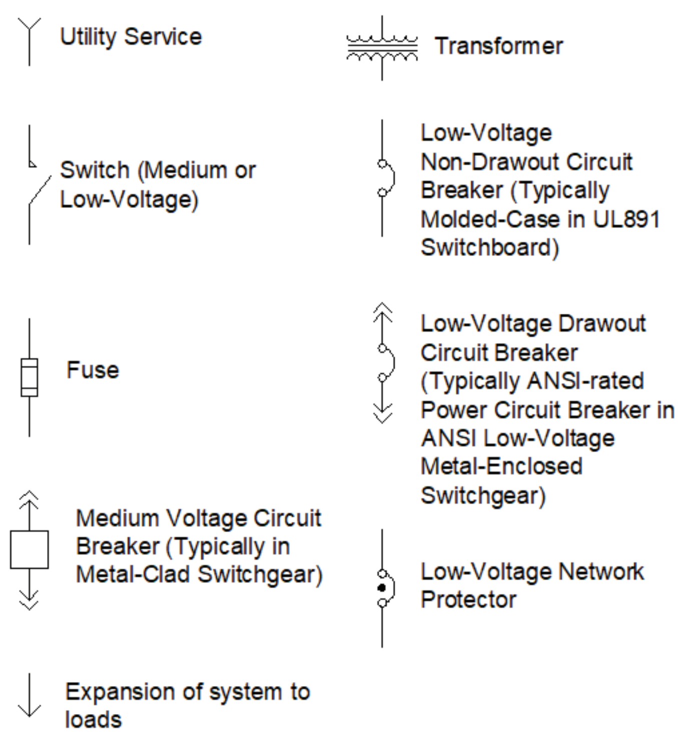
System Arrangements

Abstract: The electrical point of interconnection with a utility can vary in voltage level whether it be secondary, primary, or transmission voltages. The reliability of an electrical system is directly affected by the system arrangement and the voltage level to which it is connected. Additionally, the need for redundancy or serviceability without a complete shutdown are also considerations when evaluating various system arrangements.

Introduction

The selection of system arrangement has a profound impact upon the reliability and maintainability of the system. Several commonly used system topologies are presented here, along with the pros and cons of each. The figures for each of these assume that the distribution and utilization voltage are the same, and that the service voltage differs from the distribution/utilization voltage. The symbology (low voltage circuit breaker, low-voltage drawout circuit breaker, medium voltage switch, medium voltage breaker) reflects the most commonly-used equipment for each arrangement. The symbology used throughout this section is shown in Symbology, page 36.

Figure 15 - Symbology



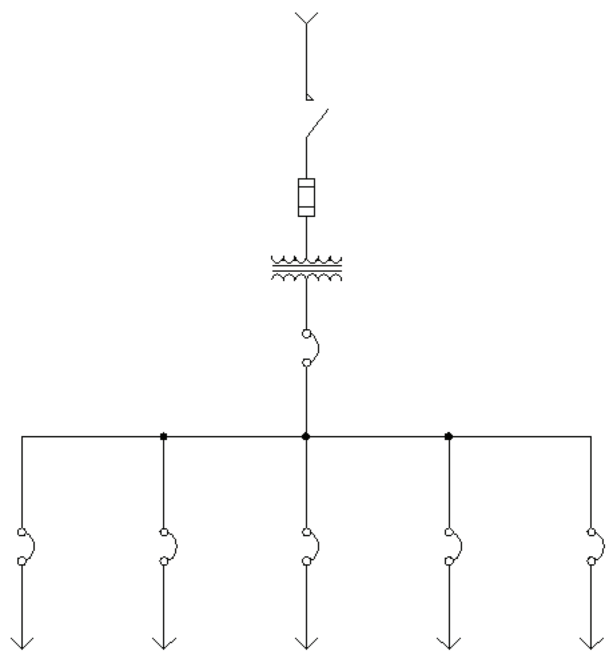
22. EEE Standard 141-1993, December 1993.

Radial System

The radial system is the simplest system topology and is shown in Radial System, page 37. It is the least expensive in terms of equipment first cost. However, it is also the least desirable since it incorporates only one utility source and the loss of the utility source, transformer, or the service or distribution equipment results in a loss of service. Further, the loads must be shut down to perform maintenance on the system. This arrangement is most used where the need for low first-cost, simplicity, and space economy outweigh the need for enhanced reliability.

Typical equipment for this system arrangement is a single unit substation consisting of a fused primary switch, a transformer of sufficient size to supply the loads, and a low-voltage switchboard.

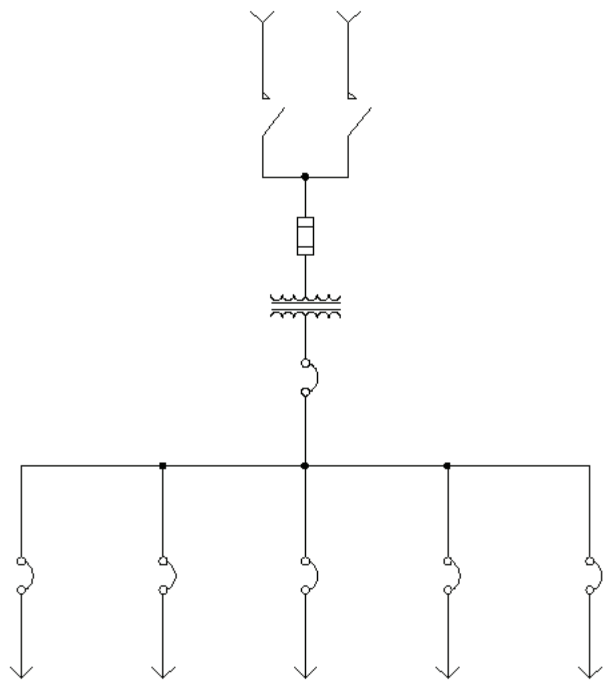
Figure 16 - Radial System



Radial System with Primary Selectivity

This arrangement is shown in Radial System with Primary Selectivity, page 38. If two utility sources are available, it provides almost the same economic advantages of the radial system in Radial System, page 37 but also gives greater reliability since the loss of one utility source does not result in a loss of service (An outage occurs between the loss of the primary utility source and switching to the alternate source unless the utility allows paralleling of the two sources). The loss of the transformer or of the service or distribution equipment still results in a loss of service. System maintenance requires shut down all loads.

Figure 17 - Radial System with Primary Selectivity



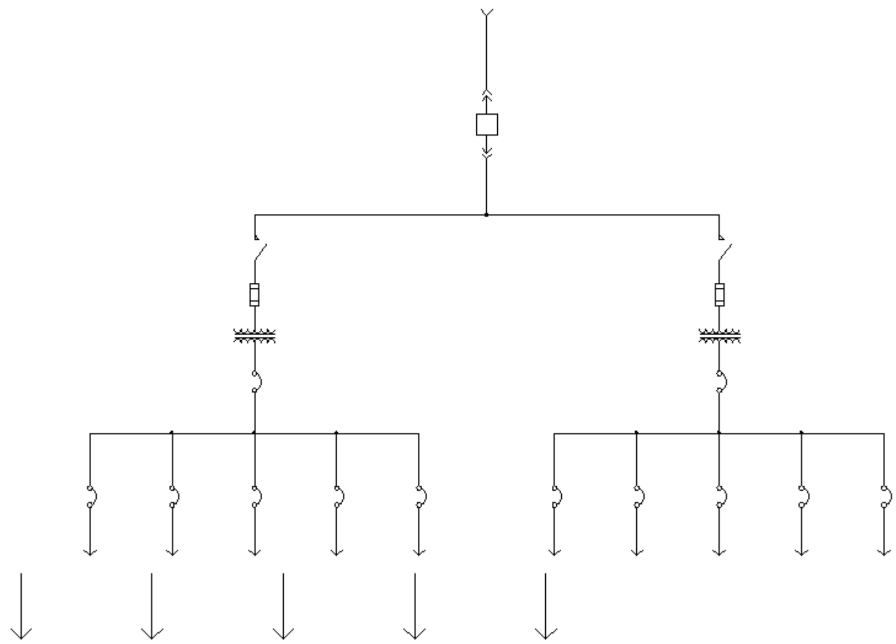
An automatic transfer scheme may optionally be provided between the two primary switches to automatically switch from an offline utility source to an available source. Most often metal-clad circuit breakers are used, rather than metal-enclosed switches. More about typical equipment application guidelines follows in a subsequent section of this guide.

Expanded Radial Systems

The radial systems shown in Radial System, page 37 and Radial System with Primary Selectivity, page 38 can be expanded by the inclusion of additional transformers. Further, these transformers can be located close to the center of each group of loads to minimize voltage drop. Reliability increases with a larger number of substations since the loss of one transformer does not result in a loss of service for all the loads.

Expanded Radial System with One Utility Source and a Single Primary Feeder, page 39 shows an expanded radial system utilizing multiple substations, but still with only one utility source and only one primary feeder.

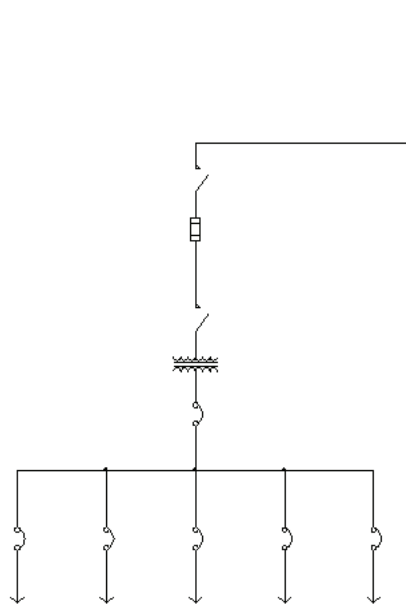
Figure 18 - Expanded Radial System with One Utility Source and a Single Primary Feeder



A more dependable and maintainable arrangement utilizing multiple primary feeders is shown in Expanded Radial system with One Utility Source and Multiple Primary Feeders, page 40. In the system shown in Expanded Radial system with One Utility Source and Multiple Primary Feeders, page 40, each unit substation is supplied by a dedicated feeder from the service entrance switchgear. Each substation is also equipped with a primary disconnect switch to allow isolation of each feeder on both ends for maintenance purposes.

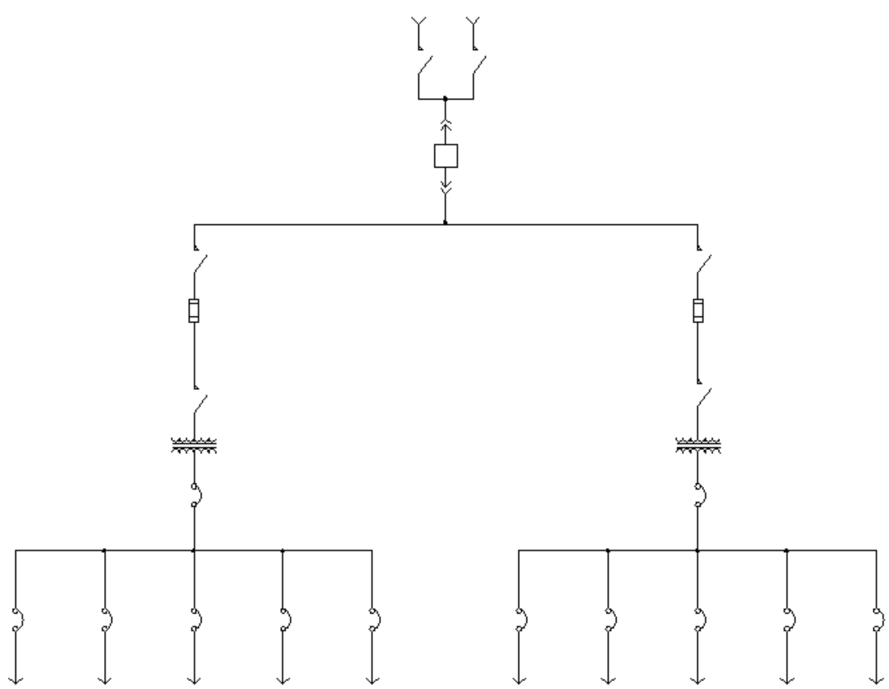
Typical service entrance equipment consists of a metal-clad switchgear main circuit breaker and metal-enclosed fused feeder switches. Metal-clad circuit breakers may be used instead of metal-enclosed feeder switches if required.

Figure 19 - Expanded Radial system with One Utility Source and Multiple Primary Feeders



Expanded Radial System with Two Utility Sources and Multiple Primary Feeders, page 40 shows an expanded radial system utilizing multiple substations and two utility sources, again with metal-clad primary switchgear but with a duplex metal-enclosed switchgear for utility source selection.

Figure 20 - Expanded Radial System with Two Utility Sources and Multiple Primary Feeders



Of the arrangements discussed this far, the arrangement of Expanded Radial System with Two Utility Sources and Multiple Primary Feeders, page 40 is the most dependable; it does not rely on a single utility source for system availability, nor does the loss of one transformer or feeder cause a loss of service to the entire facility.

However, the loss of a transformer or feeder results in the loss of service to a part of the facility. More dependable system arrangements are required if this is to be avoided.

Loop Systems

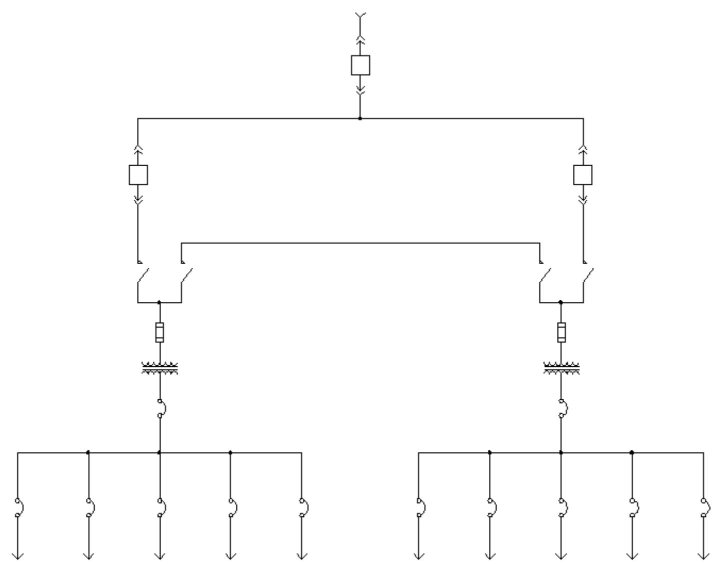
The loop system arrangement is one of several arrangements that allows one system component, such as a transformer or feeder cable, to fail without causing a loss of service to a part of the facility.

Primary Loop System, page 41 shows a primary loop arrangement. The advantages of this arrangement over previously mentioned arrangements are that a loss of one feeder cable does not cause one part of the facility to experience a loss of service and that one feeder cable can be maintained without causing a loss of service (An outage to part of the system is experienced after the loss of a feeder cable until the loop is switched to accommodate the loss of the cable).

In Primary Loop System, page 41 metal-clad circuit breakers are used as the feeder protective devices. Fused metal-enclosed-feeder switches could be utilized for this, but take care if this is considered since the feeder fuses must be able to serve both transformers and the feeder and transformer fuses have to coordinate for maximum selectivity.

The system arrangement of Primary Loop System, page 41 is designed to operate with the loop open, for example, one of the four loop switches shown would be normally-open. If closed-loop operation were required, use metal-clad circuit breakers instead to provide maximum selectivity (this arrangement is discussed further below). Momentary paralleling to allow maintenance of one section of the loop without causing an outage to one part of the facility can be accomplished with metal-enclosed loop switches, however, caution is necessary in the system design and maintenance.

Figure 21 - Primary Loop System



Secondary Selective Systems

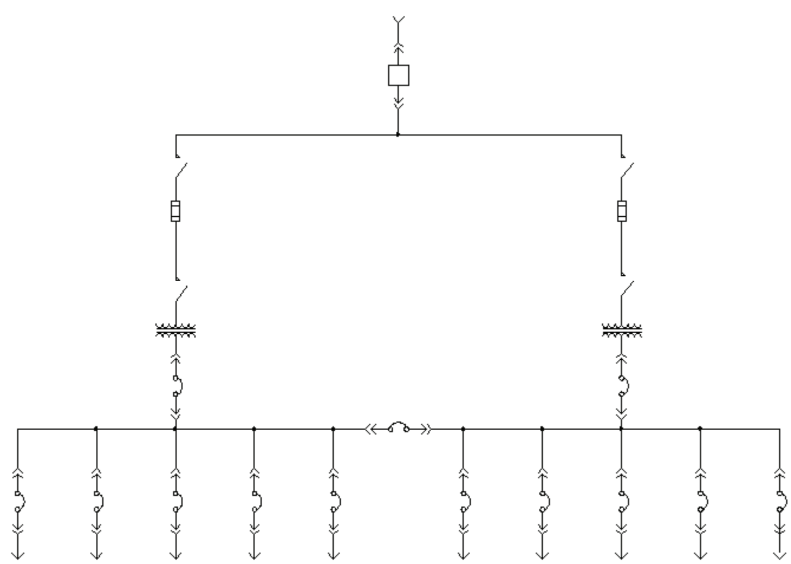
Another method of allowing the system to remain in service after the loss of one component is the secondary-selective system. Secondary-selective System, page 42 shows such an arrangement.

The system arrangement of Secondary-selective System, page 42 has the advantage of allowing for the loss of one transformer without causing a loss of service to one part of the plant. This is a characteristic none of the previously mentioned system arrangements exhibit. The system can be run with the secondary bus tie breaker normally-open or normally-closed. If the bus tie breaker is normally-closed the loss of one transformer, if directional overcurrent relays are supplied on the transformer secondary main circuit breakers, does not cause an outage. However take care must in the system design as the available fault current at the secondary switchgear can be doubled in this case.

Typical equipment for this arrangement is low-voltage power circuit-breaker switchgear with drawout circuit breakers, both for reasons of coordination and maintenance. However, a low-voltage switchboard may be utilized if care is taken in the system design and the system coordination is achievable. For a normally-closed bus tie breaker, low-voltage power switchgear is essential since the breakers lend themselves more readily to external protective relaying.

The loss of transformer means the other transformer and its associated secondary main circuit must carry the entire load. Consider this in sizing the transformer and secondary switchgear for the effectiveness of this type of system.

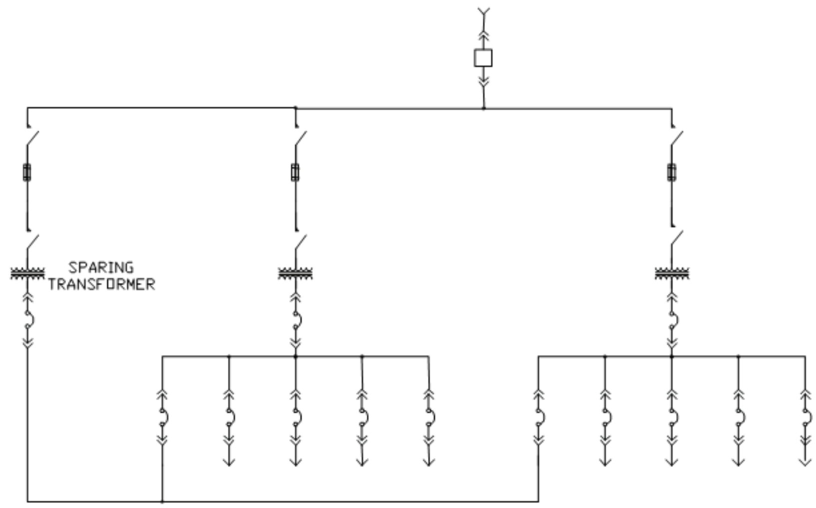
Figure 22 - Secondary-selective System



A larger-scale version of the secondary selective system is the transformer sparing scheme, shown in Transformer Sparing Scheme, page 43. This type of system allows good flexibility in switching. The system is usually operated with all of the secondary tie breakers except one (the sparing transformer secondary main/tie breaker) normally-open. The sparing transformer supplies one load bus if a transformer goes off-line or is taken off-line for maintenance. A transformer is switched out of the circuit by opening its secondary main breaker and closing the tie breaker to allow the sparing transformer to feed its loads. The sparing transformer may be allowed to feed multiple load busses if it is sized properly. Care must be used when allowing multiple transformers to be paralleled as the fault current is increased with each transformer that is paralleled, and directional relaying is required on the secondary main circuit breakers to selectively isolate an offline transformer. An electrical or key interlock scheme is required to enforce the proper operating modes of this type of system, especially since the switching is carried out over several pieces of equipment that can be in different locations. A properly designed interlocking system allows for the addition of future substations without modification of the existing interlocking.

With both types of secondary-selective system, an automatic transfer scheme may be utilized to switch between a lost transformer and an available transformer.

Figure 23 - Transformer Sparing Scheme



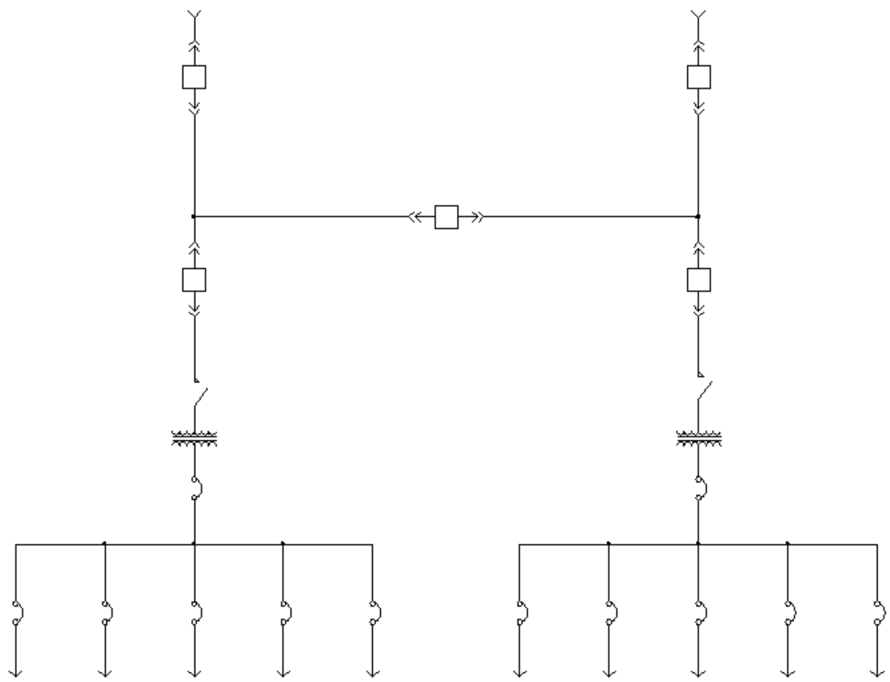
Primary Selective Systems

A selective system arrangement may also utilize the primary system equipment. Such an arrangement is shown in Primary Selective System, page 44.

As with the secondary selective system, an automatic transfer scheme may be used to automatically perform the required transfer operations, if a utility source become unavailable. The bus tie circuit breaker may be normally-closed or normally-open, depending on utility allowances. If the bus tie circuit breaker is normally-closed, take care in the protective relaying so that a fault on one utility line does not cause the entire system to be taken off-line. The available fault current with the tie breaker normally closed increases with each utility service added to the system.

Metal-clad switchgear is most used with this type of arrangement, due to the limitations of metal-enclosed load interrupter switches.

Figure 24 - Primary Selective System

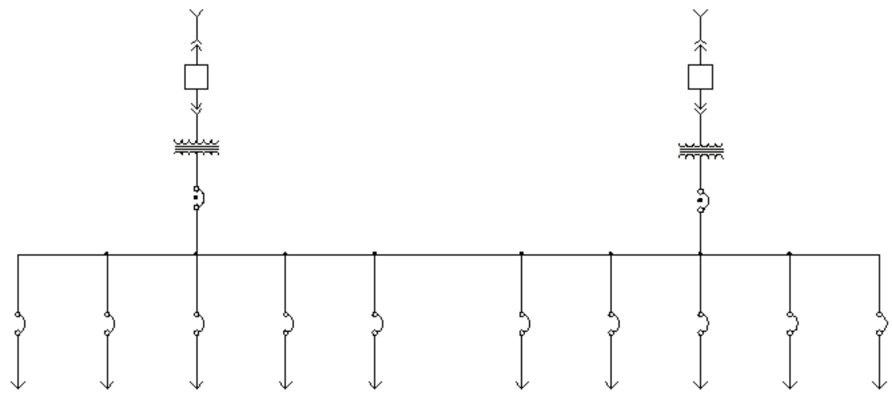


Secondary Spot-network Systems

In large municipal areas where large loads, such as high-rise buildings, must be served and a high degree of reliability, secondary network systems are often used. In a secondary network system, several utility services are paralleled at the low-voltage level, creating a highly steady system.

Network protectors are used at the transformer secondaries to isolate transformer faults which are backfed through the low-voltage system. These devices are designed to automatically isolate a faulted transformer that is backfed from the rest of the system. The transformers typically have higher-than-standard impedances to reduce the available fault current on the low-voltage network. The common secondary bus is often referred to as the “collector bus”. An example of a secondary spot-network system is shown in Secondary Spot Network, page 45.

Figure 25 - Secondary Spot Network



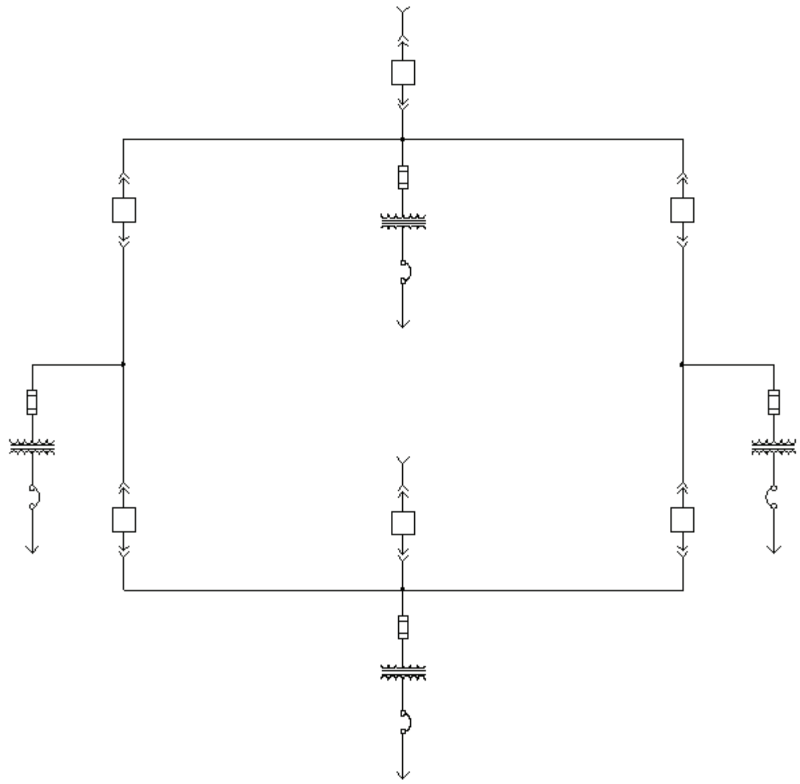
Ring Bus Systems

Essentially a loop system in which the loop is normally closed, the ring bus is a highly dependable system arrangement. A typical ring-bus system is depicted in Primary Ring Bus System, page 46.

A fault at any bus causes only the loads served by that bus to lose service. Bus differential relaying is recommended for optimum reliability with this scheme. The bus differential relaying opens both breakers feeding a bus for a fault on that bus. Metal-clad switchgear is usually used for the primary ring bus.

Although Primary Ring Bus System, page 46 shows two utility sources, this system arrangement is easily expanded to incorporate additional utility sources. As with the primary-selective system with a normally-closed bus tie breaker, the available fault current is increased with each utility source added to the system.

Figure 26 - Primary Ring Bus System



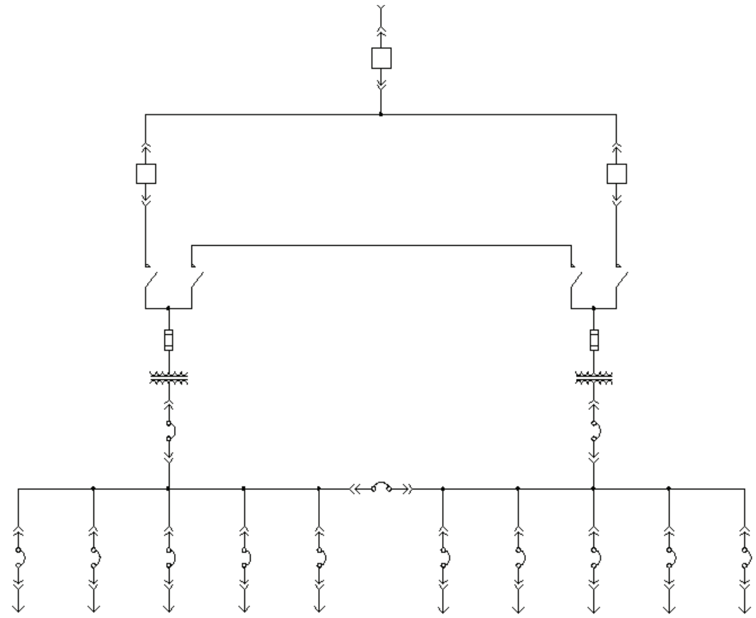
Composite Systems

The above system arrangements are the basic building blocks of power distribution system topologies but are rarely used alone for a given system. To increase system reliability, it is usually necessary to combine two or more of these arrangements. For example, one commonly used arrangement is shown in Composite System: Primary Loop/Secondary Selective, page 47.

A fault on a primary loop cable or the loss of one transformer can be accommodated without loss of service to either load bus (but with an outage to part of the system until the system is switched to accommodate the loss). In addition, a single section of the primary loop or one transformer can be taken out of service while maintaining service to the loads.

The system of Composite System: Primary Loop/Secondary Selective, page 47 can be expanded by the addition of an additional utility source and a primary bus tie breaker to form an even more dependable system, as shown in Composite System: Primary Selective/Primary Loop/Secondary Selective, page 48. With this arrangement, the loss of a single utility source, a single primary circuit breaker, a single loop feeder cable, or a single transformer can be accommodated without loss of service. And any one primary circuit breaker, any one section of the primary distribution loop, or any one transformer can be taken out of service without loss of service to the loads. However, the cost of a second utility service and two additional metal-clad breakers must be considered.

Figure 27 - Composite System: Primary Loop/Secondary Selective



A logical expansion of this system, resulting in a further increase in system reliability, is had by replacing the primary distribution loop with dedicated feeder circuit breakers from each primary bus, as shown in Composite System: Primary Selective/Primary Loop/Secondary Selective, page 48. In this system arrangement multiple primary feeder cable losses can be accommodated without jeopardizing service to the loads (However, an outage occurs until the system is switched to accommodate the losses).

An example of an extremely dependable system arrangement is given in Primary Ring Bus, Primary Source Selective, Secondary Selective System, page 49 is a re-arrangement of the primary ring-bus configuration shown in Composite System: Primary Selective/Primary Loop/Secondary Selective, page 48, along with the primary source-selective configuration shown in Composite System: Primary Loop/Secondary Selective, page 47 and a variant of the transformer sparing scheme given in Transformer Sparing Scheme, page 43. This system arrangement gives good flexibility in switching for maintenance purposes, and allows any one utility, primary switchgear bus, or transformer fail without loss of service to any of the loads (again, an outage may be taken until the system is switched to accommodate the loss, depending upon the loss under consideration). It also allows any three primary feeders to be faulted without loss of service to any of the loads. Other composite arrangements are possible.

Figure 28 - Composite System: Primary Selective/Primary Loop/Secondary Selective

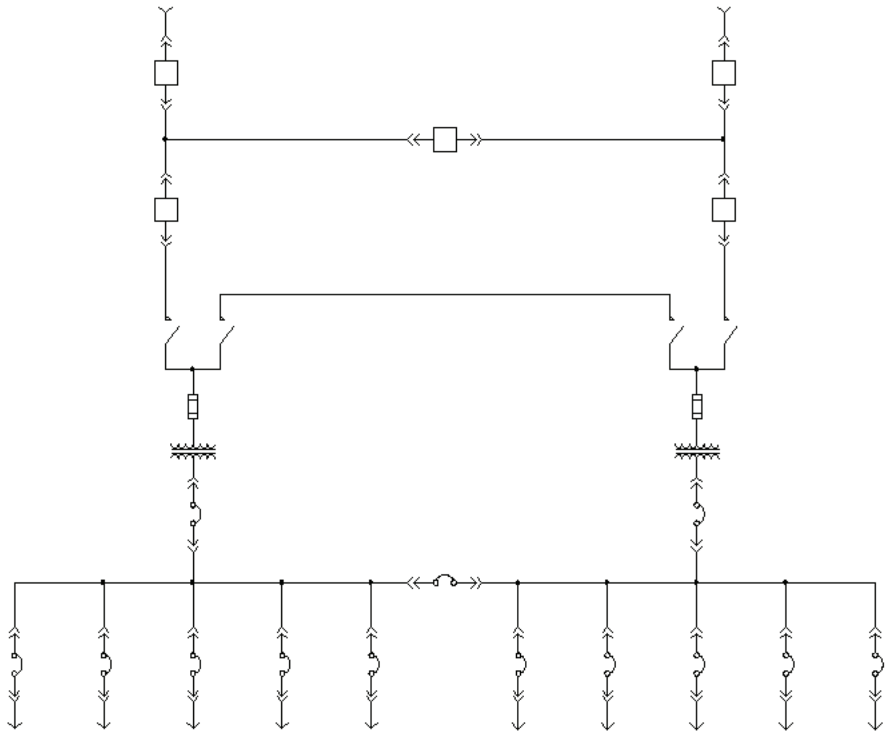


Figure 29 - Composite System: Primary Double Selective/Secondary Selective

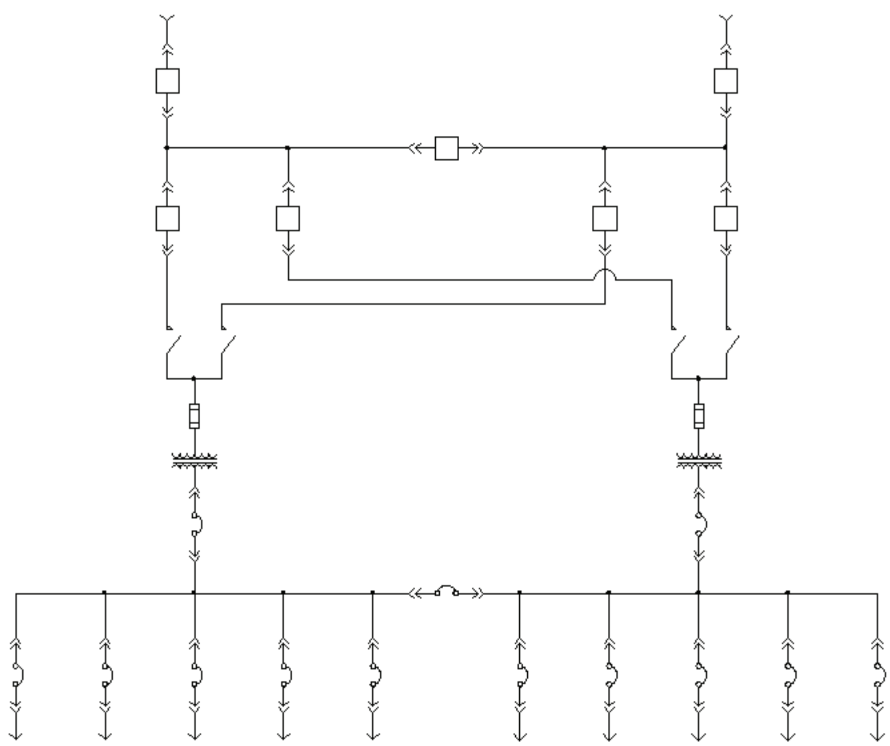
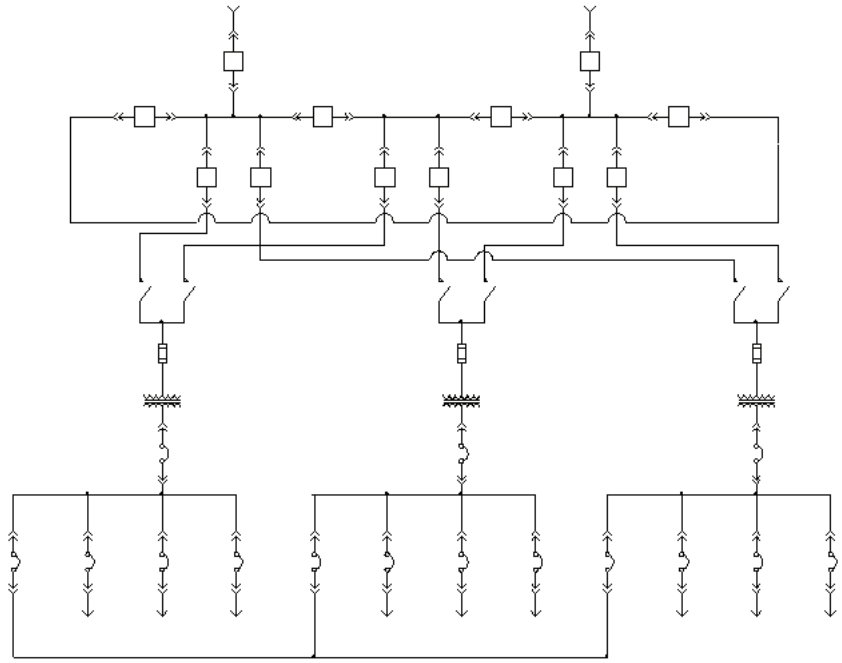


Figure 30 - Primary Ring Bus, Primary Source Selective, Secondary Selective System



Summary

Various system arrangements are presented in this section, starting with the least complex and progressing to a very complex, robust system arrangement. In general, as reliability increases so does complexity and cost. Economic considerations usually dictate how complex a system arrangement can be used, and thus have a great deal of impact on system reliability. Power System Arrangements Summary for the Basic Arrangements in this Section, page 50 and Power System Arrangements Summary for the Composite Arrangements in this Section, page 50 show the features of each system arrangement given in this section.

The formulas given in these tables are for the systems as shown in the earlier figures. They hold true for expanded versions of these system arrangements where the expansion is made symmetrically with respect to the configuration shown. They do not hold true when modifications are made to the system arrangements with respect to symmetry, with altered numbers of switching/protective devices, or for concurrent loss of different types of system components. When in doubt regarding a system which is derived from, but not identical, to the systems shown in the earlier figures, double-check these numbers.

From a maintenance perspective, the number of system elements that can be taken down for maintenance is the same as the number that can fail while maintaining service to the loads.

These tables do not attempt to address concurrent losses of different types of system components, nor are they always mean a loss of service to a particular load after a component loss while the system is being switched to an alternate configuration. However, they are a guide to the relative strengths and weaknesses of each of the system arrangements presented.

Table 6 - Power System Arrangements Summary for the Basic Arrangements in this Section

Arrangement	Utility Losses Allowed	Primary Breaker Losses Allowed	Primary Feeder Losses Allowed	Transformer Losses Allowed	Secondary Main/ Tie Breaker Losses Allowed	Cost
Radial	0	0	0	0	0	$
Radial w/ Primary Selectivity	u-1[23]	0	0	0	0	$+
Expanded Radial, Single Primary Feeder	0	0	0	0	0	$$
Expanded Radial, Multiple Primary Feeders	0	0	0	0	0	$$
Expanded Radial, Multiple Utility Sources, Multiple Primary Feeders	u-1[23]	0	0	0	0	$$+
Primary Loop System	0	1	1	0	0	$$$
Secondary-Selective System	0	0	0	1	1	$$$
Transformer Sparing Scheme	0	0	0	Varies; Maximum of T, page 50-1	T, page 50[24]	$$$$
Primary Selective	u-1[23, 25]	PB-F-u[23, 25, 26]	0	0	0	$$$$$
Secondary Spot Network	u-1 [23, 25, 27, 28]	PB-1[23, 25, 27, 28]	F-1 [23, 25, 27, 28]	T, page 50-1 [23, 25, 27, 28]	SB-1 [23, 25, 27, 28]	$$$$$
Primary Ring Bus	u-1 [23, 25, 29]	u[23, 25, 26, 29]	0	0	0	$$$$$$

Notes:

U = Number of Utility Sources

PB = Number of Primary Circuit Breakers

SF = Number of Primary Feeders

T = Number of Transformers

SB = Number of Secondary Main and Tie Circuit Breakers

$ = Relative Cost, with $=Least Expensive

Table 7 - Power System Arrangements Summary for the Composite Arrangements in this Section

Arrangement	Utility Losses Allowed	Primary Breaker Losses Allowed	Primary Feeder Losses Allowed	Transformer Losses Allowed	Secondary Main/ Tie Breaker Losses Allowed	Cost
Primary Double Selective / Secondary Selective	u-1 [23, 25]	PB-F/2-u[23, 25, 26]	F/2	T, page 50-1 [28]	T, page 50-1 [28, 24]	$$$$$$$$$$
Primary Ring Bus / Primary Selective/ Secondary Selective	u-1 [23, 25, 27, 28]	PB-F/2-u+1 [23, 25, 26, 29]	F/2	T, page 50-1 [28]	T, page 50–1 [28, 24]	$$$$$$$$$$

Notes:

U = Number of Utility Sources

PB = Number of Primary Circuit Breakers

SF = Number of Primary Feeders

T = Number of Transformers

SB = Number of Secondary Main and Tie Circuit Breakers

$ = Relative Cost, with $=Least Expensive

23. Assumes that each utility source has sufficient capacity to supply the entire system.
24. Assumes that all secondary circuit breakers, including feeder breakers, are interchangeable.
25. Assumes that each primary main and bus tie (if applicable) circuit breakers has sufficient capacity to supply the entire system.
26. Assumes that all primary circuit breakers, including feeder breakers, are interchangeable.
27. Assumes that each primary feeder has sufficient capacity to supply the entire system.
28. Assumes that each transformer, secondary main and bus tie (if applicable) circuit breaker have sufficient capacity to supply the entire system.
29. Assumes that the ring bus has sufficient capacity to supply the entire system.

System Grounding

Abstract: System grounding considerations affect many aspects of an electrical system. Knowledge of the various types of system grounding and performance characteristics is critical when designing or operating an electrical system. The voltage, system arrangement, loads connected, and continuity of service drive grounding requirements and design choices.

Introduction

The topic of system grounding is extremely important, as it affects the susceptibility of the system to voltage transients, determines the types of loads the system can accommodate, and helps to determine the system protection requirements.

The system grounding arrangement is determined by the grounding of the power source. For commercial and industrial systems, the types of power sources generally fall into four broad categories:

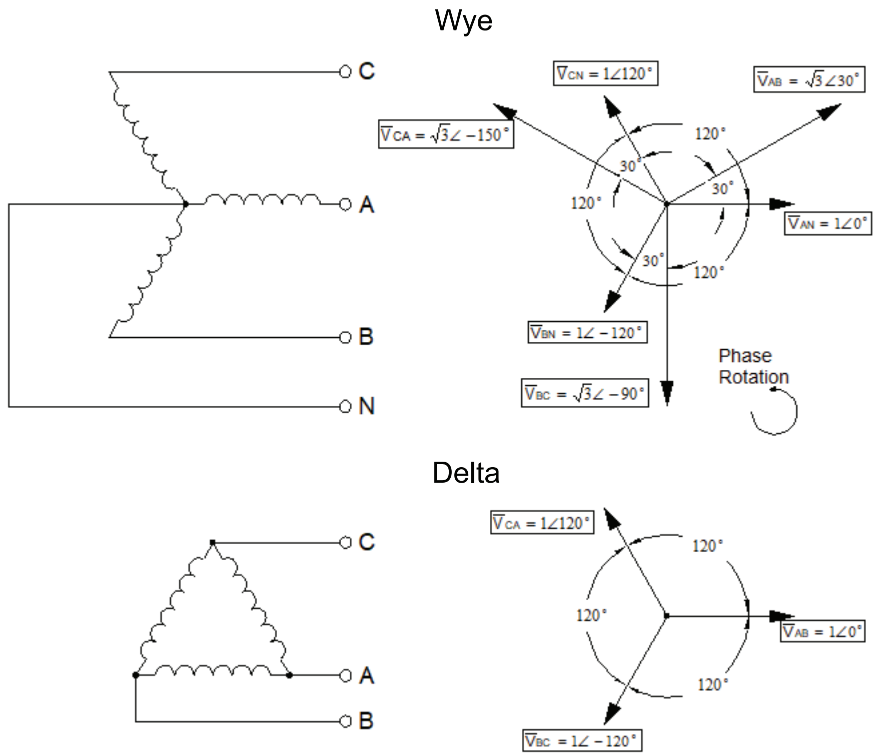
- **Utility Service:** The system grounding is usually determined by the secondary winding configuration of the upstream utility substation transformer.
- **Generator:** The system grounding is determined by the stator winding configuration.
- **Transformer:** The system grounding on the system fed by the transformer is determined by the transformer secondary winding configuration.
- **Static Power Converter:** For devices such as rectifiers and inverters, the system grounding is determined by the grounding of the output stage of the converter.

All categories fall under the NEC definition for a “separately-derived system”. The recognition of a separately derived system is important when applying NEC requirements to system grounding, as discussed below.

All the power sources mentioned above, except Static Power Converter, are magnetically operated devices with windings. To understand the system voltage relationships with respect to system grounding, it must be recognized that there are two common ways of connecting device windings: wye and delta. These two arrangements, with their system voltage relationships, are shown in Wye and Delta Winding Configurations and System Voltage Relationships, page 52. As can be seen from the figure, in the wye-connected arrangement there are four terminals, with the phase-to-neutral voltage for each phase set by the winding voltage and the resulting phase-to-phase voltage set by the vector relationships between the voltages. The delta configuration has only three terminals, with the phase-to-phase voltage set by the winding voltages and the neutral terminal not defined.

Neither of these arrangements is inherently associated with any system grounding arrangement, although some arrangements more commonly used, for reasons that are explained further below.

Figure 31 - Wye and Delta Winding Configurations and System Voltage Relationships

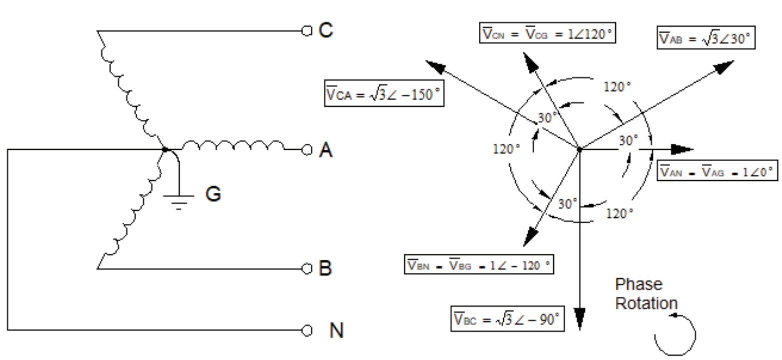


Solidly-grounded Systems

The solidly-grounded system is the most common system arrangement, and one of the most versatile. The most commonly used configuration is the solidly-grounded wye, because it supports single-phase phase-to-neutral loads.

The solidly-grounded wye system arrangement can be shown by considering the neutral terminal from the wye system arrangement in Wye and Delta Winding Configurations and System Voltage Relationships, page 52 to be grounded. This is shown in Solidly-grounded Wye System Arrangement and Voltage Relationships, page 52.

Figure 32 - Solidly-grounded Wye System Arrangement and Voltage Relationships



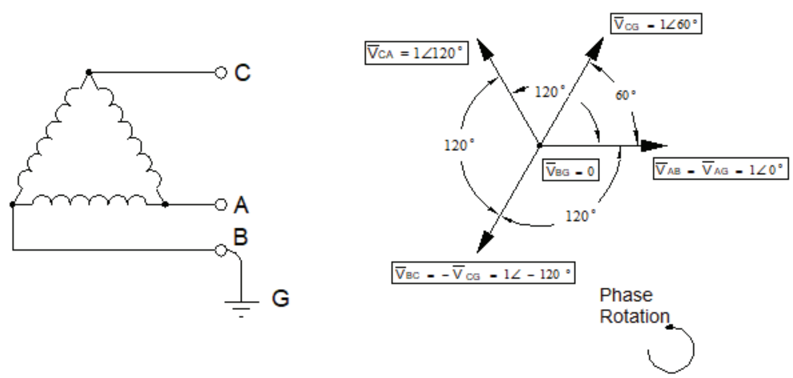
Several points regarding Solidly-grounded Wye System Arrangement and Voltage Relationships, page 52 can be noted:

- First, the system voltage with respect to ground is fixed by the phase-to-neutral winding voltage. Because parts of the power system, such as equipment frames, are grounded, and the rest of the environment essentially is at ground potential also, this has big implications for the system. It means that the line-to-ground insulation level of equipment need only be as large as the phase-to-neutral voltage, which is 57.7% of the phase-to-phase voltage. It also means that the system is less susceptible to phase-to-ground voltage transients.
- Second, the system is suitable for supplying line-to-neutral loads. The operation of a single-phase load connected between one phase and neutral is the same on any phase since the phase voltage magnitudes are equal.

This system arrangement is very common, both at the utilization level as 480 Y/277 V and 208 Y/120 V, and on most utility distribution systems.

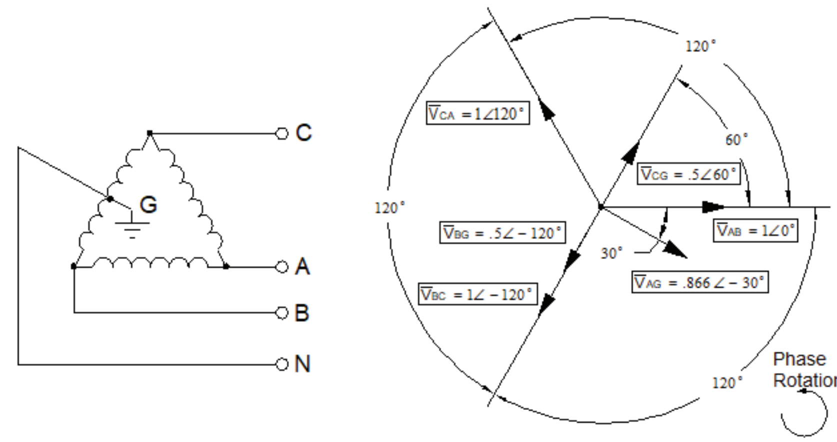
While the solidly-grounded wye system is by far the most common solidly-grounded system, the wye arrangement is not the only arrangement that can be configured as a solidly grounded system. The delta system can also be grounded, as shown in Corner-grounded Delta System Arrangement and Voltage Relationships, page 53. Compared with the solidly-grounded wye system of Solidly-grounded Wye System Arrangement and Voltage Relationships, page 52 this system grounding arrangement has a number of disadvantages. The phase-to-ground voltages are not equal, and therefore the system is not suitable for single-phase loads. And, without proper identification of the phases there is the risk of shock since one conductor, the B-phase, is grounded and could be misidentified. This arrangement is no longer in common use, although a few facilities where this arrangement is used still exist.

Figure 33 - Corner-grounded Delta System Arrangement and Voltage Relationships



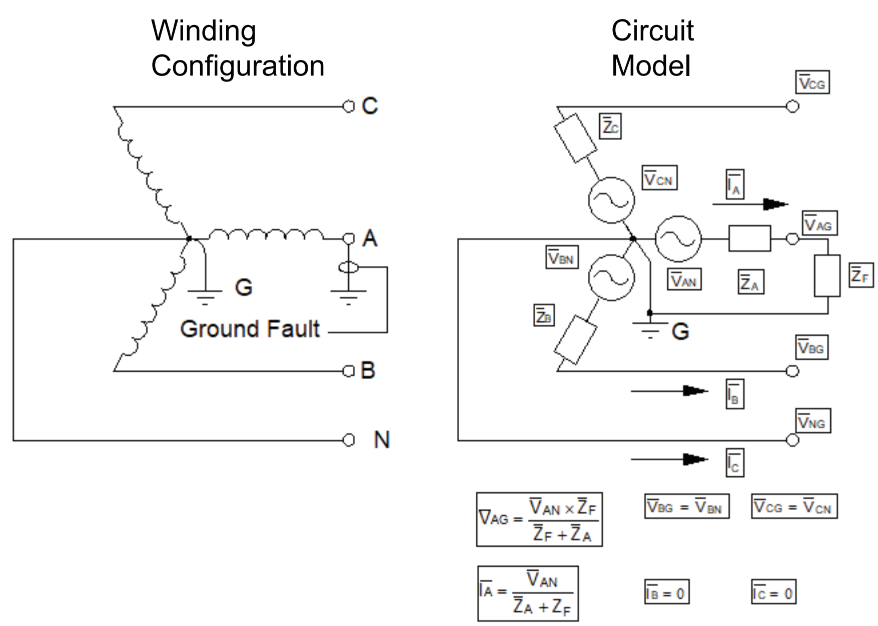
The delta arrangement can be configured in another manner, however, that does have merits as a solidly-grounded system. This arrangement is shown in Figure 34. While the arrangement of Center-Tap-grounded Delta System Arrangement and Voltage Relationships, page 54 may not appear at first glance to have merit, this system is suitable both for three-phase and single-phase loads, so long as the single-phase and three-phase load cables are kept separate from each other. This is commonly used for small services which require both 240 Vac three-phase and 120/240 Vac single-phase. The phase A voltage to ground is 173% of the phase B and C voltages to ground. This arrangement requires the BC winding to have a center tap.

Figure 34 - Center-Tap-grounded Delta System Arrangement and Voltage Relationships



A common characteristic of all three solidly-grounded system shown here, and of solidly-grounded systems in general, is that a short-circuit to ground causes a large amount of short-circuit current to flow. This condition is known as a ground current trip and is illustrated in Solidly-grounded System With a Ground Current Trip on Phase A, page 54. As seen from Solidly-grounded System With a Ground Current Trip on Phase A, page 54, the voltage on the faulted phase is depressed, and a large current flows in the faulted phase since the phase and fault impedance are small. The voltage and current on the other two phases are not affected. The fact that a solidly-grounded system supports a large ground current trip current is an important characteristic of this type of system grounding and does affect the system design. Statistically, 90-95% of all system short-circuits are ground current trips so this is an important topic. The practices used in ground current trip protection are described in Ground Fault Protection for Solidly-grounded Systems 600 V and Below, page 123.

Figure 35 - Solidly-grounded System With a Ground Current Trip on Phase A



The occurrence of a ground current trip on a solidly-grounded system necessitates the removal of the fault as quickly as possible. This is the major disadvantage of the solidly-grounded system as compared to other types of system grounding.

A solidly-grounded system is very effective at reducing the possibility of line-to-ground voltage transients. However, to do this the system must be effectively grounded. One measure of the effectiveness of the system grounding is the ratio of the available ground-fault current to the available three-phase fault current. For effectively-grounded systems this ratio is usually at least 60 (see *IEEE Recommended Practice for Grounding of Industrial and Commercial Power Systems*[30]).

Most utility systems which supply service for commercial and industrial systems are solidly grounded. Typical utility practice is to ground the neutral at many points, usually at every line pole, creating a multi-grounded neutral system. Because a separate grounding conductor is not run with the utility line, the resistance of the earth limits the circulating ground currents that can be caused by this type of grounding. Because separate grounding conductors are used inside a commercial or industrial facility, multi-grounded neutrals not preferred for power systems in these facilities due to the possibility of circulating ground currents. As explained later in this section, multi-grounded neutrals in NEC jurisdictions, such as commercial or industrial facilities, are actually prohibited in most cases by the NEC (see*The National Electrical Code*[31]). Instead, a single point of grounding is preferred for this type of system, creating a uni-grounded or single-point grounded system.

In general, the solidly-grounded system is the most popular, is required where single-phase phase-to-neutral loads must be supplied, and has the most dependable phase-to-ground voltage characteristics. However, the large ground current trip currents this type of system can support, and the equipment that this necessitates, are a disadvantage and can be hindrance to system reliability.

Ungrounded Systems

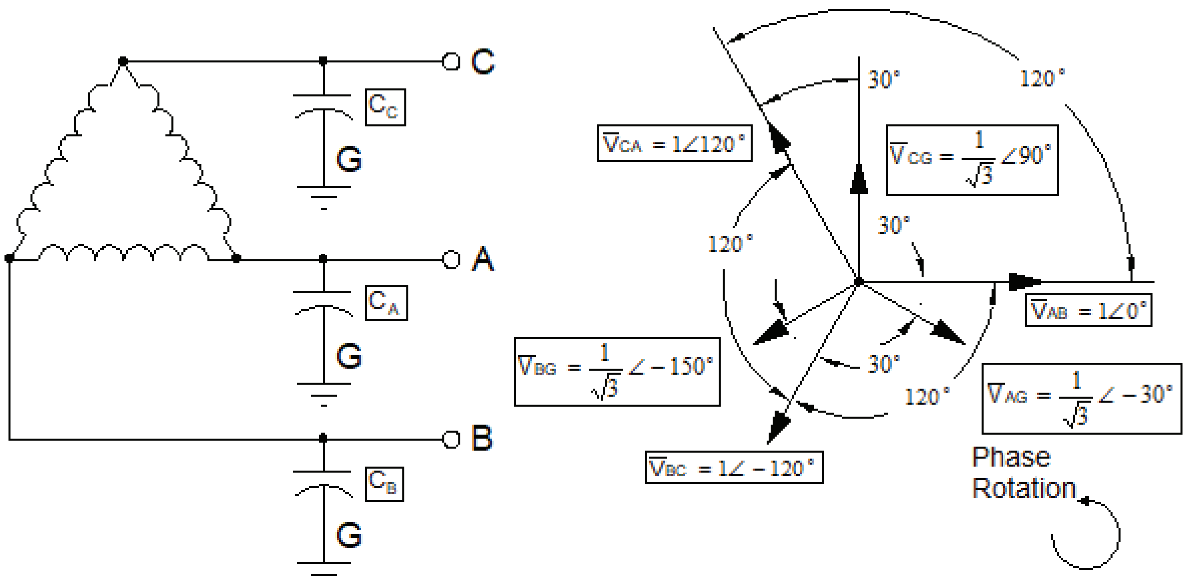
This system grounding arrangement is at the other end of the spectrum from solidly-grounded systems. An ungrounded system is a system where there is no intentional connection of the system to ground.

The term “ungrounded system” is a misnomer since every system is grounded through its inherent charging capacitance to ground. To illustrate this point and its effect on the system voltages to ground, the delta winding configuration introduced in Corner-grounded Delta System Arrangement and Voltage Relationships, page 53 is re-drawn in Ungrounded Delta System Winding Arrangement and Voltage Relationships, page 56 to show these system capacitances.

If all of the system voltages in Ungrounded Delta System Winding Arrangement and Voltage Relationships, page 56 are multiplied by $\sqrt{3}$ and all of the phase angles are shifted by 30° (both are reasonable operations since the voltage magnitudes and phase angles for the phase-to-phase voltage were arbitrarily chosen), the results are the same voltage relationships as shown in Center-Tap-grounded Delta System Arrangement and Voltage Relationships, page 54 for the solidly-grounded wye system. The differences between the ungrounded delta system and the solidly-grounded wye system, then, are that there is no intentional connection to ground, and that there is no phase-to-neutral driving voltage on the ungrounded delta system. This becomes important when the effects of a ground current trip are considered. The lack of a grounded system neutral also makes this type of system unsuitable for single-phase phase-to-neutral loads.

30. IEEE Std. 142-1991, December 1991.
31. NFPA 70, The National Fire Protection Association, Inc., 2005 Edition.

Figure 36 - Ungrounded Delta System Winding Arrangement and Voltage Relationships



The following voltage and current relationships apply:

$$\overline{V}_{AG} - \overline{V}_{BG} = \overline{V}_{AB} = 1\angle 0°$$
$$\overline{V}_{BG} - \overline{V}_{CG} = \overline{V}_{BC} = 1\angle -120°$$
$$\overline{V}_{CG} - \overline{V}_{AG} = \overline{V}ca = 1\angle 120°$$
$$\overline{I}_{AG} = j\omega C_A \overline{V}_{AG}$$
$$\overline{I}_{BG} = j\omega C_B \overline{V}_{BG}$$
$$\overline{I}_{CG} = j\omega C_C \overline{V}_{CG}$$
$$\overline{I}_{AG} + \overline{I}_{BG} + \overline{I}_{CG} = 0$$

Assuming equal conductor lengths and transposed conductors, the following is true:

$$C_A = C_B = C_C = C$$

Which allows the following manipulation of the last equation on the left:

$$\Rightarrow j\omega C\left(\overline{V}_{AG} + \overline{V}_{BG} + \overline{V}_{CG}\right) = 0$$
$$\Rightarrow \overline{V}_{AG} + \overline{V}_{BG} + \overline{V}_{CG} = 0$$

The first two equations on the left can be combined with the equation above to form a system of equations:

$$\begin{bmatrix} 1 & -1 & 0 \\ 0 & 1 & -1 \\ 1 & 1 & 1 \end{bmatrix} \begin{bmatrix} \overline{V}_{AG} \\ \overline{V}_{BG} \\ \overline{V}_{CG} \end{bmatrix} = \begin{bmatrix} 1\angle 0° \\ 1\angle -120° \\ 0 \end{bmatrix}$$

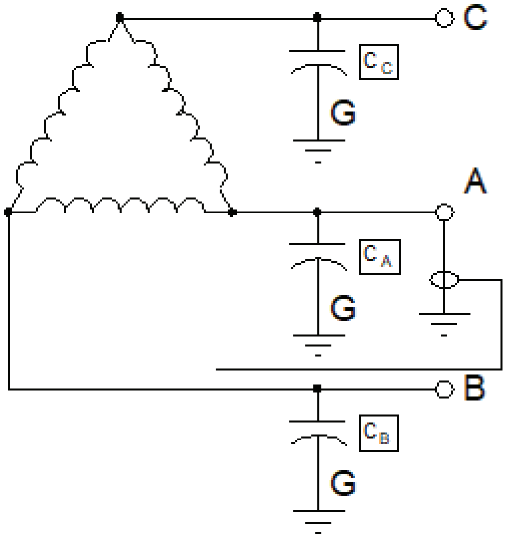
This yields the following phase-to-ground voltages:

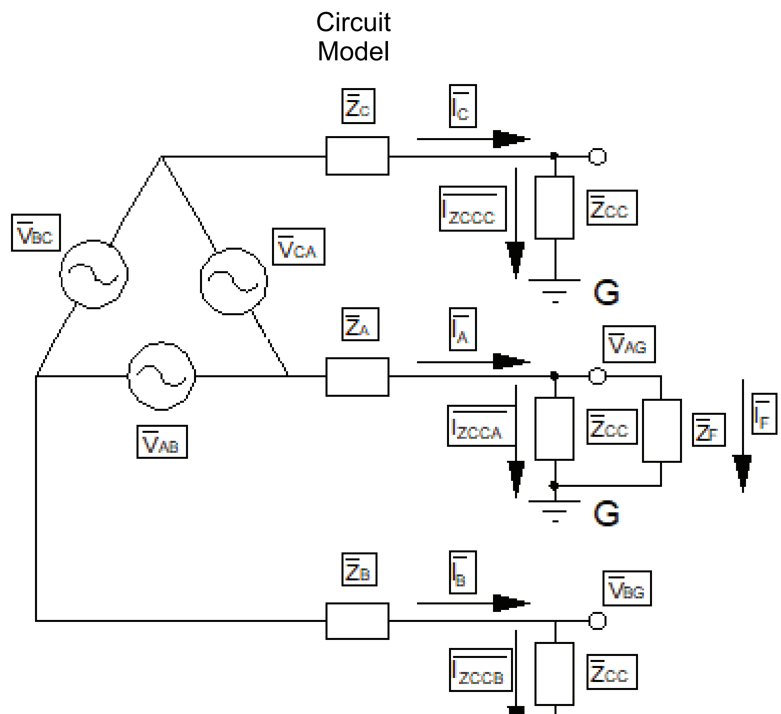
$$\overline{V}_{AG} = \frac{1}{\sqrt{3}}\angle -30°$$
$$\overline{V}_{BG} = \frac{1}{\sqrt{3}}\angle -150°$$
$$\overline{V}_{CG} = \frac{1}{\sqrt{3}}\angle 90°$$

In Ungrounded Delta System with a Ground-current Trip on One Phase, page 57, the effects of a single phase to ground current trip are shown. The equations in Ungrounded Delta System Winding Arrangement and Voltage Relationships, page 56 are not immediately practical for use, however, if the fault impedance is assumed to be zero and the system capacitive charging impedance is assumed to be much larger than the phase impedances, these equations reduce into a workable form. Ungrounded Delta System with a Ground-current Trip on One Phase, page 57 shows the resulting equations and shows the current and voltage phase relationships.

As seen from Ungrounded Delta System: Simplified Ground-current Trip Voltage and Current Relationships, page 58, the net result of a ground current trip on one phase of an ungrounded delta system is a change in the system phase-to-ground voltages. The phase-to-ground voltage on the faulted phase is zero, and the phase-to-ground voltage on the unfaulted phases are 173% of their nominal values. This has implications for power equipment; the phase-to-ground voltage rating for equipment on an ungrounded system must be at least equal the phase-to-phase voltage rating. This also has implications for the methods used for ground detection, as explained later in this guide.

Figure 37 - Ungrounded Delta System with a Ground-current Trip on One Phase





The following current and voltage relationships exist:

$$\bar{I}_A = \frac{\bar{V}_{AG}\left(\bar{Z}_F + \bar{Z}_{CC}\right)}{\bar{Z}_F \bullet \bar{Z}_{CC}}$$

$$\bar{I}_B = \bar{I}_{ZCCB} = \frac{\bar{V}_{BG}}{\bar{Z}_{CC}}$$

$$\bar{I}_C = \bar{I}_{ZCCC} = \frac{\bar{V}_{CG}}{\bar{Z}_{CC}}$$

$$\bar{V}_{BG} = \bar{V}_{AG} + \bar{I}_A \bullet \bar{Z}_A + \bar{V}_{AB} - \bar{I}_B \bullet \bar{Z}_B$$

$$\bar{V}_{CG} = \bar{V}_{AG} + \bar{I}_A \bullet \bar{Z}_A + \bar{V}_{AC} - \bar{I}_C \bullet \bar{Z}_C$$

$$\bar{I}_A + \bar{I}_B + \bar{I}_C = 0$$

This yields the following phase-to-ground voltages and phase currents:

$$\bar{V}_{AG} = \frac{\left(\bar{Z}_{CC} + \bar{Z}_C\right)\bar{V}_{AB} - \left(\bar{Z}_{CC} + \bar{Z}_B\right)\bar{V}_{CA} \bullet \bar{Z}_{CC} \bullet \bar{Z}_F}{\bar{Z}_A\left(\bar{Z}_B + \bar{Z}_C + 2\bar{Z}_{CC}\right)\left(\bar{Z}_{CC} + \bar{Z}_F\right) + \bar{Z}_B\left(\bar{Z}_C \bullet \bar{Z}_{CC} + \bar{Z}_C \bullet \bar{Z}_F + \bar{Z}^2_{CC} + 2\bar{Z}_{CC} \bullet \bar{Z}_F\right) + \bar{Z}_{CC}\left(\bar{Z}_{CC} \bullet \bar{Z}_C + 2\bar{Z}_C \bullet \bar{Z}_F + \bar{Z}^2_{CC} + 3\bar{Z}_F \bullet \bar{Z}_{CC}\right)}$$

$$\bar{V}_{BG} = \frac{-\left[\left(\bar{Z}_{CC} \bullet \bar{Z}_A + \bar{Z}_A \bullet \bar{Z}_F + \bar{Z}_C \bullet \bar{Z}_{CC} + \bar{Z}_C \bullet \bar{Z}_F + \bar{Z}^2_{CC} + 2\bar{Z}_{CC} \bullet \bar{Z}_F\right)\bar{V}_{AB} + \left(\bar{Z}_{CC} \bullet \bar{Z}_F + \bar{Z}_{CC} \bullet \bar{Z}_A + \bar{Z}_A \bullet \bar{Z}_F\right)\bar{V}_{CA}\right] \bullet \bar{Z}_{CC}}{\bar{Z}_A\left(\bar{Z}_B + \bar{Z}_C + 2\bar{Z}_{CC}\right)\left(\bar{Z}_{CC} + \bar{Z}_F\right) + \bar{Z}_B\left(\bar{Z}_C \bullet \bar{Z}_{CC} + \bar{Z}_C \bullet \bar{Z}_F + \bar{Z}^2_{CC} + 2\bar{Z}_{CC} \bullet \bar{Z}_F\right) + \bar{Z}_{CC}\left(\bar{Z}_{CC} \bullet \bar{Z}_C + 2\bar{Z}_C \bullet \bar{Z}_F + \bar{Z}^2_{CC} + 3\bar{Z}_F \bullet \bar{Z}_{CC}\right)}$$

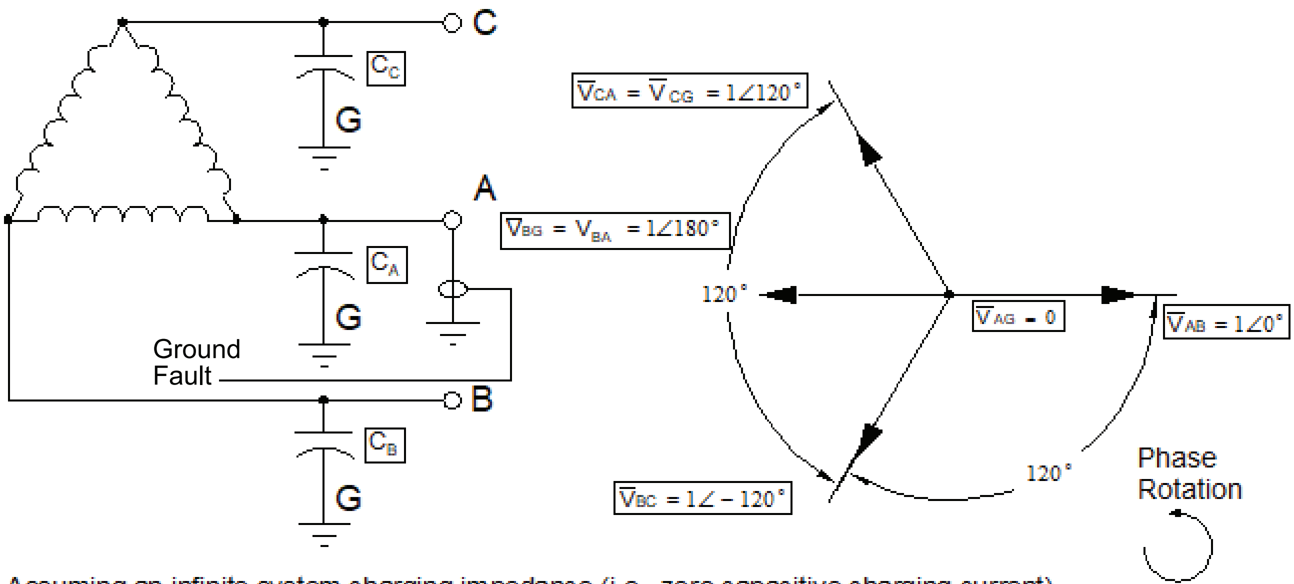
$$\bar{V}_{CG} = \frac{\left[\left(\bar{Z}_{CC} \bullet \bar{Z}_F + \bar{Z}_{CC} \bullet \bar{Z}_A + \bar{Z}_A \bullet \bar{Z}_F\right)\bar{V}_{AB} + \left(\bar{Z}_{CC} \bullet \bar{Z}_A + \bar{Z}_A \bullet \bar{Z}_F + \bar{Z}_B \bullet \bar{Z}_{CC} + \bar{Z}_B \bullet \bar{Z}_F + \bar{Z}^2_{CC} + 2\bar{Z}_{CC} \bullet \bar{Z}_F\right)\bar{V}_{CA}\right] \bullet \bar{Z}_{CC}}{\bar{Z}_A\left(\bar{Z}_B + \bar{Z}_C + 2\bar{Z}_{CC}\right)\left(\bar{Z}_{CC} + \bar{Z}_F\right) + \bar{Z}_B\left(\bar{Z}_C \bullet \bar{Z}_{CC} + \bar{Z}_C \bullet \bar{Z}_F + \bar{Z}^2_{CC} + 2\bar{Z}_{CC} \bullet \bar{Z}_F\right) + \bar{Z}_{CC}\left(\bar{Z}_{CC} \bullet \bar{Z}_C + 2\bar{Z}_C \bullet \bar{Z}_F + \bar{Z}^2_{CC} + 3\bar{Z}_F \bullet \bar{Z}_{CC}\right)}$$

$$\bar{I}_A = \frac{\left(\bar{Z}_{CC} + \bar{Z}_C\right)\bar{V}_{AB} - \left(\bar{Z}_{CC} + \bar{Z}_B\right)\bar{V}_{CA}\left(\bar{Z}_{CC} + \bar{Z}_F\right)}{\bar{Z}_A\left(\bar{Z}_B + \bar{Z}_C + 2\bar{Z}_{CC}\right)\left(\bar{Z}_{CC} + \bar{Z}_F\right) + \bar{Z}_B\left(\bar{Z}_C \bullet \bar{Z}_{CC} + \bar{Z}_C \bullet \bar{Z}_F + \bar{Z}^2_{CC} + 2\bar{Z}_{CC} \bullet \bar{Z}_F\right) + \bar{Z}_{CC}\left(\bar{Z}_{CC} \bullet \bar{Z}_C + 2\bar{Z}_C \bullet \bar{Z}_F + \bar{Z}^2_{CC} + 3\bar{Z}_F \bullet \bar{Z}_{CC}\right)}$$

$$\bar{I}_B = \frac{-\left[\left(\bar{Z}_{CC} \bullet \bar{Z}_A + \bar{Z}_A \bullet \bar{Z}_F + \bar{Z}_C \bullet \bar{Z}_{CC} + \bar{Z}_C \bullet \bar{Z}_F + \bar{Z}^2_{CC} + 2\bar{Z}_{CC} \bullet \bar{Z}_F\right)\bar{V}_{AB} + \left(\bar{Z}_{CC} \bullet \bar{Z}_F + \bar{Z}_{CC} \bullet \bar{Z}_A + \bar{Z}_A \bullet \bar{Z}_F\right)\bar{V}_{CA}\right]}{\bar{Z}_A\left(\bar{Z}_B + \bar{Z}_C + 2\bar{Z}_{CC}\right)\left(\bar{Z}_{CC} + \bar{Z}_F\right) + \bar{Z}_B\left(\bar{Z}_C \bullet \bar{Z}_{CC} + \bar{Z}_C \bullet \bar{Z}_F + \bar{Z}^2_{CC} + 2\bar{Z}_{CC} \bullet \bar{Z}_F\right) + \bar{Z}_{CC}\left(\bar{Z}_{CC} \bullet \bar{Z}_C + 2\bar{Z}_C \bullet \bar{Z}_F + \bar{Z}^2_{CC} + 3\bar{Z}_F \bullet \bar{Z}_{CC}\right)}$$

$$\bar{I}_C = \frac{\left[\left(\bar{Z}_{CC} \bullet \bar{Z}_F + \bar{Z}_{CC} \bullet \bar{Z}_A + \bar{Z}_A \bullet \bar{Z}_F\right)\bar{V}_{AB} + \left(\bar{Z}_{CC} \bullet \bar{Z}_A + \bar{Z}_A \bullet \bar{Z}_F + \bar{Z}_B \bullet \bar{Z}_{CC} + \bar{Z}_B \bullet \bar{Z}_F + \bar{Z}^2_{CC} + 2\bar{Z}_{CC} \bullet \bar{Z}_F\right)\bar{V}_{CA}\right]}{\bar{Z}_A\left(\bar{Z}_B + \bar{Z}_C + 2\bar{Z}_{CC}\right)\left(\bar{Z}_{CC} + \bar{Z}_F\right) + \bar{Z}_B\left(\bar{Z}_C \bullet \bar{Z}_{CC} + \bar{Z}_C \bullet \bar{Z}_F + \bar{Z}^2_{CC} + 2\bar{Z}_{CC} \bullet \bar{Z}_F\right) + \bar{Z}_{CC}\left(\bar{Z}_{CC} \bullet \bar{Z}_C + 2\bar{Z}_C \bullet \bar{Z}_F + \bar{Z}^2_{CC} + 3\bar{Z}_F \bullet \bar{Z}_{CC}\right)}$$

Figure 38 - Ungrounded Delta System: Simplified Ground-current Trip Voltage and Current Relationships



Assuming an infinite system charging impedance (i.e., zero capacitive charging current), the voltage and currents simplify to:

$$\boxed{\begin{array}{l} \overline{V}_{AG} = 0 \\ V_{BG} = \overline{V}_{BA} \\ \overline{V}_{CG} = \overline{V}_{CA} \\ \overline{I}_A = 0 \\ \overline{I}_B = 0 \\ \overline{I}_C = 0 \end{array}}$$

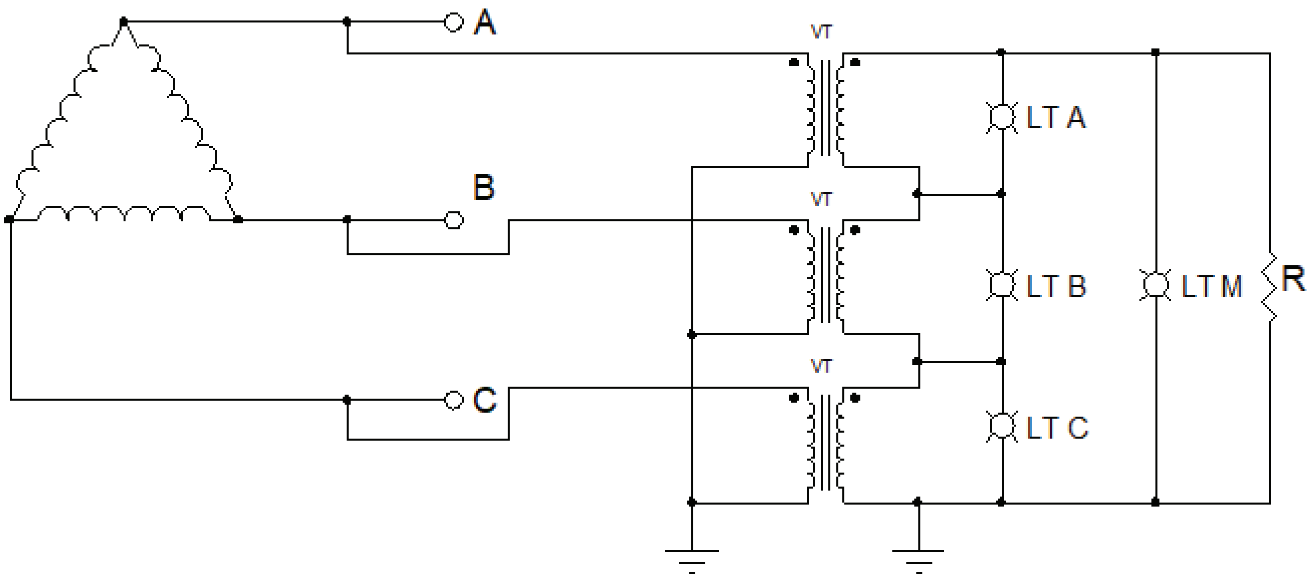
The ground currents with one phase is faulted to ground are essentially negligible. Because of this fact, from an operational standpoint ungrounded systems have the advantage of being able to remain in service if one phase is faulted to ground. However, suitable ground detection must be provided to alarm this condition (and is required in most cases by the NEC, see *The National Electrical Code*[32] as described below). In some older facilities, it has been reported that this type of system has remained in place for 40 years or more with one phase grounded. This condition is not unsafe in and of itself (other than due to the increased phase-to-ground voltage on the unfaulted phases), however, if a ground current trip occurs on one of the ungrounded phases the result is a phase-to-phase fault with its characteristic large fault current magnitude.

Another important consideration for an ungrounded system is its susceptibility to large transient overvoltages. These can result from a resonant or near-resonant condition during ground current trips, or from arcing (see *IEEE Recommended Practice for Grounding of Industrial and Commercial Power Systems*[33]). A resonant ground current trip condition occurs when the inductive reactance of the ground-current trip path approximately equals the system capacitive reactance to ground. Arcing introduces the phenomenon of current-chopping, which can cause excessive overvoltages due to the system capacitance to ground.

The ground detection mentioned above can be accomplished using voltage transformers connected in wye-broken delta, as illustrated in A Ground Detection Method for Ungrounded Systems, page 59.

32. NFPA 70, The National Fire Protection Association, Inc., 2005 Edition.
33. IEEE Std. 142-1991, December 1991.

Figure 39 - A Ground Detection Method for Ungrounded Systems



Ground Fault Location	LTA	LTB	LTC	LTM
—	Dim	Dim	Dim	Off
Phase A	Off	Bright	Bright	Bright
Phase B	Bright	Off	Bright	Bright
Phase C	Bright	Bright	Dim	Bright

In A Ground Detection Method for Ungrounded Systems, page 59, three ground detection lights “LTA”, “LTB”, and “LTC” are connected so that they indicate the A, B, and C phase-to-ground voltages, respectively. A master ground detection light “LTM” indicates a ground current trip on any phase. With no ground current trip on the system, “LTA”, “LTB”, and “LTB” glow dimly. If a ground current trip occurs on one phase, the light for that phase is extinguished and “LTM” glows brightly along with the lights for the other two phases. Control relays may be substituted for the lights if necessary. Resistor “R” is connected across the broken-delta voltage transformer secondaries to minimize the possibility of ferroresonance. Most ground detection schemes for ungrounded systems use this system or a variant thereof.

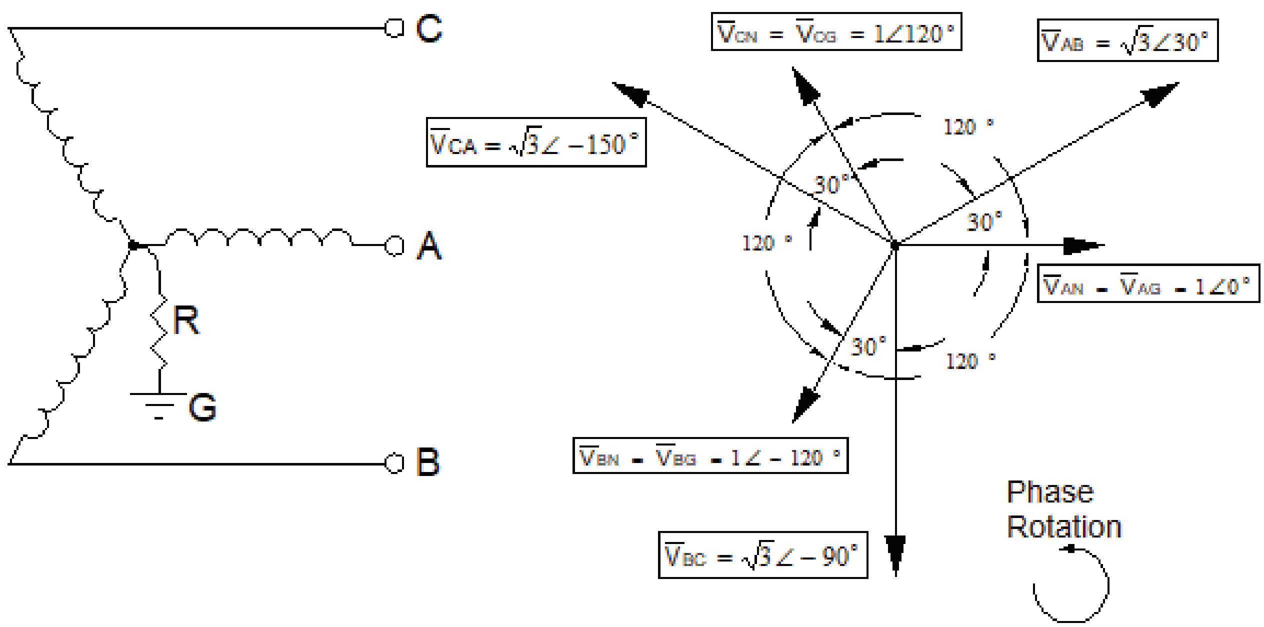
The ground detection per A Ground Detection Method for Ungrounded Systems, page 59 indicate on which phase the ground current trip occurs, but not where in the system the ground current trip occurs. This, along with the disadvantages of ungrounded systems due to susceptibility to voltage transients, was the main impetus for the development of other ground system arrangements.

Modern power systems are rarely ungrounded due to the advent of high-resistance grounded systems as discussed below. However, older ungrounded systems are occasionally encountered.

High-resistance Grounded Systems

One ground arrangement that has gained in popularity in recent years is the high-resistance grounding arrangement. For low-voltage systems, this arrangement typically consists of a wye winding arrangement with the neutral connected to ground through a resistor. The resistor is sized to allow one - ten A to flow continuously if a ground current trip occurs. This arrangement is illustrated in High-resistance Grounded System with No Ground Present, page 60.

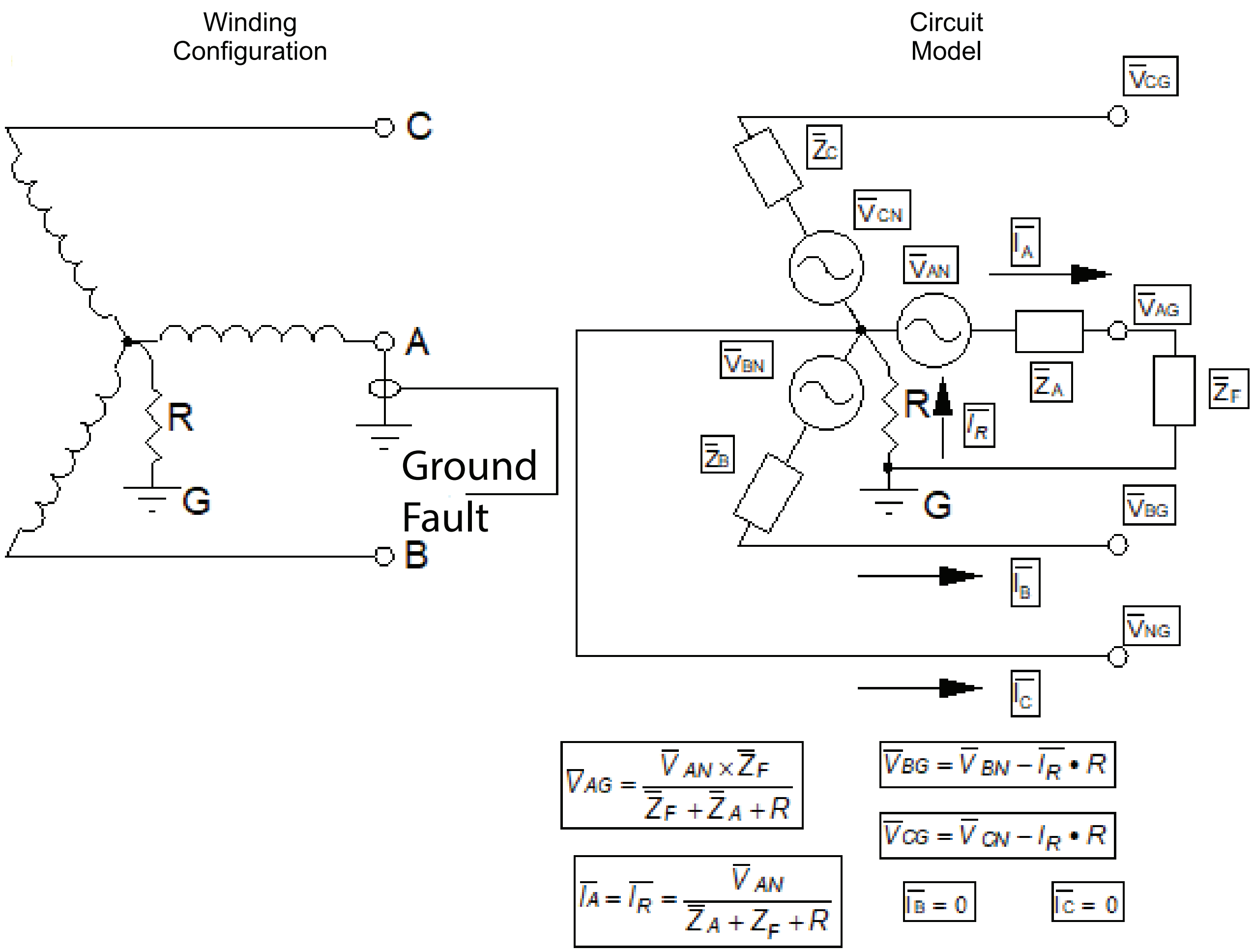
Figure 40 - High-resistance Grounded System with No Ground Present



The resistor is sized to be less than or equal to the magnitude of the system charging capacitance to ground. If the resistor is thus sized, the high-resistance grounded system is usually not susceptible to the large transient overvoltages that an ungrounded system can experience. The ground resistor is usually provided with taps to allow field adjustment of the resistance during commissioning.

If no ground current trip current is present, the phasor diagram for the system is the same as for a solidly-grounded wye system, as shown in High-resistance Grounded System with No Ground Present, page 60. However, if a ground current trip occurs on one phase the system response is as shown in High-resistance Grounded System with a Ground-current Trip on One Phase, page 61. As seen from High-resistance Grounded System with a Ground-current Trip on One Phase, page 61, the ground fault current is limited by the grounding resistor. If the approximation is made that that $\bar{Z}_A$ and $\bar{Z}_F$ are very small compared to the ground resistor resistance value R, which is a good approximation if the fault is a bolted ground fault, then the ground fault current is approximately equal to the phase-to-neutral voltage of the faulted phase divided by R. The faulted phase voltage to ground in that case would be zero and the unfaulted phase voltages to ground would be 173% of their values without a ground current trip present. This is the same phenomenon exhibited by the ungrounded system arrangement, except that the ground current fault current is larger and approximately in-phase with the phase-to-neutral voltage on the faulted phase. The limitation of the ground current trip current to such a low level, along with the absence of a solidly-grounded system neutral, has the effect of making this system ground arrangement unsuitable for single-phase line-to-neutral loads.

Figure 41 - High-resistance Grounded System with a Ground-current Trip on One Phase

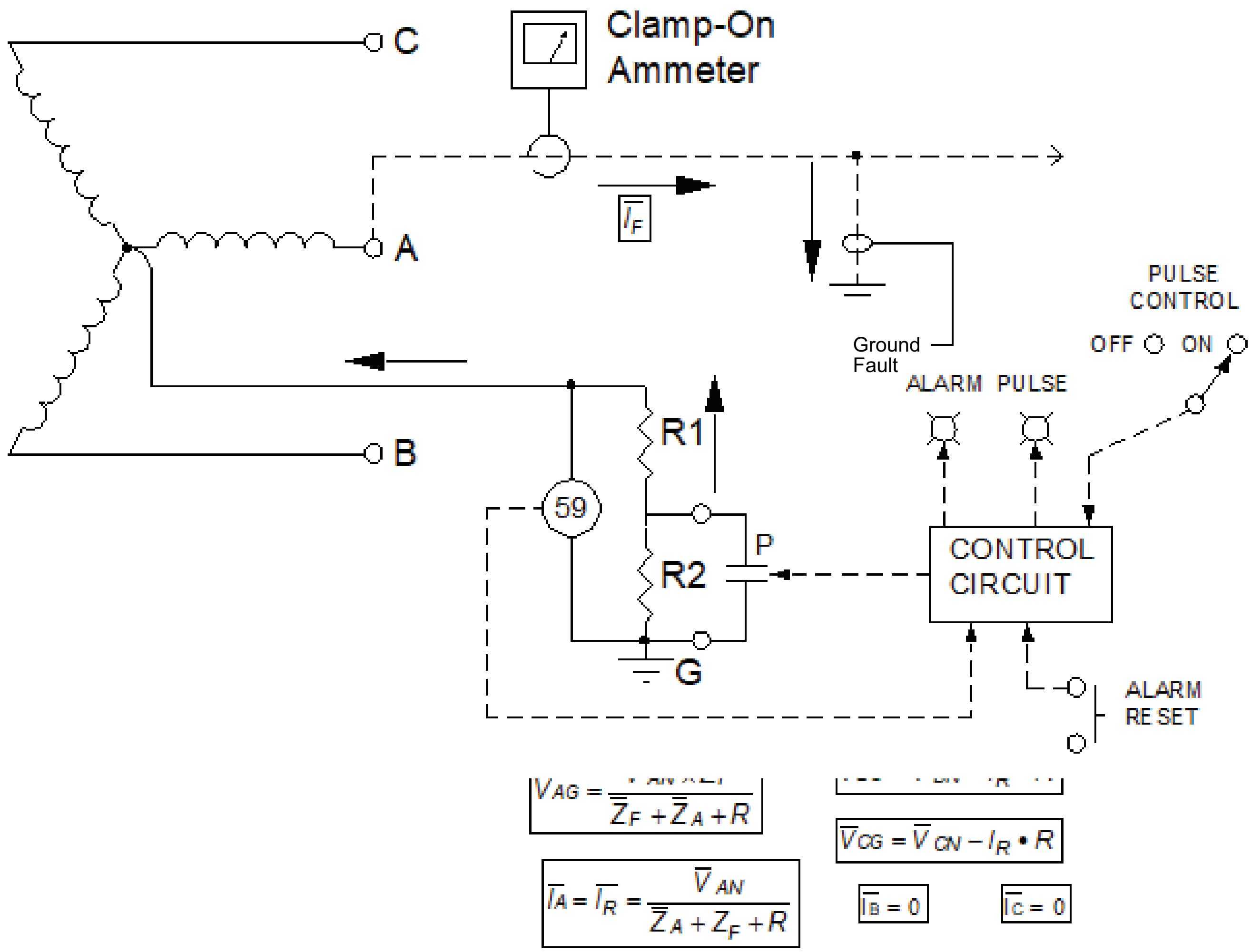


The ground current trip current is not large enough to force its removal by taking the system off-line. Therefore, the high-resistance grounded system has the same operational advantage in this respect as the ungrounded system. However, in addition to the improved voltage transient response as discussed above, the high-resistance grounded system has the advantage of allowing the location of a ground current trip to be tracked.

A typical ground detection system for a high-resistance grounded system is illustrated in Pulsing Ground Detection System, page 62. The ground resistor is shown with a tap between two resistor sections R1 and R2. When a ground current trip occurs, relay 59 (the ANSI standard for an overvoltage relay, as discussed later in this guide) detects the increased voltage across the resistor. It sends a signal to the control circuitry to initiate a ground current trip alarm by energizing the “alarm” indicator. When the operator turns the pulse control selector to the “ON” position, the control circuit causes pulsing contact P to close and re-open approximately once per second. When P closes R2 is shorted and the “pulse” indicator is energized. R1 and R2 are sized so that approximately five to seven times the resistor continuous ground current trip current flows when R2 is shorted. The result is a pulsing ground current trip current that can be detected using a clamp-on ammeter (an analog ammeter is most convenient). By tracing the circuit with the ammeter, the ground current trip location can be determined. Once the ground current trip has been removed from the system pressing the “alarm reset” button de-energizes the “alarm” indicator.

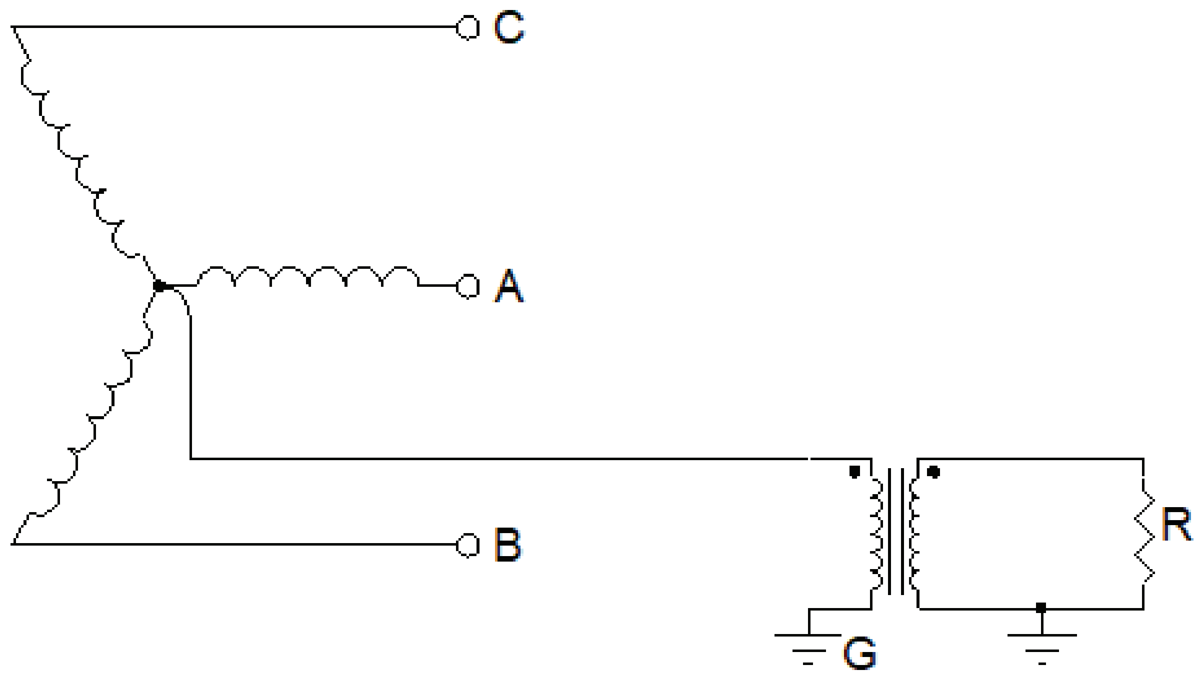
This type of system is known as a pulsing ground detection system and is very effective in locating ground current trips but is generally more expensive than the ungrounded system ground current trip indicator in High-resistance Grounded System with No Ground Present, page 60.

Figure 42 - Pulsing Ground Detection System



For medium-voltage systems, high-resistance grounding is usually implemented using a low-voltage resistor and a neutral transformer, as shown in Medium-Voltage Implementation for High-resistance Grounding, page 63.

Figure 43 - Medium-Voltage Implementation for High-resistance Grounding



Reactance Grounding

In industrial and commercial facilities, reactance grounding is commonly used in the neutrals of generators. In most generators, solid grounding may permit the level of ground-fault current available from the generator to exceed the three-phase value for which its windings are braced (see *IEEE Recommended Practice for Grounding of Industrial and Commercial Power Systems*[34]). For these cases, grounding of the generator neutral through an air-core reactance is the standard solution for lowering the ground current trip level. This reactance ideally limits the ground-fault current to the three-phase available fault current and allows the system to operate with phase-to-neutral loads.

Low-resistance Grounded Systems

By sizing the resistor in High-resistance Grounded System with a Ground-current Trip on One Phase, page 61 such that a higher ground current trip current, typically 200–800 A, flows during a ground current trip a low-resistance grounded system is created. The ground current trip current is limited but is of high enough magnitude to require its removal from the system as quickly as possible. The low-resistance grounding arrangement is typically used in medium-voltage systems which have only three-wire loads, such as motors, where limiting damage to the equipment during a ground current trip is important enough to include the resistor but it is acceptable to take the system offline for a ground current trip. The low-resistance grounding arrangement is generally less expensive than the high-resistance grounding arrangement but more expensive than a solidly grounded system arrangement.

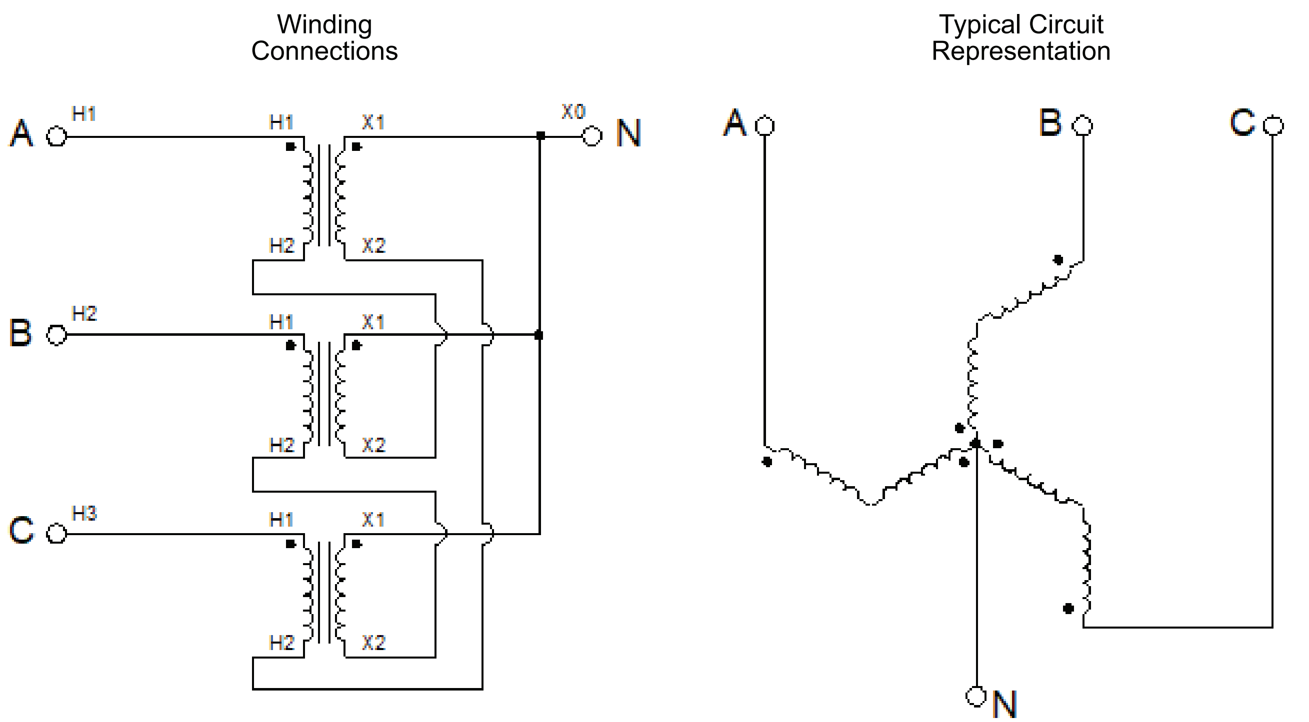
34. IEEE Std. 142-1991, December 1991.

Creating an Artificial Neutral in an Ungrounded System

In some cases, it is required to create a neutral reference for an ungrounded system. Most instances involve existing ungrounded systems which are being upgraded to high-resistance grounding. The existence of multiple transformers and/or delta-wound generators may make the replacement of this equipment economically unfeasible.

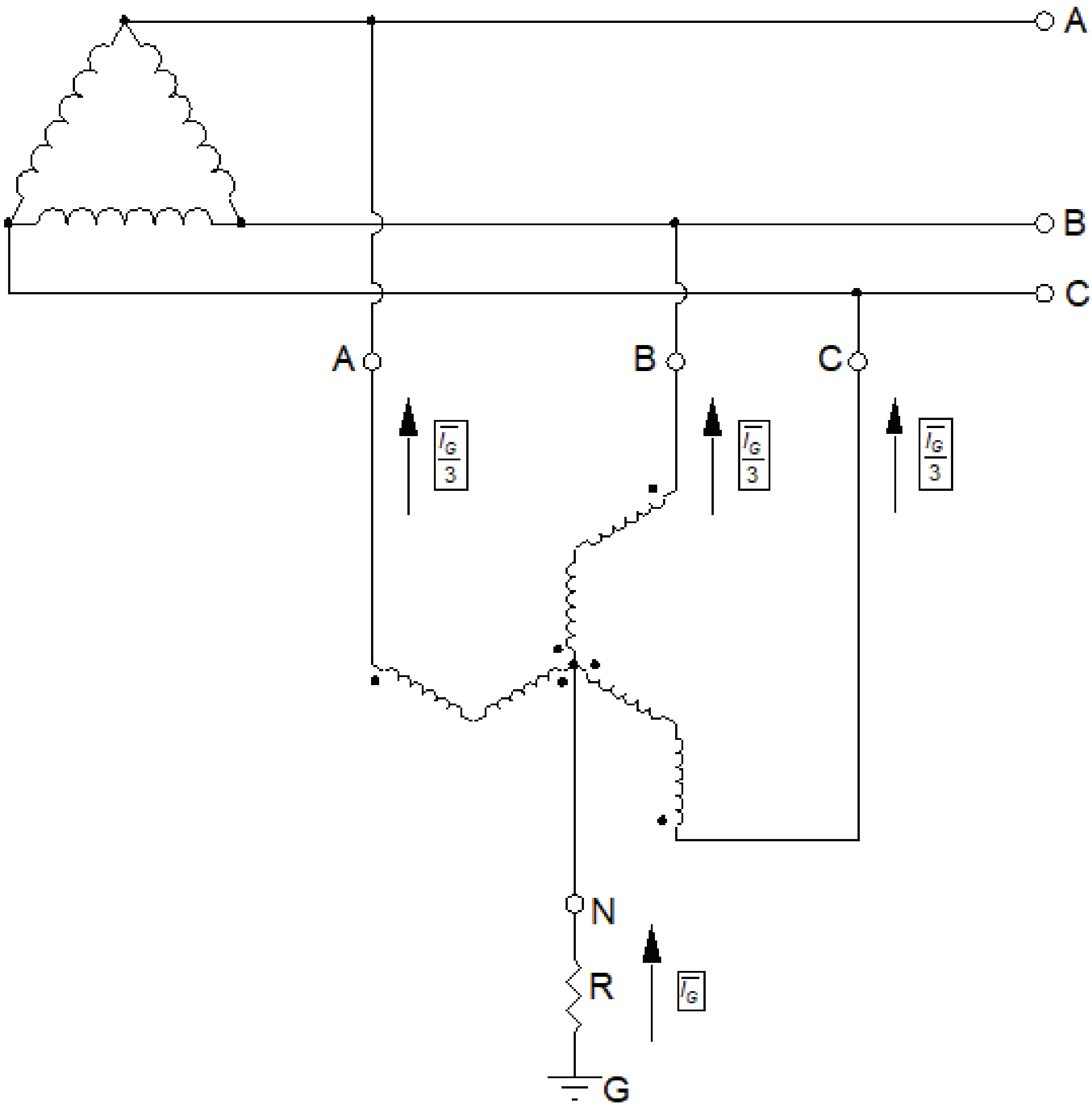
The solution is a grounding transformer. Although several different configurations exist, by far the most popular in commercial and industrial system is the zig-zag transformer arrangement. It uses transformers connected as shown in Zig-zag Grounding Transformer Arrangement, page 64.

Figure 44 - Zig-zag Grounding Transformer Arrangement



The zig-zag transformer only passes ground current. Its typical implementation on an ungrounded system, to convert the system to a high-resistance grounded system, is shown in Zig-zag Grounding Transformer Implementation, page 65. The zig-zag transformer distributes the ground current $\bar{I}_G$ equally between the three phases. For all practical purposes the system, from a grounding standpoint, behaves as a high-resistance grounded system.

Figure 45 - Zig-zag Grounding Transformer Implementation



The solidly-grounded and low-resistance grounded systems can also be implemented by using a grounding transformer, depending upon the amount of impedance connected in the neutral.

NEC Systems Grounding Requirements

The National Electrical Code [35] does place constraints on system grounding. While this guide is not intended to be a definitive guide to all NEC requirements, several points from the NEC must be mentioned and are based upon the basic principles stated above. As a starting point, several key terms from the NEC need to be defined:

35. The National Fire Protection Association, Inc., 2005 Edition.

Ground: A conducting connection, whether intentional or accidental, between an electrical circuit or equipment and the ground or to some body that serves in place of the earth.

Grounded: Connected to ground or to some body that serves in place of the earth.

Effectively Grounded: Intentionally connected to ground through a ground connection or connections of sufficiently low impedance and having sufficient current-carrying capacity to help prevent the buildup of voltages that may result in undue hazards to connected equipment or to persons.

Grounded Conductor: A system or circuit conductor that is intentionally grounded.

Solidly Grounded: Connected to ground without inserting any resistor or impedance device.

Grounding Conductor: A conductor used to connect equipment or the grounded circuit of a wiring system to a grounding electrode or electrodes.

Equipment Grounding Conductor: The conductor used to connect the non-current-carrying metal parts of equipment, raceways and other enclosures to the system grounded conductor, grounding electrode conductor, or both, at the service equipment or at the source of a separately-derived system.

Main Bonding Jumper: The connection between the grounded circuit conductor and the equipment grounding conductor at the service.

System Bonding Jumper: The connection between the grounded circuit conductor and the equipment grounding conductor at a separately-derived system.

Grounding Electrode: The conductor used to connect the grounding electrode(s) to the equipment grounding conductor, to the grounded conductor, or to both, at the service, at each building or structure where supplied by a feeder(s) or branch circuit (s), or at the source of a separately-derived system.

Grounding Electrode Conductor: The conductor used to connect the grounding electrode(s) to the equipment grounding conductor, to the grounded conductor, or to both, at the service, at each building or structure where supplied by a feeder(s) or branch circuit(s), or at the source of a separately-derived system.

Ground Fault: An unintentional, electrically conducting connection between an ungrounded conductor of an electrical circuit and the normally non–current-carrying conductors, metallic enclosures, metallic raceways, metallic equipment, or ground.

Ground Fault Current Path: An electrically conductive path from the point of a ground current trip on a wiring system through normally non–current-carrying conductors, equipment, or the ground to the electrical supply source.

Effective Ground-fault Current Path: An intentionally constructed, permanent, low-impedance electrically conductive path designed and intended to carry current underground-fault conditions from the point of a ground current trip on a wiring system to the electrical supply source and that facilitates the operation of the overcurrent protective device or ground current trip detectors on high-impedance grounded systems.

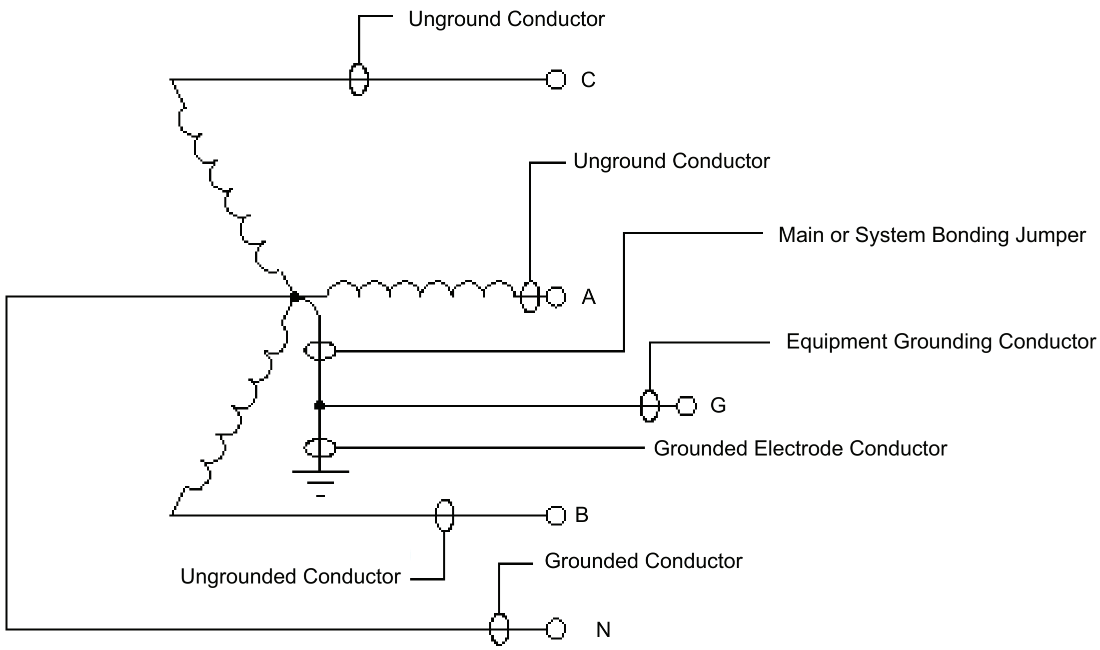
Ground-fault Circuit Interrupter: A device intended for the protection of personnel that functions to de-energize a circuit or portion thereof within an established period of time when a current to ground exceeds the values established for a Class A device. FPN: Class A ground-fault circuit interrupters trip when the current to ground has a value in the range of 4 mA to 6 mA. For further information, see UL 943, Standard for Ground-Fault Circuit Interrupters.

Ground Fault Protection of Equipment: A system intended to provide protection of equipment from damaging line-to-ground current trip currents by operating to cause a disconnecting means to open all ungrounded conductors of the faulted circuit. This protection is provided at current levels less than those required to limit conductors damage through the operation of a supply circuit overcurrent device.

Qualified Person: One who has the skills and knowledge related to the construction and operation of the electrical equipment and installations and has received safety training on the hazards involved.

With these terms defined, several of the major components of the grounding system can be illustrated by redrawing the system of NEC System Grounding Terms Illustration, page 67 and labeling the components.

Figure 46 - NEC System Grounding Terms Illustration



Reference *The National Electrical Code*[36] for the figure above.

Several key design constraints for grounding systems from the NEC (see *IEEE Recommended Practice for Grounding of Industrial and Commercial Power Systems*[37]) are as follows. These are paraphrased from the Code text.

NOTE: This guide is not intended as a substitute for familiarity with the NEC, nor is it intended as an authoritative interpretation of every aspect of the NEC articles mentioned.

- Electrical systems that are grounded must be grounded in such a manner as to limit the voltage imposed by lightning, line surges, or unintentional contact with higher-voltage lines and that stabilizes the voltage to ground during normal operation [Article 250.4(A)(1)]. In other words, if a system is considered solidly grounded the ground impedance must be low.
- If the system can be solidly grounded at 150 V to ground or less, it must be solidly grounded [Article 250.20(B)]. There is therefore no such system as a “120 V Ungrounded Delta” in use, even though such a system is physically possible.
- If the system neutral carries current it must be solidly grounded [Article 250.20 (B)]. This is indicative of single-phase loading and is typical for a 4-wire wye (such as Solidly-grounded Wye System Arrangement and Voltage Relationships, page 52) or center-tapped four-wire delta (such as Center-Tap-grounded Delta System Arrangement and Voltage Relationships, page 54) system.

36. NFPA 70, The National Fire Protection Association, Inc., 2005 Edition.
37. IEEE Std. 142-1991, December 1991.

- Certain systems are permitted, but not required, to be solidly grounded. They are listed as electric systems used exclusively to supply industrial electric furnaces for melting, refining, tempering, and the like, separately derived systems used exclusively for rectifiers that supply only adjustable-speed industrial drives, and separately derived systems supplied by transformers that have a primary voltage rating less than 1000 V provided that certain conditions are met [Article 250.21].
- If a system 50 - 1000 Vac is not solidly grounded, ground detectors must be installed on the system unless the voltage to ground is less than 120 V [Article 250.21].
- Certain systems cannot be grounded. They are listed as circuits for electric cranes operating over combustible fibers in Class III locations as provided in Article 503.155, circuits within hazardous (classified) anesthetizing locations and other isolated power systems in health care facilities as provided in 517.61 and 517.160, circuits for equipment within electrolytic cell working zone as provided in Article 668, and secondary circuits of lighting systems as provided in 411.5(A) [Article 250.22]. Some of the requirements for hazardous locations and health care facilities are covered in Electrical Energy Management.
- For solidly-grounded systems, an unspliced main bonding jumper must be used to connect the equipment grounding conductor(s) and the service disconnect enclosure to the grounded conductor within the enclosure for each utility service disconnect [Article 250.24(B)].
- For solidly-grounded systems, an unspliced system bonding jumper must be used to connect the equipment grounding conductor of a separately derived system to the grounded conductor. This connection must be made at any single point on the separately derived system from the source to the first system disconnecting means or overcurrent device [250.30(A)(1)].
- A grounding connection on the load side of the main bonding or system bonding jumper on a solidly-grounded system is not permitted [Articles 240.24(A)(5), 250.30(A)]. The reasons for this are explained in below and in Arc Flash Considerations.
- Ground fault protection of equipment must be provided for solidly grounded wye electrical services, feeder disconnects on solidly-grounded wye systems, and building or structure disconnects on solidly-grounded wye systems under the following conditions:
  1. The voltage is greater than 150 V to ground but does not exceed 600 V phase-to-phase.
  2. The utility service, feeder, or building or structure disconnect is rated 1000 A or more.
  3. The disconnect in question does not supply a fire pump or continuous industrial process.[Articles 215.10, 230.95, 240.13].
- Where ground current trip protection is required per Article 215.10 or 230.95 for a health care facility, an additional step of ground current trip protection is required in the next downstream device toward the load, except for circuits on the load side of an essential electrical system transfer switch and between on-site generating units for the essential electrical system and the essential electrical system transfer switches [Article 517.17]. Specific requirements for health-care systems are described in Emergency and Standby Power Systems.
- The alternate source for an emergency or legally-required standby system is not required to have ground current trip protection. For an emergency system, ground-fault indication is required [Articles 700.26, 701.17]. Emergency and Standby Power Systems describes the requirements for Emergency and Standby Power Systems.

- All electrical equipment, wiring, and other electrically conductive material must be installed in a manner that creates a permanent, low-impedance path facilitating the operation of the overcurrent device. This circuit must have the ability to carry the ground current trip current imposed upon it. [Article 250.4(A)(5)]. The intent of this requirement is to allow ground current trip current magnitudes to be sufficient for the ground current trip protection/detection to detect (and for ground current trip protection to clear) the fault, and for a ground current trip not to cause damage to the grounding system.
- High-impedance grounded systems may be utilized on AC systems of 480 - 1000 V where:
  1. Conditions of maintenance and supervision so that only qualified persons access the installation.
  2. Continuity of power is required.
  3. Ground detectors are installed on the system.
  4. Line-to-neutral loads are not served. [Article 250.36]
- For systems over 1000 V:
  1. The system neutral for solidly-grounded systems may be a single point grounded or multigrounded neutral. Additional requirements for each of these arrangements apply [Article 250.184].
  2. The system neutral derived from a grounding transformer may be used for grounding [Article 250.182].
  3. The minimum insulation level for the neutral of a solidly-grounded system is 600 V. A bare neutral is permissible under certain conditions [Article 250.184 (A) (1)].
  4. Impedance grounded neutral systems may be used where conditions 1, 3, and 4 for the use of high-impedance grounding on systems 480-1000 V above are met [Article 250.186].
  5. The neutral conductor must be identified and fully insulated with the same phase insulation as the phase conductors [Article 250.186 (B)].
- Zig-zag grounding transformers must not be installed on the load side of any system grounding connection [Article 450.5].
- When a grounding transformer is used to provide the grounding for a three-phase four-wire system, the grounding transformer must not be provided with overcurrent protection independent of the main switch and common-trip overcurrent protection for the three-phase, four-wire system [Article 450.5 (A) (1)]. An overcurrent sensing device must be provided that causes the main switch or common-trip overcurrent protection to open if the load on the grounding transformer exceeds 125% of its continuous current rating [Article 450.5 (A) (2)].

Again, these points are not intended to be an all-inclusive reference for NEC grounding requirements. They do, however, summarize many of the major requirements. When in doubt, consult the NEC.

System Protection

Abstract: To protect personnel, equipment, and maintain continuity of service for an electrical system, protection or fault interrupting devices are required. Adequate system designs allow for the system to withstand and isolate faults while not causing additional damage and/or outages. System protection is paramount and must be understood by all persons interacting or responsible for electrical systems.

Introduction

An important consideration in power system design is system protection. Without system protection, the power system itself, which is intended to be of benefit to the facility in question, would itself become a hazard.

The major concern for system protection is protection against the effects of destructive, abnormally high currents. These abnormal currents, if left unchecked, could cause fires or explosions resulting in risk to personnel and damage to equipment. Other concerns, such as transient overvoltages, are also considered when designing power system protection although they are generally considered only after protection against abnormal currents has been designed.

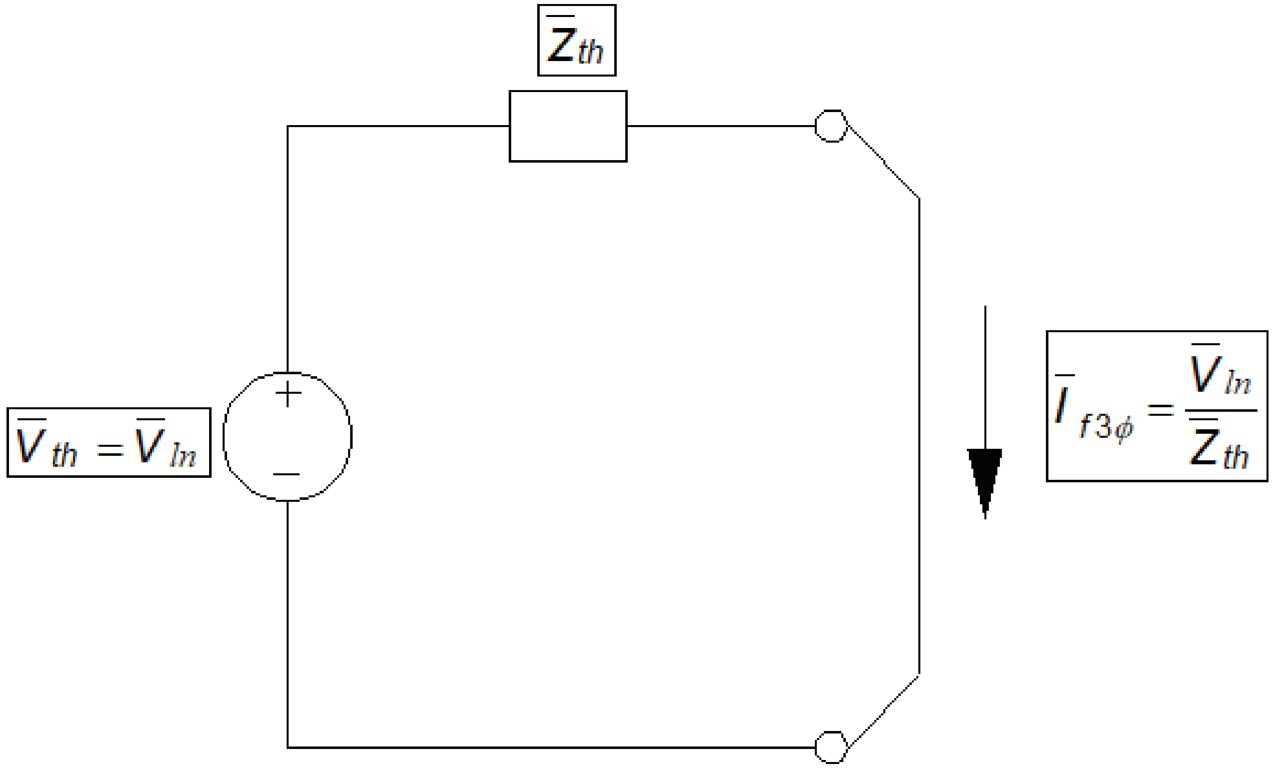
Characterization of Power System Faults

Any current in excess of the equipment rated current or the ampacity of a conductor may be considered an overcurrent. Overcurrents can generally be categorized as overloads or faults. An overload is a condition where load equipment draws more current than the system can supply within its limits. The main hazard with overload conditions is the thermal heating effects of overloaded equipment and conductors. Faults are unintentional connections of the power system resulting in overcurrents much larger in magnitude than overloads.

Faults are categorized in several different ways. A fault with very little impedance in the unintended connection is referred to as a short circuit or bolted fault (the latter term is used since a short circuit can be thought of as a bus bar inadvertently bolted across two phase conductors or from phase to ground). A fault to ground is referred to as a ground current trip. A fault between all three phases is referred to as a three-phase fault. A fault between two phases is referred to as a phase-to-phase fault. A fault containing enough impedance in the unintentional connection to significantly affect the fault current versus. a true short circuit is known as an impedance fault. An arcing fault has the unintentional connection made via an electrical arc through an ionized gas such as air. All these terms are used in practice to characterize the nature of a fault.

To quantitatively characterize a fault, it is necessary to calculate how much fault current could be produced at a given location in the system. In most cases, this is the three-phase short-circuit current, which is the current produced if all three phases were shorted to each other and/or to ground. The simplest method for illustrating this is to reduce the power system at the point in question to its Thevenin equivalent. The Thevenin equivalent is the equivalent single voltage source and impedance that produce the same short-circuit results as the power system itself. The Thevenin equivalent voltage $\bar{V}_{th}$is the open-circuit voltage at the point in question, and the Thevenin equivalent impedance $\bar{Z}_{th}$ is the impedance of the power system at the point in question with the source voltage equal to zero. If a further simplification is made, such that the system can be reduced to its single-phase equivalent, then a simple three-phase fault current calculation for the three-phase fault current $\bar{I}_{f3\Phi}$ can be performed as shown in Simplified Three-phase Fault Calculation, page 71.

Figure 47 - Simplified Three-phase Fault Calculation



The Thevenin impedance for a power system at a given point in the system is referred to as the short-circuit impedance. In the great majority of power systems, the short-circuit impedance is predominately inductive, therefore one simplification that is often made is to treat the impedance purely as inductance. This has the effect of causing the fault current to lag the system line-to-neutral voltage by 90º. If the system is an ungrounded delta system, the equivalent line-to-neutral voltage is obtained by performing a delta-wye conversion of the source voltage.

The phase-to-phase fault value is calculated from the three-phase fault value, if it is remembered that the line-to-line voltage magnitude is equal to the line-to-neutral voltage magnitude multiplied by √3 and that there will be twice the impedance in the circuit since the return path must be considered. These two facts, taken together, allow computation of the line-to-line fault current magnitude $|\bar{I}_{(fl\text{-}l)}|$ as:

$$\left|\bar{I}_{f\,l-l}\right| = \frac{\sqrt{3}\left|\bar{I}_{f3ø}\right|}{2} \qquad (7–1)$$

This, however, is as far as this simplified analysis method take us. To further characterize fault currents, a method for calculating unbalanced faults must be used. The universally-accepted method for this is a method known as the method of symmetrical components.

In the method of symmetrical components, unbalanced currents and voltages are broken into three distinct components: positive sequence, negative sequence, and zero sequence. These sequence components are thought of as independent sets of rotating balanced phasors. The positive sequence set rotates in the standard A-B-C phase rotation. The negative sequence set rotates in the negative or C-B-A phase rotation. In the zero sequence, set all three phase components are in phase with one another. The positive, negative and zero sequence components are further simplified by referring only to the A-phase phasor of each set; these are referred to as $\bar{V}_1$for the positive sequence set, $\bar{V}_2$for the negative sequence set and $\bar{V}_0$ for the zero-sequence set. For a given set of phase voltages $\bar{V}_a$, $\bar{V}_b$, $\bar{V}_c$, the sequence components are related to the phase voltages as follows:

$$\bar{V}_1 = 1/3(\bar{V}_a + a\bar{V}_b + a^2\bar{V}_c) \quad (7\text{–}2)$$

$$\bar{V}_2 = 1/3(\bar{V}_a + a^2\bar{V}_b + a\bar{V}_c) \quad (7\text{–}3)$$

$$\bar{V}_0 = 1/3(\bar{V}_a + \bar{V}_b + \bar{V}_c) \quad (7\text{–}4)$$

$$\bar{V}_a = \bar{V}_1 + \bar{V}_2 + \bar{V}_0 \quad (7\text{–}5)$$

$$\bar{V}_b = a^2\bar{V}_1 + a\bar{V}_2 + \bar{V}_0 \quad (7\text{–}6)$$

$$\bar{V}_c = a\bar{V}_1 + a^2\bar{V}_2 + \bar{V}_0 \quad (7\text{–}7)$$

Where:

$a = 1\angle 120^\circ$

The system may be separated into positive, negative, and zero-sequence networks depending upon the fault type and the resulting sequence quantities, then combined per (7-5), (7-6), and (7-7) to yield the phase values.

Modern short-circuit analysis is performed using computers. Even large systems are quickly analyzed via short-circuit analysis software. Even so, some heuristic benefit can be gained by knowing how the method of symmetrical components works. For example, certain protective relays are often set in terms of negative-sequence values and ground currents are often referred to as zero-sequence quantities in the literature.

Another factor that must be considered is the existence of DC quantities in fault currents. Because of the system inductance, the current cannot change instantaneously, therefore upon initiation of a fault the system must go through a transient condition that bridges the gap between the faulted and unfaulted conditions. This transition involves DC currents. For a generic single-phase AC circuit with an open-circuit voltage $v(t)=V_m\sin((\omega t+\theta))$ and a short-circuit impedance consisting of resistance R and inductance L, the fault current for a fault initiated at time t = 0 can be expressed as in *Electrical Transients in Power Systems*[38]:

$$i(t) = V_m/\sqrt{}(R^2 + (\omega L)^2[\sin(\omega t+\theta-\phi))e^{-(R/L)t}] \quad (7\text{–}8)$$

Where:

$\phi = \tan^{-1}(\omega L/R)$

The angle ϕ can be recognized to be the angle of the Thevenin impedance. Several key points can be taken from (7-8):

- When the fault occurs such that $(\theta-\phi) = 0$ no transient occurs. For a purely inductive circuit this would mean that $\theta = 90^\circ$ and thus the fault is initiated when the voltage is at its peak.
- When the fault occurs such that $(\theta-\phi) = 90^\circ$ the maximum transient occurs. For a purely inductive circuit this would mean that $\theta = 0^\circ$ and thus the fault is initiated when the voltage is zero.
- The time constant of the circuit is (L/R) and thus the higher the value of L/R the longer the transient lasts. Instead of (L/R) power systems typically are defined in terms of (X/R), where (X/R) is the ratio of the inductive reactance of the short-circuit impedance to its resistance. Thus, the higher (X/R) or the “X/R ratio”, the longer the short-circuit transient lasts. This has great implications on the rating of equipment.

A typical plot of fault current on a distribution system with a low X/R ratio and closing angle such that a small transient is produced is shown in Fault Current for System with Low X/R Ratio and Small-transient Closing Angle, Normalized to a Steady-state

38. Alan Greenwood, New York, John Wiley and Sons Inc., 1971.

Magnitude of 1, page 73. In contrast with this is the plot shown in Fault Current for System with Higher X/R Ratio and Closing Angle of 0, Normalized to a Steady-state Magnitude of 1, page 74, which is the fault current for a system with a high X/R ratio and closing angle of 0 such that there is a large transient.

Figure 48 - Fault Current for System with Low X/R Ratio and Small-transient Closing Angle, Normalized to a Steady-state Magnitude of 1

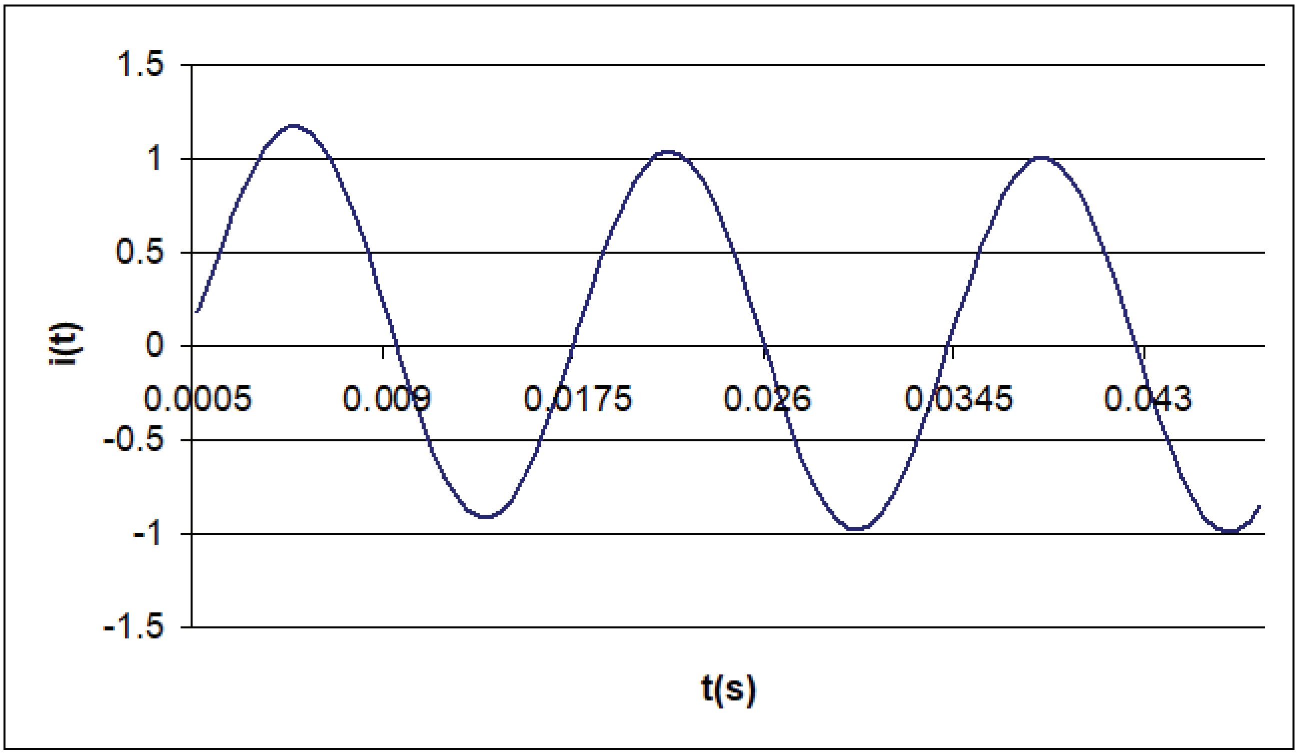
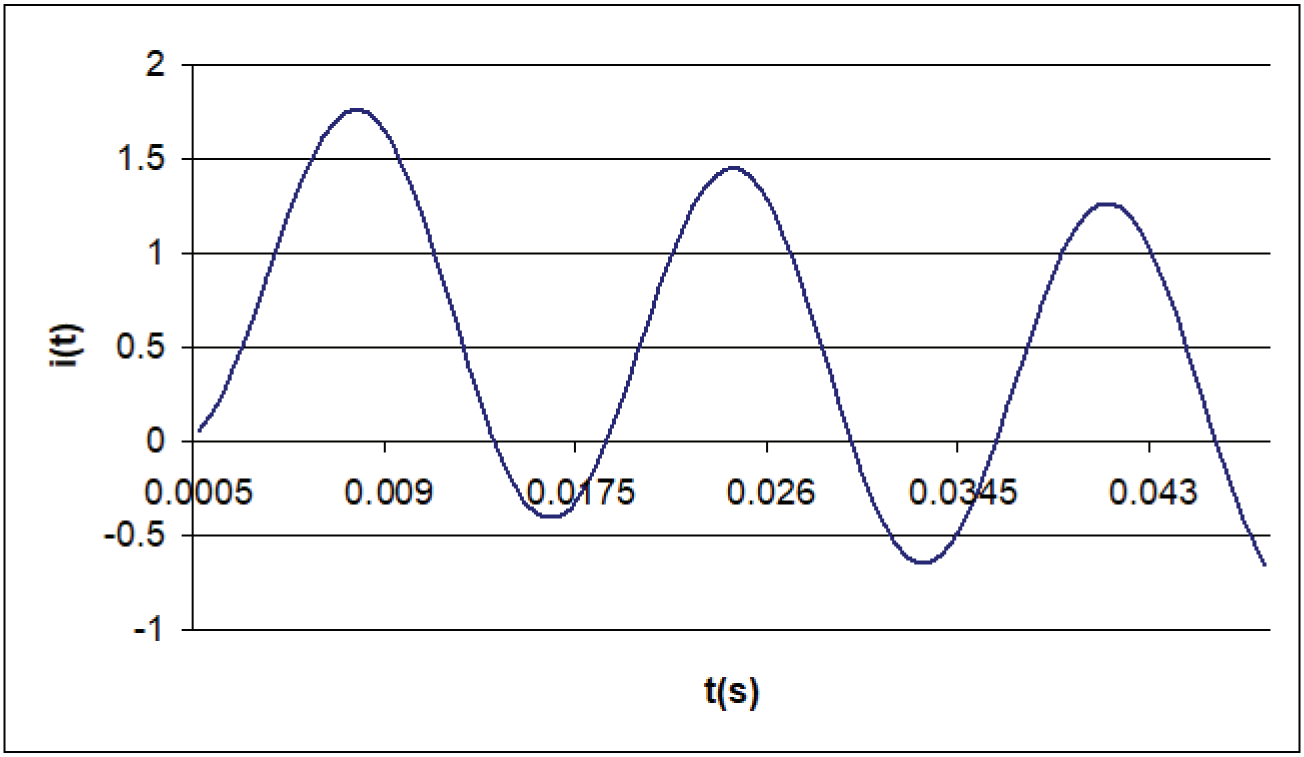


Figure 49 - Fault Current for System with Higher X/R Ratio and Closing Angle of 0, Normalized to a Steady-state Magnitude of 1



Steady-state Component of Waveform in Figure 49, page 75 shows only the steady-state component of the waveform of Fault Current for System with Higher X/R Ratio and Closing Angle of 0, Normalized to a Steady-state Magnitude of 1, page 74 and Transient Component of Waveform in Figure 49, page 75 shows only the transient component.

Figure 50 - Steady-state Component of Waveform in Figure 49

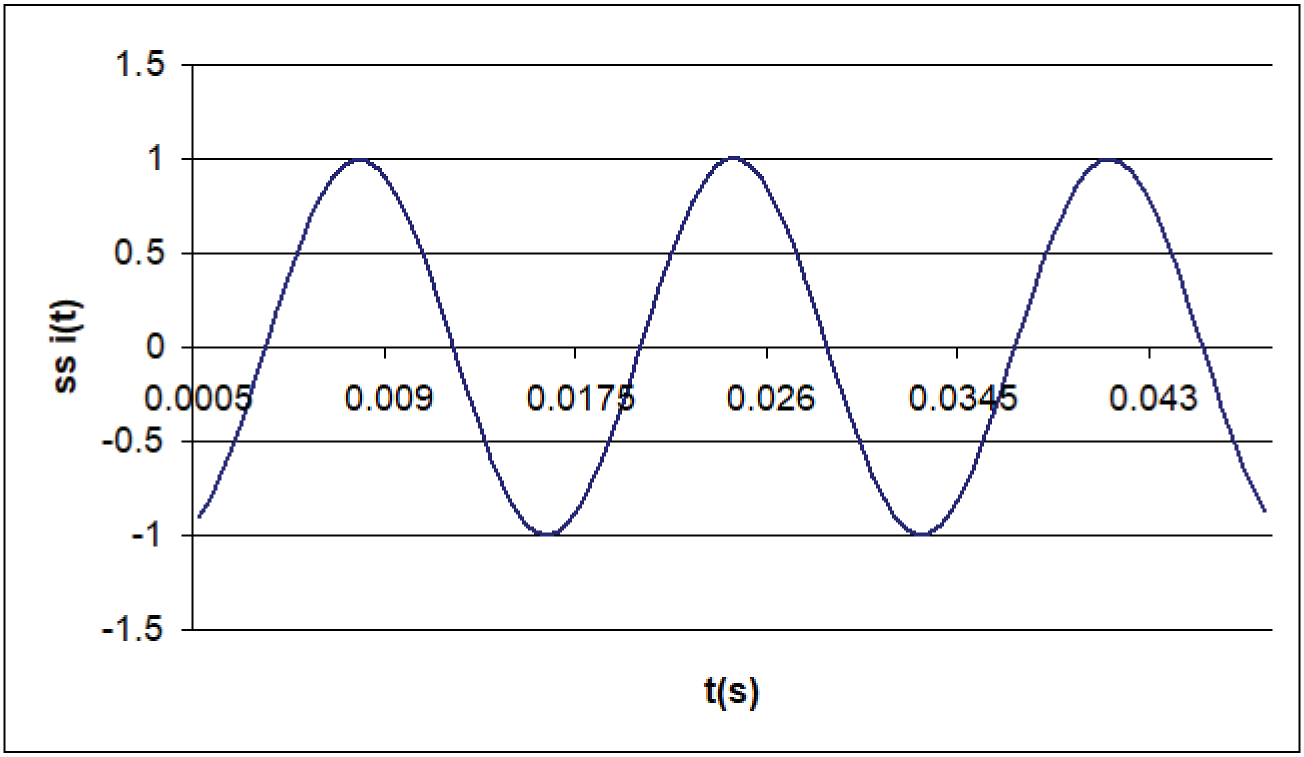
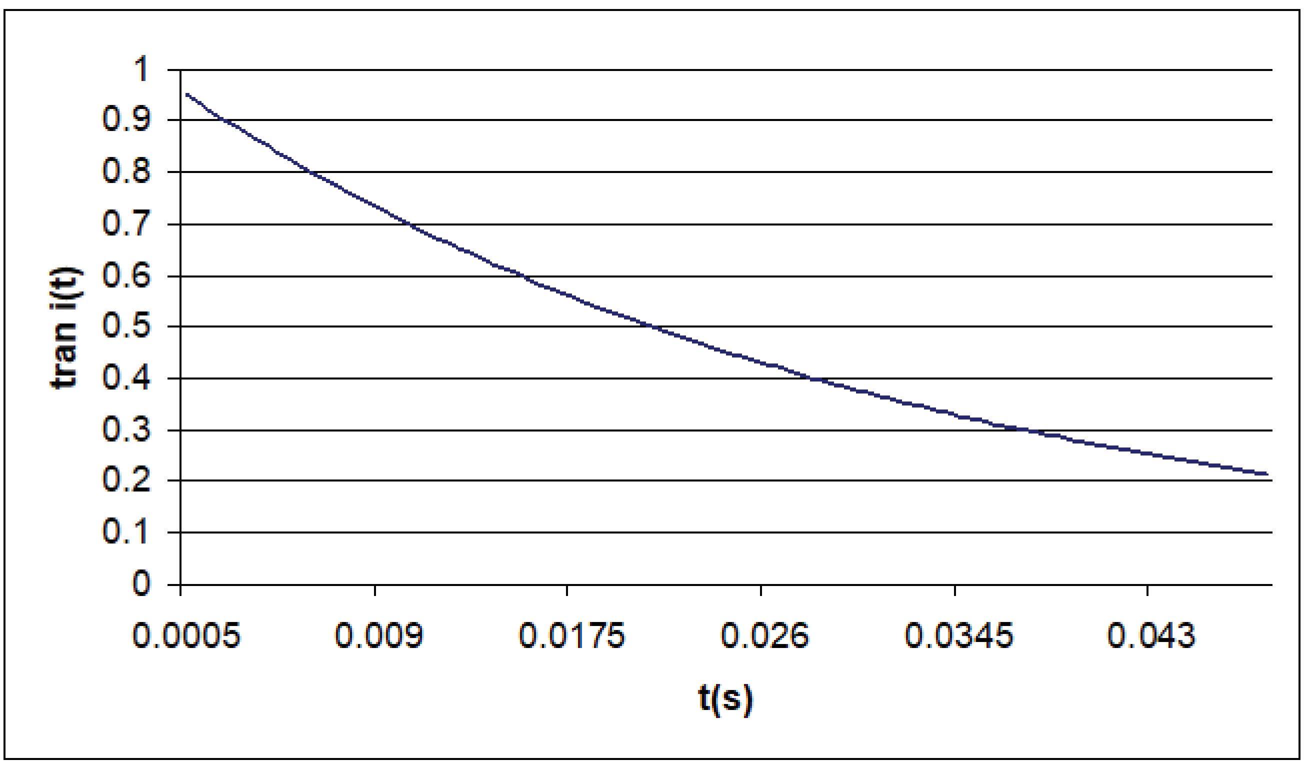


Figure 51 - Transient Component of Waveform in Figure 49



The fault current is often described in terms of its RMS Symmetrical and RMS Asymmetrical values. The RMS symmetrical value is the RMS value considering the steady-state component only. The RMS asymmetrical value is the RMS value over the first cycle considering both the steady-state and transient components at the worst-case closing angle. As a simplification of (7-5) an approximate asymmetry factor can be calculated as detailed in *IEEE Recommended Practice for Protection and Coordination of Industrial Power Systems*[39].

$$\text{Asymmetry Factor} = \sqrt{1 + 2e\left(\frac{2\pi}{X/R}\right)} \qquad (7\text{–}9)$$

For example, this asymmetry factor for an X/R ratio of 25 is 1.6, meaning that the approximate worst-case RMS asymmetrical value over the first cycle for the fault current at an X/R ratio of 25 is no greater than the RMS symmetrical value multiplied by 1.6.

For motors and generators, which have a high X/R ratios, calculations for the transient performance during a fault are simplified by representing the short-circuit impedances differently for different time periods after the fault initiation. The reactive component of the short-circuit impedance for the first half-cycle into the fault is the subtransient reactance (X''_d). For the first several cycles into the fault the reactance is larger and is termed the transient reactance (X'_d . For the long-term fault, currents (up to 30 cycles or so into the fault) the reactance is even larger and is termed the synchronous reactance (X_d. The synchronous reactance is much larger than either the transient or subtransient reactance and models the phenomenon of AC decrement; after the DC component decays the AC component continues to decay, eventually reaching a value that can be less than the generator rated load current.

In general, the closer the fault is to a generator or generators the higher the X/R ratio and thus the larger the DC offset. The AC decrement of the fault from generator sources is pronounced. Faults from most utility services are sufficiently far removed from generation and have enough resistance in the distribution lines that there is less DC offset and essentially no AC decrement. The fault current contribution from induction motors has a high DC offset but also decays rapidly to zero over the first few cycles since there is no applied field excitation. The fault current contribution from synchronous motors has a large DC component and decays to zero but at a slower rate than for induction motors due to the applied field excitation. For a given point in the system, the fault current is the sum of the contributions from all these sources and the DC offset, DC decay, and AC decrement are all dependent upon the relative location of the fault with respect to these sources.

The existence of the transient is of vital importance to selecting the proper equipment for system protection. Because standards for equipment short-circuit ratings vary (more is stated regarding this in subsequent sections of this guide), even more speed and efficiency is gained by using a computer for short circuit calculations; the various equipment rating standards can be considered to produce accurate results for comparison with the equipment ratings.

Methods Of Reducing Short-circuit Current

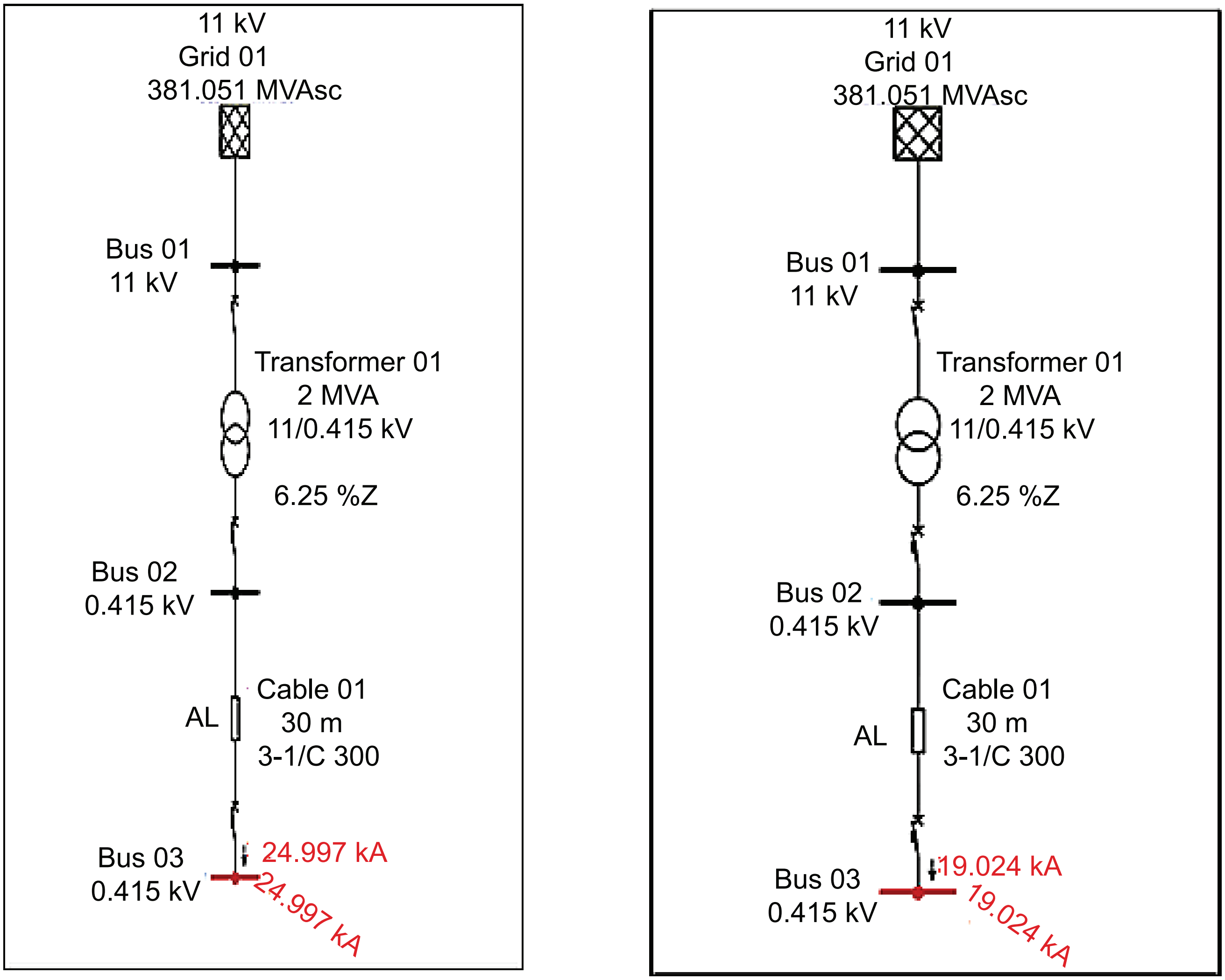
An electrical circuit in which a very low resistance path has been accidently opened. When the resistance in a circuit decreases the current in the circuit increases drastically, which can damage the circuit and cause fires. As a result, certain equipment and other concepts have been used to reduce the short-circuit current:

Increasing the cable length: There are numerous approaches available to minimize the trip current in a low voltage system. Increasing the cable length is one technique.

The trip current in bus 03 is 24.997 kA, and the cable length is 30 meters. However, because the breaking current of a low voltage circuit breaker is 20 kA, increasing the cable length from 30 to 50 meters. reduces the trip current to within 20 kA. The trip current on bus 03 is now 19.024 kA. The trip current decreases when the cable length is increased as shown in the ETAP Simulation for Different Cable Length, page 77.

39. IEEE Std. 242-2001, December 2001.

Figure 52 - ETAP Simulation for Different Cable Length

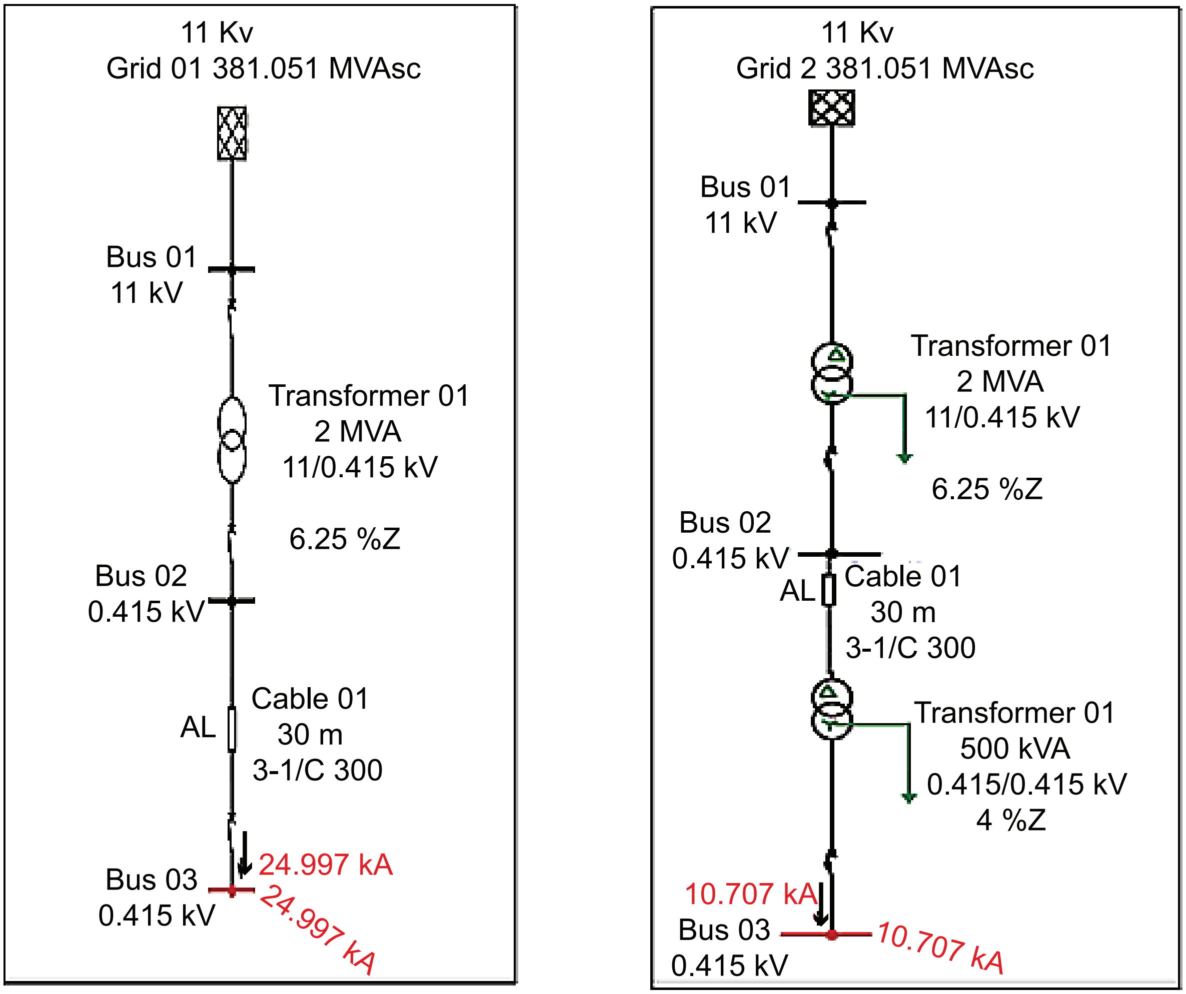


Lighting transformers:

A lighting transformer is nothing but a 1:1 transformer. The transformer turns ratio is the number of turns of the primary winding divided by the number of turns of the secondary coil.

The trip current in bus 03 is 24.997 kA, and the cable length is 30 meters. However, because the breaking current of a low voltage circuit breaker is 20 kA, a lighting transformer has been installed between the cable and bus 03. The trip current is now within 20 kA of the safe limit. The trip current on bus 03 is now 10.707 kA. The trip current is reduced as shown in Lighting Transformer, page 78.

Figure 53 - Lighting Transformer

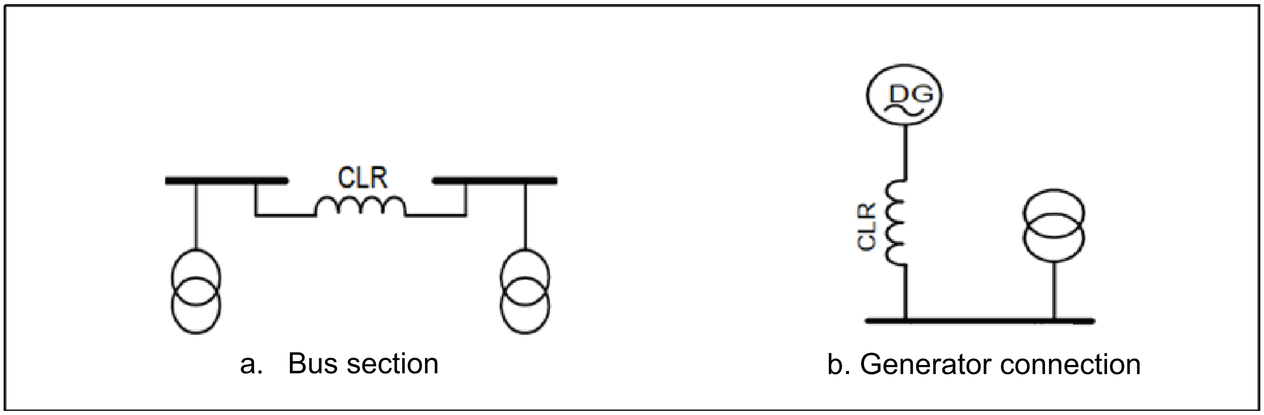


There are numerous approaches available to minimize the trip current in a medium voltage system. One option is to use a current-limiting reactor.

Current limiting reactor (CLR):

Although the CLR introduces impedance into the circuit degrading the voltage profile during normal operation, it can be a cost-effective solution obviating the need for upgrading system switchgear due to an increase in the trip level. A current limiting reactor is a series reactor connected into the circuit for limiting trip current. Above the result is a trip current limit the some values.

Figure 54 - Application of CLR



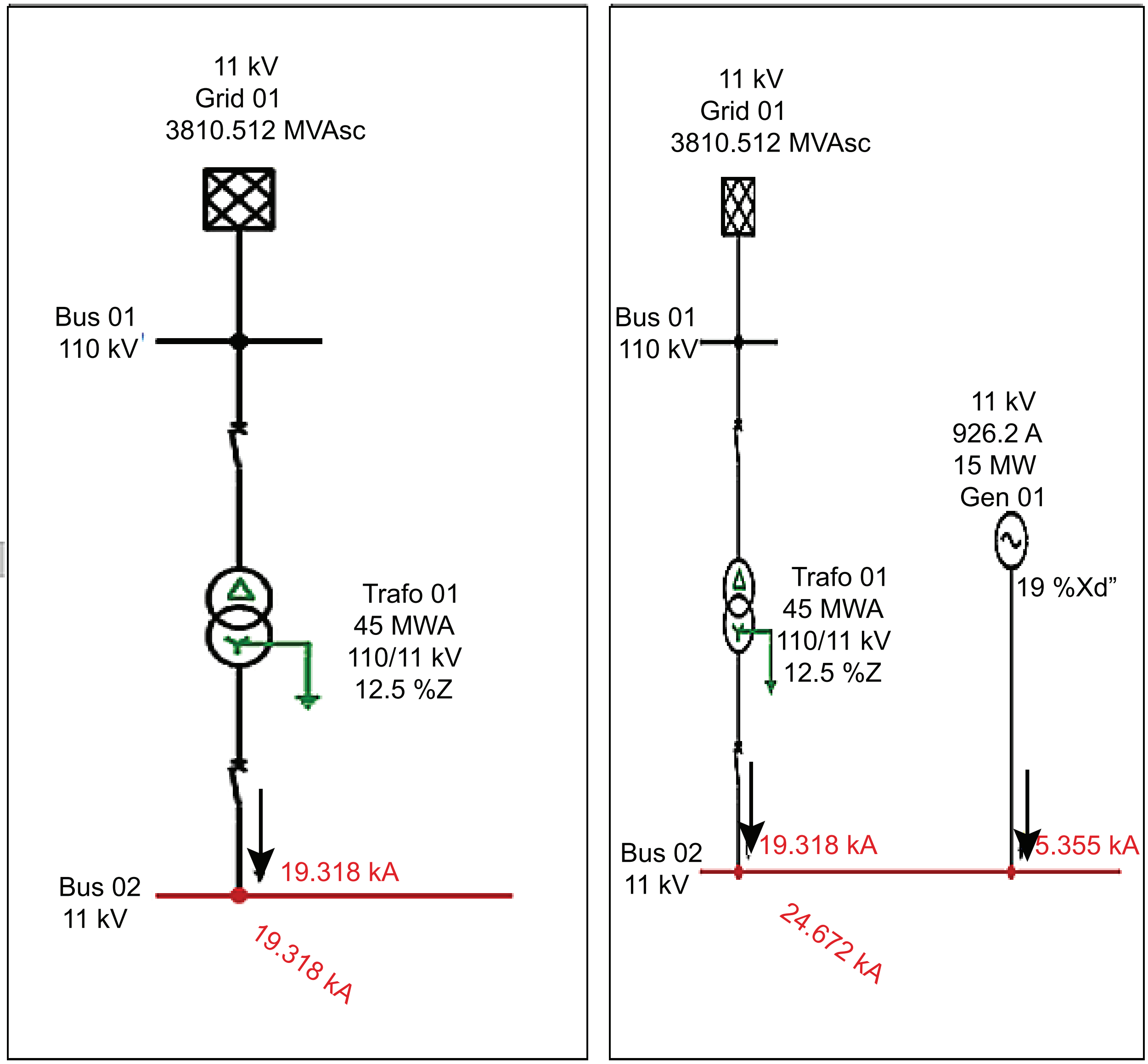
Applications of the CLR for limiting trip level are varied. One of the more attractive applications is often the bus section application (see Application of CLR, page 79). For this arrangement, the CLR is placed between two bus bars to connect them together.

Disadvantages include:

- Voltage drop
- Increasing power loss
- Reduced grid power factor
- High space requirements

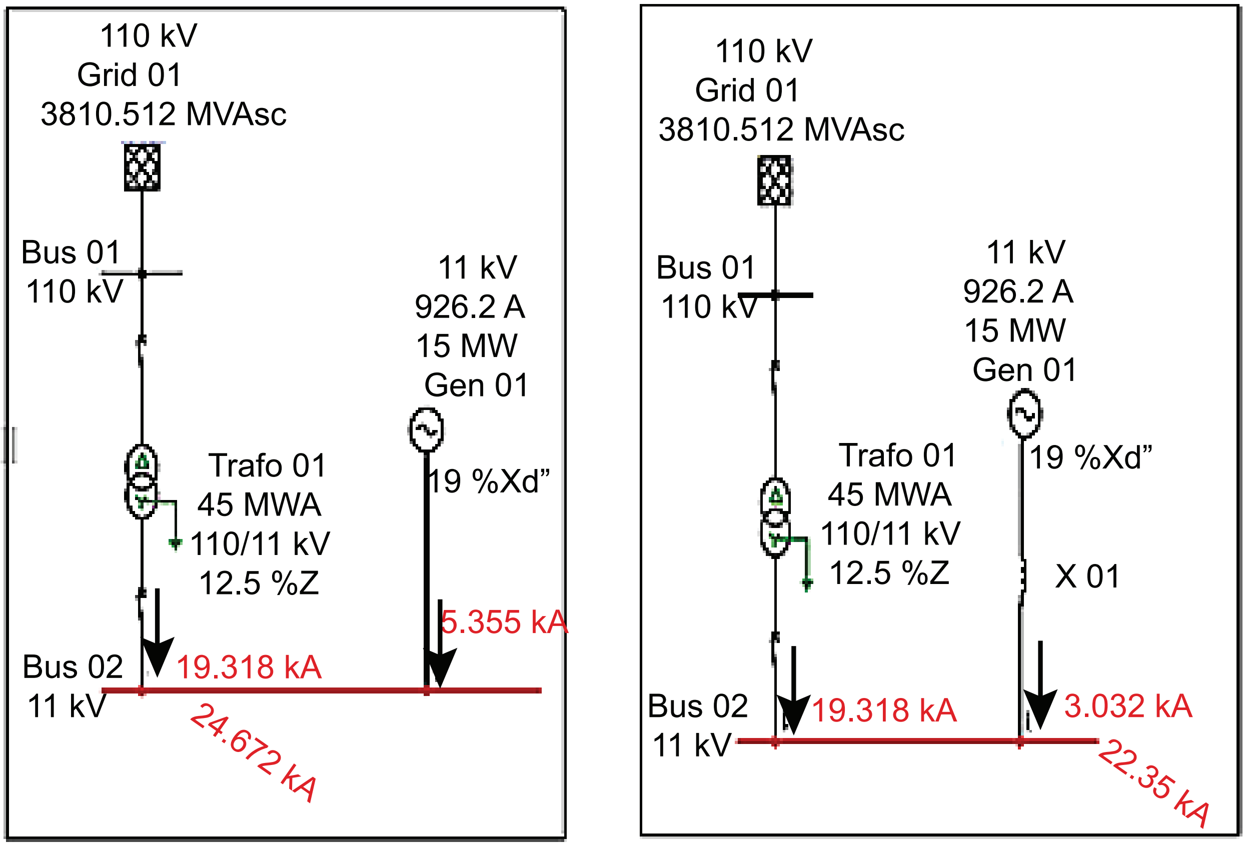
For the system bus 02, as shown in Add a Generator, page 80, the trip current is 19.318 kA under normal conditions. However, as the system power increases to 15 MW for internal purposes by employing one generator, the trip current has increased to 24.672 kA, as shown in Add a Generator, page 80. How to reduce the fault current? Whenever we have use some methods, that are given below.

Figure 55 - Add a Generator



The trip current on bus 02 is from 24.672 kA to 22.35 kA as a result of the above configuration (see Figure 55). The trip current is reduced if the reactor impedance is increased as shown in With Current Limiting Reactor, page 81.

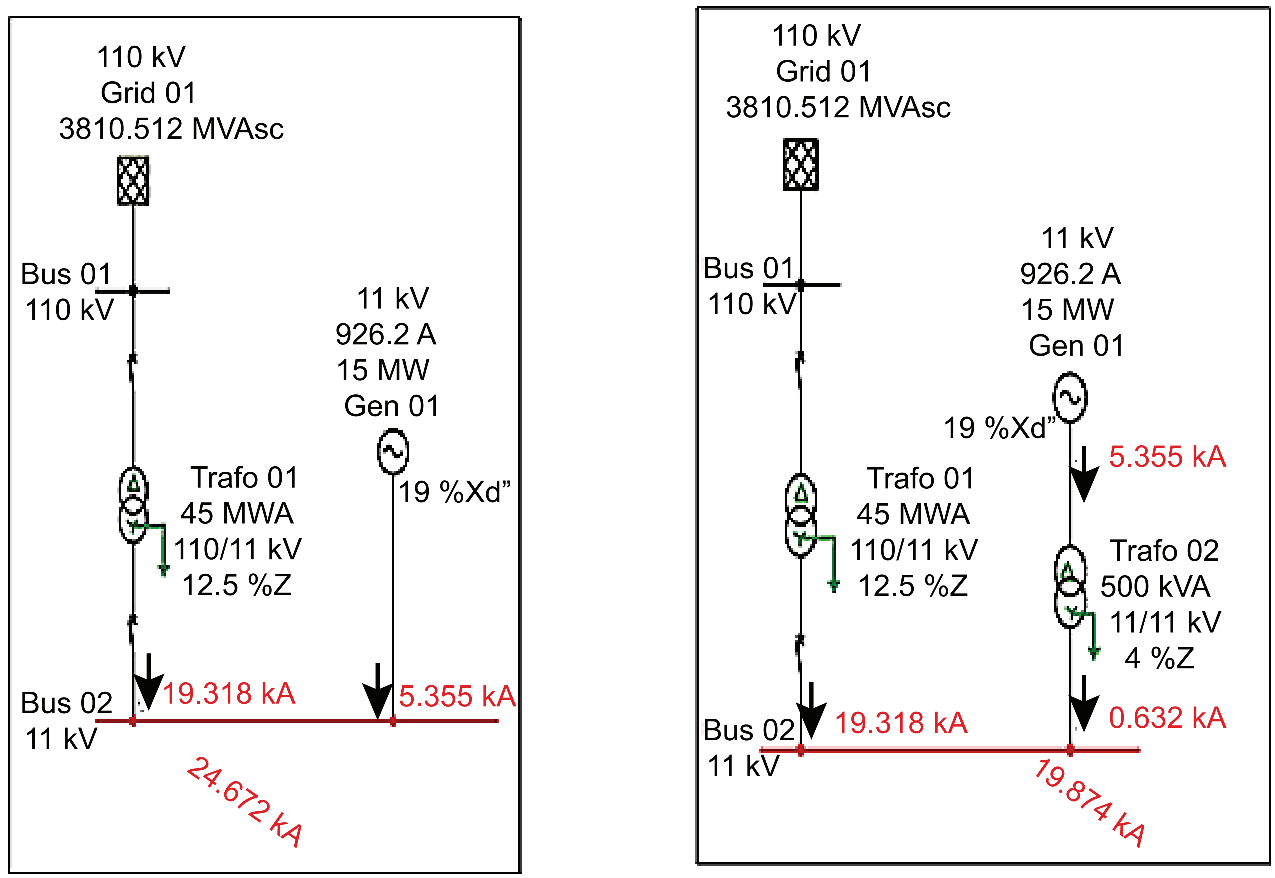
Figure 56 - With Current Limiting Reactor



Unit ratio transformer:

The number of turns on a transformer’s secondary divided by the number of turns on its primary is the turns ratio. If the unit ratio transformer is connected between generator bus 02 and, the trip current of bus 02 is reduced from 24.672 kA to 19.874 kA. The ETAP result is depicted in ETAP Result with Unit Ratio Transormer, page 82.

Figure 57 - ETAP Result with Unit Ratio Transormer



Low Voltage Fuses

The simplest of all overcurrent protective devices is the fuse. A fuse is an overcurrent protective device with a circuit-opening fusible part that is heated and severed by the passage of the overcurrent through it (see *IEEE Recommended Practice for Protection and Coordination of Industrial Power Systems*[40]).

Several definitions are of interest for low-voltage fuses (see *IEEE Recommended Practice for Protection and Coordination of Industrial Power Systems*[40]):

Ampere rating: The RMS current that the fuse can carry continuously without deterioration and without exceeding temperature rise limits. In accordance with NEC (see *The National Electrical Code*[41]) article 210.20 and *The National Electrical Code*[41]) a fuse (or any branch-circuit overcurrent device) shall not be less than the noncontinuous load plus 125% of the continuous load. The exception being where the assembly, including the overcurrent devices protecting the branch circuit(s), is listed for operation at 100% of its rating, the ampere rating of the overcurrent device shall be permitted to be not less than the sum of the continuous load plus the noncontinuous load.

Current-limiting fuse: A current-limiting fuse interrupts all available currents at its threshold current and below its maximum interrupting rating, limits the clearing time at rated voltage to an interval equal to or less than the first major or symmetrical loop duration, and limits peak let-through current to a value less than the peak current possible with the fuse replaced by a solid conductor of the same impedance.

40. IEEE Std. 242-2001, December 2001.
41. NFPA 70, The National Fire Protection Association, Inc., 2020 Edition.

Dual-element fuse: A cartridge fuse having two or more current-responsive elements in series in a single cartridge. The dual-element design is a construction technique frequently used to obtain a desired time-delay response characteristic.

I2t: A measure of heat energy developed within a circuit during the fuse's melting or arcing. The sum of melting and arcing I^2t is generally stated as total clearing I^2t.

Interrupting rating: The rating based upon the highest RMS current that the fuse is tested to interrupt under the conditions specified.

Melting time: The time required to melt the current-responsive element on a specified overcurrent.

Peak let-through current (Ip): The maximum instantaneous current through a current-limiting fuse during the total clearing time.

Time delay: For Class H, K, J, and R fuses, a minimum opening time of ten seconds to an overload current five times the ampere rating of the fuse, except for Class H, K, and R fuses rated 0-30 A, 250 V, in which case the opening time can be reduced to eight seconds. For Class G, Class CC, and plug fuses, a minimum time delay of 12 seconds on an overload of twice the fuses' ampere rating.

Total Clearing time: The total time between the beginning of the specified overcurrent and the final interruption of the circuit, at rated voltage.

Voltage Rating: The RMS voltage at which the fuse is designed to operate. All low-voltage fuses operate at any lower voltage (note that this is characterized as AC or DC, or both).

Low-voltage fuses are classified according to the standard to which they are designed. Low-voltage Fuse Classes, page 83 lists the various fuse classes and pertinent data for each class.

Fuses, like most protective devices, exhibit inverse time-current characteristics. A typical fuse time-current characteristic is shown in Typical Class J Fuse Time — Current Characteristic, page 85. Logarithmic scales are used for both the time and current axies, to cover a wide range. The characteristic represents a band of operating times for which the lower boundary is the minimum melting time curve, above which the fuses can be damaged. The upper boundary is the total clearing time curve, above which the fuse opens. For a given fault current, the actual fuse opening time is within this band.

Table 8 - Low-voltage Fuse Classes

Fuse Class	Voltage Ratings	Ampere Ratings	Interrupting Ratings (RMS)	Current Limiting	Standards	Notes
C	600 Vac 0–600 Vdc	0–12000 A Varies	200,000 A Varies	Varies	UL 248-3-2000, CSA C22.2 NO. 248.2-2000	Plug-style
CA	600 Vac 0–600 Vdc	0–30 A Varies	200,000 A Varies	Yes Yes	UL 248-3-2000, CSA C22.2 NO. 248-3-2000	No mounting holes
CB	600 Vac 0–600 Vdc	0–60 A Varies	200,000 A Varies	Yes Yes	UL 248-3-2000, CSA C22.2 NO. 248-3-2000	Mounting holes in end blades
CC	600 Vac 0–600 Vdc	0–30 A Varies	200,000 A Varies	Yes	UL 248-4-2000 , CSA C22.2 NO. 248.4-2000	Rejection-style;
G	480 Vac 6000 V 480 Vdc	25–60 A 0–20 A Varies	100,000 A 100,000 A Varies	Yes Yes Yes	UL 248-5-2000, CSA C22.2 NO. 248.5-2000	Non-interchangeable dimensions with other fuse classes
H	250 Vac 600 Vac 0–600 Vdc	0–600 A 0–600 A Varies	10,000 A 10,000 A Varies	No No	UL 248-6-2000, CSA C22.2 NO. 248.6-2000	

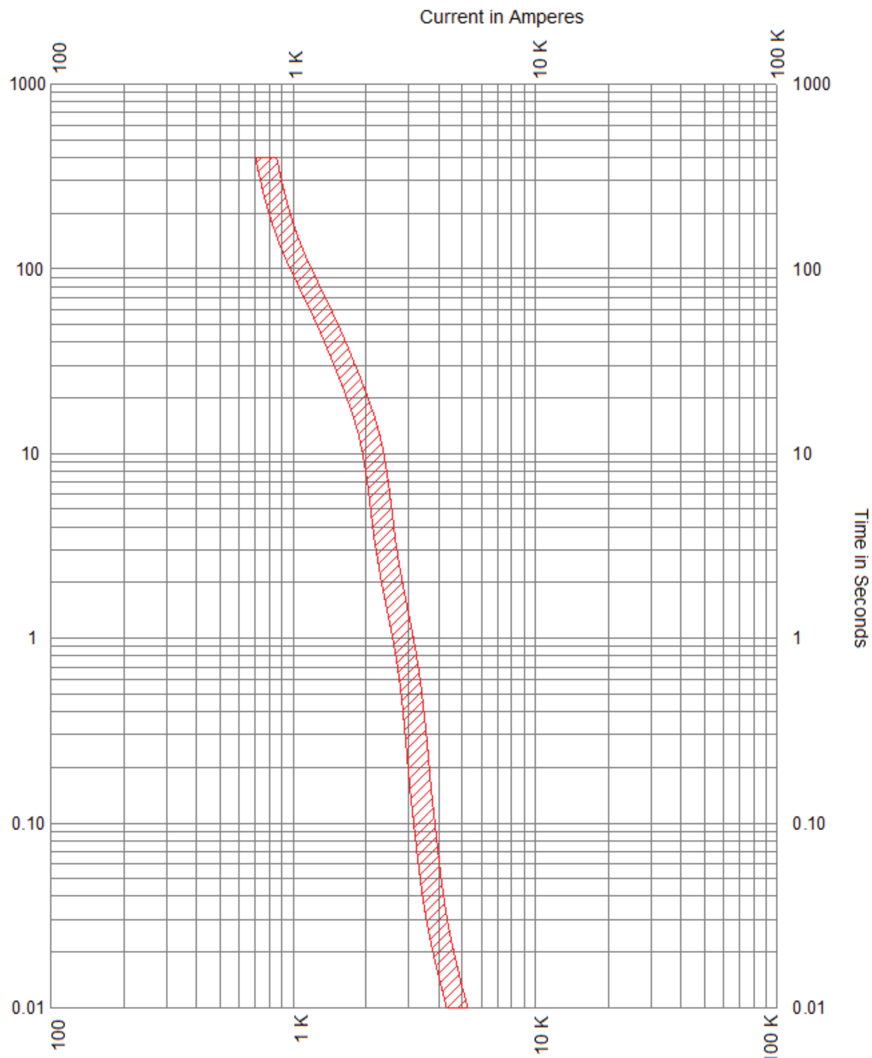
Table 8 - Low-voltage Fuse Classes (Continued)

J	600 Vac 0–600 Vdc	0–600 A Varies	200,000 A Varies	Yes Yes	UL 248-8-2000, CSA C22.2 NO. 248.8-2000	
K	250 Vac 250 Vac 250 Vac 600 Vac 600 Vac 600 Vac 0–600 Vdc	0–600 A 0–600 A 0–600 A 0–600 A 0–600 A 0–600 A Varies	50,000 A 100,000 A 200,000 A 50,000 A 100,000 A 200,000 A Varies	Yes[42] Yes[42] Yes[42] Yes[42] Yes[42] Yes[42]	UL 248-9-2000, CSA C22.2 NO. 248-9-2000	Divided into low (K-1), medium (K-5), and high (K-9) I**p** and I**2**t sub-classes; Dimensions interchangeable with class H fuses
L	600 Vac 0–600 Vdc	601–6000 A Varies	200,000 A Varies	Yes	UL 248-10-2000, CSA C22.2 NO. 248.10-2000	Bolt-on construction
R	250 Vac 600 Vac 0–600 Vdc	0–600 A 0–600 A Varies	200,000 A 200,000 A Varies	Yes Yes	UL 248-12-2000, CSA C22.2 NO. 248.12-2000	Divided into medium (RK-1 and high (RK-5) I**p** and I**2**t sub-classes; Will fit class H or Class K fuse holders, but Class R fuse holders will not fit any other type;
T	300 Vac 600 Vdc 0–600 Vdc	0–1200 A 0–1200 A Varies	200,000 A 200,000 A Varies	Yes Yes	UL 248-15-2000, CSA C22.2 NO 248.15-2000	Similar to Class J, but dimension-ally smaller
Plug Fuses Type C or Type S	125 Vac 125 Vdc	0–30 A 0–30 A	10,000 A 10,000 A	NO	UL 248-11-2000, CSA NO. 248.11-2000	Type S has rejection features

IEEE Recommended Practice for Protection and Coordination of Industrial Power Systems[43]

42. Because of their interchangeability with Class H fuses, class K-1, K-5, and K-9 fuses cannot be marked as “current-limiting”.
43. IEEE Std. 242-2001, December 2001.

Figure 58 - Typical Class J Fuse Time — Current Characteristic



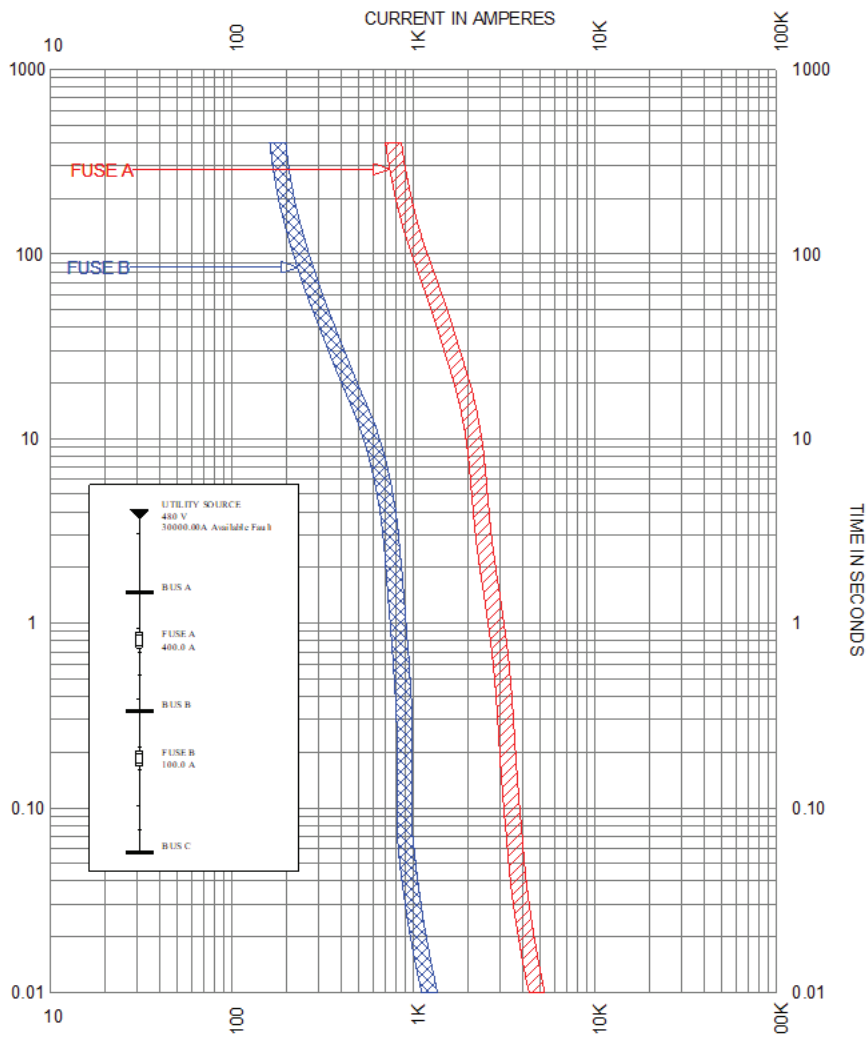
In some cases, the fuse average melting time only is given. This can be treated as the fuse opening time with a tolerance of ±15%. The -15% boundary is the minimum melting time and the +15% boundary is the total clearing time.

The time-current characteristic does not extend below .01 seconds. This is since below .01 seconds the fuse is operating in its current-limiting region and the fuse I^2t is of increasing importance.

The time-current characteristic curves are used to demonstrate the coordination between protective devices in series. The basic principle of system protection is that for a given fault current ideally only the device nearest the fault opens, minimizing the effect of the fault on the rest of the system. This principle is known as selective coordination and is analyzed with the use of the device time-current characteristic curves.

As an example, consider a 480 V system with two sets of fuses in series, with a system available trip current of 30,000 A. Bus “A” uses a 400 A class J fuses which supply, among others, bus “B”. Bus “B” uses a 100 A class J fuses. Coordination between the 400 A and 100 A fuses is shown via the time-current curves of Fuse Coordination Example, page 86, along with a one-line diagram of the part of the system under consideration. Because the time bands for the two fuses do not overlap, these are coordinated for all operating times above .01 seconds. It can be stated that these two sets of fuses are coordinated through approximately 4200 A, since at 4200 A Fuse A has the potential to begin operating in its current-limiting region. Fuse B has the potential to begin operating its current-limiting region at 1100 A. For currents above approximately 4000 A, therefore, both sets of fuses have the potential to be operating in the current-limiting region. When both sets of fuses are operating the current-limiting region the time-current curves cannot be used to the determine coordination between them. Instead, for a given fault current the minimum melting I^2t for Fuse A must be greater than the maximum clearing I^2t for Fuse B. In practice, instead of publishing I^2t data fuse manufacturers typically publish ratio tables showing the minimum ratios of fuses of a given type that coordinate with each other.

Figure 59 - Fuse Coordination Example



Low-voltage fuse AC interrupting ratings are based upon a maximum power factor of .2, corresponding to a maximum X/R ratio of 4.899. To evaluate a low-voltage fuse's interrupting rating on a system with a higher X/R ratio the system symmetrical fault current must be multiplied by a multiplying factor (see *IEEE Recommended Practice for Protection and Coordination of Industrial Power Systems*[44]):

$$\text{MULT} = 1 + e^{(-\pi(X/R)_{actual})}/1 + e^{(-\pi(X/R))_{test}} \qquad (7–10)$$

Where:

$(X/R)_{actual}$ is the actual system X/R.

$(X/R)_{test}$ is the test X/R.

44. IEEE Std. 242-2001, December 2001.

The available symmetrical fault current multiplied by the multiplying factor per (7-10) can be compared to the fuse interrupting rating.

The use of fuses requires a holder and a switching device in addition to the fuses themselves. Because they are single-phase devices, a single blown fuse from a three-phase set causes a loss of phase condition, which can lead to motor damage. Replacing fuses typically requires opening equipment doors and/or removing cover panels. Also, replacement fuses must be stocked to get a circuit with a blown fuse back on-line quickly. For these reasons, the use of low-voltage fuses in modern power systems is generally discouraged.

Low Voltage Molded-case Circuit Breakers

The molded-case circuit breaker is the "workhorse" for system protection for 600 V and below. A circuit breaker is a device designed to open and close by nonautomatic means and to open the circuit automatically on a predetermined overcurrent without damage to itself when properly applied within its rating (see *The National Electrical Code*[45]).

The following terms apply to molded-case circuit breakers (see *IEEE Recommended Practice for Protection and Coordination of Industrial Power Systems*[46], and *Molded-Case Circuit Breakers, Molded Case Switches and Circuit-Breaker Enclosures*,[47]):

Voltage: Circuit breakers are designed and marked with the maximum voltage at which they are applied. Circuit breaker voltage ratings distinguish between delta-connected, three-wire systems and wye-connected, four-wire systems. As stated in NEC article 240.85 *The National Electrical Code* (see *The National Electrical Code*[45]), a circuit breaker with a straight voltage rating, such as 240 V circuit breaker with a straight voltage rating, shall be permitted to be applied in a circuit in which the nominal voltage between any two conductors does not exceed the circuit breakers voltage rating. A two-pole circuit breaker shall not be used for protecting a three-phase, corner-grounded delta circuit unless the circuit breaker is marked 1ϕ - 3ϕ to indicate such suitability.

A circuit breaker with a slash rating, such as 120/240 V or 480Y/277 V, shall be permitted to be applied in a solidly-grounded circuit where the nominal voltage of any conductor to ground does not exceed the lower of the two values of the circuit breaker's voltage rating and the nominal voltage between any two conductors does not exceed the higher value of the circuit breaker's voltage rating.

Frequency: Molded-case circuit breakers are normally suitable for 50 Hz or 60 Hz. Some have DC ratings as well.

Continuous current or Rated current: This is the maximum current a circuit breaker can carry continuously at a given ambient temperature rating without tripping (typically 40°C). In accordance with NEC (see *The National Electrical Code*[45]) article 210 for a circuit breaker (or any branch circuit overcurrent device) that supplies continuous loads or any combination of continuous and noncontinuous loads, the rating of the overcurrent device shall not be less than the noncontinuous load plus 125% of the continuous load. The exception is where the assembly, including the overcurrent devices protecting the circuit(s), is listed for operation at 100% of its rating, the ampere rating of the overcurrent device shall be permitted to be not less than the sum of the continuous load plus the noncontinuous load.

Poles: The number of poles is the number of ganged circuit breaker elements in a single housing. Circuit breakers are available with one, two, or three poles, and four poles for certain applications. Per NEC (see *The National Electrical Code*[45]) article 240.85 a two-pole circuit breaker cannot be used for protecting a three-phase, corner-grounded delta circuit unless the circuit breaker is marked 1ϕ - 3ϕ to indicate such suitability.

45. NFPA 70, The National Fire Protection Association, Inc., 2020 Edition.
46. IEEE Std. 242-2001, December 2001.
47. UL 489, Underwriter's Laboratories Inc., October 24,2016.

Control voltage: The control voltage rating is the AC or DC voltage designated for application to control devices intended to open or close a circuit breaker. In most cases this only applies to accessories that are custom ordered, such as motor operators.

Interrupting rating: This is the highest current at rated voltage that the circuit breaker is intended to interrupt under standard test conditions.

Short-time or withstand rating: This characterizes the circuit-breaker's ability to withstand the effects of short-circuit current flow for a stated period. Molded-case circuit breakers typically do not have a withstand rating, although some newer-design breakers do.

Instantaneous override: A function of an electronic trip circuit breaker that causes the instantaneous function to operate above a given level of current if the instantaneous function characteristic has been disabled.

Current limiting circuit breaker: This is a circuit breaker which does not employ a fusible element and, when operating in its current-limiting range, limits the let-through I^2t to a value less than the I^2t of a ½-cycle wave of the symmetrical prospective current.

HID: This is a marking that indicates that a circuit breaker has passed additional endurance and temperature rise tests to assess its ability for use as the regular switching device for high intensity discharge lighting. Per NEC 240.83 (D) a circuit breaker, which is used as a switch in an HID lighting circuit must be marked as HID. HID circuit breakers can also be used as switches in fluorescent lighting circuits. SWD marked circuit breakers may not be used as switches for HID circuits.

SWD: This is a marking that indicates that a circuit breaker has passed additional endurance and temperature rise tests to assess its ability for use as the regular switching device fluorescent lighting. Per NEC 240.83 (D) a circuit breaker which is used as a switch in an SWD lighting circuit must be marked as SWD or HID.

Frame: The term Frame is applied to a group of circuit breakers of similar configuration. Frame size is expressed in amperes and corresponds to the largest ampere rating available in that group.

Thermal-magnetic circuit breaker: This type of circuit breaker contains a thermal element to trip the circuit breaker for overloads and a faster magnetic instantaneous element to trip the circuit breaker for short circuits. On many larger thermal-magnetic circuit breakers the instantaneous element is adjustable.

Electronic trip circuit breaker: An electronic circuit breaker contains a solid-state adjustable trip unit. These circuit breakers are extremely flexible in coordination with other devices.

Sensor: An electronic-trip circuit breaker's sensor is usually an air-core current transformer (CT) designed specifically to work with that circuit breaker's trip unit. The sensor size, in conjunction with the rating plug, determines the electronic-trip circuit breaker's continuous current rating.

Rating plug: An electronic trip circuit breaker's rating plug can vary the circuit breaker's continuous current rating as a function of its sensor size.

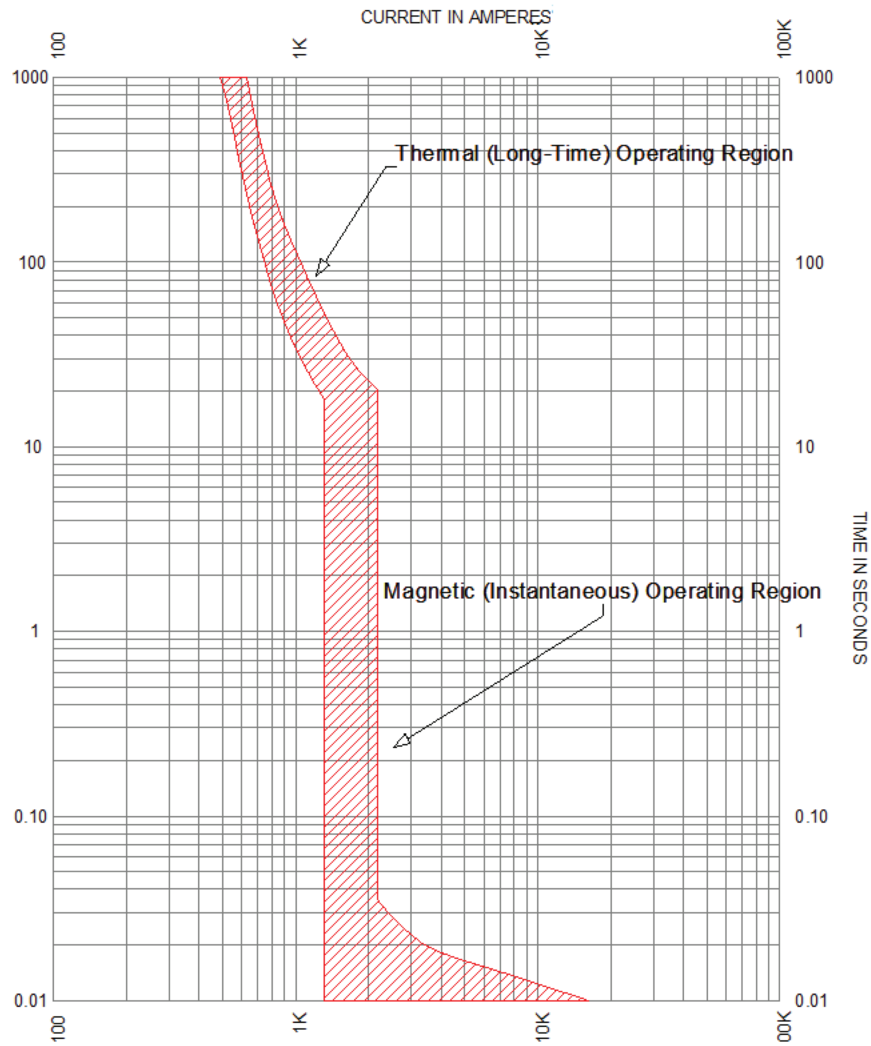
Typical molded-case circuit breakers are shown in Molded-case Circuit Breakers, page 89. In Molded-case Circuit Breakers, page 89 on the left is a thermal-magnetic circuit breaker, and on the right is an electronic-trip circuit breaker. The thermal-magnetic circuit breaker is designed for cable connections and the electronic circuit breaker is designed for bus connections, but neither type is inherently suited for one connection type over another. Note the prominently-mounted operating handle on each circuit breaker.

Circuit breakers can be mounted in stand-alone enclosures, in switchboards, or in panelboards (more information on switchboards and panelboards is given in a later section of this guide).

Figure 60 - Molded-case Circuit Breakers

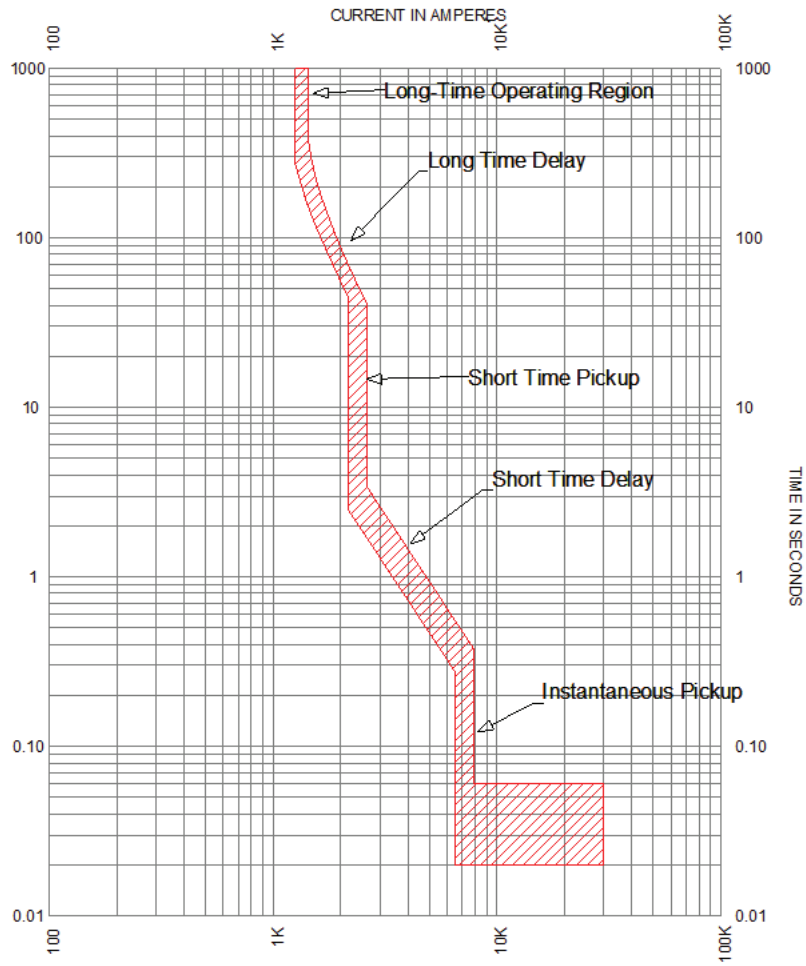
A typical thermal-magnetic circuit breaker time-current characteristic is shown in Thermal Magnetic Circuit Breaker Time-Current Characteristic, page 90. There are two distinct parts of the characteristic curve: The thermal or long-time characteristic is used for overload protection and the magnetic or instantaneous characteristic is used for short-circuit protection. There is a band of operating times for a given fault current. The lower boundary represents the lowest possible trip time, and the upper boundary represents the highest possible trip time for a given current.

Figure 61 - Thermal Magnetic Circuit Breaker Time-Current Characteristic



The time-current characteristic for an electronic-trip circuit breaker is shown in Electronic-Trip Circuit Breaker Time-Current Characteristic, page 91. The characteristic for an electronic trip circuit breaker consists of the long-time pickup, long-time delay, short-time pickup, short-time delay, and instantaneous pickup parameters, all of which are adjustable over a given range. This adjustability makes the electronic-trip circuit breaker very flexible when coordinating with other devices. The adjustable parameters for an electronic trip circuit breaker are features of the trip unit. In many cases the trip unit is also available without the short-time function. In catalog data the long-time characteristic is listed as L, the short-time is listed as S, and the instantaneous as I. Therefore, an LSI trip unit has long-time, short-time, and instantaneous characteristics, whereas an LI trip unit has only the long-time and instantaneous characteristics. For circuit breakers that have a short-time rating, the instantaneous feature may be disabled, enhancing coordination with downstream devices.

Figure 62 - Electronic-Trip Circuit Breaker Time-Current Characteristic

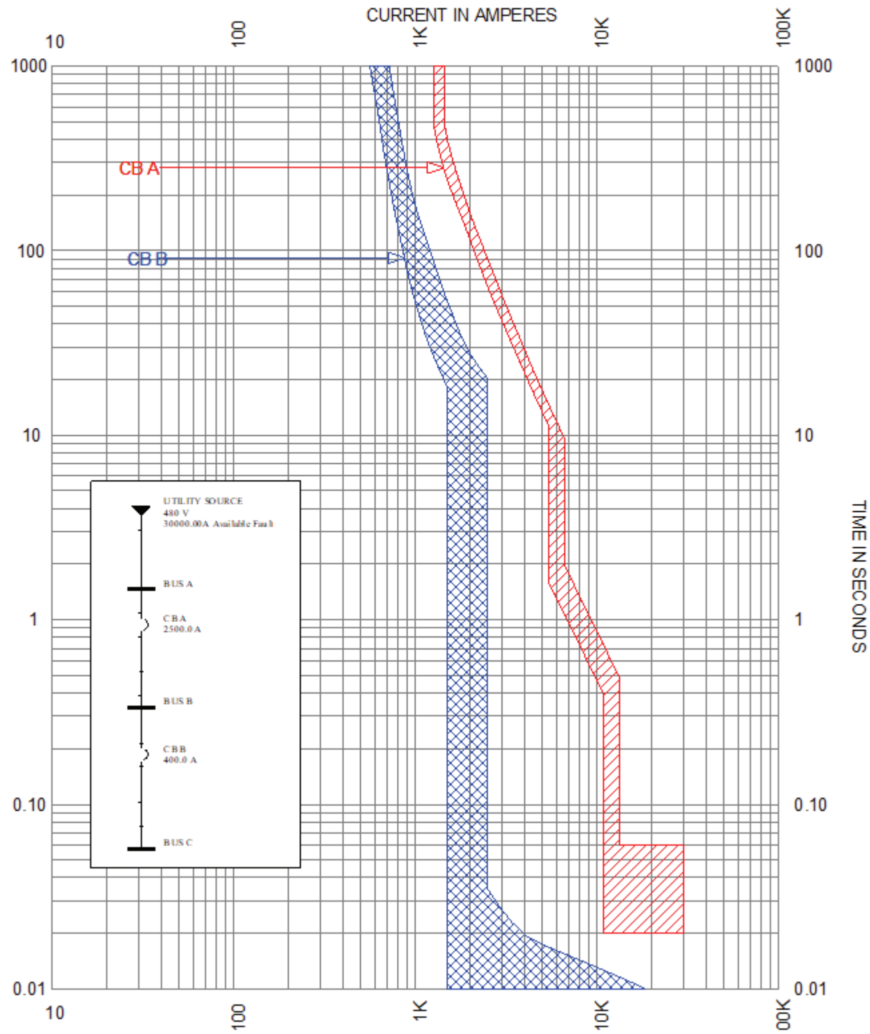


If the instantaneous feature has been disabled, be cognizant of any instantaneous override feature the breaker has, which engages the instantaneous function above a given level of current even if it has been disabled to help protect the circuit breaker from damage.

Another feature available on electronic-trip circuit breakers is ground-fault protection, which is discussed in detail later in this section.

Typical coordination between an electronic and a thermal magnetic circuit breaker is shown in Typical Molded-case Circuit Breaker Coordination, page 92. Because the time bands do not overlap, these two devices are coordinated.

Figure 63 - Typical Molded-case Circuit Breaker Coordination



A further reduction in the let-through energy for a fault in the region between two electronic-trip circuit breakers can be accomplished through zone-selective interlocking. This consists of wiring the two trip units such that if the downstream circuit breaker senses the fault (typically this is based upon the short-time pickup) it sends a restraining signal to the upstream circuit breaker. The upstream circuit breaker continues to time out as specified on its characteristic curve, tripping if the downstream device does not clear the fault. However, if the downstream device does not sense the fault and the upstream devices does, the upstream device does not have the restraining signal from the downstream device and trips with no intentional delay. For example, if zone-selective interlocking were present in the system of Typical Molded-case Circuit Breaker Coordination, page 92 and fault occurs on bus C circuit breaker B senses the fault and send a restraining signal to circuit breaker A. Circuit breaker A is coordinated with circuit breaker B, so circuit breaker B trips first. If circuit breaker B does not clear the fault, circuit breaker A times out on its time-current characteristic per Typical Molded-case Circuit Breaker Coordination, page 92 and trips. If the fault occurs at bus B, circuit breaker B does not detect the fault and thus does not send the restraining signal to circuit breaker A. Circuit breaker A senses the fault and trips with no intentional delay, which is faster than dictated by its time-current characteristic per Typical Molded-case Circuit Breaker Coordination, page 92. Care must be used when applying zone-selective interlocking where there are multiple sources of power and fault currents can flow in either direction through a circuit breaker.

Typical Characteristics of Molded-case Circuit Breakers for Commercial and Industrial Applications, page 93 shows typical characteristics of molded-case circuit breakers (see IEEE Recommended Practice for Protection and Coordination of Industrial Power Systems[48]). This table is for reference only, when specifying circuit breakers manufacturer's use actual catalog data.

Table 9 - Typical Characteristics of Molded-case Circuit Breakers for Commercial and Industrial Applications

Frame Size (A)	Number of Poles	Interrupting Rating at AC Voltage (kA, RMS symmetrical)				
		120 V	240 V	277 V	480 V	600 V
100	1 1	10 65		14 65		
100, 150	2,3 2,3 2,3		18 65 100		14 25 65	14 18 25
225, 250	2,3 2,3 2,3		25 65 100		22 25 65	22 22 25
400, 600	2,3 2,3 2,3		42 65 100		30 65	22 25 35
800, 1000	3		42 65 200		30 50 100	22 25 65
1200	3 3 3		42 65 200		30 50 100	22 25 65
1600, 2000	3 3		65 125		50 100	42 65
3000, 4000	3 3		100 200		100 150	85 100

The continuous current rating is set by the sensor and rating plug sizes for a given electronic-trip circuit breaker. This can be smaller than the frame size. As can be seen from Typical Characteristics of Molded-case Circuit Breakers for Commercial and Industrial Applications, page 93, more than one interrupting rating can be available for a given frame size.

Molded-case circuit breakers are tested for interrupting capabilities with test X/R ratios as shown in AC Test Circuit Characteristics for Molded-case Circuit Breakers, page 93 (see *Molded-Case Circuit Breakers, Molded Case Switches and Circuit-Breaker Enclosures*,[49]). As with fuses, when a circuit breaker is applied in a circuit with an X/R ratio larger than its test X/R, then multiply the available RMS symmetrical fault current by the multiplying factor per equation (7-10) for comparison with the circuit breaker interrupting rating.

Table 10 - AC Test Circuit Characteristics for Molded-case Circuit Breakers

Interrupting Rating (RMS symmetrical)	Test Circuit Power Factor	$(X/R)_{test}$
10,000 or less	0.45–0.50	1.732
10,001–20,000	0.25–0.30	3.180
Over 20,000	0.15–0.20	4.899

Molded-Case Circuit Breakers, Molded Case Switches and Circuit-Breaker Enclosures.[49]

Current-limiting circuit breakers are also available. Coordination between two current-limiting circuit breakers when they are both operating in the current limiting range is typically determined by test.

48. IEEE Std. 242-2001, December 2001.
49. UL 489, Underwriter's Laboratories Inc., October 24,2016.

Low-voltage molded case circuit breakers are not maintainable devices. Loss of a component generally requires replacement of the entire circuit breaker unless the circuit breaker has been specifically designed for maintainability.

Magnetic-only circuit breakers which have only magnetic tripping capability are available. These are often used as short-circuit protection for motor circuits (discussed in more detail in Surge Protection, page 128). For this reason, these are often referred to as motor circuit protectors.

Molded case switches are also available. These do not have a thermal element; however, most have a magnetic element which opens the switch above a specified current to shield the switch from damage due to lack of a short-time rating.

Molded-case circuit breakers are available with several different options, such as stored-energy mechanisms, key interlocks, motor operators. Refer to specific manufacturer's literature for details.

Because the switching means is included with the device, molded-case circuit breakers give inherent flexibility of operation. This allows circuits to be reclosed without removing cover panels and exposing the operator to hazardous voltages. Three-pole circuit breakers are used for three-phase circuits, alleviating the concern for single-phasing. Circuit breakers are not one-time devices, eliminating the need to store spares in the event of a fault. These characteristics make molded-case circuit breakers very versatile protective devices.

Low Voltage Power Circuit Breakers

For larger systems, those devices closest to the source of power often require the ability to coordinate with multiple levels of coordinating devices. In the case of circuit breakers, this generally requires a short-time rating as described in Low Voltage Molded-case Circuit Breakers, page 87. In addition, in this type of application, maintainability is desired due to the cost of a single circuit breaker. Low-voltage power circuit breakers fill these needs.

AC low-voltage power circuit breakers are designed and manufactured per ANSI/IEEE Standard C37.13-2015 and UL 1066-2022 (depending on the circuit breaker, they may have been designed to one of the superseded standards referenced). These are generally electronic-trip circuit breakers, although in existing installations older dashpot-operated units may be encountered. The tripping characteristics are essentially identical to those for electronic-trip molded-case circuit breakers, per Thermal Magnetic Circuit Breaker Time-Current Characteristic, page 90, except that the instantaneous function may be disabled in all cases, unlike that of a molded-case circuit breaker. Preferred Ratings for Low-voltage AC Power Circuit Breakers with Instantaneous Direct-acting Phase Trip Elements, page 95 and Preferred Ratings for Low-voltage AC Power Circuit Breakers Without Instantaneous Direct-acting Phase Trip Elements, page 96 give the preferred ratings for low-voltage AC power circuit breakers (see *IEEE Recommended Practice for Protection and Coordination of Industrial Power Systems*[50]). In addition, fused-power circuit breakers are also available with higher interrupting ratings, although many modern-design power circuit breakers do not require fuses to obtain short-circuit ratings up to 200 kA RMS symmetrical.

The short-time rating is an important characteristic of the low-voltage power circuit breaker. The rated time duration of the short-time rating is one half second (two periods of one half second current separated by a 15 second interval of zero current) (see *IEEE Standard for Low-Voltage AC Power Circuit Breakers Used in Enclosures*[51]). Because of this short-time rating, low-voltage power circuit breakers are also suitable for protective relaying applications, as described below. Therefore, if a low-voltage power circuit breaker is not equipped with a direct-acting trip unit it should not be subjected to more than one half second trip delay time at its short-time

50. IEEE Std. 242-2001, December 2001.
51. ANSI/IEEE Standard C37.13-2015, December 05.

rating (see *IEEE Standard for Low-Voltage AC Power Circuit Breakers Used in Enclosures*[52]).

Figure 64 - Low-voltage Power Circuit Breaker

Table 11 - Preferred Ratings for Low-voltage AC Power Circuit Breakers with Instantaneous Direct-acting Phase Trip Elements

System Nominal Voltage (V)	Rated Maximum Voltage (V)	Insulation (dielectric) Withstand (V) (V)	Three-phase Short-circuit Current Rating (A)[53]	Frame Size (A)	Range of trip device current ratings (A)[54]
600	635	2,200	14,000	225	40–225
600	635	2,200	22,000	600	40–600
600	635	2,200	22,000	800	100–800
600	635	2,200	42,000	1,600	200–1,600
600	635	2,200	42,000	2,000	200–2,000
600	635	2,200	65,000	3,000	2,000–3000
600	635	2,200	65,000	3,200	2,000–3200
600	635	2,200	85,000	4,000	4,000
480	508	2,200	22,000	225	40–225
480	508	2,200	30,000	600	100–600
480	508	2,200	30,000	800	100–800
480	508	2,200	50,000	1,600	400–1,600
480	508	2,200	50,000	2,000	400–2,000
480	508	2,200	65,000	3,000	2,000–3,000

52. ANSI/IEEE Standard C37.13-2015, December 05.
53. Ratings in this column are RMS symmetrical values for single-phase (two pole) circuit breakers and three-phase average RMS symmetrical values of three-phase (three-pole) circuit breakers. When applied on systems where rated maximum voltage may appear across a single pole, the short-circuit current ratings are 87% of these values. See 5.6 in IEEE Std C37.13-1990.
54. The continuous-current-carrying capability of some circuit-breaker-trip-device combinations may be higher than the trip-device current rating. See 10.1.3 in IEEE Std C37.13-1990.

Table 11 - Preferred Ratings for Low-voltage AC Power Circuit Breakers with Instantaneous Direct-acting Phase Trip Elements (Continued)

480	508	2,200	65,000	3,200	2,000–3,200
480	508	2,200	85,000	4,000	4,000
240	254	2,200	25,000	225	40–225
240	254	2,200	42,000	600	150–600
240	254	2,200	42,000	800	150–800
240	254	2,200	65,000	1,600	600–1,600
240	254	2,200	65,000	2,000	600–2,000
240	254	2,200	85,000	3,000	2,000–3,000
240	254	2,200	85,000	3,200	2,000–3,200
240	254	2,200	130,000	4,000	4,000

NOTE: See IEEE Std C37.13-1990 and ANSI C37.16-2000.

IEEE Recommended Practice for Protection and Coordination of Industrial Power Systems[55]

Table 12 - Preferred Ratings for Low-voltage AC Power Circuit Breakers Without Instantaneous Direct-acting Phase Trip Elements

Rated Maximum Voltage (V)	Frame Size (A)	Range of Trip Device Current Ratings (A)[56]		
		Setting of Short-time Delay Trip Element		
		Minimum Time Band	Intermediate Time Band	Maximum Time Band
635	225	100–225	125–225	150–225
635	600	175–600	200–600	250–600
635	800	175–800	200–800	250–800
635	1,600	360–1,600	400–1,600	500–1,600
635	2,000	250–2,000	400–2,000	500–2,000
635	3,000	2,000–3,000	2,000–3,000	2,000–3,000
635	3,200	2,000–3,200	2,000–3,200	2,000–3,200
635	4,000	4,000	4,000	4,000
508	225	100–225	125–225	150–225
508	600	175–600	200–600	250–600
508	800	175–800	200–800	250–800
508	1,600	350–1600	400–1,600	500–1,600
508	2,000	350–2,000	400–2,000	500–2,000
508	3,000	2,000–3,000	2,000–3,000	2,000–3,000
508	3,200	4,000	4,000	2,000–3,200
508	4,000	4,000	4,000	4,000
254	225	100–225	125–225	150–225
254	600	175–600	200–600	250–600
254	800	175–800	200–800	250–800
254	1,600	350–1,600	400–1,600	500–1,600
254	2,000	350–2,000	400–2,000	500–2,000

55. IEEE Std. 242-2001, December 2001.
56. The continuous-current-carrying capability of some circuit-breaker-trip-device combinations may be higher than the trip-device current rating. See 10.1.3 in IEEE Std C37.13-1990.

Table 12 - Preferred Ratings for Low-voltage AC Power Circuit Breakers Without Instantaneous Direct-acting Phase Trip Elements (Continued)

254	3,000	2,000–3,000	2,000–3,000	2,000–3,000
254	3,200	2,000–3,200	2,000–3,200	2,000–3,200
254	4,000	4,000	4,000	4,000

NOTE: See IEEE Std C37.13-1990 and ANSI C37.16-2000.

IEEE Recommended Practice for Protection and Coordination of Industrial Power Systems[57]

As with molded-case circuit breakers, low-voltage power circuit breakers are tested at a given power factor. The test power factor is 15% for unfused circuit breakers and 20% for fused circuit breakers. Short Circuit Multiplying Factors for Low-voltage Power Circuit Breakers, page 97 shows the multiplying factors for both fused and unfused circuit breakers for various short-circuit power factors. The multiplying factors for unfused circuit breakers are calculated similarly to those for molded-case circuit breakers, but those for fused circuit breakers are based upon RMS rather than peak current and differ slightly from the multiplying factors obtained from equation (7-10) (see *IEEE Standard for Low-Voltage AC Power Circuit Breakers Used in Enclosures*[58]).

Table 13 - Short Circuit Multiplying Factors for Low-voltage Power Circuit Breakers

System Short-Circuit Power Factor	System X/R Ratio	Multiplying Factor x RMS Symmetrical Short-Circuit Current, for Unfused Power Circuit Breakers	Multiplying Factor x RMS Symmetrical Short-Circuit Current, for Fused Power Circuit Breakers
20	4.9	1.00	1.00
15	6.6	1.00	1.07
12	8.27	1.04	1.12
10	9.95	1.07	1.15
8.5	11.72	1.09	1.18
7	14.25	1.11	1.21
5	20.0	1.14	1.26

IEEE Standard for Low-Voltage AC Power Circuit Breakers Used in Enclosures[58]

Use of low-voltage power circuit breakers allows optimum flexibility in coordination, since the instantaneous function may be disabled. Further, since these are designed for heavy-duty use in an industrial environment they are most often configured as drawout circuit breakers with stored-energy mechanisms in ANSI low-voltage metal enclosed switchgear (described in IEEE 1584). This makes them ideal for low-voltage automatic transfer applications. Their inherent operational flexibility serves to make them the ideal device for circuit protection in industrial applications where the ability to coordinate with downstream devices is a premium consideration.

Medium-voltage Fuses

The definition of fuse in Low Voltage Fuses, page 82 is equally applicable to medium-voltage fuses. Recall from Basic Principles, page 33 that the medium-voltage level is defined by ANSI C84 as containing standard system voltages from 2400 through 69,000 V, and that the high voltage level contains standard system voltages from 115 kV through 230 kV. The medium-voltage level, strictly, is defined by ANSI C84 as greater than 1000 V and less than 100,000 V. Similarly, the high-voltage level is defined as greater than 100,000 V through 230,000 V. Strictly speaking, high-voltage

57. IEEE Std. 242-2001, December 2001.
58. ANSI/IEEE Standard C37.13-2015, December 05.

fuse standards are used for both medium- and high-voltage fuses. However, the focus of this section is on medium voltage fuses 1 kV through 38 kV.

The following standards apply to medium-voltage fuses (see *IEEE Recommended Practice for Protection and Coordination of Industrial Power Systems*[59]):

- IEEE Std. C37.41-2016
- IEEE Std. C37.42-2016
- IEEE Std. C37.48-2020

Those definitions in Low Voltage Fuses, page 82 which do not specifically reference low-voltage fuses are also valid for medium-voltage fuses. Generally, medium-voltage fuses can be divided into two major categories : Current-limiting and expulsion. Current-limiting fuses were defined in Low Voltage Fuses, page 82l, and the same basic definition applies to medium-voltage fuses. Expulsion fuses are defined as follows (see *IEEE Recommended Practice for Protection and Coordination of Industrial Power Systems*[59]):

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

In addition, medium-voltage fuses are further classified as power fuses or distribution fuses as follows (see *IEEE Recommended Practice for Protection and Coordination of Industrial Power Systems*[59]):

Power fuse: Defined by ANSI C37.42-1996 as having dielectric withstand (BIL) strengths at power levels, applied primarily in stations and substations, with mechanical construction basically adapted to station and substation mountings.

Distribution fuse: Defined by ANSI C37.42-1996 as having dielectric withstand (BIL) strengths at distribution levels, applied primarily on distribution feeders and circuits, and with operating voltage limits corresponding to distribution voltages. These are further subdivided into distribution current limiting fuses and distribution fuse cutouts, as described below.

Current-limiting fuses interrupt in less than one half cycle when subjected to currents in their current-limiting range. This is an advantage as it limits the peak fault current to a value less than the prospective fault current as described above for low-voltage fuses. This provides current-limiting fuses with high interrupting ratings and allows them to shield downstream devices with lower short-circuit ratings in some cases. However, the same technologies that combine to give medium-voltage current-liming fuses their current-limiting characteristics can also produce thermal issues when the fuses are loaded at lower current levels. For this reason, the following definitions apply to current-limiting fuses (see *IEEE Recommended Practice for Protection and Coordination of Industrial Power Systems*[59]).

Backup current-limiting fuse: A fuse capable of interrupting all currents from its maximum rated interrupting current down to its rated minimum interrupting current.

General purpose current-limiting fuse: A fuse capable of interrupting all currents from the rated interrupting current down to the current that causes melting of the fusible element in no less than one hour.

Full-range current-limiting fuse: A fuse capable of interrupting all currents from its rated interrupting current down to the minimum continuous current that causes melting of the fusible elements.

Due to the limitations of backup and general-purpose current limiting fuses, current-limiting power fuses have melting characteristics defined as E or R, defined as follows:

E-Rating: The current-responsive element for ratings 100 A or below shall melt in 300 seconds at an RMS current within the range of 200% to 240% of the continuous-current rating of the fuse unit, refill unit, or use link. The current-responsive element

59. IEEE Std. 242-2001, December 2001.

for ratings above 100 A shall melt in 600 seconds at an RMS current within the range of 220% to 264% of the continuous-current rating of the fuse unit, refill unit, or fuse link.

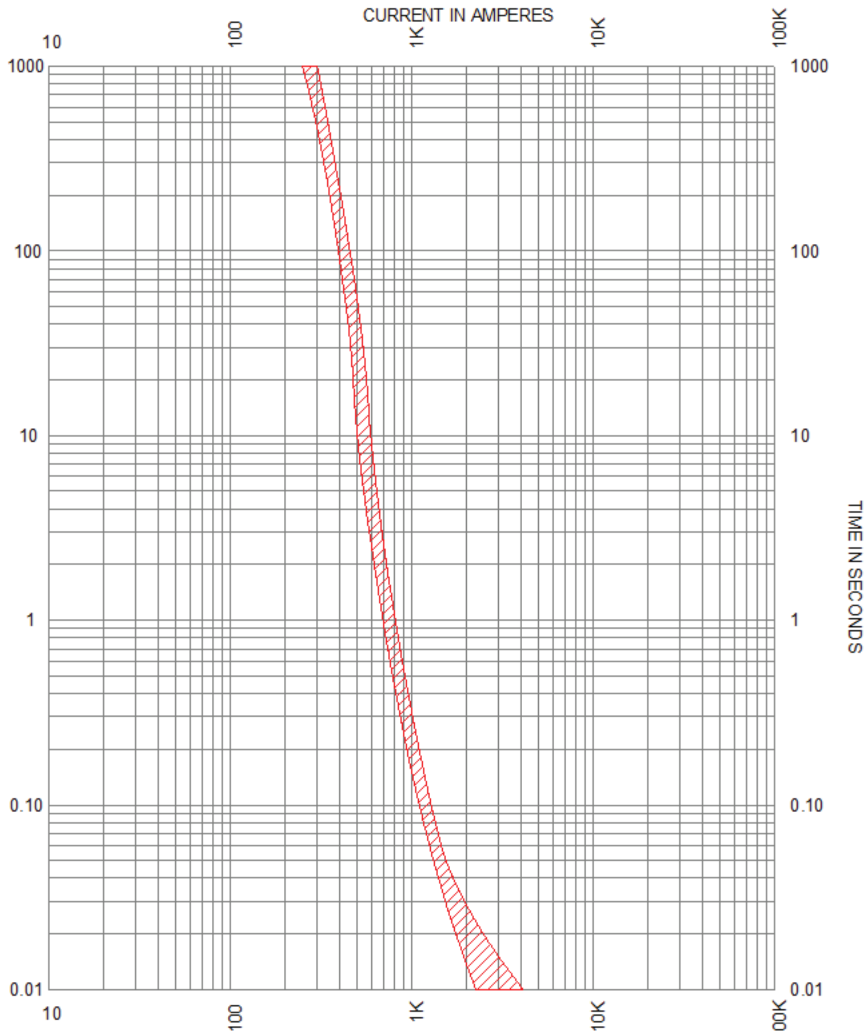
R-Rating: The fuse shall melt in the range of 15 seconds to 35 seconds at a value of current equal to 100 times the R number.

Similarly, distribution current-limiting fuses are defined by given characteristic ratings, one of which is the C rating, defined as follows:

C-Rating: The current-responsive element shall melt at 100 seconds, at an RMS current within the range of 170% to 240% of the continuous-current rating of the fuse unit.

A typical time-current curve for an E-rated current-limiting power fuse is shown in Typical E-rated Current-limiting Power Fuse Time-current Characteristic, page 100. This is a 125E-rated fuse. The curve starts at approximately 250 A for a minimum melting time of 1000 seconds. Take care with backup and general-purpose current-limiting fuses so that the load current does not to exceed the E- or R-rating of the fuse. Failure to do this can result in the development of a hot-spot and subsequent loss of the fuse and its mounting. For fuses enclosed in equipment, this can have disastrous consequences since loss of the fuse and/or its mounting can lead to an arcing fault in the equipment. The boundary of the characteristic, denoting the minimum-melting current, should be further derated to consider pre-loading of the fuse (consult the fuse manufacturer for details). As with low-voltage fuses, the current-limiting fuse characteristic does not extend below .01 seconds since the fuse is in its current-limiting range below this interrupting time.

Figure 65 - Typical E-rated Current-limiting Power Fuse Time-current Characteristic



A current-limiting power fuse consists of a fuse mounting (typically fuse clips) and the fuse unit itself. These are frequently mounted in metal-enclosed switchgear. A distribution current-limiting fuse may consist of a disconnecting-style holder or clips, and the fuse unit. Distribution current-limiting fuses may also be provided with under-oil mountings for use with distribution transformers. They are frequently used for capacitor protection as well, with clips designed to mount to the capacitor.

Figure 66 - Current-limiting Power Fuses and Mountings

Current-limiting power fuses are typically used for short circuit protection of instrument transformers, power transformers, and capacitor banks. **Maximum Ratings for Current-limiting Power Fuses 2.75 – 38 kV**, page 101 gives maximum ratings for medium-voltage current-limiting power fuses from 2.75 through 38 kV.

Table 14 - Maximum Ratings for Current-limiting Power Fuses 2.75 – 38 kV

Rated Maximum Voltage (kV)	Continuous-current Ratings (A), Maximum	Short-circuit Maximum Interrupting Ratings (kA RMS symmetrical)
2.75	225, 450[60], 750[60], 1350[60]	50.0, 50,0, 40.0, 40.0
2.75/4.76	450[60]	50.0
5.5	225, 400, 750[60], 1350[60]	50.0, 62.5, 40.0, 40.0
8.25	125, 200[60]	50.0, 50.0
15.5	65, 100, 125[60], 200[60]	85.0, 50.0, 85.0, 50.0
25.8	50, 100[60]	35. 0, 35.0
38.0	50, 100[60]	35. 0, 35.0

IEEE Recommended Practice for Protection and Coordination of Industrial Power Systems[61]

During interruption current-limiting fuses produce significant arc voltages. These must be considered in selecting equipment. They are typically compared to the BIL level of the equipment, including downstream equipment at the same voltage level. The maximum permissible overvoltages for current-limiting power fuses are shown in Maximum Permissible Overvoltages for Current-limiting Power Fuses, page 102 (see *IEEE Recommended Practice for Protection and Coordination of Industrial Power Systems*[61]).

60. Parallel fuses.
61. IEEE Std. 242-2001, December 2001.

Table 15 - Maximum Permissible Overvoltages for Current-limiting Power Fuses

Rated Maximum Voltage (kV, RMS)	Maximum Peak Overvoltages (kV, Crest)	
	0.5 A to 12 A	Over 12 A
2.8	13	9
5.5	25	18
8.3	38	26
15.0	68	47
15.5	70	49
22.0	117	70
25.8	117	81
27.0	123	84
38.0	173	119

IEEE Recommended Practice for Protection and Coordination of Industrial Power Systems[62]

In practice, the arc voltages for current-limiting fuses generally indicate the use of the smallest available fuse voltage class for the given system voltage, for example, 5.5 kV fuses instead of 8.3 kV fuses for a 4160 V system.

After a fault interruption, in a three-phase set of current-limiting fuses all three fuses are replaced, even if only one fuse interrupted the fault. This is due to the possibility of damage to the other two fuses due to the fault, which could change their time-current characteristics and make them unsuitable to carry load current without loss.

Because medium-voltage current-limiting fuses interrupt short circuits without the expulsion of gas or flame, they are widely utilized in a variety of applications.

Power expulsion fuses generally consist of an insulating mounting and a fuse holder which accepts the fuse refills. The fuse holder may be of the disconnecting or non-disconnecting type. Only the refill is replaced when a fuse interrupts an overcurrent, and if only one phase of a three-phase set interrupted the fault, only that fuse needs replacement. Power expulsion fuses are typically used in substations and enclosed equipment.

Distribution expulsion fuses are generally distribution fuse cutouts, which are adapted to pole or cross arm mounting. They consist of the fuse holder and refill unit. The fuse holder is usually of the disconnecting type. These are typically used as pole-mounted fuses on utility distribution systems.

Expulsion fuses use the liberation of de-ionizing gasses to interrupt overcurrents. Boric acid is typically used as the interrupting medium for power expulsion fuses and bone fiber is typically used for distribution fuse cutouts. When an expulsion fuse interrupts an overcurrent the interrupting medium liberates de-ionizing gas, interrupting the overcurrent. The exhaust gasses are then emitted from the fuse, accompanied by noise. The exhaust gasses for a boric acid fuse may be condensed by an exhaust control device (commonly called an exhaust filter, silencer, or snuffler).

Unlike current-limiting fuses, expulsion-type fuses interrupt high overcurrents at natural current zeros. They are therefore non-current-limiting, and as a result typically have lower interrupting ratings than current-limiting fuses. Maximum Continuous Current and Short Circuit Interrupting Ratings for Refill Type Boric-acid Expulsion-type Power Fuses, page 103 shows the maximum continuous current and short-circuit interrupting ratings for refill-type boric-acid expulsion-type power fuses (see *IEEE Recommended Practice for Protection and Coordination of Industrial Power Systems*[62]). Because expulsion-type fuses are non-current-limiting, they do not produce the significant arc voltages that current-limiting fuses produce, and thus it is permissible to use a fuse with a larger voltage class than the system, for example, a 14.4 kV-rated fuse on a 4160 V system. This makes expulsion-type fuses particularly

62. IEEE Std. 242-2001, December 2001.

useful on systems which may be upgraded in the future to a higher voltage. However, the lower interrupting ratings of expulsion-type fuses are often an issue versus. current-limiting fuses as the largest expulsion-type fuse interrupting ratings require larger physical dimensions which cannot always be easily accommodated in enclosed equipment. Further, in some cases the expulsion-type fuses prohibit some space-saving mounting configurations in enclosed equipment that are available with current-limiting fuses.

Table 16 - Maximum Continuous Current and Short Circuit Interrupting Ratings for Refill Type Boric-acid Expulsion-type Power Fuses

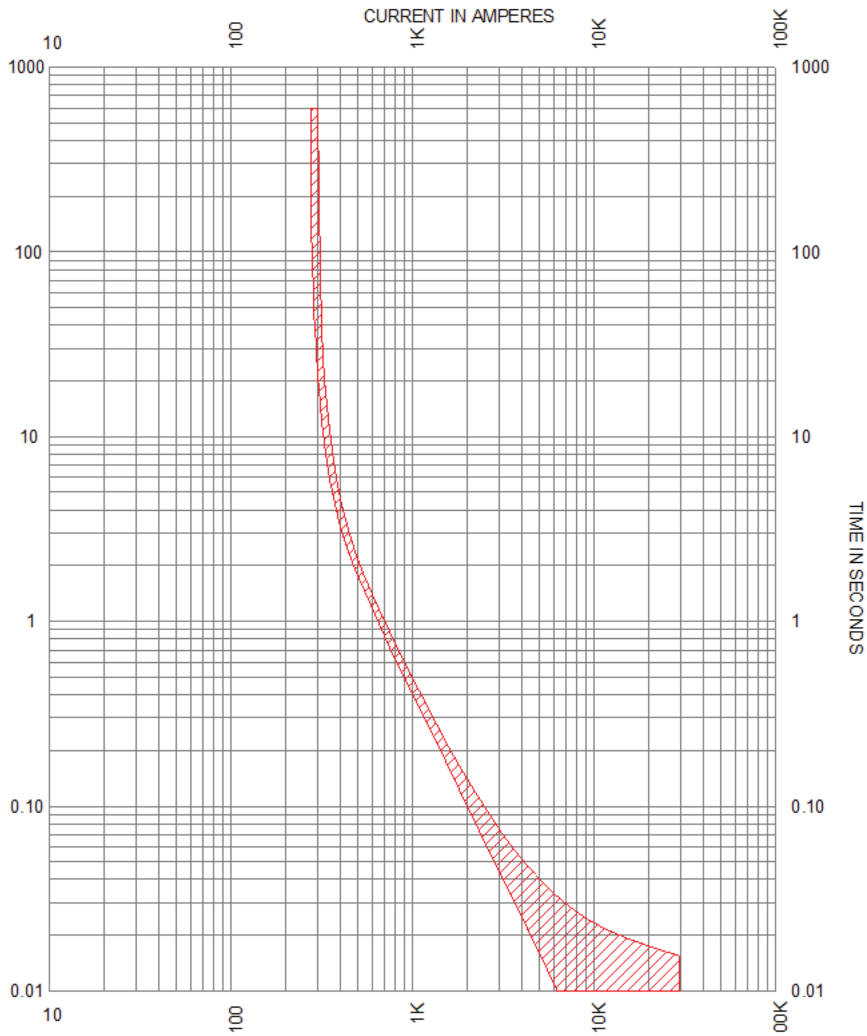
Rated Maximum Voltage (kV)	Continuous-current Ratings (A), Maximum	Short-circuit Maximum Interrupting Ratings (kA, RMS Symmetrical)
2.8	200 ,400, 720[63]	19.0, 37.5, 37.5
4.8	200, 400, 720[63]	19.0, 37.5, 37.5
5.5	200, 400, 720[63]	19.0, 37.5, 37.5
8.3	200,4 00, 720[63]	16.6, 29.4, 29.4
14.4	200, 400, 720[63]	14.4, 29.4, 29.4
15.5	200, 400, 720[63]	14.4, 34.0, 29.4
17.0	200, 400, 720[63]	14.4, 34.0, 25.0
25.8	200, 300, 540[63]	10.5, 21.0, 21.0
27.0	200, 300	12.5, 20.0
38.0	200, 300, 540[63]	8.45, 17.5, 16.8

IEEE Recommended Practice for Protection and Coordination of Industrial Power Systems[64]

E-ratings are used for power expulsion fuses. A typical time-current characteristic for a 125E boric-acid fuse is given in Typical Boric Acid Power Expulsion Fuse Time-current Characteristic, page 104.

63. Parallel fuses.
64. IEEE Std. 242-2001, December 2001.

Figure 67 - Typical Boric Acid Power Expulsion Fuse Time-current Characteristic



The characteristic extends to the available fault current (in this case, 29.4 kA), unlike the current-limiting fuse. It is common practice to treat these as current-limiting fuses so far as the E-rating is concerned, that is, the maximum load current is usually kept below the E-rating. However, the boric-acid fuse is not subject to damage when loaded above its E-rating, and they are often referred to in the industry as non-damageable due to this fact.

When applying medium-voltage fuses, the voltage rating and the interrupting rating are of importance. The maximum line-to-line voltage of the system should not exceed the fuse voltage rating. The published interrupting rating for power fuses is typically for a test X/R ratio of 15, and for distribution fuses the test X/R ratio is typically eight; consult the fuse manufacturer for derating factors for X/R ratios above these values. Also consult the manufacturer if the test X/R is in doubt.

Medium-voltage fuses provide economical short-circuit protection when applied within their ratings, particularly for transformers, cables, and capacitors. For more sophisticated protection at the medium-voltage level, employ other means.

Medium-voltage Circuit Breakers

The medium-voltage circuit breaker is the device of choice when sophisticated system protection at the medium-voltage level is required.

Most modern medium-voltage circuit breakers use a vacuum as the interrupting means, although sulfur-hexafluoride (SF_6), and other gas-insulated circuit breakers exist. As with medium-voltage fuses, the same standards are used for both medium and high-voltage circuit breakers. The applicable standards are ANSI/IEEE C37.04-2018, IEEE C37.06-2018, and IEEE C37.09-2018. In addition, IEEE C37.010-2016 and IEEE C37.011-2019 give valuable application advise for these devices.

Medium-voltage circuit breakers are generally not equipped with integral trip units as low-voltage circuit breakers are. Instead, protective relays must be used to sense abnormal conditions and trip the circuit breaker accordingly.

Most modern medium-voltage circuit breakers are rated on a symmetrical current basis. The following rating definitions apply (see *IEEE Standard Rating Structure for AC High-Voltage Circuit Breakers*[65]):

Rated Maximum Voltage: The highest RMS phase-to-phase voltage for which the circuit breaker is designed.

Rated Power Frequency: The frequency at which the circuit breaker is designed to operate.

Figure 68 - Medium-voltage Circuit Breaker, for Use In Metal-Clad Switchgear

Rated Dry Withstand Voltage: The RMS voltage that the circuit breaker in new condition is capable of withstanding for one minute under specified conditions.

Rated Wet Withstand Voltage: The RMS voltage that an outdoor circuit breaker or external components in new condition are capable of withstanding for ten seconds.

65. ANSI/IEEE Standard C37.04-1999, June 1999. Reaffirmed 6/12/2006.

Rated Lightning Impulse Withstand Voltage: The peak value of a standard 1.2 x 50 µs wave, as defined in IEEE Std 4-2013, that a circuit breaker in new condition is capable of withstanding.

Rated Continuous Current: The current in RMS symmetrical amperes that the circuit breaker is designed to carry continuously.

Rated Interrupting Time: The maximum permissible interval between the energizing of the trip circuit at rated control voltage and the interruption of the current in the main circuit in all poles.

Rated Short Circuit Current (Required Symmetrical Interrupting Capability): The value of the symmetrical component of the short-circuit current in RMS amperes at the instant of arcing contact separation that the circuit breaker shall be required to interrupt at a specified operating voltage, on the standard operating duty cycle, and with a DC component of less than 20% of the current value of the symmetrical component.

Required Asymmetrical Interrupting Capability: The value of the total RMS short-circuit current at the instant of arcing contact separation that the circuit breaker shall be required to interrupt at a specified operating voltage and on the standard operating duty cycle. This is based upon a standard time constant of 45 milliseconds (X/R ratio =17 for 60 Hz and 14 for 50 Hz systems) and an assumed relay operating time of one-half cycle.

Rated closing and latching capability: The circuit breaker shall be capable of closing and latching any power frequency making current whose maximum peak is equal to or less than 2.6 (for 60 Hz power frequency; 2.5 for 50 Hz power frequency) times the rated short-circuit current.

Rated Short-Time Current: The maximum short-circuit current that the circuit breaker can carry without tripping for a specified period of time.

Maximum Permissible Tripping Delay: The maximum delay time for protective relaying to trip the circuit breaker during short-circuit conditions, based upon the rated short-time current and short-time current-carrying time period.

Rated Transient Recovery Voltage (TRV): At its rated maximum voltage, a circuit breaker is capable of interrupting three-phase grounded and ungrounded terminal faults at the rated short-circuit current in any circuit in which the TRV does not exceed the rated TRV envelope. For a circuit breaker rated below 100 kV, the rated TRV is represented by a one-cosine wave, with a magnitude and time-to-peak dependent upon the rated maximum voltage of the circuit breaker.

Rated Voltage Range Factor K: Defined in earlier versions of IEEE Standard Rating Structure for AC High-Voltage Circuit Breakers[66] as the factor by which the rated maximum voltage may be divided to determine the minimum voltage for which the interrupting rating varies linearly with the interrupting rating at the rated maximum voltage by the following formula:

$$I_{vop} = I_{vmax} \times (V_{max}/V_{op}) \qquad (7–11)$$

Where:

- I_{vmax} is the rated short-circuit current at the maximum operating voltage.
- V_{max} is the rated maximum operating voltage.
- V_{op} is the operating voltage where V_{op} $V \geq (V_{max}/K())$.
- I_{vop} is the short-circuit current interrupting capability where $I_{vop} \leq I_{vmax}$.

For values of V_{op} below ($V_{max} \div K$) the short-circuit interrupting capability was considered to be equal to ($I_{v\,max} \times K$). This model was more representative of older technologies such as air-blast interruption. Because most modern circuit breakers employ vacuum technology, the current version of *IEEE Standard Rating Structure for*

66. ANSI/IEEE Standard C37.04-1999, June 1999. Reaffirmed 6/12/2006.

AC High-Voltage Circuit Breakers[67] assumes that K = 1, which gives the same short circuit rating for all voltages below the rated voltage. However, in practice designs with K > 1 still exist and are in common use.

Preferred Ratings for Indoor Circuit Breakers with k = 1.0, page 107 shows the preferred ratings for circuit breakers from *AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis – Preferred Ratings and Related Required Capabilities*[68] where K = 1. Preferred Ratings for Indoor Circuit Breakers with Voltage Range Factor k > 1.0, page 108 shows the preferred ratings for circuit breakers where K > 1.

Table 17 - Preferred Ratings for Indoor Circuit Breakers with k = 1.0

Rated Maximum Voltage, (kV)	Rated Voltage Range Factor K	Rated Contin-uous Current (A RMS)	Rated Short-Circuit and Short-Time Current (kA RMS)	Rated TRV		Rated Interrupting Time (ms)	Rated Max. Permissi-ble Tripping Time Delay Y (s)	Rated Closing and Latching Current, (kA Peak)
				Rated Peak Voltage E_2, (kV peak)	Rated Time to Peak T_2, (µs)			
4.76	1.0	1200,2000	31.5	8.9	50	83	2	82
4.76	1.0	1200, 2000	40	8.9	50	83	2	104
4.76	1.0	1200, 2000, 3000	50	8.9	50	83	2	130
8.25	1.0	1200, 2000, 3000	40	15.5	60	83	2	104
15	1.0	1200, 2000	20	28	75	83	2	52
15	1.0	1200, 2000	25	28	75	83	2	65
15	1.0	1200, 2000	31.5	28	75	83	2	82
15	1.0	1200, 2000, 3000	40	28	75	83	2	104
15	1.0	1200, 2000, 3000	50	28	75	83	2	130
15	1.0	1200, 2000, 3000	63	28	75	83	2	164
27	1.0	1200	16	51	105	83	2	42
27	1.0	1200, 2000	25	51	105	83	2	65
38	1.0	1200	16	71	125	83	2	42
38	1.0	1200, 2000	25	71	125	83	2	65
38	1.0	1200, 2000, 3000	31.5	71	125	83	2	82
38	1.0	1200, 2000, 3000	40	71	125	83	2	104

AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis – Preferred Ratings and Related Required Capabilities[68]

Although 83 milliseconds or five cycles is the "preferred" value per *IEEE Standard Rating Structure for AC High-Voltage Circuit Breakers*[69] for the rated interrupting time, three-cycle designs are common.

Other related preferred ratings, such as dielectric ratings and capacitance switching ratings, are also given in *AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis – Preferred Ratings and Related Required Capabilities*[68].

67. ANSI/IEEE Standard C37.04-1999, June 1999. Reaffirmed 6/12/2006.
68. ANSI Standard C37.06-2000, May 2000.
69. ANSI/IEEE Standard C37.04-1999, June 1999. Reaff 6/12/2006.

Table 18 - Preferred Ratings for Indoor Circuit Breakers with Voltage Range Factor k > 1.0

Rated Maximum Voltage, kV	Rated Voltage Range Factor K	Rated Continuous Current at 60 Hz (A RMS)	Rated Short-Circuit Current at Rated Maximum kV (kA RMS)	Rated Interrupting Time, Cycles	Rated Maximum Voltage Divided by K, kV RMS	Maximum Symmetrical Interrupting Capability and Rated Short-Time Current (kA, RMS)	Closing and Latching Capability 2.7 K Times Rated Short-Circuit Current (kA Crest)
4.76	1.36	1200	8.8	5	3.5	12	32
4.76	1.24	1200, 2000	29	5	3.85	36	97
4.76	1.19	1200, 2000, 3000	41	5	4.0	49	132
8.25	1.25	1200, 2000	33	5	6.6	41	111
15.0	1.30	1200, 2000	18	5	11.5	23	62
15.0	1.30	1200, 2000	28	5	11.5	36	97
15.0	1.30	1200, 2000, 3000	37	5	11.5	48	130
38.0	1.65	1200, 2000, 3000	21	5	23.0	35	95
38.0	1.0	1200, 3000	40	5	38.0	40	108

AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis – Preferred Ratings and Related Required Capabilities[70]

To apply medium-voltage circuit breakers, it is important to understand how the system X/R ratio affects the circuit breaker interrupting rating. As stated above, for 60 Hz systems the asymmetrical interrupting capability is based upon an X/R ratio of 17. Thus, for systems where the X/R ratio is 17 or lower, the circuit breaker has adequate asymmetrical interrupting capability so long as 100% of the symmetrical short-circuit current rating is equal to or above the available RMS symmetrical fault current. For X/R ratios above 17, the available RMS symmetrical fault current must be compared to the short-circuit current rating of the circuit breaker multiplied by a multiplying factor determined from *IEEE Application Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis*[71]. Because the multiplying factors from I*EEE Application Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis*[71]do not usually exceed 1.25, the fault current may be compared to 80% of the circuit breaker interrupting rating regardless of X/R ratio in most cases. The close and latch rating is evaluated using equation (7-9) to obtain the asymmetrical fault current at the circuit breaker. Reference *IEEE Application Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis*[71]contains a full method for determining the suitability of a circuit breaker for duty on a given system, and along with the requirements for low-voltage short-circuit calculations from *IEEE Standard for Low-Voltage AC Power Circuit Breakers Used in Enclosures*[72]forms the basis for what the industry terms as ANSI short-circuit analysis. Capacitance switching and generator applications are also areas of concern when applying medium-voltage circuit breakers. Preferred capacitance switching values are given in *AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis – Preferred Ratings and Related Required Capabilities*[70]and must not be exceeded. Generator applications, for generators rated above 3 MVA, must be approached with carefully due to the high X/R ratios encountered. Often, breakers with longer interrupting times are desirable in large generator applications to allow the fault current to decay to the point that there is a natural current zero for interruption.

As stated above, medium-voltage circuit breakers are typically provided without integral trip units. For this reason, custom protection must be provided via protective relays, discussed in the next section. Circuit breakers are equipped with tripping and

70. ANSI Standard C37.06-2000, May 2000.
71. IEEE Std C37.010-2016, April 2017.
72. ANSI/IEEE Standard C37.13-2015, December 05.

closing coils to allow tripping and closing operations via protective relays, manual control switches, PLC's, SCADA systems. The circuit breaker internal control circuitry is arranged per IEEE C37.11-1997. Circuit breakers are also equipped with a number of auxiliary contacts to allow interlocking and external indication of circuit breaker position.

For medium-voltage protection applications, circuit breakers offer flexibility that cannot be obtained with fuses. Further, they do not require a separate switching device as fuses do. These benefits are gained at a price: Circuit breaker applications are more expensive than fuse applications, both due to the inherent cost of the circuit breakers themselves and due to the protective relays required. For many applications, however, circuit breakers are the only choice that offers the flexibility required. Large medium-voltage services and distribution systems and most applications involving medium-voltage generation employ circuit breakers.

Protective Relays

For medium-voltage circuit breaker applications, protective relays serve as the "brains" that detect abnormal system conditions and direct the circuit breakers to operate. They also serve to provide specialized protection in low-voltage power circuit breaker applications for functions not available in the circuit breaker trip units.

Most modern protective relays are solid-state electronic or microprocessor-based devices, although older electromechanical devices are still available. Solid-state electronic or microprocessor-based relays offer more flexibility and functionality than electromechanical relays, including the ability to interface with common communications protocols such as MODBUS for integration into a SCADA environment. However, they do require "reliable" control power to maintain operation during abnormal system conditions. This control power is most often provided by a DC battery system, although AC UPS-based systems are also encountered.

Electromechanical relays are typically single-phase devices. Solid-state electronic relays are typically available in single-phase or three-phase versions. Microprocessor-based relays are typically three-phase devices. While electromechanical and solid-state electronic relays typically incorporate one relay function per device, microprocessor-based relays usually encompass many functions in one device, making a single microprocessor-based relay capable of performing the same functions that would require several electromechanical or solid-state relays. This functionality usually makes microprocessor-based relays a good choice for new installations.

Figure 69 - Microprocessor-based Protective Relay

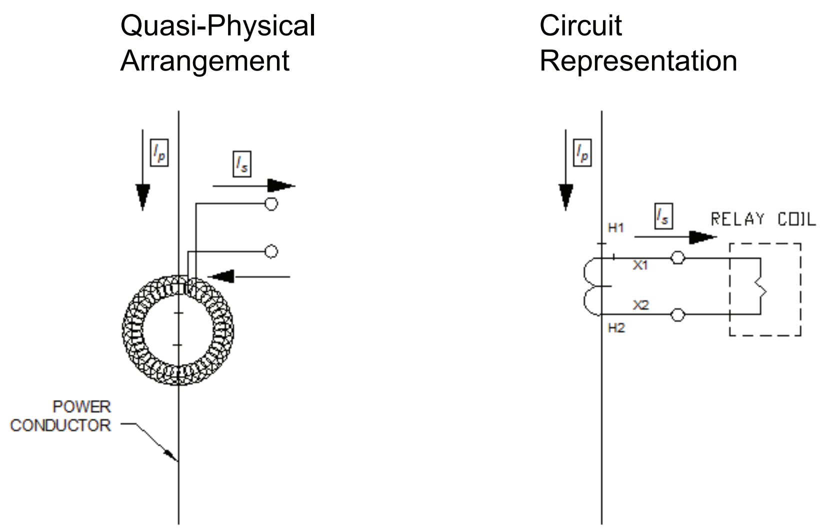
Protective relays are not rated for direct connection to the power system where they are applied. For this reason, instrument transformers are used to reduce the currents and voltages to the levels for which the relays are designed. Instrument transformers generally fall into one of two broad categories: Current Transformers (CT’s) and Voltage Transformers (VT’s). The loads on instrument transformers, such as relays and meters, are known as burdens to distinguish them from power system loads.

A current transformer consists of a coil toroidally-wound around a ferromagnetic core. The conductor for which the current is to be measured is passed through the center of the toroid. The magnetic field generated by the current through the conductor causes current to flow in the coil. In essence, a CT may be thought of as a conventional transformer with one primary turn.

CT’s in the United States typically have 5 A-rated secondaries, with primary ratings from 10 – 40,000 A and larger. For relaying applications in industrial facilities, CT ratios are typically 50:5 – 4000:5. IEEE Std. C57.13-2016 designates certain ratios as standard, as well as a classification system for relaying performance. The classification system consists of a letter and a number. The letter may be C, designating that the percent ratio correction may be calculated, or T, denoting that the ratio correction has been determined by test. The number denotes the voltage that the CT can deliver to a “standard burden” (as described in IEEE Std. C37.13-2016) at 20 times the rated secondary current without exceeding 10% ratio error. As a more accurate alternative, manufacturer-published CT excitation curves may be used to determine the accuracy. For a relaying application, the issue at hand is the performance of the relay during worst-case short-circuit conditions, when the CT secondary currents are the largest and may cause the secondary voltage to exceed the CT’s rating due to the voltage developed across the relay input coil. This condition causes the CT to saturate, significantly changing the ratio and thus the accuracy of the measurement. For cases of severe CT saturation the relay may respond in an unpredictable manner, such as not operating or producing “chatter” of its output contacts.

CT's where the power conductor passes through the window formed by the toroidal CT winding are known as window-type CT’s. CT’s designed with an integral bus bar running through device are known as bus-bar type CT’s. Other designs, such as wound primary CT’s for metering applications and non-saturating air-core CT’s, are available. Additional information on CT application can be found in *IEEE Recommended Practice for Protection and Coordination of Industrial Power Systems*[73].

Figure 70 - Current Transformer



Voltage transformers (VT’s) are used to step the power system voltage down to a level that the relay can utilize. The operation of voltage transformers is essentially the same as for conventional power transformers except that the design has been optimized for accuracy. Like current transformers, voltage transformers are assigned accuracy classes by IEEE Std. C57.13-2016. VT accuracy classes are designated W, X,M Y, Z, and ZZ in order of increasing burden requirements. Refer to *IEEE Recommended Practice for Protection and Coordination of Industrial Power Systems*[73]for more information regarding the application of voltage transformers.

Protective relays are classified by function. To make circuit representations easier, each function has been defined and assigned a number by IEEE Std. C37.2-2022. The IEEE standard function numbers are given in Commonly Used Protective Relay Device Function Numbers, page 112. Commonly Used Suffix Letters Applied to Relay Function Numbers, page 112 gives the commonly-used suffix letters to further designate protective functions *IEEE Recommended Practice for Protection and Coordination of Industrial Power Systems*[73].

These designations can be combined in various ways. For example, 87T denotes a transformer differential relay, 51N denotes a residual ground time-overcurrent relay, 87B denotes a bus differential relay.

73. IEEE Std. 242-2001, December 2001.

Table 19 - Commonly Used Protective Relay Device Function Numbers

Relay Device Function Number	Protection Function
21	Distance
25	Synchronizing
27	Undervoltage
32	Directional Power
40	Loss of Excitation (field)
46	Phase unbalance (current unbalance, negative sequence current)
47	Phase-sequence Voltage (reverse phase voltage)
49	Thermal (generally thermal overload)
50	Instantaneous Overcurrent
51	Time-overcurrent
59	Overvoltage
60	Voltage unbalance (between two circuits)
67	Directional Overcurrent
81	Frequency (over and underfrequency)
86	Lockout
87	Differential

IEEE Recommended Practice for Protection and Coordination of Industrial Power Systems[74]

Table 20 - Commonly Used Suffix Letters Applied to Relay Function Numbers

Suffix Letter	Relay Application
A	Alarm only
B	Bus protection
G	Ground fault protection [relay current transformer (CT) in a system neutral circuit] or generator protection]
GS	Ground-fault protection (relay CT is toroidal or ground sensor)
L	Line Protection
M	Motor Protection
N	Ground fault protection (relay coil connected in residual CT circuit)
T	Transformer protection
V	Voltage

IEEE Recommended Practice for Protection and Coordination of Industrial Power Systems[74]

Several commonly-used protective functions are described below. Where a protective function is described it may be a dedicated relay (electromechanical, solid-state electronic, or microprocessor-based) or a single protective function contained within a microprocessor-based relay. In some manufacturer’s literature the individual functions are referred to as elements.

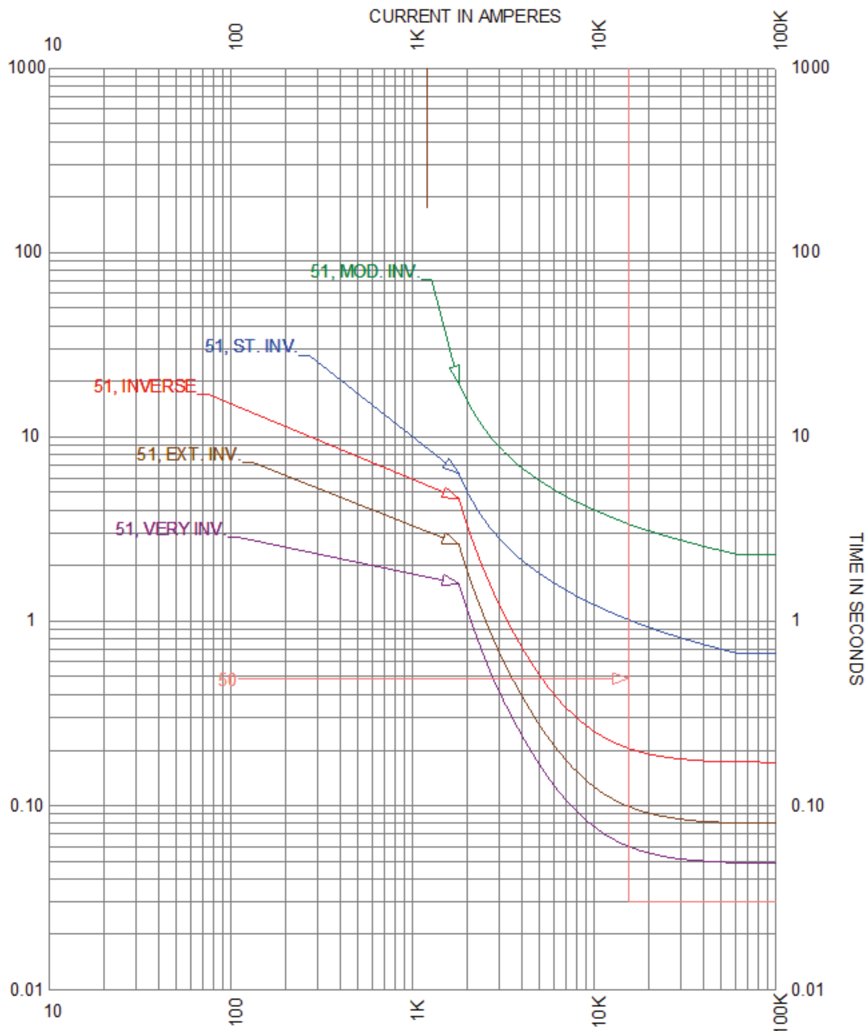
Overcurrent Relays (Devices 50, 51)

Overcurrent relays are the most commonly-used protective relay type. Time-overcurrent relays are available with various timing characteristics to coordinate with other protective devices and to shield specific equipment. Instantaneous overcurrent

74. IEEE Std. 242-2001, December 2001.

relays have no inherent time delay and are used for fast short-circuit protection. 50 and 51 Overcurrent Relay Characteristics, page 113 shows the timing characteristics of several typical 51 time-overcurrent relay curve types, along with the 50 instantaneous characteristic.

Figure 71 - 50 and 51 Overcurrent Relay Characteristics



The pickup level is set by the tap setting, which may be primary, secondary, or per unit current values. Each relay curve has a time dial/delay setting that allows the curve to be shifted up or down on the time-current characteristic curve. In 50 and 51 Overcurrent Relay Characteristics, page 113, the time dial settings are different to give enough space between the curves to show their differences.

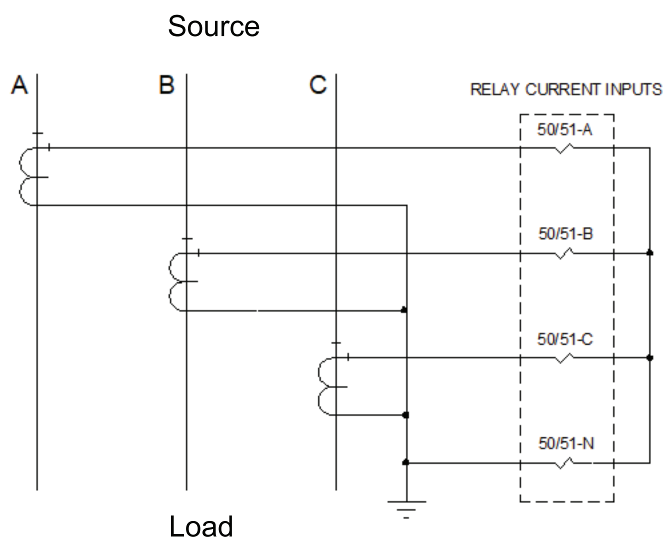
The above are IEEE-standard curves; others are available, depending upon the relay make and model. A solid-state electronic or microprocessor-based relay has all of these curves available on one unit; electromechanical relays must be ordered with a given characteristic that cannot be changed.

The 50 instantaneous function is only provided with a pickup setting. The 30 milliseconds delay shown in 50 and 51 Overcurrent Relay Characteristics, page 113 for the 50 function is typical and considers both the relay logic operation and the output contact closing time. Most microprocessor-based units also have an adjustable delay for the 50 function; when an intentional time delay is added the 50 is referred to as a definite-time overcurrent function. On solid-state electronic and microprocessor-based relays, the 50 function may be enabled or disabled. On electromechanical relays, the 50 function can be added as an instantaneous attachment to a 51 time-overcurrent relay. If a relay has both 50 and 51 functions present and enabled is referred to as a 50/51 relay.

Typically, overcurrent relays are employed as one per phase. In solidly-grounded medium-voltage systems, the most common choice for ground fault protection is to add a fourth relay in the residual connection of the CT's to monitor the sum of all three phase currents. This relay is referred to as a residual ground overcurrent or 51N (or 50/51N) relay.

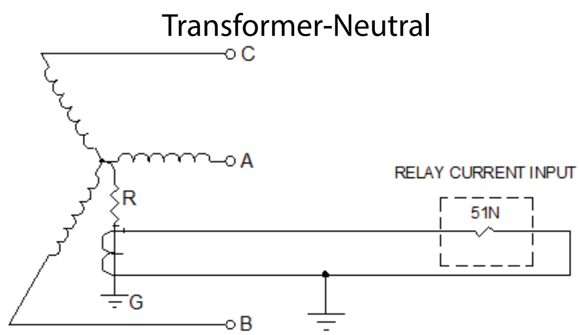
The CT arrangement for 50/51 and 50/51N relays for a solidly-grounded system is shown in Overcurrent Relay Arrangement with CT's, Including 50/51N, page 114.

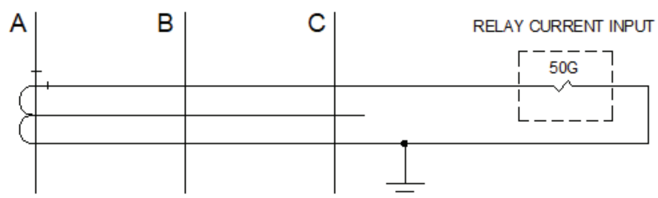
Figure 72 - Overcurrent Relay Arrangement with CT's, Including 50/51N



For a low-resistance-grounded system, the use of an overcurrent relay connected to a CT in the service transformer or generator neutral is usually the preferred option. This CT should have a ratio smaller than the phase CT's, and the relay pickup range in conjunction with the neutral CT should allow a pickup as low as 10% of the neutral resistor rating. For a feeder circuit downstream from the service transformer, a zero-sequence CT is recommended, again with a ratio small enough to allow a pickup as low as 10% of the neutral resistor rating. When an overcurrent relay is utilized with a zero-sequence CT it is referred to as a 50G, 51G or 50/51G relay depending upon relay type used. Transformer Neutral and Zero-Sequence Ground Relaying Applications for Resistance-grounded Systems, page 115 shows typical arrangements for both these applications.

Figure 73 - Transformer Neutral and Zero-Sequence Ground Relaying Applications for Resistance-grounded Systems

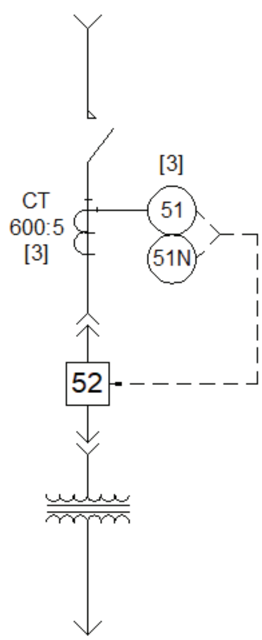




For ungrounded systems, little ground current flows during a single phase-to-ground fault. Low-voltage solidly-grounded systems are discussed below.

The typical application of phase and residual neutral ground overcurrent relays in one-line diagram form is shown in Typical Application of Overcurrent Relays, page 115.

Figure 74 - Typical Application of Overcurrent Relays



In Typical Application of Overcurrent Relays, page 115, the designation 52 is the IEEE Std. C37.2-2022 designation for a circuit breaker. The phase relays are designated 51 and the residual ground overcurrent relay is designated 51N (both without instantaneous function). *IEEE Recommended Practice for Protection and*

Coordination of Industrial Power Systems[75] denotes that there are three phase overcurrent relays and three CTs. The dotted line from the relays to the circuit breaker denotes that the relays are wired to trip the circuit breaker on an overcurrent condition.

Another type of overcurrent relay is the voltage-restrained overcurrent relay 51V and the voltage-controlled relay 51C. Both are used in generator applications to allow the relay to be set below the generator full-load current due to the fact that the fault contribution from a generator decays to a value less than the full-load current of the generator. The 51C relay does not operate on overcurrent unless the voltage is below a preset value. The 51V relay pickup current shifts as the voltage changes, allowing it to only respond to overcurrents at reduced voltage. Both require voltage inputs, and thus require voltage transformers for operation.

Directional Overcurrent Relays (Devices 67, 67N)

When fault currents can flow in more than one direction with respect to the load current it is often desirable to determine which direction the fault current is flowing and trip the appropriate devices accordingly. This is usually due to the need to de-energize only those parts of the power system that must be de-energized to contain a given fault.

Standard overcurrent relays cannot distinguish the direction of the current flow. Directional relays (67, 67N) are required to perform this function.

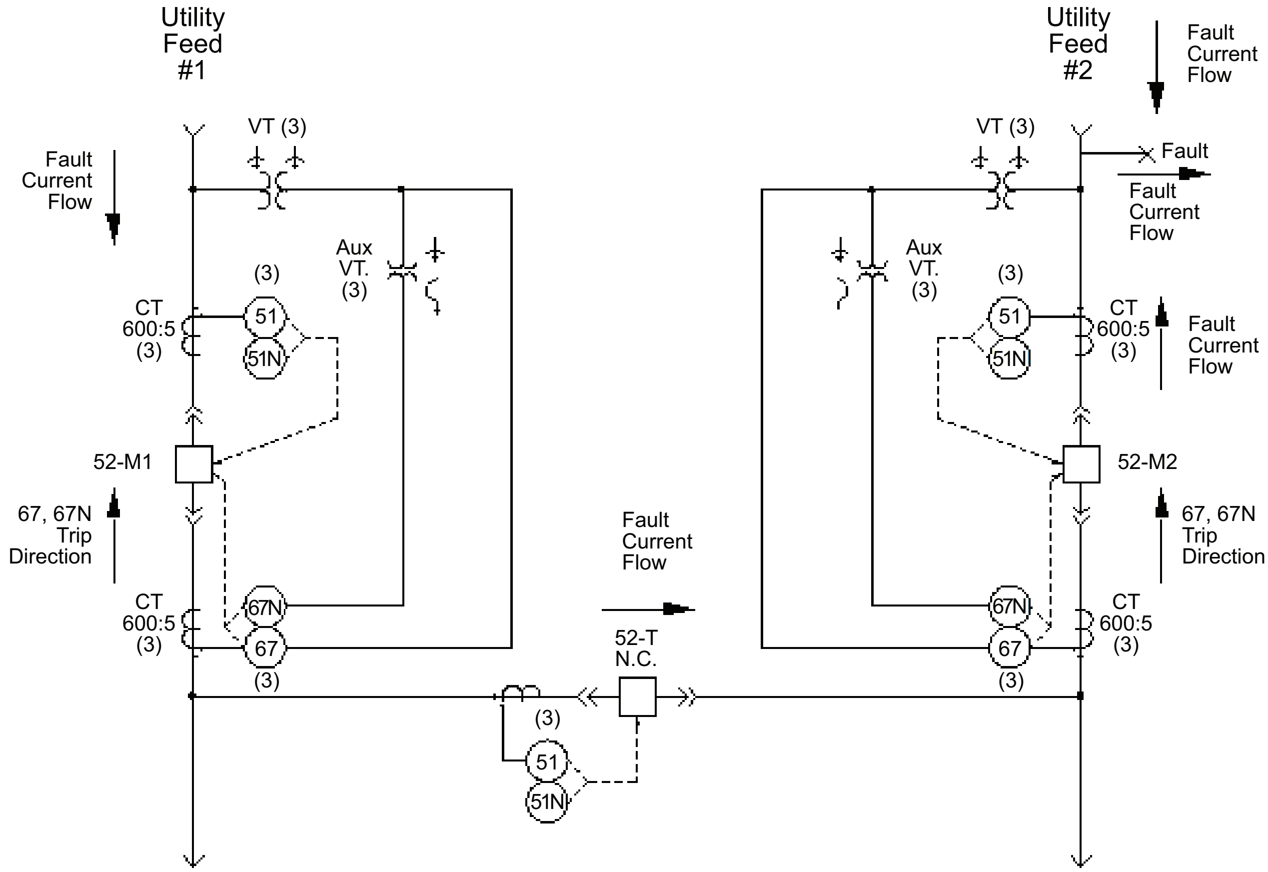
An important concept in the application of directional overcurrent relays is polarization. Polarization is the method used by the relay to determine the direction of current flow. For phase directional overcurrent relays, this is accomplished by the use of voltage transformers, which provide a voltage signal to the relay and allow it to distinguish the current direction. The details of polarization methods are not discussed here, but can be found in *IEEE Recommended Practice for Protection and Coordination of Industrial Power Systems*[75]. Because the voltage on a faulted phase can be unreliable, each phase is restrained via the voltage from a different phase. Care must be used when defining CT polarities as each manufacturer typically defines a preferred polarity to match their standard connection diagrams.

Polarization for a 67N relay is more difficult. They must be polarized with zero-sequence current or zero-sequence voltage. Electromechanical 67N relays must be polarized via either a CT in the source transformer neutral (zero-sequence current polarization) or three VT's connected with a wye-connected primaries and broken-delta connected secondaries (refer to A Ground Detection Method for Ungrounded Systems, page 59 for an example of the wye-broken delta connection with ferroresonance-swamping resistor). Solid-state 67N relays usually must be polarized the same way but do sometimes offer a choice of either method. Microprocessor-based relays typically offer a choice of either method and, in some cases, can self-polarize by calculating the zero-sequence voltage from the measured three-phase line voltage.

As an example of the effectiveness of directional overcurrent relays, consider the primary-selective system arrangement from Radial System, page 37. The primary main and tie circuit breakers and an example of protective relaying for those circuit breakers are shown in Example Protective Relaying Arrangement for Closed-Transition Primary-selective System, page 117.

75. IEEE Std. 242-2001, December 2001.

Figure 75 - Example Protective Relaying Arrangement for Closed-Transition Primary-selective System



In Example Protective Relaying Arrangement for Closed-Transition Primary-selective System, page 117 the bus tie circuit breaker is normally-closed, paralleling the two utility feeds. Each main circuit breaker and the bus tie circuit breaker are protected via 51 and 51N relays. The mains also have 67 and 67N relays. The 67 relays are polarized via the line voltage transformers, and auxiliary voltage transformers connected in wye-broken delta are supplied for polarization of the 67N relays. The polarization results in the indicated tripping directions for these relays. The need for the 67 and 67N relays is demonstrated by considering a fault on one of the utility feeds. Should utility feed #2, for example, experience a fault, the fault current is supplied both from the upstream system feeding utility feed #2 and from utility feed #1 through circuit breakers 52-M1, 52-T, and 52-M2. Because the 51 and 51N relays for 52-M1 and 52-M2 are likely set identically, they both respond to the fault at the same time, tripping 52-M1 and 52-M2 and de-energizing the entire downstream system. To avoid this, the 67 and 67N relays are set to coordinate with the 51 and 51N relays, respectively, so that the 67 and 67N relays trip first. For a fault on utility feed #2, the 67 and 67N relays for 52-M1 does not trip due to the fact that the current is flowing in the direction opposite to the tripping direction. However, the 67 and 67N relays on 52-M2 senses current in the tripping direction and trip 52-M2. The downstream system is still energized by 52-M1 and 52-T after 52-M2 trips.

Directional Power Relays (Device 32)

Directional power relays function when the measured real power flow in the tripping direction is exceeded. They are used when the power flow in a given direction is undesirable or harmful to system components.

One common use of 32 relays is at the utility service when onsite generators are paralleled with the utility. Under normal conditions, the incoming power from the utility is measured and generator power output is controlled so that power is not exported to the utility. Should the generator controls malfunction, the generator may begin to source power to the utility. The 32 relay then trips the service breaker offline, isolating the system from the utility. Of course, this would not apply if surplus power is to be intentionally sold to the utility in a co-generation arrangement.

Another use of the 32 relay is for the anti-motoring of generators, should prime-mover power be lost.

32 relays are most often supplied as single-phase devices, or as a single-phase function in the case of microprocessor-based relays. They require both current and voltage sensing to function.

In most applications, 32 relays should be time-delayed allowing the system to ride through momentary power surges.

Undervoltage Relays (Device 27)

Undervoltage relays operate when the system voltage falls below a pre-determined level. They are used in multiple applications. The most common application is a bus undervoltage relay, which alarms or trips a bus offline if the system voltage becomes unacceptably low. In this application, the relay should be time-delayed to ride through momentary dips in voltage, for example for a fault downstream from the relay.

27 relays are commonly used as the signal to an automatic bus transfer system to initiate the transfer from a failed source to an active source. In this application, also, they should be delayed to ride through momentary dips in voltage.

27 relays may also be used as permissive devices, for example to disallow closure of a circuit breaker if the system voltage is not above a pre-defined level. In this application the relay is typically configured to have instantaneous pickup, with time-delayed drop-out so that that the system voltage has been above the preset level for a specified period of time before circuit breaker closure is allowed.

Phase-Sequence Voltage Relays (Device 47)

47 relays generally detect the negative-sequence component of the system voltage, and are thus inherently three-phase devices. They may be set in terms of voltage balance or in terms of negative sequence voltage. They are used in a variety of applications, usually in conjunction with 27 and/or 59 relays.

For protection of motors, 47 relays are useful since a loss of one phase may not be detected for a running motor. This is due to the fact that a lightly-loaded motor (or group of lightly-loaded motors) may keep the voltage on the lost phase high enough to avoid pickup by a 27 relay on that phase. This fact usually justifies the use of the 47 relay whenever 27 relays are used for bus or motor protection.

47 relays may also be used for permissive functions in conjunction with a 27 relay, as described above. In this role the 47 relay helps so that a circuit breaker does not close if the system phase rotation is reversed, such as by the swapping of phase cables.

As with the 27 relay, the 47 relay should have a time delay to allow the system to ride through transient conditions. When a 27 and 47 relay are combined into the same electromechanical or solid-state electronic device, the device is referred to as a 27/47 relay.

E . Overvoltage Relays (Device 59)

59 relays respond to voltages above a pre-determined level. They are most often used in conjunction with 27 relays in generator applications to shield voltage-sensitive devices from overvoltage. They may also be used as permissive devices, usually in

conjunction with 27 relays. Either application gives a voltage “window” within which the system is allowed to operate. In this application 59 relays should be time-delayed just as 27 relays are.

59 relays may also be used for ground-fault detection on high-resistance grounded or ungrounded systems. Application for a high-resistance grounded system is shown in Pulsing Ground Detection System, page 62. For an ungrounded system the 59 relay may be used across the broken-delta secondary of a ground-detection VT circuit, such as the circuit shown in A Ground Detection Method for Ungrounded Systems, page 59.

When an electromechanical or solid-state electronic relay includes both 27 and 59 functions it is referred to as a 27/59 relay. When an electromechanical or solid-state electronic relay includes 27, 47, and 59 functions it is referred to as a 27/47/59 relay.

F. Lockout Relays (Device 86)

The lockout relay is used to trip a device and prevent its reclosure until the lockout relay is reset. In most cases the lockout relay is essentially a switch, and in fact is typically mounted in close proximity to circuit breaker control switches. The relay is spring-loaded, and a trip coil, when energized, causes the lockout relay to trip the connected devices and prevent them from reclosing. There is typically a conspicuous target on the lockout relay to alert operating personnel that it has tripped. When the lockout relay is reset, the opening springs are compressed and the relay is ready for the next tripping operation.

86 relays are commonly used where one protective relay must trip several protective devices, and where reclosure of the tripped devices needs to be controlled to avoid closing onto a fault.

G. Differential Relays (Device 87)

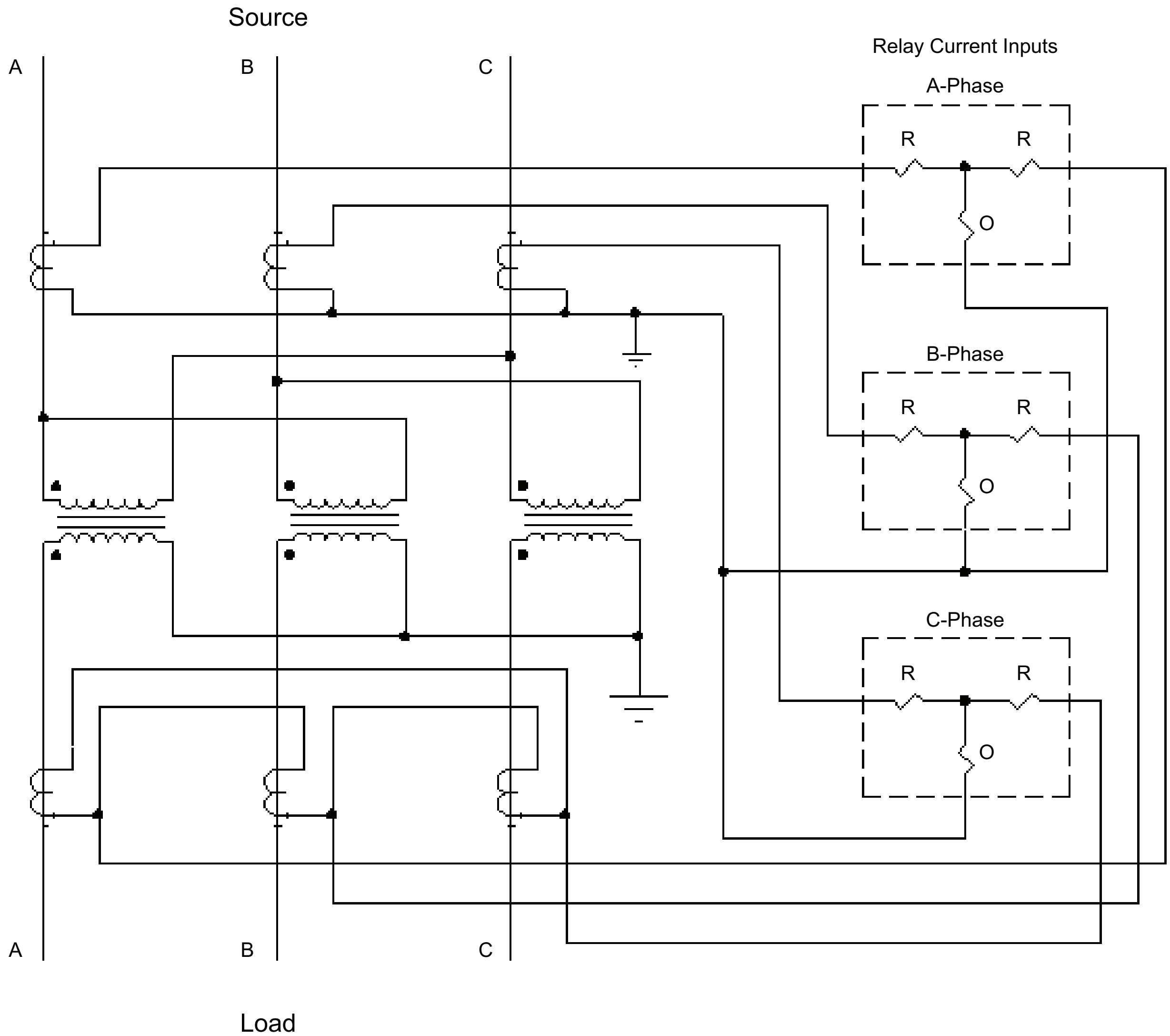
Differential relays operate on the principle that if the current flowing into a device does not equal the current flowing out, a fault must exist within the device.

Differential relays generally fall within one of two broad categories: Current-differential or high-impedance differential.

Current-differential relays are typically used to shield large transformers, generators, and motors. For these devices detection of low-level winding-to-ground faults is essential to avoid equipment damage. Current differential relays typically are equipped with restraint windings to which the CT inputs are to be connected. For electromechanical 87 current differential relays, the current through the restraint windings for each phase is summed and the sum is directed through an operating winding. The current through the operating winding must be above a certain percentage (typically 15%-50%) of the current through the restraint windings for the relay to operate. For solid-state electronic or microprocessor-based 87 relays the operating windings exist in logic only rather than as physical windings.

A typical application of current-differential relays for protection of a transformer is shown in Typical Application of Current-differential Relays for Delta-wye Transformer Protection, page 120. In Typical Application of Current-differential Relays for Delta-wye Transformer Protection, page 120, the restraint windings are labeled as “R” and the operating windings are labeled as “O”. Because the delta-wye transformer connection produces a phase shift, the secondary CT’s are connected in delta to counteract this phase shift for the connections to the relays. Under normal conditions the operating windings carry no current. For a large external fault on the load side of the transformer, differences in CT performance in the primary vs. the secondary (it is impossible to match the primary and secondary CT’s due to different current levels) are taken into account by the proper percentage differential setting. Because the CT ratios in the primary versus secondary is not always able to match the current magnitudes in the relay operating windings during normal conditions, the relays are equipped with taps to internally adjust the current levels for comparison. The specific connections in this example apply to a delta primary/wye secondary transformer or transformer bank only. The connections for other winding arrangement vary, to properly cancel the phase shift. For many solid-state electronic and microprocessor-based relays, the phase shift is made internally in the relay and the CT’s may be connected the same on the primary and secondary sides of the transformer regardless of the transformer winding connections. The manufacturer's literature for a given relay make and model must be consulted when planning the CT connections.

Figure 76 - Typical Application of Current-differential Relays for Delta-wye Transformer Protection

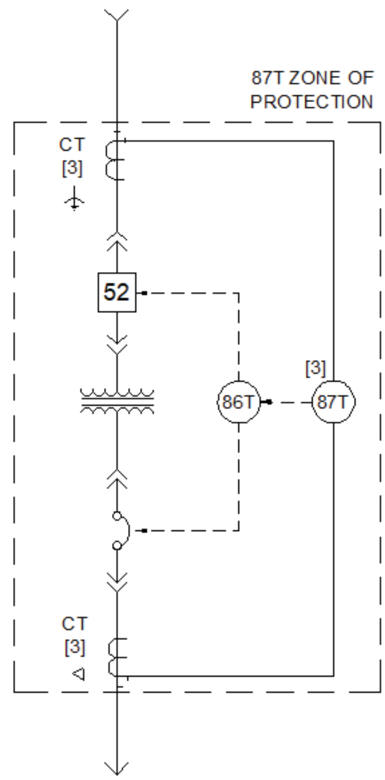


Percentage-differential characteristics are available as fixed-percentage or variable percentage. The difference is that a fixed-percentage relay exhibits a constant percentage restraint, and for a variable-percentage relay the percentage restraint increases as the restraint current increases. For an electromechanical relay, the percentage characteristic must be specified for each relay; for solid-state electronic or microprocessor-based relays these characteristics are adjustable. For transformers relays with an additional harmonic restraint are available. Harmonic restraint restrains the relay when certain harmonics, normally the 2nd and 5th, are present. These harmonics are characteristic of transformer inrush and without harmonic restraint the transformer inrush may cause the relay to operate.

An important concept in the application of differential relays is that the relay typically trips fault interrupting devices on both sides of the transformer. This is due to the fact that motors and generators on the secondary side of the protected device contributes to the fault current produced due to an internal fault in the device. An example one-line diagram representation of the transformer differential protection from Typical Application of Current-differential Relays for Delta-wye Transformer Protection, page

120 is given in Transformer Differential Relay Application from Figure 76 in One-line Diagram Format, page 121.

Figure 77 - Transformer Differential Relay Application from Figure 76 in One-line Diagram Format



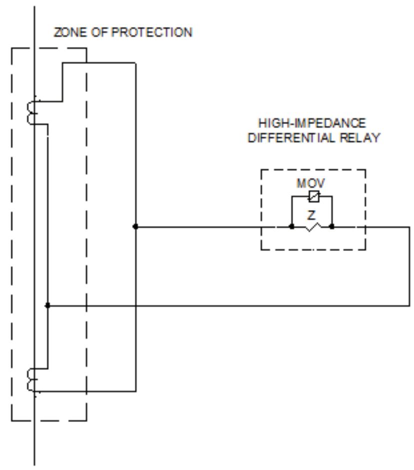
The secondary protective device is shown as a low-voltage power circuit breaker. It is important that the protective devices on both sides of the transformer be capable of fault-interrupting duty and suitable for relay tripping.

In High-impedance Differential Relay Concept, page 122 a lockout relay is used to trip both the primary and secondary overcurrent devices. The lockout relay is designated 86T since it is used for transformer tripping, and the differential relay is denoted 87T since it is protecting the transformer. The wye and delta CT connections are also noted.

An important concept in protective relaying is the zone of protection; a zone of protection is the area that a given protective relay and/or overcurrent device(s) are to protect. While the zone of protection concept applies to any type of protection (note the term zone selective interlocking as described earlier in this section), it is especially important in the application of differential relays because the zone of protection is strictly defined by the CT locations. In High-impedance Differential Relay Concept, page 122 the zone of protection for the 87T relay is shown by the dashed-line box around the transformer. For faults within the zone of protection, the currents in the CT's do not sum to zero at the relay operating windings and the relays operate. Outside the zone of protection the operating winding currents should sum to zero (or be low enough that the percentage restraint is not exceeded), and therefore the relays do not operate.

The other major category of differential relays, high-impedance differential relays, use a different principle for operation. A high-impedance differential relay has a high-impedance operating element, across which the voltage is measured. CT's are connected such that during normal load or external fault conditions the current through the impedance is essentially zero. But, for a fault inside the differential zone of protection, the current through the high-impedance input is non-zero and causes a rapid rise in the voltage across the input, resulting in relay operation. A simplified schematic of a high-impedance differential relay is shown in High-impedance Differential Relaying Applied to a Primary-selective System, page 123 to illustrate the concept. The relay only has one set of input terminals, without restraint windings. This means that any number of CT's may be connected to the relay as needed to extend zone of protection, so long as the CT currents sum to zero during normal conditions. That a voltage-limiting MOV connected across the high-impedance input is shown. This is to keep the voltage across the input during a fault from damaging the input.

Figure 78 - High-impedance Differential Relay Concept

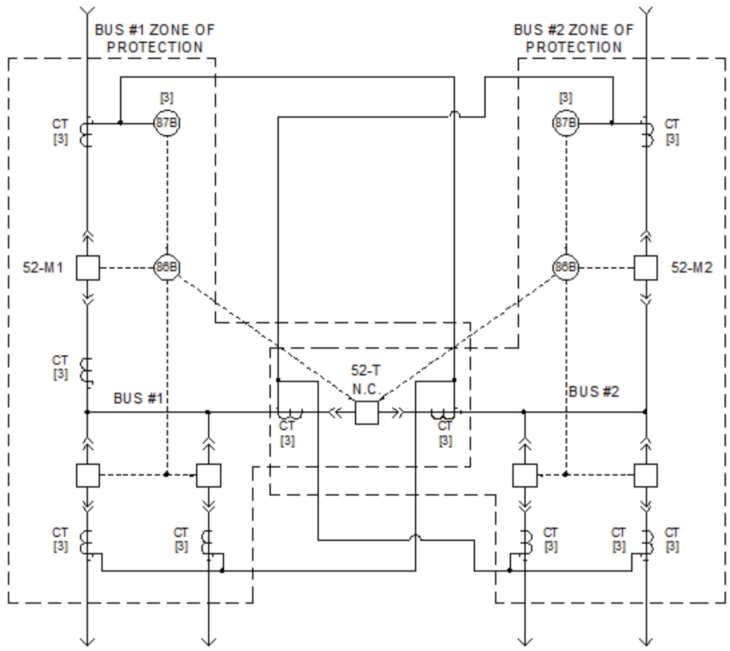


High-impedance differential relays are typically used for bus protection. Bus protection is an application that demands many sets of CT's be connected to the relays. It is also an application that demands that that relay be able to operate with unequal CT performance, since external fault magnitudes can be quite large. The high-impedance differential relay meets both requirements.

High-impedance Differential Relay Concept, page 122 shows the application of bus differential relays to a primary-selective system. In High-impedance Differential Relay Concept, page 122 the zones of protection for Bus #1 and Bus #2 overlap. Here the 86 relay is extremely useful due to the large number of circuit breakers to be tripped. All circuit breakers attached to the protected busses are equipped with differential CT's and are tripped by that busses' respective 86 relay. The 87 relays are denoted 87B since they are protecting busses. The same applies for the 86B relays. The protective zones overlap; this is typical practice so that that all parts of the bus work are protected.

The high-impedance differential relay is typically set in terms of voltage across the input. The voltage setting is typically set so that if one CT is fully saturated and the others are not the relay do not operate. By its nature, the high-impedance differential relay is less sensitive than the current-differential relay, but since it is typically applied to shield bussing, where fault magnitudes are typically high, the additional sensitivity is not required.

Figure 79 - High-impedance Differential Relaying Applied to a Primary-selective System



Other Protective Relays Types

Only a small selection of the most used protective relay types are given here. For more in-depth descriptions of their application, and for descriptions of other protective relay types, see reference *IEEE Recommended Practice for Protection and Coordination of Industrial Power Systems*[76].

Ground Fault Protection for Solidly-grounded Systems 600 V and Below

Because the ground fault is the most common type of system fault, and because low-voltage systems are necessarily the largest portion of most industrial and commercial facilities, low-voltage ground-fault protection has become a specialized area of development for system protection. Unlike the relayed ground-fault protection systems shown in Protective Relays, page 109, these systems are specially designed to provide sensitive protection for four-wire systems with imbalanced loads.

The *The National Electrical Code*[77] requires ground-fault protection for most solidly-grounded electrical systems 1000 A or more and above 150 V to ground but not exceeding 600 V phase-to-phase. For this reason, the ground-fault systems described herein are prevalent in systems meeting these criteria.

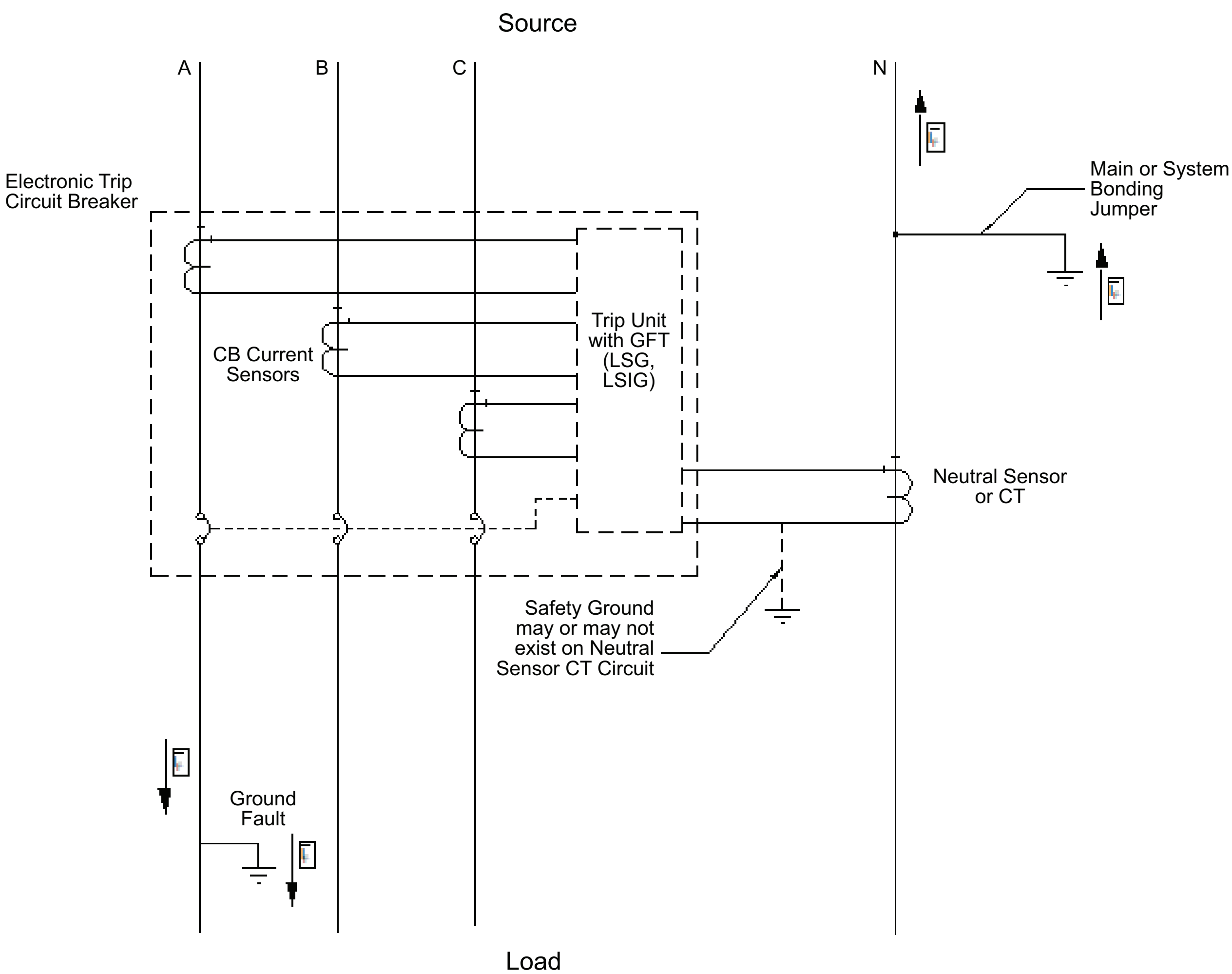
The low-ground fault protection methods in this section are for solidly-grounded systems only and augment the ground detection methods given in System Grounding, page 51 for ungrounded and high-resistance-grounded systems. Low-resistance grounded systems at the low-voltage level are uncommon but can be protected per the guidelines given above for relayed ground fault protection.

76. IEEE Std. 242-2001, December 2001.
77. NFPA 70, The National Fire Protection Association, Inc., 2020 Edition.

Ground-fault Protection for Radial Systems

Ground-fault protection for low-voltage radial systems is straightforward. For electronic trip units the tripping logic is typically built into the circuit breaker, and only the neutral CT or sensor must be connected to complete the ground fault protection system. Such an arrangement is illustrated in Low-voltage Ground Fault Protection for Four-wire Radial System with Electronic-trip Circuit Breaker, page 124.

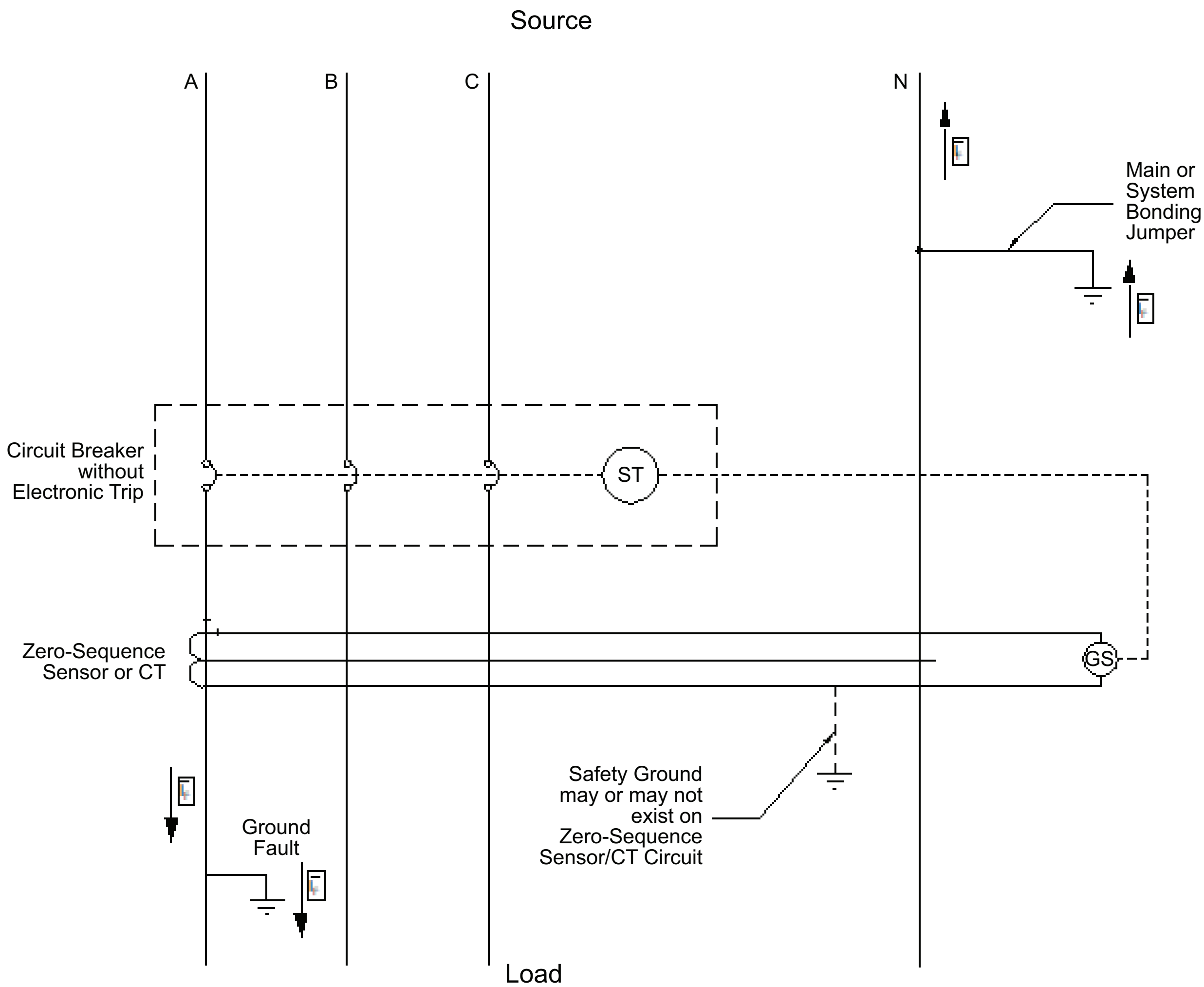
Figure 80 - Low-voltage Ground Fault Protection for Four-wire Radial System with Electronic-trip Circuit Breaker



In Low-voltage Ground Fault Protection for Four-wire Radial System with Electronic-trip Circuit Breaker, page 124 the neutral sensor may be an air-core CT or a conventional iron-core CT. The ground fault current is diverted around the neutral sensor when it is placed on the load-side of the main or system bonding jumper (see System Grounding, page 51 for the definition of main and system bonding jumpers and related discussion). Under normal unbalanced-load conditions the neutral sensor detects the neutral current and stops the circuit breaker from tripping. If the system is a three-wire system without a system neutral the neutral CT is omitted.

If the circuit breaker is not equipped with an electronic trip system, an external ground fault relay may be used with a zero-sequence sensor to trip the circuit breaker. The circuit breaker must be equipped with a shunt trip attachment in this case. Low-voltage Ground Fault Protection for Four-wire Radial System Without Electronic Trip Circuit Breaker, page 125 shows an example of this arrangement. In Low-voltage Ground Fault Protection for Four-wire Radial System Without Electronic Trip Circuit Breaker, page 125 the external ground fault relay is noted as “GS”. In low-voltage systems this is the typical notation rather than “51G”, although “51G” could also be used. In a three-wire system the neutral is omitted, and the zero-sequence sensor includes the phase conductors only.

Figure 81 - Low-voltage Ground Fault Protection for Four-wire Radial System Without Electronic Trip Circuit Breaker



These methods provide sensitive ground fault protection for solidly-grounded radial systems. However, if multiple sources are involved a more involved system is required to obtain acceptable ground-fault protection.

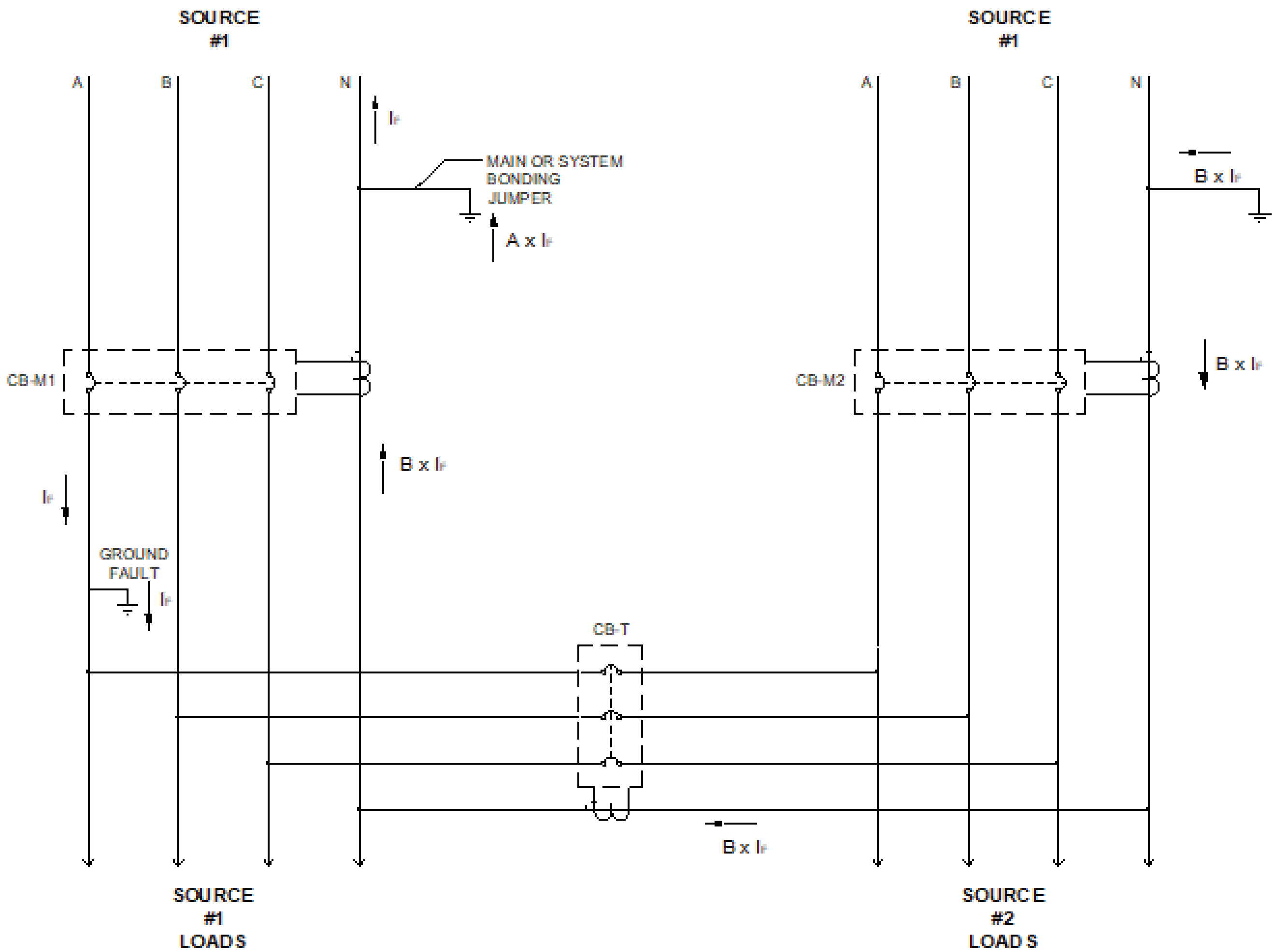
Modified-differential Ground Fault Systems

Because four-pole circuit breakers are not in common use in the United States, the issue of multiple ground current return paths has a large effect upon ground-fault protection in four-wire systems. To illustrate this point, consider a secondary-selective system as shown in Secondary-selective System with Radial Ground-fault Protection of Figure 80 Applied, page 126.

A ground fault on one bus has two return paths: Through its source-transformer main/ system bonding jumper or the other source-transformer main/system bonding jumper neutral. How much ground fault current flows in each path is dependent upon the ground or zero-sequence impedances of the system, which is difficult to evaluate. Therefore, assume a factor of A x the total ground-fault current flows through the source transformer main/system bonding jumper neutral and B x the total ground-fault current flows through the other transformer main/system bonding jumper, where A + B = 1. As can be seen from Secondary-selective System with Radial Ground-fault

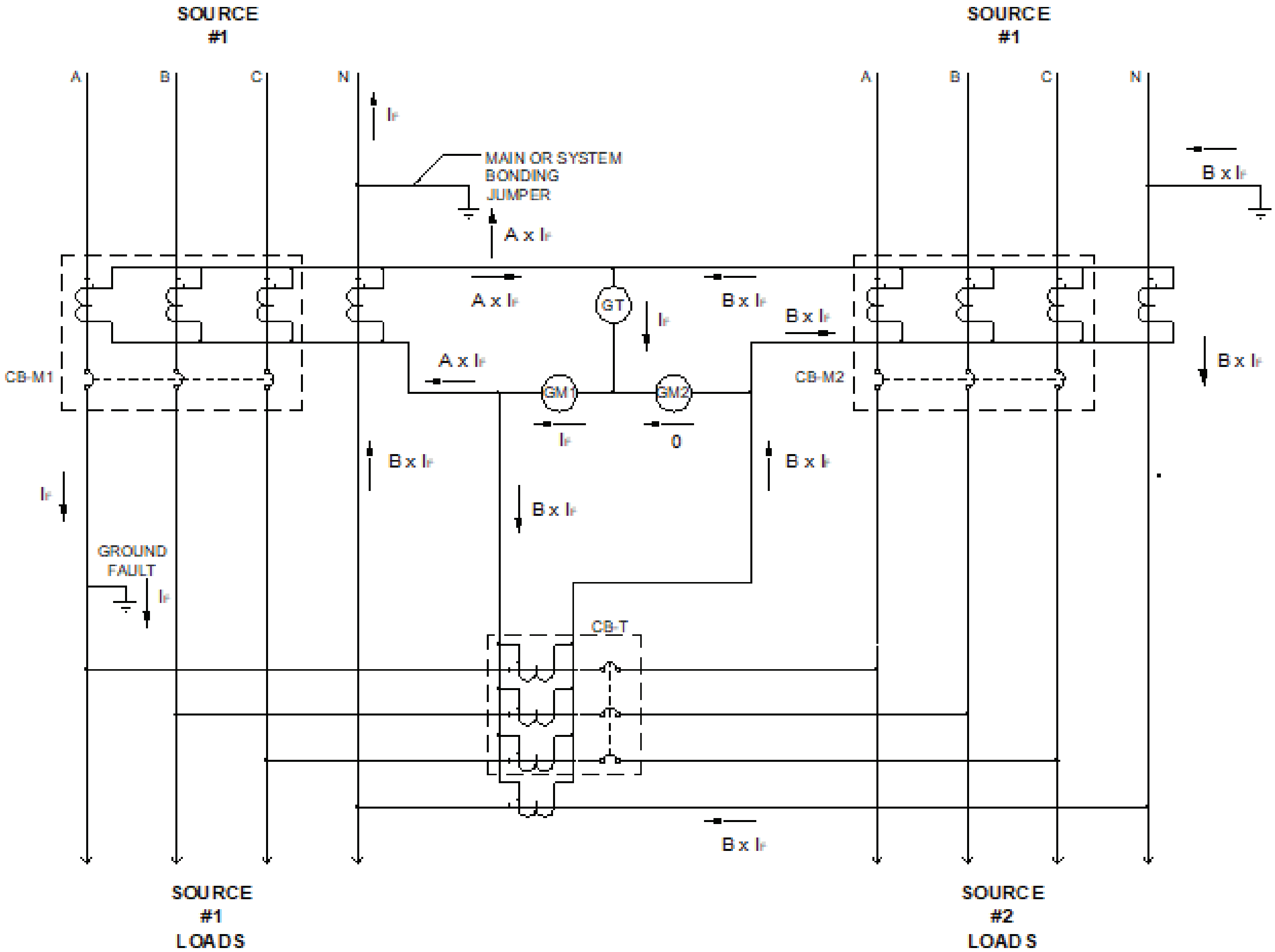
Protection of Figure 80 Applied, page 126, the ground-fault protection for the faulted bus can be de-sensitize or, worse, the wrong circuit breaker(s) may trip.

Figure 82 - Secondary-selective System with Radial Ground-fault Protection of Figure 80 Applied



The solution is the modified-differential ground fault system. A typical example of such a system is shown in Secondary-selective System with Radial Ground-fault Protection of Figure 80 Applied, page 126.

Figure 83 - Modified-differential Ground-fault Protection for Secondary-selective System



In Secondary-selective System with Radial Ground-fault Protection of Figure 80 Applied, page 126 the breaker internal sensors are shown, but the trip units are omitted for clarity. The ground-fault function for CB-M1 is noted as GM1, for CB-M2 is noted as GM2, and for CB-T is noted as GT. In this arrangement, regardless of the ground current dividing factors A and B the correct circuit breakers sense the ground fault and trip. This system works regardless of whether CB-T is normally-open or normally-closed. Non-electronic circuit breakers could also be used, but external CT's and ground relays would have to be utilized.

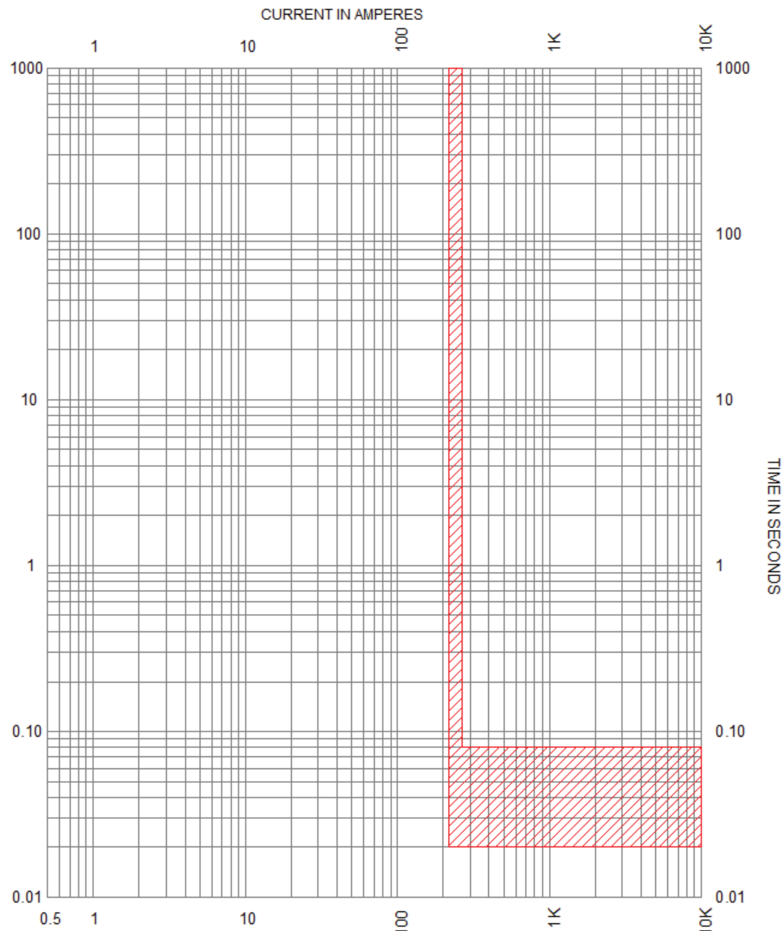
For unusual system arrangements or arrangements with more than two sources, the system of Secondary-selective System with Radial Ground-fault Protection of Figure 80 Applied, page 126 can be expanded. These are usually custom-engineered solutions.

Four-pole Circuit Breaker

Another possible option, in lieu of the modified differential ground fault system, is the use of four-pole circuit breakers. These switch the neutral as well as the phase conductors, separating the neutrals of multi-source circuits. This method does not work if sources are paralleled. Four-pole circuit breakers are not common in the United States for this reason, as well the increased physical equipment sizes they necessitate.

Ground Fault Time - Current Characteristics

Figure 84 - Typical Electronic-trip Circuit Breaker Ground-Fault Protection Time-Current Characteristic



This characteristic is adjustable both for pickup and time delay. Discrete relays for use with non-electronic circuit breakers are also available with similar characteristics.

Take care when coordinating ground-fault protection if multiple levels of ground-fault protection do not exist downstream from the service or source of a separately-derived system. The NEC Article 230.95 (A) service-entrance requirement The National Electrical Code[78]for a maximum of 1200 A pickup and maximum one second delay at 3000 A ground-fault current can lead to a lack of coordination for downstream feeder and branch-circuit ground faults. This is one of the reasons for the use of other than solidly-grounded systems where maximum system reliability is to be achieved.

Surge Protection

Surge protection is protection of conductors and equipment against the effects of voltage surges. These are usually due to lightning, although switching transients can also cause damaging overvoltages. Unlike overvoltage relaying, surge protection is directly connected to the power circuit, and for the maximum protection is usually located as close as physically practical to the protected equipment.

78. NFPA 70, The National Fire Protection Association, Inc., 2020 Edition.

Medium-voltage Surge Protection

Medium-voltage surge protection is generally accomplished with surge arresters. A surge arrester exhibits an impedance which decreases with the line voltage. Older technologies included spark-gap arresters, which provided surge protection when the voltage became high enough to ionize the air in an internal spark gap. Modern surge arrestors employ metal-oxide varistor (MOV) technology, which exhibit a non-linear resistance which changes with the applied voltage. These generally provide better protection than spark-gap arrestors, although they do have limits on the continuous voltage that may be applied to the arrester without damage.

Surge arrestors are connected phase-to-grounded, even on ungrounded systems. When MOV surge arrestors are used, they must be sized for the maximum anticipated phase-to-ground voltage. MOV surge arrestors have a duty-cycle voltage rating and a maximum continuous operating voltage (MCOV) rating; the MCOV rating is the quantity to be compared to the phase-to-ground voltage. Also of importance is the arrester's classification as distribution-class, intermediate-class, or station-class; these classes are defined in terms of the energy the surge arrestor can absorb without damage, in ascending order as listed. Table 21 gives commonly-applied MOV surge arrestor ratings versus the system voltage. In general, use of surge arrestors with the lowest MCOV exceeding the anticipated line-to-ground voltage provides the maximum protection. Detailed insulation coordination studies can also be performed with the use of transient analysis software. For low-resistance-grounded systems, selection of the lowest acceptable surge arrestor rating involves comparing the overvoltage versus time characteristic of the surge arrestor to the maximum time a ground fault remains on the system prior to tripping.

For motor circuits, surge capacitors are also often employed. These provide dV/dt protection for the motor windings. Take care when sizing surge capacitors and the effects of harmonic currents must be evaluated so that the capacitors do not rupture.

Both surge capacitors and surge arresters are applied without dedicated overcurrent protection. For this reason, loss of these devices results in some equipment damage. In the case of surge arresters, use of polymer housings results in minimal damage should the arrester fail; the housing simply splits to relieve the internal overpressure. Use of porcelain housings which can sustain large internal overpressures can result in severe damage if the arrester fails. In the case of surge capacitors, since they are typically filled with dielectric fluid and have steel housings, they can sustain high internal overpressures, and failure of the housing due to internal overpressure can result in catastrophic equipment damage and risk to personnel.

Applicable standards include IEEE Std. C62.11 and IEEE Std. C62.22.

Table 21 - Commonly-applied Ratings for Metal-oxide Surge Arrestors

Duty-cycle Voltage (kV)	MCOV (kV)	Four-wire Effectively-grounded Neutral System [79]	Three-wire Grounded and Resistance-Grounded Wye Systems[80]
3	2.6	4160Y/ 2400	2400
6	5.1	8320Y/ 4800	4160 4800
9	7.7	12000Y/ 6930 12470Y /7200	6900
10	8.4	13200Y/ 7620 13800Y/ 7970	
12	10.2		
15	12.7	20780Y/12000	12000 12470
18	15.3	22860Y/ 13200 24940Y/ 14400	13200 13800
21	17.0		
24	19.5		
27	22.0	34500Y/ 19920	20780
30	24.4		22860
36	29.0		24940

Low-voltage Surge Protection

Strictly speaking, low-voltage surge protection is via smaller versions of the MOV arresters used in medium-voltage systems. Various versions of these are available, including mountings which fit the circuit-breaker spaces in panelboards. These are generally manufactured to the same standards as their medium-voltage counterparts.

A more commonly-used device is the surge protective device (SPD). The SPD is a device classification unique to UL and is intended to provide a degree of protection for sensitive utilization equipment against the effects of transient voltages. An SPD usually include MOVs for voltage clamping as well as filtering for surge attenuation. They are designed and manufactured to UL Std.1449, which requires consideration for device loss modes due to the intended installation location. UL 1449 defines three general installation classifications: Permanently Connected, Cord Connected, and Direct Plug-In. SPDs are intended for use on the load side of an overcurrent protective device such as a circuit breaker. They often include status indication for identification of a failed unit. Surge Protector Devices are generally considered the preferred means of low-voltage surge protection.

79. Use of this system category requires a solid ground conductor (non-earth) path back to the upstream transformer or generator neutral.
80. Includes grounded-wye systems where the path to the upstream transformer neutral includes an earth path.

Protection of Specific System Components

Power Cables

For low-voltage power cables, so long as they are protected at their ampacities per NEC Article 240.5 *The National Electrical Code, NFPA 70*[81] they can be considered adequately protected.

For medium-voltage power cables, proper protection requires both sizing per the NEC ampacity tables and comparing the overcurrent protective device time-current characteristic with the cable damage characteristic per IPCEA Publication P-32-382. The cable damage characteristic for a #1/0 AWG copper conductor is shown in Medium-voltage Cable Protection Example, page 132 as compared with the time-current characteristic of a 300E fuse. Per NEC Article 240.100 (C) *The National Electrical Code, NFPA 70*[81], the factor to be considered is the short-circuit performance of the cable; indeed, NEC Article 240.101 (A) allows the rating of a fuse protecting the conductor to be up to three times the ampacity of the conductors (six times for a circuit breaker or electronically-actuated fuse). As seen in Medium-voltage Cable Protection Example, page 132, the 300E fuse indeed does not provide overload protection for the cable at its ampacity (200 A) but is within the limits of NEC 240.101 (A). Even though the fuse allows the cable ampacity to be exceeded, the continuous load on the cable should not exceed the published conductor ampacity. The 300E fuse does, however, adequately protect the cable for short-circuits, as evidenced by the cable damage characteristic being to the right and above the fuse characteristic.

When overcurrent relays are used to protect medium-voltage power cables the procedure is the same, but a 51 pickup of no more than 125%-150% of the maximum load on the cable.

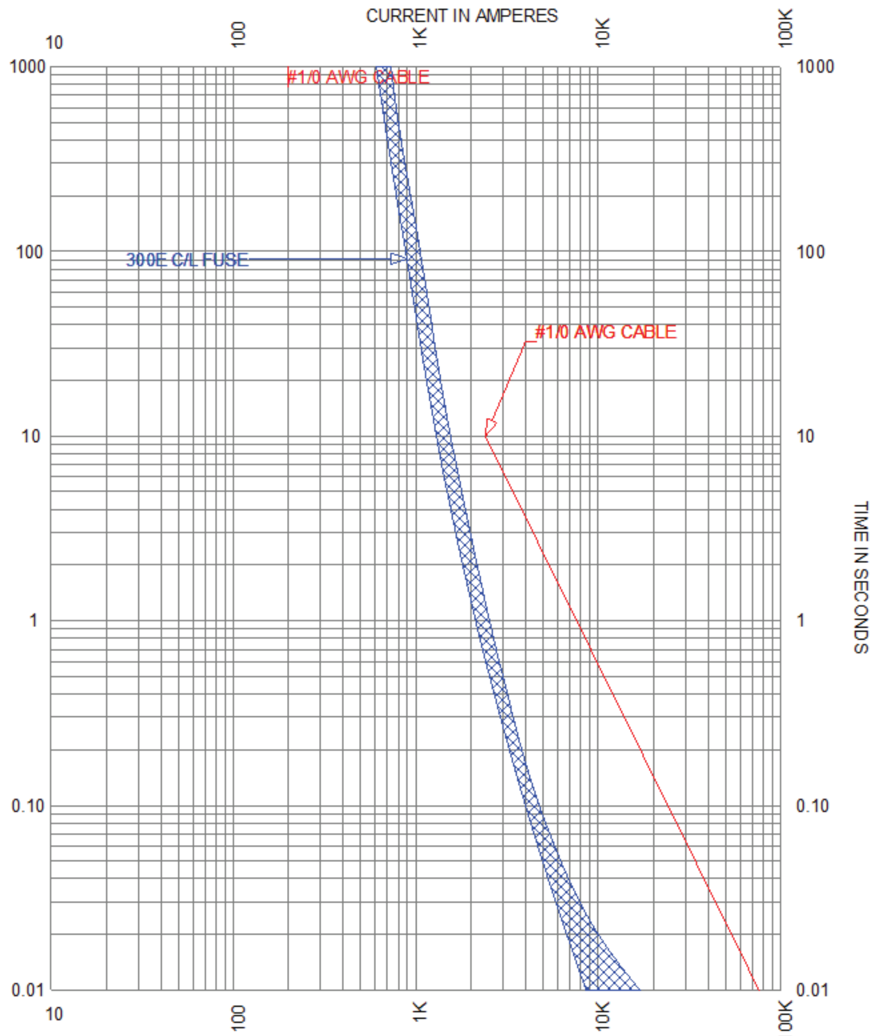
Transformer Protection

Transformer protection consists of both overload protection and short-circuit protection.

Overload protection is usually accomplished via proper selection of the secondary overcurrent protective device. NEC Article 450 *The National Electrical Code, NFPA 70*[81] gives specific primary and secondary overcurrent device ratings that cannot be exceeded. These vary depending upon the accessibility of the transformer to unqualified persons and the impedance of the transformer. The smallest protective device that allows the rated full-load current of the transformer gives the maximum practical overcurrent protection. Increasing the secondary overcurrent device size beyond this may be necessary for short-term overloads or for coordination with downstream devices, but in any case, the requirements of NEC Article 450 must be met.

81. The National Fire Protection Association, Inc., 2020 Edition.

Figure 85 - Medium-voltage Cable Protection Example

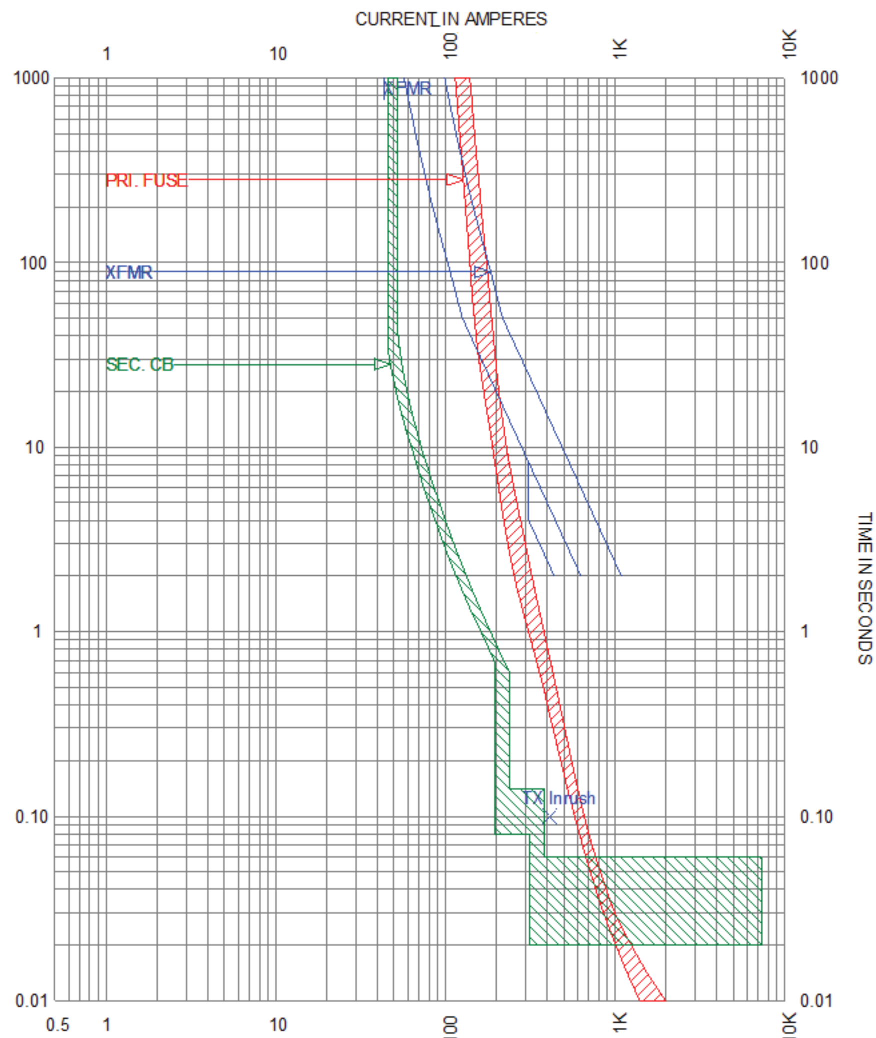


Short-circuit protection involves comparison of the transformer damage curve per IEEE Std. C57.109-2018 with the primary overcurrent device time-current characteristic. In general, the damage curve must be to the right and above the primary overcurrent device characteristic. Another constraint on the primary overcurrent device is that it must be capable of withstanding the inrush of the transformer without tripping (and without damage for current-limiting fuses). An example time-current characteristic showing protection for a 1000 kVA 13.2 kV Delta:480Y/277 V, 5.75% Z dry-type transformer is shown in Example Protection for a 1000 kVA, 13.2 kV Delta:480Y/27 7V, 5.75% Z Dry-type Transformer, page 133. The transformer is protected with a 65E current-limiting primary fuses and a 1200 A electronic-trip secondary circuit breaker. As seen from the figure, the fuses do withstand the inrush without damage since the inrush point is to the left and below the fuse minimum melt curve. The transformer is protected from short-circuits by the primary fuses. The secondary circuit breaker provides overload protection at the full-load current of the transformer. The primary fuse and secondary circuit-breaker characteristics overlap for high fault currents; this is unavoidable and is considered acceptable. The fuse curve and the transformer damage curve overlap; this is unavoidable, but these should overlap at the lowest current possible. For currents below the fuse/transformer damage curve overlap the secondary circuit breaker must protect the transformer; the lower the point of overlap, the more likely the fault is an external fault on the load side of the secondary circuit breaker and therefore greater chance the secondary circuit breaker effectively protects the transformer for faults in this region.

Also, the transformer damage characteristic is shown twice. Because transformer is a delta-wye transformer, a ground-fault on the secondary side of the transformer results in only 57.7% of the maximum three-phase primary fault current while one secondary winding experiences the full fault current. This is illustrated in Fault-current Flow for Delta-Wye Transformer L-N Faults and Delta-Delta Transformer L-L Faults, page 134, as well as the corollary for delta-delta transformers. The damage characteristic has therefore been shifted to 57.7% of its published value to account for secondary line-to-ground faults. Also, the shifted curve has another, more conservative curve shown; this is the frequent-fault curve and is applicable only to the secondary overcurrent device since faults between the transformer secondary and the secondary overcurrent protective device should not be frequent.

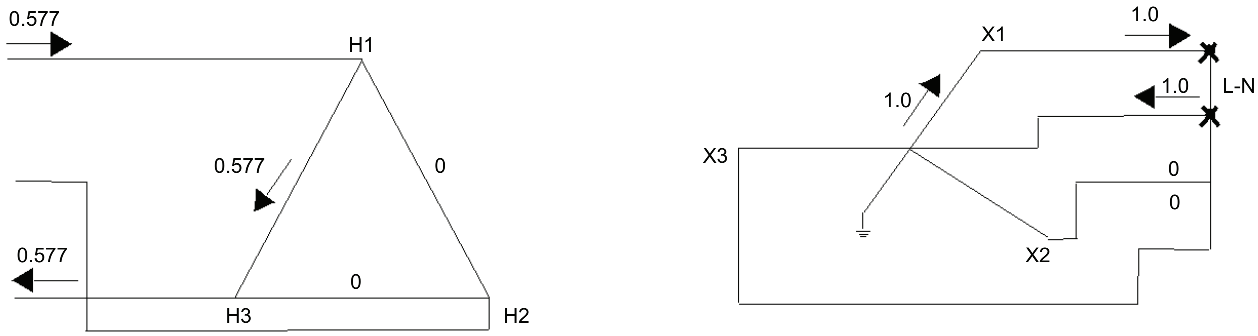
Additional devices, such as thermal overload alarms/relays and sudden-pressure relays, are also available for protection of transformers. These are typically specified with the transformer itself and can provide very good protection. However, even if these devices are installed the primary and secondary overcurrent devices must be coordinated with the transformer as described above.

Figure 86 - Example Protection for a 1000 kVA, 13.2 kV Delta:480Y/27 7V, 5.75% Z Dry-type Transformer

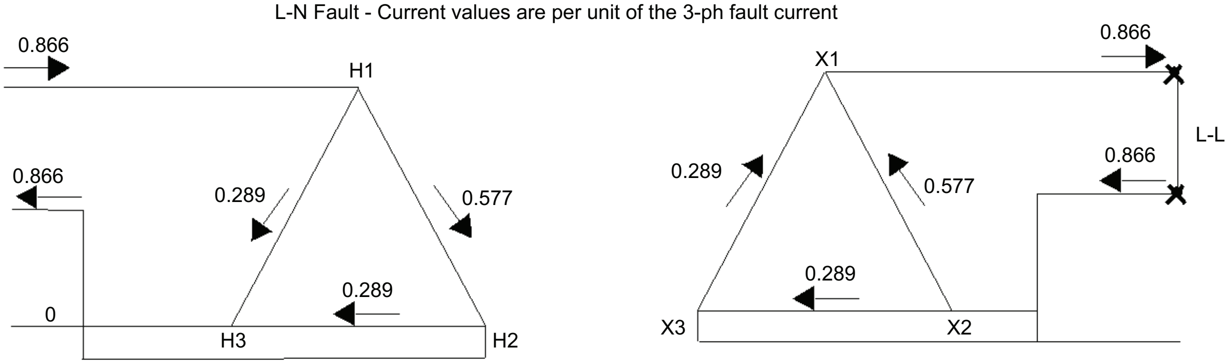


Differential protection for transformers, as described above, is very effective for transformer internal faults. If differential protection is supplied, it is the primary protection for internal faults and operates before the primary overcurrent device. The primary overcurrent device serves as a backup protective device for internal faults in this case.

Figure 87 - Fault-current Flow for Delta-Wye Transformer L-N Faults and Delta-Delta Transformer L-L Faults



L-N Fault - Current values are per unit of the 3-ph fault current



L-L Fault - Current values are per unit of the 3-ph fault current

Generator Protection

The subject of generator protection is a complex one, and due to this fact it is not presented here. Refer to *IEEE Recommended Practice for Protection and Coordination of Industrial Power Systems*[82] for detailed descriptions of generator protection methods, as well as descriptions of protective relay types that are not discussed above that used for generator protection.

Other Devices and Additional Information

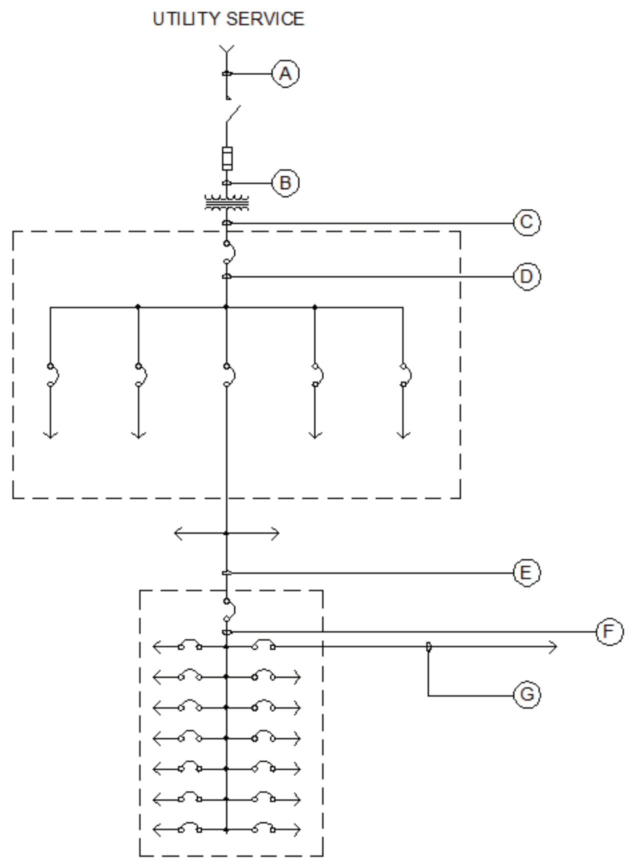
For protection other devices, refer to *IEEE Recommended Practice for Protection and Coordination of Industrial Power Systems*[82] and/or the applicable standards for the device in question. For additional information on the protection of cables and transformers, refer to *IEEE Recommended Practice for Protection and Coordination of Industrial Power Systems*[82].

Protection Selectivity

The selectivity of protection refers to its ability to isolate an abnormal condition to the smallest portion of the system possible. In most cases selectivity is a function of how well-coordinated the overcurrent protective devices in the system are. As an example, consider the system of Example System for Selectivity Discussion, page 135.

82. IEEE Std. 242-2001, December 2001.

Figure 88 - Example System for Selectivity Discussion



Example System for Selectivity Discussion, page 135 shows a small radial system with a medium-voltage utility service, a service substation consisting of a primary switch step-down transformer protected by a primary fuse, and a secondary switchboard. One of the switchboard feeder circuit breakers is shown feeding al lighting panel and other loads.

For optimum selectivity, a fault at point G should only cause its lighting panel feeder circuit breaker to trip. The panel main circuit breaker and all devices upstream should not be affected. If the lighting panel feeder circuit breaker time-current characteristic does not coordinate with that of the lighting panel main, the main may trip, de-energizing the entire panelboard.

Going upstream, a fault at point F should only cause the panelboard main circuit breaker to trip and a fault at point E should only cause the switchboard main circuit breaker to trip. A fault at point D may cause the switchboard main circuit breaker to trip or the primary fuse to blow, but the effect on the system is the same since all of the loads will be de-energized in either event. A fault at point C should only cause the transformer primary fuse to blow.

Lack of selectivity causes more of the system to be de-energized for a fault in a given location. The severity of the outage increases as the fault location is considered farther and farther upstream. In this example, if the transformer primary fuses and the upstream utility recloser, protective relays, or fuses are not coordinated the entire utility distribution line, or a segment of the line, could be de-energized, affecting other customers.

To analyze system selectivity, a time-current coordination study must be performed. This study analyzes the time-current coordination characteristics of the protective devices in the system and plots them on time current curves such as those illustrated in this section. Coordination is achieved between two devices if their time-current bands show sufficient clear space between them on the time-current curve or, in the case of protective relays, if sufficient margin for overtravel, manufacturing tolerances, circuit breaker speed, and safety are achieved

Coordination is not always possible to maintain in the high fault-current ranges. However, in most cases an acceptable compromise can be reached since high-level faults are a rare occurrence.

Another important concept is that of backup protection. In this case, for a fault at point G if the lighting panel feeder circuit breaker fails to trip the panelboard main circuit breaker should trip as dictated by its time-current curve. If selective coordination exists between the panelboard main circuit breaker and the switchboard feeder circuit breaker, then the switchboard feeder circuit breaker will not trip. So, backup protection must consider one level upstream versus primary protection unless additional backup protective devices are installed.

Utility Considerations

Abstract: Nearly all utility companies have direct control over the requirements for connections to their system. Many requirements align with published codes and standards. However, take care to ensure each utility company's exact standards are met. In addition, special requirements for microgrids and other forms of distributed generation may be involved.

Introduction

Most industrial and commercial facilities are served from public utilities. However, the utility interface is often the most neglected aspect of system design. This is especially true at the medium-voltage level. Often, the service equipment manufacturer is expected to resolve issues that severely impact the design of the system. This can result in unexpected costs and project delays. Address these issues during the system design stage, where the impacts to system reliability and cost can be adequately managed; only by knowing the utility's requirements is this possible.

The Utility's Jurisdiction

Because utilities must serve multiple consumers, they must take the steps they consider necessary to maximize dependable service over their entire system. Because of this, most utilities impose requirements on the design of the systems to which they supply power.

Those elements of the system design over which the utility has jurisdiction vary from utility to utility. The utility always dictates which service voltages are available for a given size of service. The utility usually has some jurisdiction over the service disconnect and service overcurrent protection. Certainly, the utility has jurisdiction over (and usually the only access to) their revenue meters and metering instrument transformers. However, in some cases the utility requires jurisdiction over the entire service equipment, and can impose requirements upon system protection, equipment control power, and other parts of the system design. In some cases, the over-all arrangement of the system itself, including emergency/standby power systems, may be dictated by the utility. Because in most cases the utility is the sole service provider for a given region, negotiating these requirements is usually not feasible. Therefore, knowledge of the utility's requirements is vital to successful, on-time, on-budget system design and construction.

Utility Service Requirement Standards

Each utility typically maintains its own series of standards for individual consumer service requirements. Such requirements are often published in the form of a "service requirements handbook" or similarly titled publication. The format of the standards, and the standards themselves, vary from utility to utility. This can be challenging to those engineers who design industrial and commercial facilities in different areas, and to equipment manufacturers.

In recognition of this issue, EUSERC (Electric Utility Service Equipment Requirements Committee) was formed in 1983, combining southern-California-based PUSERC and northern-California-based WUESSC, which were older organizations formed in 1947 and 1950, respectively. The purposes of EUSERC are to promote uniform electric service requirements among its member utilities, to publish existing utility service requirements for electric service equipment, and to provide direction for development of future metering technology. EUSERC publishes a manual *EUSERC Manual*[83]which delineates requirements for electric service equipment through 34.5 kV. At the time of publication, 80 utilities from 12 states are involved with EUSERC. While EUSERC does not eliminate the need for individual utility requirements, it does help a great deal in making electrical service equipment more standardized and less costly.

System Topology and Protection

Requirements for the system topology are designed to increase both the reliability of the over-all utility system and with the reliability of service to the installation in question. These requirements typically take the following forms:

- Restrictions on the size of services.
- Restrictions on, or requirements for, normal and alternate services and transfer equipment between the two.
- Restrictions or requirements for the configuration of emergency and standby power systems.
- Restrictions on the types of service disconnecting devices allowed.
- Restrictions on the types of service overcurrent protection allowed.
- Requirements for service cable compartments in service equipment.
- Requirements or restrictions on the number and types of protective relaying.
- Requirements for the service switchgear as a whole.

The most common requirement, which is applied to virtually every utility installation, is that the service overcurrent device must coordinate with the upstream utility overcurrent device, typically a recloser or utility substation circuit breaker. If there is standby power on the premises, the utility typically requires that paralleling the alternate power source with the utility source not be possible unless stipulated in the rate agreement for the service in question.

Requirements for restricted access to service cable termination and service disconnect compartments in the service switchgear are another common. In some cases, these must be in a dedicated switchgear or switchboard section, increasing the service equipment footprint. In many cases grounding means must be provided with the equipment to allow the utility's preferred safety grounding equipment to be installed. In some cases, requirements may be imposed on the entire service switchgear, such as electrical racking for circuit breakers or barriers that are not standard for the equipment type used.

In some cases, the control power for the service switchgear, such as a battery, must be designed to the utility's specifications.

Additional protective relaying may be required to minimize abnormal conditions which, although not harmful to the system being served, affect the reliability of the utility system. In some cases, the makes and models of protective relays for the service overcurrent protection are restricted to those the utility has approved.

Revenue Metering Requirements

Often the utility's revenue metering requirements can have an effect the over-all system topology. There are two basic utility revenue metering arrangements:

83. Electric Utility Service Equipment Requirements Committee, 2005 Edition.

Hot-Sequence Metering: The metering instrument transformers are placed ahead of the service disconnect.

Cold-Sequence Metering: The metering instrument transformers are placed on the load side of the service disconnect.

With hot-sequence metering, the instrument transformers and meters may be placed on the last distribution pole for overhead services, or in a dedicated utility-supplied metering compartment outside the facility to be metered for underground services. In these cases, the effect of the utility's instrument transformers and meters on the overall design for the facility power system and equipment is usually minimal. However, in many cases the end-user, at their expense, must supply a utility instrument transformer compartment which houses the instrument transformers. The design requirements for these compartments are often detailed and are present to ensure that no tampering occurs with the instrument transformers or meters. These compartments typically take an entire section, or part of a section, of the service switchgear or a switchboard, increasing the footprint of this equipment. In some cases, the service equipment must provide housing for the meters as well, along with convenient access for the utility's personnel. The utility typically provides and installs the instrument transformers and meters, although a few utilities require the end-user or equipment manufacturer to install these. In extreme cases the end-user must supply the instrument transformers and send them to the utility for testing. Identifying the requirements early in the design process helps to insure that all parties are aware of the costs involved.

Utility revenue metering instrument transformers for services up to 600 V typically consist of two or three current transformers depending upon the system configuration, unless the service is small enough to be directly metered. In some cases, voltage transformers may be required as well. Both the current and voltage transformers are designed for metering, with the current transformers typically being bar or wound-primary type. For services over 600 V, both voltage and current transformers are required, either two or three of each depending upon the system configuration. In some cases, the utility will not allow the voltage transformers to be fused.

Additional Regulatory Requirements

In some cases, there may be additional state regulatory requirements which apply. These are typically concern distributed generation and may severely restrict or otherwise impact the system design. These requirements must be fully understood before the system design is begun to avoid expensive changes later in the process. The Public Service Commission or similar governmental regulatory agency for the region in question typically controls these requirements.

Utility Information Requirements for System Design

In designing the power system for any commercial or industrial facility the following information is crucial to adequate system design:

- Nominal service voltage.
- Maximum available fault current and associated X/R ratio.
- Minimum available fault current.
- Data on the utility's nearest upstream protective device (device type and ratings, relay type and settings if applicable).
- Latest edition of the utility's service handbook or similar publication.
- Latest edition of additional state regulatory requirements, if applicable.
- Contact information for utility's system engineer or equivalent for the region in question.
- Utility rate agreement, if available.

All of these, except items six and eight, should be available from the serving utility. Item six should be available from the regional Public Service Commission or similar governmental regulatory agency. Item eight may not be available at the outset but should be taken into consideration as soon as it becomes available.

Power Quality Considerations

Abstract: Power system health is paramount to the longevity of power distribution system equipment and the reliability of continuous power. Power quality affects distribution equipment, as well as downstream process level equipment and loads. It is vital that power quality is considered in the design of a system as well as allowing for monitoring functionality after the equipment is installed and commissioned to monitor health, troubleshoot issues, and capture issues and occurrences.

Introduction

The term power quality may take on any one of several definitions. The strict definition of power quality is "the concept of powering and grounding electronic equipment in a manner that is suitable to the operation of that equipment and compatible with the premises wiring system and other connected equipment" (see *IEEE Recommended Practice for Powering and Grounding Electronic Equipment*[84]). In practice, however, the term power quality is often used to denote the proximity of the system voltage to its sinusoidal form at the nominal voltage level. Deviation from this sinusoidal norm therefore denotes a power quality issue. Strictly speaking, this deviation is a power disturbance, defined as "any deviation from the nominal value (or from some selected thresholds based upon tolerance) of the AC input power characteristics" *IEEE Recommended Practice for Powering and Grounding Electronic Equipment*[84]. The most common power disturbances are, as defined by IEEE Recommended Practice for Powering and Grounding Electronic Equipment[84]:

Overvoltage: An RMS increase in the AC voltage, at the power frequency, for a period of time greater than one minute. Typical values are 110% - 120% of nominal.

Undervoltage: An RMS decrease in the AC voltage, at the power frequency, for a period of time greater than one minute. Typical values are 80 – 90% of nominal.

Swell: An increase in RMS voltage or current at the power frequency for durations from .5 cycle – one minute. Typical values are 110% - 180% of nominal.

Sag: An RMS reduction in the AC voltage, at the power frequency, for durations from ½ cycle to a few seconds.

Interruption: The complete loss of voltage. A momentary Interruption is a voltage loss (<10% of nominal) for a time period between .5 cycles and three seconds). A temporary interruption is a voltage loss (<10% of nominal) for a time period between three seconds and one minute. A sustained interruption is the complete loss of voltage for a time period greater than one minute.

Notch: A switching (or other) disturbance of the normal power system voltage waveform, lasting less than ½ cycle; which is initially of opposite polarity to the waveform, and is thus subtractive from the normal waveform in terms of the peak value of the disturbance voltage. This includes a complete loss of voltage for up to ½ cycle.

Transient: A subcycle disturbance in the AC waveform that is evidenced by a sharp discontinuity of the waveform. It may be of either polarity and may be additive to, or subtractive from, the nominal waveform.

Flicker: A variation in input voltage, either magnitude or frequency, sufficient in duration to allow visual observation of a change in electric light source intensity.

Harmonic Distortion: The mathematical representation of distortion of the pure sine waveform. This refers to the distortion of the voltage and/or current waveform, due to the flow of non-sinusoidal currents.

84. IEEE Std. 1100-2005, December 2005.

Electrical Noise: Unwanted electrical signals that produce undesirable effects in the circuits of the control systems in which they occur. Noise may be further categorized as transverse-mode noise, which is measurable between phase conductors but not phase-to-ground, and common-mode noise, which is measurable phase-to-ground but not between phase conductors. This noise may be conducted or radiated. Also referred to as RFI (radio-frequency interference) or EMI (electro-magnetic interference).

The causes of the common power disturbances listed can vary greatly. Common causes are listed in Common Power Disturbance Causes, page 142.

Table 22 - Common Power Disturbance Causes

Disturbance	Common Causes
Overvoltage	Voltage regulator malfunction Improperly set transformer taps Improperly applied power factor correction capacitors
Undervoltage	Voltage regulator malfunction Improperly set transformer taps Large source impedance ("weak" system)
Voltage swell	Recovery of system voltage following a fault Remote switching (capacitors, etc.)
Voltage sag	Remote fault Cold-load pickup (motor starting, transformer energization.) Large step loads
Transient (Typically voltage surges)	Lightning strikes Close-in switching (capacitors,) Complex circuit phenomena such as current chopping, restrikes, system resonance.
Flicker	Arcing Loads such as arc furnaces Also, same sources that cause voltage sags and swells
Notches and harmonic distortion	Power electronic converter equipment such as rectifiers, inverters, drives, which produce non-sinusoidal load current and commutation notches
Interruptions	Faults causing overcurrent protective device operation Utility maintenance activities
Electrical noise	Power Electronic converter equipment such as drives Conductors and power equipment which carry large amounts of current Arcing in overcurrent protective devices

Power disturbances can greatly affect utilization equipment. For example, sensitive electronic medical equipment can malfunction, adjustable speed motor drives may trip off-line. Interruptions can cause microprocessor-based equipment such as computers to lose data. In extreme conditions, such as for voltage surges caused by direct lightning strikes, both power equipment and utilization equipment may be subject to stop functioning. With the high reliability requirements imposed upon power systems, it is imperative that power system disturbances, or potential disturbances, be mitigated to avoid down-time, equipment loss, and risk to human life.

Power Quality Metrics

There are various methods for categorizing the severity of power disturbances. The most typical indices for measuring power quality disturbances are:

Distortion Factor: The ratio of the root square value of the harmonic content to the root square value of the fundamental quantity, expressed as a percentage of the fundamental, also known as total harmonic distortion [85].

$$\text{Distortion Factor}\,(THD) = \sqrt{\frac{\sum_{h=2}^{n} V_h^2}{V_1^2}} \times 100\% \qquad (13\text{–}1)$$

Where:

- V_h is the RMS harmonic voltage (or current) value at a frequency of n times the fundamental frequency.
- V_1 is the RMS fundamental-frequency voltage or current.

Alternate forms for the distortion factor are given in IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems[86] as percentages of the nominal voltage or demand load current for the system under consideration, for use in evaluation of the harmonic content of the system voltage or current. These are referred to as Total Harmonic Distortion (THD_{Vn}) and Total Demand Distortion (TDD), defined as follows:

$$THD_{Vn} = \sqrt{\frac{\sum_{h=2}^{n} V_h^2}{V_n^2}} \times 100\% \qquad (13\text{-}2)$$

$$TDD = \sqrt{\frac{\sum_{h=2}^{n} I_h^2}{I_L^2}} \times 100\% \qquad (13\text{-}3$$

Where:

- V_h is the RMS value of the n^{th} harmonic component of the voltage.
- V_n is the RMS nominal fundamental voltage value.
- I_h is the RMS value of the n^{th}.
- I_L is the maximum demand load current, typically the average maximum monthly demand over a 12-month period.

Crest Factor: The ratio of the peak value of a periodic function to the RMS value, that is:

$$\text{Crest factor (cf)} = y_{peak}/y_{rms} \qquad (13\text{–}4)$$

Where:

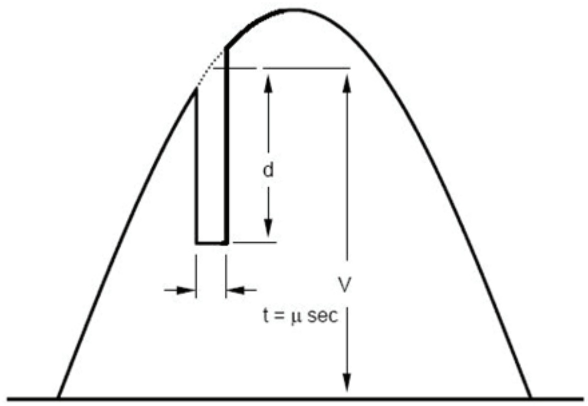
- Y_{peak} is the peak value of a periodic function.
- Y_{rms} is the RMS value of the function.

85. IEEE Recommended Practice for Powering and Grounding Electronic Equipment, IEEE Std. 1100-2005, December 2005.
86. IEEE Std. 519-2014, June 2014.

Because power system voltages and currents are nominally sinusoidal, the nominal crest factor for these would be √2 , which is 1.414 (see Electric Power Fundamentals, page 10 for details).

Notch Area: A notch in the power system voltage (or current) is illustrated in Common Power Disturbance Causes, page 142 *IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems*[87]:

Figure 89 - Voltage (or Current) Notch Illustration



The notch area for the notch as illustrated in Common Power Disturbance Causes, page 142 is defined as:

$$a_n = t \times d \qquad (13\text{–}5)$$

Where:

- A_n is the notch area in volt-microseconds.
- t is the notch time duration in microseconds.
- d is the notch depth in Volts.

Recovery Time: This is the time needed for the output voltage or current to return to a value within the regulation specification after a step load or line change.

Displacement Power Factor: The ratio of the active power of the fundamental wave, in Watts, to the apparent power of the fundamental wave, in VA. This is the traditional definition of power factor.

Total Power Factor: The ratio of the total input power, in watts, to the total VA input. This includes the effects of harmonics.

K Factor: A measure of a transformer's ability to serve non-sinusoidal loads. The K factor is defined as:

$$K = \sum_{h=1}^{h_{max}} \left(I_{h(pu)}^2 \bullet h^2 \right) \qquad (13\text{–}6)$$

Where:

- I_h is the harmonic component at h times the fundamental frequency.
- h is the harmonic order of Ih in multiples of the fundamental frequency.
- h_{max} is maximum harmonic order present.

87. IEEE Std. 519-2014, June 2014.

Voltage Surges

The causes of voltage surges may be split into two major categories: Power system switching and environmental (see *IEEE Recommended Practice for Powering and Grounding Electronic Equipment*[88]). Both exhibit decaying oscillatory transients. Capacitor switching close to the point under consideration is the most common cause of switching surges, while lightning is the most common cause of environmentally-induced voltage surges. Both can cause severe damage to unprotected power system components, with the potential for lightning damage being the most severe; in the worst case, lightning damage can be catastrophic.

Surge arrestors, as described in System Protection, page 69, are typically used to minimize voltage surges. On low-voltage systems surge protective devices (SPD), also described in System Protection, page 69 are also used. For motors, surge capacitors are an option. In severe cases, custom-designed R-C snubber circuits may be required as well.

Voltage Sags, Swells and Interruptions

Voltage sags, swells and interruptions have many causes. Remote switching or lightning strikes can cause voltage swells, as can the recovery of the system voltage after a fault. Voltage sags can be caused due to transformer or motor inrush or large step loads, especially on systems without large amounts of available fault current. Voltage interruptions are generally caused due to protective device operation.

Protection of sensitive equipment against voltage sags and swells can be difficult. Fast-acting voltage regulators offer one means of defense against these phenomena, although any voltage regulator must be properly applied to avoid worsening the problem. Fast-acting voltage regulators can generally be classified as tap-switching, buck-boost, or ferroresonant (also known as CVT “constant voltage transformer”) types (see *IEEE Recommended Practice for Powering and Grounding Electronic Equipment*[88]). New solid-state tap switching technologies for voltage regulators provide faster response than older, electromechanical switching technologies. Other devices, such as “power line conditioners” which combine some TVSS functions with voltage regulation and noise reduction, and motor-generator sets, are also used (see *IEEE Recommended Practice for Powering and Grounding Electronic Equipment*[88]).

Protection of sensitive loads against voltage interruptions is efficiently performed with an uninterruptible power supply or UPS. This device is available in several different topologies and is crucial where microprocessor-based devices are to be powered. UPS discussed in more detail in Emergency Power Distribution Equipment, page 184.

Harmonic Distortion

Harmonic distortion is a subject of great interest in modern power systems. Harmonic distortion results from non-sinusoidal load currents. These currents are the result of non-linear loads, such as drives, which employ power electronic devices to rectify the AC waveform. These devices draw non-sinusoidal currents which, in turn, cause non-linear voltages to be developed in the system.

IEEE Standard 519-1992 *IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems*[89] gives recommended limits for current distortion due to consumer loads and voltage distortion in the utility supply voltage. Both are referenced at the point on the utility system where multiple customers can be served, referred to as the Point of Common Coupling (PCC). The requirements from *IEEE Recommended Practices and Requirements for Harmonic Control in Electrical*

88. IEEE Std. 1100-2005, December 2005.
89. IEEE Std. 519-2014, June 2014.

Power Systems[90] for current distortion limits on general distribution systems 120 V – 69 kV are given in Harmonic Distortion, page 145. IEEE 519-1992 Harmonic Voltage Distortion Limits, page 146 shows the corresponding utility voltage distortion limits.

The current limits are given both as limits on the individual harmonic levels and a limit on the TDD, and that as the ratio I_{sc}/I_L increases the limits also increase. The reason for this is that the current distortion limits are designed to limit the voltage distortion at the PCC, and the voltage distortion for a given current distortion worsens with a larger source impedance ($\bar{V} = \bar{I} \bullet \bar{Z}$)

Table 23 - IEEE 519-1992 Harmonic Current Distortion Limits for General Distribution Systems 120 V Through 69 kV

Maximum Harmonic Current Distortion in Percent of IL						
Individual Harmonic Order (Odd Harmonics)						
Lsc/IL	<11	11<h<17	17≤h<23	23≤h<35	35≤h	TDD
<20*	4.0	2.0	01.5	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

Even harmonics are limited to 25% of the odd harmonic limits above.

Current distortions that result in a DC offset, half-wave converters, are not allowed.

*All power generation equipment is limited to these values of current distortion, regardless of actual L SC /IL.

Where:

I_{SC} = maximum short-circuit current at PCC

I_L = maximum demand load current (fundamental frequency component) at PCC

IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems[90]

Table 24 - IEEE 519-1992 Harmonic Voltage Distortion Limits

Bus Voltage at PCC	**Individual Voltage Distortion** (%)	**THD**Vn (%)
69 kV and below	3.0	5.0
69.001 through 161 kV	1.5	2.5
161.001 kV and above	1.0	1.5

NOTE: High-voltage systems can have up to 2.0% THD where the cause is an HVDC terminal that attenuates by the time it is tapped for a user.

IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems, IEEE Std[91]

Mitigation of harmonic distortion is generally accomplished by one of the following means:

- Passive tuned filters
- Use of phase multiplication on power conversion equipment

Passive tuned filters are simple series L-C filters. A single tuned passive filter can effectively mitigate one harmonic frequency. They are generally tuned to a value below the harmonic frequency to be attenuated to avoid a resonance condition at that frequency. These are custom-engineered solutions that must be designed specifically for the circuit in question. Passive filters are also used for power factor correction.

90. IEEE Std. 519-2014, June 2014.
91. 519-2014, June 2014.

However, there is a limit to their effectiveness and if higher-order harmonics must be attenuated their use is generally not cost-effective. Take care in all cases to balance the harmonic and power factor correction considerations.

Phase multiplication operates on the principle that if m six-pulse rectifiers are shifted 60/m degrees from each other, are controlled by the same delay angle, and are loaded equally, the only harmonics present are:

$h = kq \pm 1$ (13–7)

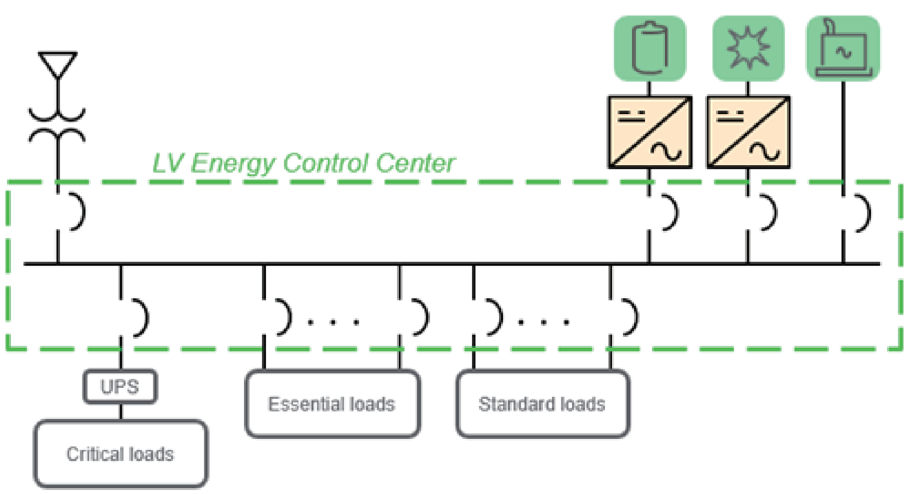
Where:

- h is a harmonic order present.
- q = 6m and is known as the pulse number of the circuit.
- k is any integer.

Thus, for standard six-pulse rectifiers the harmonic orders present are 5, 7, 11, 13,…. 18-pulse rectifiers are the current state-of-the-art; for an 18-pulse rectifier (m = 3), the harmonic orders present are 17, 19, 35, 37, …,. For an 18-pulse converter, the lower-order harmonics are thus eliminated. For systems with large numbers of phase-multiplied converters the harmonic current limits in NFPA Emergency Power System Levels, page 186 are increased by the factor $(q/6)^{1/2}$, where q is the pulse-number of the predominate non-linear load on the system. In this case the limits for the harmonic orders that do not fit equation (11-7) for the q of the predominate non-linear load are multiplied by a factor of 0.25. Phase-shifting transformer connections are used to achieve the 60/m degree phase shift between six-pulse rectifier units.

Active Harmonic Filters (AHF) can help greatly reduce harmonics and bring systems in compliance with IEEE-519 or other harmonic limits imposed by the utility companies. Current state-of-the-art designs measure the current, filter out the fundamental frequency of the measured current, and inject current that is the negative of the result into the system to cancel the harmonics up to a given harmonic order. These systems are generally used in existing installations that have existing six-pulse drives where replacing the drives is not a cost-effective solution, or where multiple smaller six-pulse drives are utilized since phase multiplication for a drive below 100 HP is generally not cost-effective. State-of-the-art units can also dynamically correct the power factor as well as phase imbalance and are advantageous vs. passive filters both in their effectiveness and their flexibility in power factor correction.

Figure 90 - Active Harmonic Filters

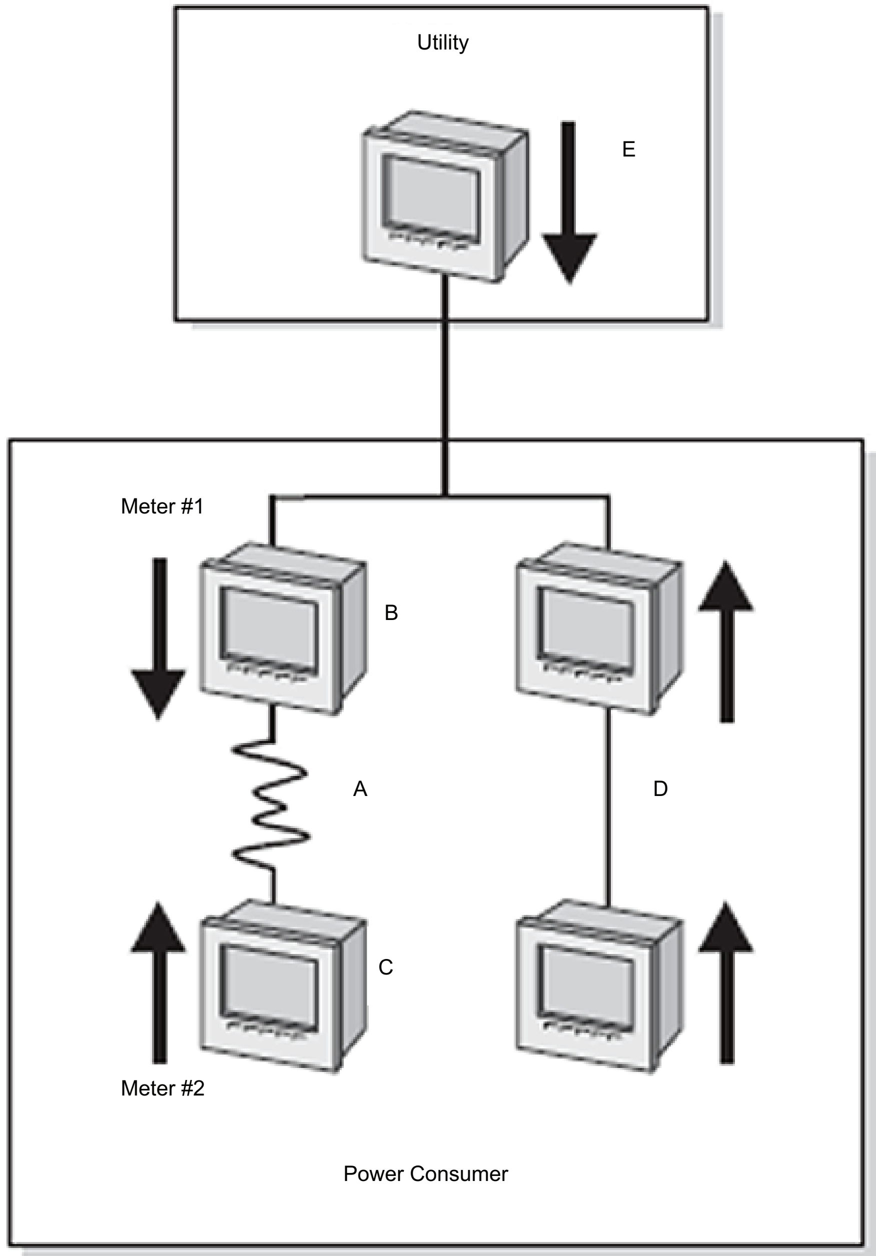


Power Quality Monitoring

Power quality monitoring is vital when sensitive equipment or processes are to be powered, and for the overall reliability of the system. Microprocessor-based technology allows the most common power-quality instrumentation to be combined into a single monitoring device which incorporates waveform capture, measures of the power quality metric values per the above discussion, and conventional current, voltage, power, and energy measurements, with minimum/maximum logging capabilities. These devices are typically true RMS-reading instruments, with measurements up to a given harmonic (typically 31^{st} harmonic or higher). The capabilities and sampling rate of the PQ meter must be matched to the sensitivity of the equipment that is being monitored. Not all PQ meters have the required sampling rate to capture fast transients.

Another important consideration is the Disturbance Direction Detection feature that is available in some PQ meters. This feature allows facility staff to quickly pinpoint and isolate the source of the PQ problem and rapidly recover from a potential outage. Refer to the image below.

Figure 91 - Power Quality Monitoring



In most cases, a power quality centric EPMS (Energy & Power Monitoring Software) is required to analyze the waveforms, timestamps, sequence of events, etc. to realize a cohesive view of the power quality issues in a facility. Refer to Electrical Energy Management, page 220 for more details.

The inclusion of power monitoring equipment in the initial power system design makes diagnosis of any subsequent power quality issues, if they arise, much easier and more efficient. Reference IEEE Recommended Practice for Monitoring Electric Power Quality[92] contains much information on power quality monitoring and should be consulted for further reference.

92. IEEE Std. 1159-2019, August 2019.

Safety Considerations

Arc Flash Hazard

Abstract: The precedence for eliminating arc flash hazards has evolved into a major consideration for both the design and implementation of power distribution systems and the operation and maintenance of the gear. Awareness of high incident energy and overall high risks and hazard present in customer facilities has changed the landscape for the better. To reduce hazards and risks, equipment design and layout, and operational practices have improved to keep operators and bystanders safer.

Introduction

The method of which to analyze arc flash hazards has evolved through several iterations of NFPA 70E, NPFA 70, and IEEE 1584 standards which modified the calculation methods to provide more accurate data based on testing, as well as UL 2986. Analysis of hazards has also evolved to consider both the actual arc flash hazard and the impeding risk or chance of an occurrence. Manufacturer design and engineered controls have also taken into consideration these changes. Energy reducing methods are also now required for certain applications.

Background

Electrical arcs form when a medium that is normally an insulator, such as air, is subjected to an electric field strong enough to cause it to become ionized. This ionization causes the medium to become a conductor which can carry current. The phenomenon of electrical arcing is as old as the world itself. Lightning is a natural form of electrical arcing. Man-made electrical arcs exist in devices such as arc furnaces. However, utilization of electrical energy invariably requires equipment where unintentional arcing between conductors becomes a possibility.

Electric arcs in equipment liberate large amounts of uncontrolled energy in the form of intense heat and light. Unintentional arcing in power equipment can impose several different types of hazards:

- Heat from arc can cause severe flash burns many feet away (temperatures can reach 20,000 K, four times the temperature at the surface of the sun.).
- Byproducts from the arc, such as molten metal spatter, can cause severe injury.
- Pressure wave effects caused by the rapid expansion of air and vaporization of metal can distort enclosures and cause doors and cover panels to be ejected with severe force, injuring personnel.
- Sound levels can damage hearing.

Example of Arcing Damage to Equipment, page 151 gives an indication of the amount of uncontrolled energy an arc can contain, as seen by the amount of damage to the equipment shown.

Electrical safety has traditionally been concerned only with electric shock hazards. The recognition of arc flash hazards began formally in 1981 with a paper "*The Other Electrical Hazard: Arc Blast Burns*" [93]by Ralph Lee, presented at the 1981 IEEE IAS Annual Meeting. This paper established theoretical modeling for the heat energy incident upon a surface a given distance from the arc. Subsequent developments followed over the next 20 years, including testing to develop more accurate empirical calculation methods and to evaluate protective clothing.

93. Lee, R., "The Other Electrical Hazard: Electrical Arc Blast Burns,", vol. 1A-18, no. 3, May/June 1982.

Figure 92 - Example of Arcing Damage to Equipment

At the time of publication, there are two basic standards which establish requirements for arc flash hazards. The first is NFPA 70E, *Standard for Electrical Safety in the Workplace*[94], which defines the basic practices to be followed for electrical safety, including protective clothing levels which must be worn for given levels of arc flash incident energy and what steps must be taken prior to live work on electrical equipment. The second is the *IEEE Guide for Performing Arc-Flash Hazard Calculations*, IEEE 1584-2018[95] which gives the engineer the methods for calculating the severity of arc flash incident energy levels. The NEC *The National Electrical Code, NFPA 70,*[96] requires only that certain equipment (switchboards, panelboards, industrial control panels, meter socket enclosures, and motor control centers in other than dwelling occupancies and likely to require examination, adjustment, servicing, or maintenance while live) be field marked to warn qualified persons of potential electric arc flash hazards.

NFPA 70E Requirements for Arc Flash Hazards

NFPA 70E *Standard for Electrical Safety in the Workplace*[94]is divided into four chapters: Safety Related Work Practices (Chapter 1), Safety Related Maintenance Requirements (Chapter 2), Safety Requirements for Special Equipment (Chapter 3), and Installation Safety Requirements (Chapter 4). The discussion here is centered upon Chapter 1.

Several terms are of particular importance when discussing arc flash hazards (see *Standard for Electrical Safety in the Workplace*[94]):

Flash Hazard: A dangerous condition associated with the release of energy caused by an electric arc.

Incident Energy: The amount of energy impressed on a surface, a certain distance from the source, generated during an electrical arc event. One of the units used to measure incident is calories per square centimeter (cal/cm^2).

Flash Hazard Analysis: A study investigating a worker's potential exposure to arc-flash energy, conducted for the purpose of injury prevention and the determination of safe work practices and appropriate levels of PPE.

Live Parts: Energized conductive components.

94. NFPA 70E, The National Fire Protection Association, 2021 Edition.
95. IEEE 1584-2018, September 2018.
96. The National Fire Protection Association, Inc., 2020 Edition.

Exposed (as applied to live parts): Capable of being inadvertently touched or approached nearer than a safe distance by a person. It is applied to parts that are not suitably guarded, isolated, or insulated.

Shock Hazard: A dangerous condition associated with the possible release of energy caused by contact or approach to live parts.

Flash Protection Boundary: An approach limit at a distance from exposed live parts within which a person could receive a second degree burn if an electrical arc flash were to occur.

Limited Approach Boundary: An approach limit at a distance from an exposed live part within which a shock hazard exists.

Restricted Approach Boundary: An approach limit at a distance from an exposed live part within which there is an increased risk of shock, due to electrical arc over combined with inadvertent movement, for personnel working in close proximity to the live part.

Qualified Person: One who has skills and knowledge related to the construction and operation of the electrical equipment and installations and has received safety training on the hazards involved.

Working on (live parts): Intentionally coming in contact with live parts with the hands, feet, or other body parts, with tools, probes, or with test equipment, regardless of the personal protective equipment a person is wearing. There are two categories of "working on": Diagnostic (testing) is taking readings or measurements of electrical equipment, circuit parts with approved test equipment that does not require making any physical change to the electric equipment, conductors, or circuit parts. Repair is any physical alteration of electrical equipment, conductors, or circuit parts.

Working near (live parts): Any activity inside the Limited Approach Boundary.

Electrically Safe Work Condition: A state in which the conductor or circuit part to be worked on or near has been disconnected from energized parts, locked/tagged in accordance with established standards, tested to ensure the absence of voltage, and grounded if determined necessary.

NFPA 70E [97] Chapter 1 covers personnel responsibilities (both the employer and the worker have specific responsibilities for safety), training requirements, the establishment of an electrical safety program, and the establishment of an electrically safe working condition. These are not discussed in detail here, but the reader is strongly encouraged to refer to the NFPA 70E *Standard for Electrical Safety in the Workplace*[98] to become more familiar with them as they are important topics.

For arc flash hazard considerations, the focus is on Article 130, "Working On or Near Live Parts". The basic requirement is that live parts over 50 V to ground to which an employee might be exposed should be put into an electrically safe work condition prior to working on or near them, unless the employer can demonstrate that de-energizing introduces additional or increased hazards or is infeasible due to equipment design or operational limitations. In this case live work requires an Energized Electrical Work Permit, for which the requirements are given in Article 130.2. Some exemptions are given to the requirement for an electrical work permit, such as testing, troubleshooting, performed by qualified persons.

The approach boundaries to live parts are defined above, and are illustrated in Approach Boundaries, page 154. These form a series of boundaries from exposed, energized electrical conductor(s) or circuit part(s). The requirements for crossing these become increasingly restrictive as the worker moves closer to the exposed live part(s). The limited, restricted, and prohibited approach boundaries are shock protection boundaries and are defined in NFPA 70E table 130.4(E)(a) *Standard for Electrical Safety in the Workplace*[98]. Qualified persons can approach live parts 50 V or higher up to the restricted approach boundary, and can only cross this boundary if they are insulated or guarded and no uninsulated part of the body crosses the

97. The National Fire Protection Association, 2021 Edition.
98. NFPA 70E, The National Fire Protection Association, 2021 Edition.

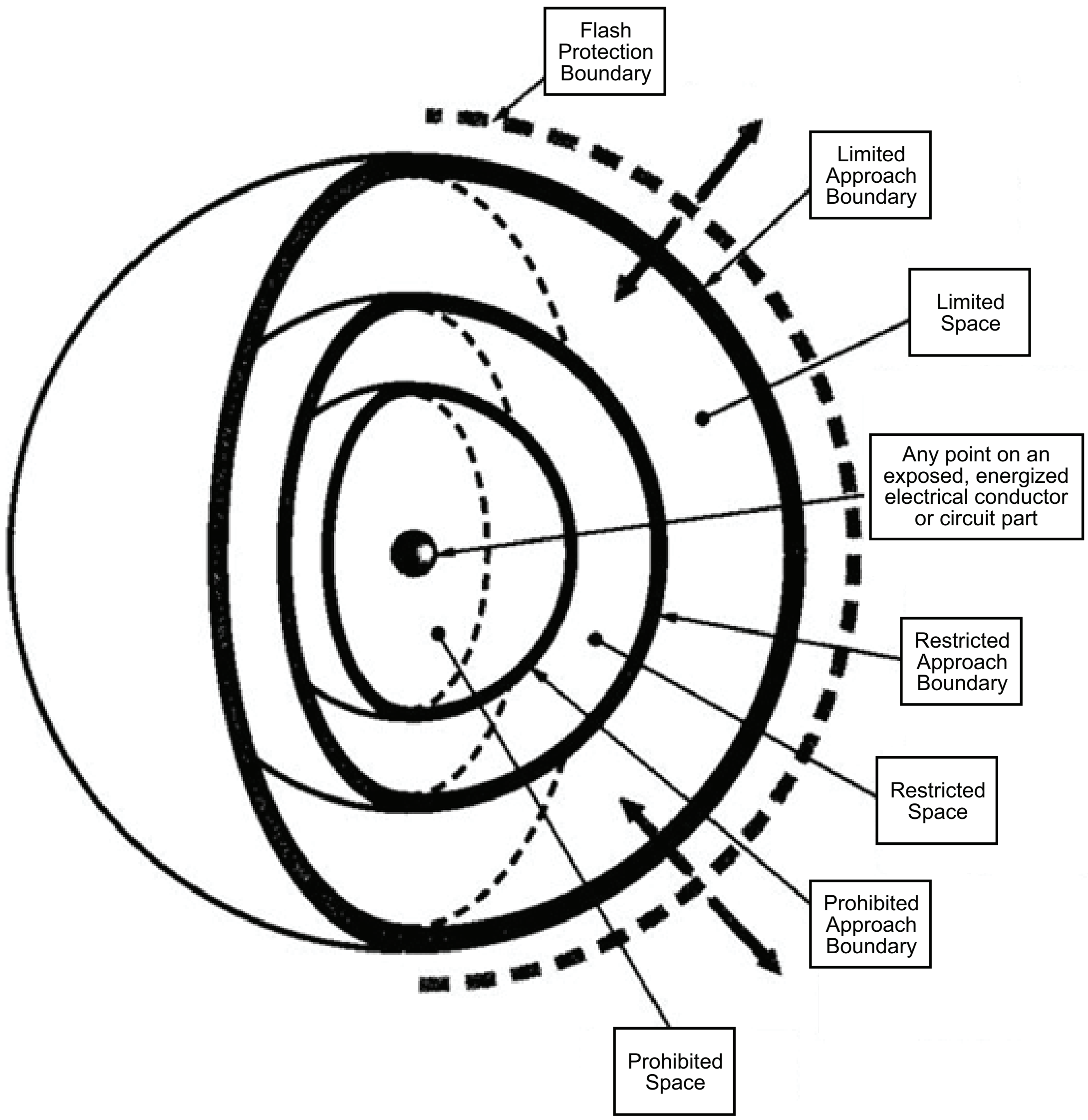
prohibited approach boundary, if the person is insulated from any other conductive object, or if the live part is insulated from the person and from any other conductive objects at a different potential. Unqualified persons must stay outside the limited approach boundary unless they are escorted by a qualified person. Unqualified persons cannot cross the restricted approach boundary.

An Arc Flash Risk Assessment must be performed to protect personnel from the possibility of injury due to arc flash. This can be done by identifying the arc flash hazard and using the table found in 130.5(C) to estimate the likelihood of occurrence of an arc flash incident, and to determine if any additional protective measures are required, including the use of PPE. This is called the “Arc Flash PPE Category Method”. Using this method is only permissible if equipment is in a proper state as recommended by the manufacture. The second method permissible for determine the appropriate PPE is by performing an 130.5(G) Incident Energy Analysis Method.

Arc flash boundary is covered in 130.5(E) which can be determined two ways:

- The arc flash boundary shall be the distance at which the incident energy equals 1.2 cal/cm^2 or
- using the Table 130.7(C)(15)(a) or Table 130.7(C)(15)(b).

Figure 93 - Approach Boundaries



Approach Boundaries, page 154 is from *Standard for Electrical Safety in the Workplace*[99]

Per 130.5(H) All electrical equipment, such as switchboards, panelboards, industrial control panels, meter socket enclosures, and motor control centers that are in other than dwelling units and that are likely to require examination, adjustment, servicing, or maintenance while energized shall be marked with a label containing all of the following information. (1) Nominal system voltage (2) Arc flash boundary (3) At least of the of the following: Available incident energy, minimum arc rating of clothing or site-specific level of PPE.

The classifications for personal protective equipment (PPE) for arc flash protection are given in NFPA Table 130.7 (C)(15)(c), reproduced in Personal Protective Equipment (PPE), page 155. PPE for arc flash protection is given an Arc Rating in cal/cm^2, which must be compared to the arc flash incident energy for the location in question to select the proper clothing. Employees working within the flash protection boundary must wear nonconductive head protection wherever there is a danger of head injury from electric shock or burns or from flying objects resulting from electrical explosion. Face, neck, chin and eye protection must be worn wherever there is a danger of injury from electric arcs or flashes or from flying objects resulting from electrical explosion. Body protection, in the form of flame-retardant (FR) clothing as defined in Personal Protective Equipment (PPE), page 155, must be worn where there is possible exposure to arc flash incident energy levels of 1.2 cal/cm^2; an exception allows Category 0 clothing to be worn for exposures of 2 cal/cm^2 or lower. An example of a full flash suit is shown in Example of a Full Flash Suit, page 156.

Table 25 - Personal Protective Equipment (PPE)

Arc-flash PPE Category	PPE
1	**Arc-rated Clothing, Minimum Arc Rating of 4 cal/cm2 (16.75 J/cm2)**[100] Arc-rated long-sleeve shirt and pants or arc-rated coverall Arc-rated face shield[101] or arc flash suit hood Arc-rated jacket, parka, high-visibility apparel, rainwear, or hard hat liner (AN)[102] **Protective Equipment** Hard hat Safety glasses or safety goggles (SR) Hearing protection (ear canal inserts)[102] Heavy-duty leather gloves, arc-rated gloves, or rubber insulating gloves with leather protectors (SR)[103] Leather footwear[104]
2	**Arc-rated Clothing, Minimum Arc Rating of 8 cal/cm2 (33.5 J/cm2)**[100] Arc-rated long-sleeve shirt and pants or arc-rated coverall Arc-rated flash suit hood or arc-rated face shield[101] and arc-rated balaclava Arc-rated jacket, parka, high-visibility apparel, rainwear, or hard hat liner (AN)[105] **Protective Equipment** Hard hat Safety glasses or safety goggles (SR) Hearing protection (ear canal inserts)[102] Heavy-duty leather gloves, arc-rated gloves, or rubber insulating gloves with leather protectors (SR) [103] Leather footwear[104]
3	**Arc-rated Clothing Selected so that the System Arc Rating Meets the Required Minimum Arc Rating of 25 cal/cm2 (104.7 J/cm2)**[100] Arc-rated long-sleeve shirt (AR) Arc-rated pants (AR) Arc-rated coverall (AR) Arc-rated arc flash suit jacket (AR)

99. NFPA 70E, The National Fire Protection Association, 2021 Edition.
100. Arc rating is defined in Article 100.
101. Face shields are to have wrap-around guarding to protect not only the face but also the forehead, ears, and neck, or, alternatively, an arc-rated arc flash suit hood is required to be worn.
102. Other types of hearing protection are permitted to be used in lieu of or in addition to ear canal inserts provided they are worn under an arc-rated arc flash suit hood.
103. Rubber insulating gloves with leather protectors provide arc flash protection in addition to shock protection. Higher class rubber insulating gloves with leather protectors, due to their increased material thickness, provide increased arc flash protection.
104. Footwear other than leather or dielectric shall be permitted to be used provided it has been tested to demonstrate no ignition, melting or dripping at the minimum arc rating for the respective arc flash PPE category.
105. The arc rating of outer layers worn over arc-rated clothing as protection from the elements or for other safety purposes, and that are not used as part of a layered system, shall not be required to be equal to or greater than the estimated incident energy exposure.

Table 25 - Personal Protective Equipment (PPE) (Continued)

	Arc-rated arc flash suit pants (AR) Arc-rated arc flash suit hood Arc-rated gloves or rubber insulating gloves with leather protectors (SR)[106] Arc-rated jacket, parka, high-visibility apparel, rainwear, or hard hat liner (AN) [107] **Protective Equipment** Hard hat Safety glasses or safety goggles (SR) Hearing protection (ear canal inserts)[108] Leather footwear[109]
4	**Arc-Rated Clothing Selected, Minimum Arc Rating of 40 cal/cm2 (167.5 J/cm2)**[110] Arc-rated long-sleeve shirt (AR) Arc-rated pants (AR) Arc-rated coverall (AR) Arc-rated arc flash suit jacket (AR) Arc-rated arc flash suit pants (AR) Arc-rated arc flash suit hood Arc-rated gloves or rubber insulating gloves with leather protectors (SR)[106] Arc-rated jacket, parka, high-visibility apparel, rainwear, or hard hat liner (AN) The arc rating of outer layers worn over arc-rated clothing as protection from the elements or for other safety purposes, and that are not used as part of a layered system, shall not be required to be equal to or greater than the estimated incident energy exposure. **Protective Equipment** Hard hat Safety glasses or safety goggles (SR) Hearing protection (ear canal inserts)[108] Leather footwear[109]
	AN: As needed (optional). AR: As required. SR: Selection required.

Standard for Electrical Safety in the Workplace[111]

Figure 94 - Example of a Full Flash Suit

106. Rubber insulating gloves with leather protectors provide arc flash protection in addition to shock protection. Higher class rubber insulating gloves with leather protectors, due to their increased material thickness, provide increased arc flash protection.
107. The arc rating of outer layers worn over arc-rated clothing as protection from the elements or for other safety purposes, and that are not used as part of a layered system, shall not be required to be equal to or greater than the estimated incident energy exposure.
108. Other types of hearing protection are permitted to be used in lieu of or in addition to ear canal inserts provided they are worn under an arc-rated arc flash suit hood.
109. Footwear other than leather or dielectric shall be permitted to be used provided it has been tested to demonstrate no ignition, melting or dripping at the minimum arc rating for the respective arc flash PPE category.
110. Arc rating is defined in Article 100.
111. NFPA 70E, The National Fire Protection Association, 2021 Edition.

IEEE 1584

IEEE 1584[112] is the guide for determining arc flash incident energy levels and protection boundaries. It contains an empirical calculation method based upon extensive test results using a Design-of-Experiments (DOE) method, resulting in a 95% confidence level. In situations where the empirical method does not apply, the "Lee" method from Lee, R., "The Other Electrical Hazard: Electrical Arc Blast Burns,"[113] is recommended, and is described in IEEE 1584. IEEE 1584 only considers the heat of an arc, and not the secondary effects such as molten metal spatter and pressure-wave effects.

IEEE 1584 Empirical Method

This method is valid for the following systems with the following characteristics:

- Voltages in the range of 208 V–15 kV, three-phase
- Frequencies of 50 Hz or 60 Hz
- Bolted fault current in the range:
  - LV: 500–106 kA
  - MV: 200–65 kA
- Grounding of all types, not a variable in 2018 calculations
- Standard box per voltage level; Max dimension "49"
- Gaps between conductors:
  - LV: 6.35–76.2 mm
  - MV: 19.05–254 mm
- Working distance >12 in.
- Electrode configurations:
  - VCB: Vertical electrodes in a cubic box enclosure (equivalent to 2002 in box)
  - VCBB: VCB with electrodes terminating in an insulating barrier
  - HCB: Horizontal electrodes in a cubic box enclosure
  - VOA: Vertical open-air (equivalent to 2002 open air)
  - HOA: Horizontal open-air
- Enclosure Size Correction Factor: enclosure correction factor de-rates incident energy for larger-than-standard box sizes.

Steps for performing calculations:

1. Determine electrode configuration.
2. Arcing current calculation.
   - I_{bf} is the bolted fault current for three-phase faults (symmetrical rms) (kA)
   - $I_{arc\ 600}$ is the average rms arcing current at V_{oc} = 600 V (kA)
   - $I_{arc\ 2700}$ is the average rms arcing current at V_{oc} = 2700 V (kA)
   - $I_{arc\ 14300}$ is the average rms arcing current at V_{oc} = 14300 V (kA)
   - G is the gap distance between the electrodes (mm)
   - k1 to k 10 are the coefficients provided in Table 5 of IEEE1584–2018
   - lg is $\log_{10}$
3. Determine clearing time based on the arcing current in Step 1. The use of time current curves (TCC) may be used for this step. Ensure the clearing time considers this such as the condition of equipment, alternate fault sources, or time delays in the control circuit.

112. IEEE Guide for Performing Arc Flash Hazard Calculations, IEEE 1584-2018, September 2018.
113. IEEE Transactions on Industry Applications, vol. 1A-18, no. 3, May/June 1982.

4. Determine the Incident Energy.

$$E_{\leq 600} = 12.552/50(Tx10)\{k1 + k2lgG + (k3I_{arc\,600}/k4I_{bf}^7 + k5I_{bf}^6 + k6I_{bf}^5 + k7I_{bf}^4 + k8I_{bf}^3 + k9I_{bf}^2 + k10I_{bf}) + k11lgI_{bf} + k12lgD + k13lgI_{arc} + lg(1/CF)] \quad (8\text{–}1)$$

5. Determine the Arc Flash Boundary.

$$AFB_{\leq 600} = \{k1 + k2lgG + (k3I_{arc\,600}/k4I_{bf}^7 + k5I_{bf}^6 + k6I_{bf}^5 + k7I_{bf}^4 + k8I_{bf}^3 + k9I_{bf}^2 + k10I_{bf}) + k11lgI_{bf} + k13lgI_{arc} + lg(1/CF)] - lg(20/T)]/\text{-}k12 \quad (8\text{–}2)$$

Arcing Current Variation: First pass in the calculations is done with 100% arcing current, as used in Step 2. To ensure the worst case is used, the following formulas are used to provide minimum arc rating. Use the worst case incident energy.

$$I_{arc\,min} = I_{arc} \times (1 - 0.5 \times VarC_f) \quad (8\text{–}3)$$

$$VarC_f = k1V_{oc}^6 + k2V_{oc}^5 + k3V_{oc}^4 + k4V_{oc}^3 + k5V_{oc}^2 + k6V_{oc} + k7$$

The incident energy is proportional to the arcing time, which is set by the overcurrent protective device time-current characteristic and the arcing current level. Because overcurrent protective device tripping times are lower for larger currents due to inverse time-current characteristics, this is an important point. Larger bolted fault currents lead to larger predicted arcing fault currents, which lead to generally lower values of arc flash incident energy. Lower bolted fault currents lead smaller predicted arcing fault currents, which lead to generally higher values of incident energy.

“Lee” Method

Where the IEEE 1584 empirical method cannot be used due to being outside the limits of applicability as defined above, the theoretically-derived “Lee” method per A. C. Parsons, “Arc Flash Application Guide Arc Flash Energy Calculations for Circuit Breakers and Fuses”[114] may be used. This is based upon maximum power transfer and is very conservative above 15 kV. To calculate the incident energy with this method, the following equations are used (see *IEEE Guide for Performing Arc Flash Hazard Calculations*[115]):

$$E = 5.12 \times 10^6 VI_{bf}(t/D^2) \quad (8\text{–}4)$$

$$D_b = \sqrt{5.12 \times 10^5 VI_{bf}(t/E_b)} \quad (8\text{–}5)$$

Simplified Device Equations

Further testing was performed for circuit breakers and current-limiting fuses, and simplified equations of the form ($A+B_{log□}I_{bf}$) were developed. These are given in IEEE Guide for Performing Arc Flash Hazard Calculations[115]. The equations for fuses are applicable within the bolted fault current ranges given in IEEE Guide for Performing Arc Flash Hazard Calculations[115]. The equations for circuit breakers yield conservative results and should only be used when they are within the ranges of applicability given in IEEE Guide for Performing Arc Flash Hazard Calculations [115] and where nothing else about a particular circuit breaker is known.

Manufacturers also publish device-specific equations for certain devices, such as fuses and some high-performance circuit breakers. These are preferred versus the IEEE 1584 Empirical Method since they more accurately model the arc-flash performance of a given device.

114. Square D/Schneider Electric Engineering Services, August 2004.
115. IEEE 1584-2018, September 2018.

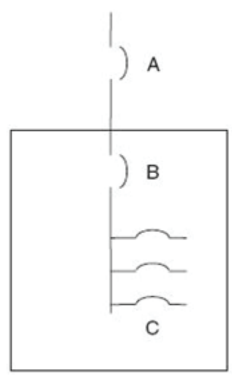
Application Guidelines

Arc Flash Calculations

The following guidelines are helpful when performing arc flash calculations (see The National Electrical Code, NFPA 70,[116]):

- When choosing a calculation method, be sure the system conditions fall into the calculation method's range of applicability.
- Use the newest methods given in IEEE 1584-2018. Older methods given in previously published papers are superseded by this standard.
- If the manufacturer publishes device-specific equations, use them.
- Use realistic fault current values. The actual minimum available fault current, rather than the worst-case values typically used for short-circuit analysis, give more conservative (and realistic) results.
- Consider the effects of arc fault propagation to the line side of the main overcurrent device when determining which device to use to calculate the arcing time. For example, for the electrical panel in Example Electrical Panel, page 159, device A would be used rather than device B for calculating the arcing time for a fault on the panelboard bus, since the fault can propagate to the line side of device B. Make similar considerations for switchboards, MCC's.

Figure 95 - Example Electrical Panel



- Quantify the variables. The working distance, bus gap, equipment configuration, and system grounding are all dependent upon the particular installation and must be accurately determined.
- Be aware of motor contribution. Motor contribution can both increase and decrease the arc flash incident energy, depending upon where in the system the arcing fault occurs.
- Use a computer for analysis. This is the most efficient way to accurately calculate the incident energies and flash protection boundaries where multiple sources, such as generation and motor contribution, must be taken into account. Several commercial software packages are available for arc flash hazard analysis. Be aware, though, what the user-configurable options for the software are and be sure they are set correctly for accurate results.

System Design

Arc flash hazard analysis is typically performed after the system design process, including the time-coordination study, is complete. This can result in the need for "tweaking" of overcurrent protective device settings to obtain acceptable arc flash results or, in the worst case, system re-design with additional equipment. The following guidelines, if observed during the system design phase, can serve to minimize the need for such activities:

116. The National Fire Protection Association, Inc., 2020 Edition.

- Use a dedicated main overcurrent device at transformer secondaries. The secondary of a transformer is one of the most difficult places to achieve acceptable arc flash hazard levels. If multiple mains are used for transformer secondaries, the arc flash hazard level downstream from the main but ahead of the feeders must be calculated using the transformer primary device timing characteristics, significantly increasing the incident energy. If the secondary main and feeders are in the same switchboard or panel, this is usually not be applicable due to arc fault propagation to the line side of the main device as described above. For ANSI low-voltage switchgear per ANSI C37.20.1, however, this can be of real benefit, as well as in cases where the secondary overcurrent device is remote from the feeders.
- Closely coordinate devices where possible. The lower the clearing time for the predicted arcing current, the lower the arc flash incident energy.
- Use high-performance devices, such as low-arc-flash circuit breakers, where possible. These significantly reduces the arc flash incident energy.
- Use bus differential protection and/or zone selective interlocking where possible. This is high-speed protection that can significantly lower the arc flash incident energy.

Another code required can be found in NFPA 70, article 240.87 The National Electrical Code, NFPA 70,[117]. Where the highest continuous current trip setting for which the actual overcurrent device installed in a circuit breaker is rated or can be adjusted is 1200 A or higher, one of the following means shall be provided and be set to operate at less than the available arcing current:

- Zone-selective interlocking.
- Differential relaying.
- Energy-reducing maintenance switching with local status indicator.
- Energy-reducing active arc flash mitigation system.
- An instantaneous trip setting. Temporary adjustment of the instantaneous trip setting to achieve arc energy reduction shall not be permitted.
- An instantaneous override function.
- An approved equivalent means.

Arc Flash Avoidance: Help personnel avoid the hazards or add distance between hazard and operator.

Table 26 - Arc Flash Mitigation Types and Impacts

Arc Flash Mitigation Types	Protection During Operation	Protection During Maintenance / Abnormal Operation	Reduced Incident Energy (cal / cm²)	Recovery Time	Impact on Foot-print	Impact on Commis-sioning	Modify-ing Existing Equip-ment	Ca-pEx	OpEx
Remote operation	Yes	No	Yes [118]	N/A	Low	None	Easily	$	$
Time Delay Switch (TDS operation)	Limited	No	Yes[118]	N/A	None	None	Easily	$	$
Absence of voltage tester	Limited	No	Yes [118]	N/A	None	None	Possible	$	$
Infrared (IR) windows	Limited	No	Yes [118]	N/A	None	None	Easily	$	$
Close door racking	Limited	No	Limited	N/A	None	None	Possible	$	$

117. The National Fire Protection Association, Inc., 2020 Edition.
118. A. C. Parsons, “Arc Flash Application Guide Arc Flash Energy Calculations for Circuit Breakers and Fuses”, Square D/Schneider Electric Engineering Services, August 2004.

Table 26 - Arc Flash Mitigation Types and Impacts (Continued)

Remote racking system	Yes	No	Yes [119]	N/A	None	None	Easily	$	$
Partial de-energization / load redundancy multiple sources (Main-Tie-Main)	Limited	Limited	Limited	Partial operation hours / days	High	Medium	Difficult	$$	$

Table 27 - Prevention Methods That Reduce Arc Flash Risk

Prevention By Design: Arc Flash Mitigation Types	Protection During Operation	Protection During Maintenance / Abnormal Operation	Reduced Incident Energy(cal / cm²)	Recovery Time	Impact on Footprint	Impact on Commis-sioning	Modify-ing Existing Equip-ment	CapEx	OpEx
Barriers / ANSI compartmental-ization	Yes	Limited	No	N/A	None	Low	Applica-tion depend-ent	$	$
High resistance grounding	Limited	Limited	No	N/A	Low	High	Possible	$$	$
Gas insulated switchgear	Yes	Limited	No	N/A	Improves	Medium	No		
Shielded solid insulatedswitch-gear	Yes	Limited	No	N/A	Improves	Medium	No		
IR thermographic study	Increases exposure	Increases exposure	No	Predicitve	None	None	N/A	$	$$
Continuous thermal monitoring	Alert only	Alert only	No	Predicitve	Low	Low	Possible	$$	$
Continuous humidity monitoring	Alert only	Alert only	No	Predicitve	None	Low	Easily	$	

Table 28 - Incident Energy Reduction Methods

Prevention By Design: Arc Flash Mitigation Types	Protection During Operation	Protection During Maintenance / Abnormal Operation	Reduced Incident Energy (cal / cm²)	Recovery Time	Impact on Foot-print/ Commis-sioning	Impact on Commis-sioning	Modify-ing Existing Equip-ment	CapEx	OpEx
Energy reducing maintenance switch	Limited	Limited	Less than 8/12	Hours / days[120] depend-ing on ERMS switch been turn-ed on	None /Low	Low	Possible	$$	$
Circuit breaker with instantaneous or override below arcing level	Limited	Limited	Less than 8/12	Hours / days	None /Medium	Medium	Limited	$$	$

119. A. C. Parsons, “Arc Flash Application Guide Arc Flash Energy Calculations for Circuit Breakers and Fuses”, Square D/Schneider Electric Engineering Services, August 2004.
120. For additional information on arc flash mitigation methods, refer to *Schneider Electric Arc Flash Mitigation Guide V11.*

Table 28 - Incident Energy Reduction Methods (Continued)

Adaptive settings	Limited	No	Less than 40	Weeks / months	None /Low	Low	Possible	$	$
Current-limiting circuit breakers /fuses	Limited	Limited	Less than 8/12	Hours / days	Medium /Low	Low	Limited	$$	$
Digital multi-function relay	Yes	Yes	Less than 8/12	Weeks / months	Low/High	High	Possible	$	$
Zone selective interlocking	Yes	Yes	Less than 12	Hours / days [121] depending on calorie availability	None /Medium	Medium	Possible	$$	$
Differential protection	Limited	Limited	Less than 8/12	Hours / days	Low/High	High	Possible	$$$	$
Transfer trip scheme (virtual main)	Yes	Yes	Less than 8/12	Hours / days	Low /Medium	Medium	Possible	$$	$
Arc flash detection device (optical sensors)	Yes	Yes	Less than 8/12	Hours / days	Medium /Medium	Medium	Application dependent	$$	$
High speed shorting switch (quenchers)	Yes	Yes	Less than 1.2	Hours / days	High/High	High	Possible	$	$
Line side isolation with passive reduction	Yes	Yes	Less than 1.2	Hours / days	Low/Low	Low	Possible	$	$

NFPA 70E article 205.32 states that a single-line diagram, where provided for the electrical system, shall be maintained in a legible condition and shall be kept current. If utilizing the incident energy analysis method of determine the arc flash hazard, the analysis must be reevaluated when changes occur in the electrical system that could affect the results of the analysis and reevaluated at intervals not to exceed five years, per NFPA 70E article, 130.5(G). An effective method of accomplishing this is to have a study performed and maintained to be kept current. The concept of a digital twin can accomplish this.

The general approach of a digital twin model is a virtual representation of a distribution system that can be as simple as a single-line diagram with relevant data to complex, updated real-time data, via digital readings through networked metering and communication. Digital twins can create a foundation for the customer and clients to support reliability assessment, asset management, real-time interfaces for SCADA systems, and system studies.

121. For additional information on arc flash mitigation methods, refer to *Schneider Electric Arc Flash Mitigation Guide V11.*

Electrical Distribution Equipment

Power Distribution Equipment

ABSTRACT: Many factors affect the type and layout of power equipment. Ultimately, cost, resiliency, and maintainability will drive the equipment selection. Many companies are adopting zero energized work policies. Take care in equipment and layout selections to meet these policies.

Introduction

Power Distribution Equipment is a term generally used to describe any apparatus used for the generation, transmission, distribution, or control of electrical energy. This section concentrates upon commonly used power distribution equipment: Panelboards, Switchboards, Low-Voltage Motor Control Centers, Low-Voltage Switchgear, Medium Voltage Power and Distribution Transformers, Medium-Voltage Metal Enclosed Switchgear, Medium Voltage Motor Control Centers, and Medium-Voltage Metal-Clad switchgear. Each has its own unique standards and application guidelines, and one facet of good power system design is the knowledge of when to apply each type of equipment and the limitations of each type of equipment. The equipment described herein are typically custom-engineered on a per-order basis.

NEMA Enclosure Types

One common characteristic of the equipment types covered in this section is that they are all enclosed for safety. The enclosures for enclosed equipment generally follow the guidelines set forth in NEMA 250-2003 Enclosures for Electrical Equipment (1000 Volts Maximum)[122], and, although this standard is intended for equipment less than 1000 V, it is also true of medium-voltage power equipment.

The most common NEMA enclosure types are as follows (see Enclosures for Electrical Equipment (1000 Volts Maximum)[122]):

Type 1: Enclosures constructed for indoor use to provide a degree of protection to personnel against access to hazardous parts and to provide a degree of protection of the equipment inside the ingress of solid foreign objects.

Type 3R: Enclosures constructed for either indoor or outdoor use to provide a degree of protection to personnel against access to hazardous parts; to provide a degree of protection of the equipment inside the enclosure against ingress of solid foreign objects (falling dirt and windblown dust); to provide a degree of protection with respect to harmful effects on the equipment due to the ingress of water (rain, sleet, snow); and that is undamaged by the external formation of ice on the enclosure.

Type 4: Enclosures constructed for either indoor or outdoor use to provide a degree of protection to personnel against access to hazardous parts; to provide a degree of protection of the equipment inside the enclosure against ingress of solid foreign objects (falling dirt and windblown dust); to provide a degree of protection with respect to harmful effects on the equipment due to the ingress of water (rain, sleet, snow, splashing water, and hose directed water); and that is undamaged by the external formation of ice on the enclosure.

Type 4X: Enclosures constructed for either indoor or outdoor use to provide a degree of protection to personnel against access to hazardous parts; to provide a degree of protection of the equipment inside the enclosure against ingress of solid foreign objects (windblown dust); to provide a degree of protection with respect to harmful

122. NEMA Standards Publication 250-2023.

effects on the equipment due to the ingress of water (rain, sleet, snow, splashing water, and hose directed water); that provides an additional level of protection against corrosion; and that is undamaged by the external formation of ice on the enclosure.

Type 5: Enclosures constructed for indoor use to provide a degree of protection to personnel against access to hazardous parts; to provide a degree of protection of the equipment inside the enclosure against the ingress of solid foreign objects (falling dirt and settling airborne dust, lint, fibers, or other items); and to provide a degree of protection with respect of harmful effects on the equipment due to the ingress of water (dripping and light splashing).

Type 12: Enclosures constructed (without knockouts) for indoor use to provide a degree protection to personnel against access to hazardous parts; to provide a degree of protection of the equipment inside the enclosure against ingress of solid foreign objects (falling dirt and circulating dust, lint, fibers, or other items); and to provide a degree of protection with respect to harmful effects on the equipment due to the ingress of water (dripping and light splashing).

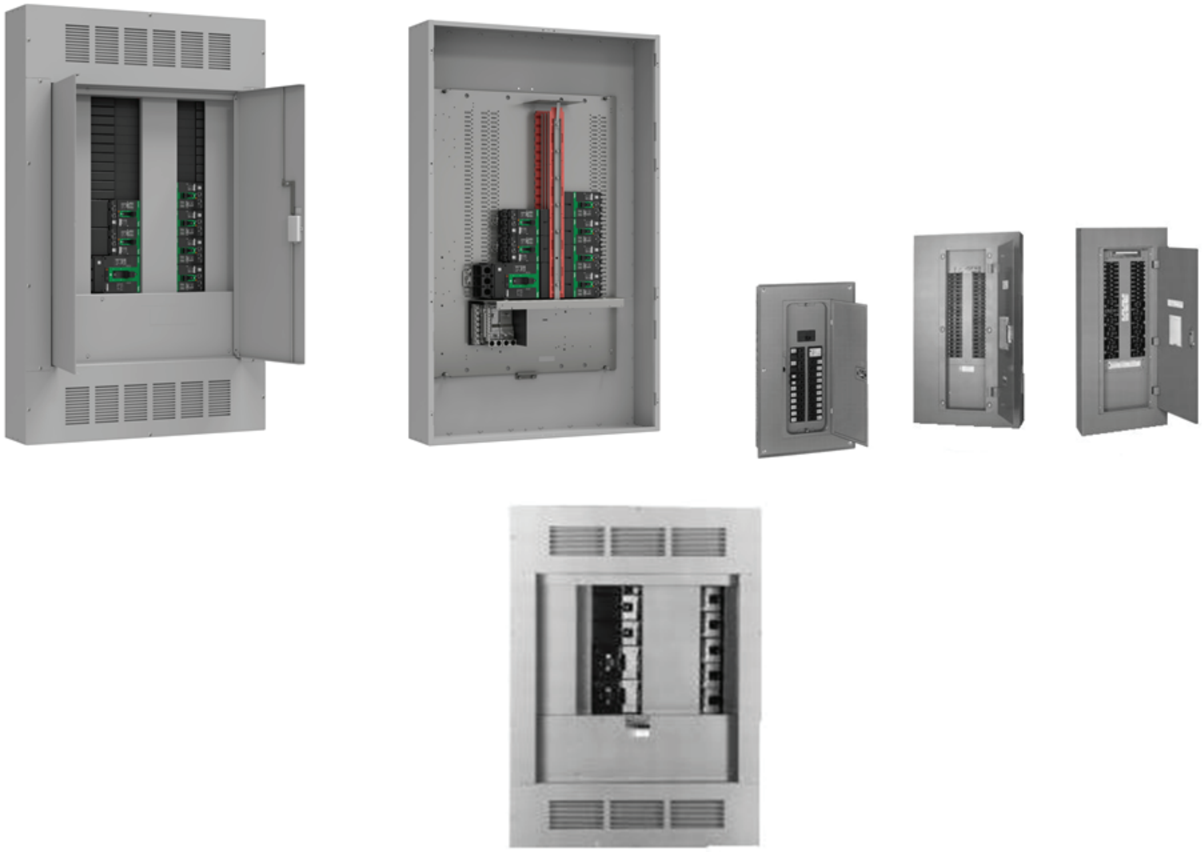
Table 29 - Panelboards: Quick Reference

Available Voltage Ratings	120–600 V
Available Current Ratings	30–6001200
Available Short-circuit Ratings	Through 200 kA
Major Industry Standards	UL 50, UL 67, CSA C22.2 No. 29, CSA C22.2 No. 94, NEMA PB 1, Federal Specification W-P-115C, NEC
Typical Enclosure Types	1, 3R, 5, 12
Primary NEC Requirements	Article 408

Panelboards are the most common type of power distribution equipment. A panelboard is defined as “a single panel or group of panel units designed for assembly in the form of a single panel, including buses and automatic overcurrent devices, and equipped with or without switches for the control of light, heat, or power circuits; designed to be placed in a cabinet or cutout box placed in or against a wall, partition, or other support; and accessible only from the front” (see The National Electrical Code[123]). It typically consists of low-voltage molded-case circuit breakers arranged with connections to a common bus, with or without a main circuit breaker. Panelboards, page 165 shows typical examples of panelboards.

123. NFPA 70, The National Fire Protection Association, Inc., 2003 Edition.

Figure 96 - Panelboards



Panelboards are used to group the overcurrent protection devices for several circuits together into a single piece of equipment. In small installations they may serve as the service equipment. The NEC The National Electrical Code[124] divides panelboards into two categories:

Lighting and Appliance Branch-Circuit Panelboard: A panelboard having more than ten percent of its overcurrent devices protecting lighting and appliance branch circuits.

Power Panelboard: A panelboard having ten percent or fewer of its overcurrent devices protecting lighting and appliance branch circuits.

Separated Distribution Panelboard: A panelboard combining the above Lighting and Appliance Branch-Circuit and Power Panelboards.

Lighting and appliance branch-circuit panelboards are limited to a maximum of 42 overcurrent devices, excluding mains. UL 67 UL Standard for Safety for Panelboards, UL 67, Underwriters Laboratory, Inc.[125] designates Class CTL Panelboard as the marking for appliance and branch circuit panelboards; CTL stands for “circuit limiting”. In some manufacturer’s literature lighting and appliance branch-circuit panelboards for residential or light commercial use are referred to as load centers.

Panelboards are available with built-in main devices or as main lugs only (MLO). The NEC The National Electrical Code[124] requires appliance and branch circuit panelboards to be individually protected on the supply side by not more than two main circuit breakers or two sets of fuses having a combined rating no greater than the rating of the panelboard. Lighting and appliance branch circuit panelboards are not required to have individual protection if the feeder overcurrent device is no greater than the rating of the panelboard.

124. NFPA 70, The National Fire Protection Association, Inc., 2003 Edition.
125. November 2003.

Power panelboards must be protected by an overcurrent device with a rating not greater than that of the panelboard (see The National Electrical Code[126]).

Various methods for attaching the circuit breakers to the panelboard bus are available, such as plug-on, bolt on. The circuit breakers are typically purchased separately. Often, the enclosure, interior, and trim assemblies for the panelboard itself are purchased separately as well. This is typically true of larger panelboards and gives a great deal of flexibility about use of the same interior with different enclosures and trims.

Panelboards are available with several accessories. Subfeed lugs allow taps directly from the panelboard bus without the need for overcurrent devices. Circuit breaker locking devices allow locking of circuit breakers in the open or closed position (the breakers still trip on an overcurrent condition). Various types of trims are available, with various locking means available for trims that are equipped with doors. Various digital solutions are available for communications, metering, maintenance mode switching and surge protection.

Switchboards

Table 30 - Switchboards: Quick Reference

Available Voltage Ratings	120–600 V
Available Current Ratings	800–5000 A
Available Short-circuit Ratings	Through 200 kA
Major Industry Standards	UL 891, NEMA PB 1, NEC
Typical Enclosure Types	1, 3R
Primary NEC Requirements	Article 408

The definition of a switchboard is “a large single panel, frame, or assembly of panels on which are mounted on the face, back, or both, switches, overcurrent and other protective devices, buses, and usually instruments” (see *The National Electrical Code*[127]). Switchboards are free-standing equipment, unlike panelboards, and are generally accessible from the rear as well as from the front. They may consist of multiple sections, connected by a common through-bus. Unlike panelboards, the number of overcurrent devices in a switchboard is not limited.

Switchboards generally house molded case circuit breakers or fused switches. They are generally the next level upstream from panelboards in the electrical system, and in some small to medium-size electrical systems they serve as the service equipment. Switchboards, page 167 shows an example of a switchboard.

126. NFPA 70, The National Fire Protection Association, Inc., 2003 Edition.
127. NFPA 70, The National Fire Protection Association, Inc., 2005 Edition.

Figure 97 - Switchboards

Switchboards are available with a main circuit breaker or fusible switch, or as main lugs only. The available ampacities and multi-section availability makes them more flexible than panelboards. They are generally available utilizing either copper or aluminum bussing, and with a variety of bus plating options. Custom bussing for retrofit applications is also possible.

Switchboard circuit breakers may be stationary-mounted (also referred to as fixed-mounted), where they can be removed only by unbolting of electrical connections and mounting supports, or drawout-mounted, where they can be without the necessity of removing connections or mounting supports. It is possible to insert and remove drawout devices with the main bus energized. The section that contains the main circuit breaker(s) or service disconnect devices is referred to as a main section. A section containing branch or feeder circuit breakers is referred to as a distribution section.

Devices mounted in the switchboard may be either panel mounted (also referred to as group mounted), where they are mounted on a common base or mounting surface, or individually mounted, where they do not share a common base or mounting surface. Individually mounted devices may or may not be in their own compartments. A device which is segregated from other devices by metal or insulating barriers and which is not readily accessible to personnel unless special means for access are used is referred to an isolated device. Group and Individually-mounted Devices, page 168 shows examples of sections with group and individually-mounted devices.

The main through-bus is often referred to as the horizontal bus. The bussing in a section which connects to the through-bus is referred to as the section bus (also known as vertical bus). The bussing that connects the section bus to the overcurrent devices is referred to as the branch bus. Section and branch busses may be smaller than the main through-bus; if this is the case UL 891 (see *The National Electrical Code*[128]) gives the required section bus size as a function of the number of overcurrent devices connected to it.

128. NFPA 70, The National Fire Protection Association, Inc., 2005 Edition.

Figure 98 - Group and Individually-mounted Devices

Group-mounted   Individually-mounted

Switchboards are available with several accessories, including custom-engineered options such as utility metering compartments, automatic transfer schemes, and modified-differential ground fault for switchboards with multiple mains. However, the internal barriering requirements are minimal.

Low-voltage Motor Control Centers

Table 31 - Low-voltage Motor Control Centers: Quick Reference

Available Voltage Ratings	120–600 V
Available Current Ratings	600–2500 A
Available Short-circuit Ratings	Through 100 kA
Major Industry Standards	NEMA ICS-18, UL 845, NEC
Typical Enclosure Types	1, 1A, 3R, 12
Primary NEC Requirements	Article 430

A motor control center (MCC) is defined as “a floor-mounted assembly of one or more enclosed vertical sections typically having a common power bus and typically containing combination motor control units” (see *UL Standard for Safety for Motor Control Centers*[129]). Motor control centers are used to group several combination motor controllers together at a given location with a common power bus. MCCs are typically found in large commercial or industrial buildings where there are many electric motors that need to be controlled from a central location. Low-Voltage Motor Control Center, page 169 shows an example of a motor control center.

129. UL 845, Underwriters Laboratories, Inc., August 2021.

Figure 99 - Low-Voltage Motor Control Center

MCCs are classified into two classes by *UL Standard for Safety for Motor Control Centers*[130]and *Motor Control Centers*[131]:

Class I Motor Control Centers: Mechanical groupings of combination motor control units, feeder tap units, other units, and electrical devices arranged in an assembly.

Class II Motor Control Centers: A Class I motor control center provided with manufacturer-furnished electrical interlocking and wiring between units, as specifically described in overall control system diagrams supplied by the user.

MCC wiring is classified by *UL Standard for Safety for Motor Control Centers*[130]and *Motor Control Centers*[132] into three types:

Type A Wiring: User (field) load and control wiring are connected directly to device terminals internal to the unit; provided on Class I MCCs only.

Type B Wiring: User (field) control wiring is connected to unit terminal blocks; the field load wiring is connected either to power terminal blocks or directly to the device terminals.

Type C Wiring: User (field control wiring is connected to master terminal blocks mounted at the top or bottom of vertical sections which contain combination motor control units or control assemblies; the field load wiring is connected to master power terminal blocks mounted at the top or bottom of vertical sections or directly to the device terminals.

130. UL 845, Underwriters Laboratories, Inc., August 2021.
131. NEMA Standards Publication ICS 18-2007.
132. NE MA Standards Publication ICS 18-2001.

MCCs generally consist of a common power bus and a vertical bus for each section to which combination motor controllers are plugged on. The combination starter consists of motor starter, fuses or circuit breakers, and power disconnect. MCCs may also have push buttons, indicator lights, variable-frequency drives (VFDs), programmable logical controllers (PLCs), and metering equipment. The individual plug-in units are often referred to as buckets and may be inserted and removed with the main bus energized so long as the disconnecting device for the individual unit is open. A vertical wireway is supplied internal inter-unit connections and field connections within each section.

MCCs offer the opportunity to group several motor starters together in one location with a space-efficient footprint versus individual control cabinets, and like switchboards are available with many options. Removable plug-on units allow quick change-outs if spare units are kept on hand for the most common sizes of starters in the facility. Low-voltage soft-starters and variable-speed drives may also be mounted within MCCs.

Low-voltage Switchgear

Table 32 - Low-voltage Switchgear: Quick Reference

Available Voltage Ratings	120–600 V
Available Current Ratings	1600–6000 A
Available Short-circuit Ratings	Through 200 kA
Major Industry Standards	ANSI/IEEE C37.20.1, ANSI/IEEE C37.51, NEMA SG-5, CAN/CSA C22.2 NO 31-M89, UL 1558
Typical Enclosure Types	1, 3R

Low-voltage switchgear, more properly termed *metal –enclosed low-voltage power circuit breaker switchgear*, is defined per *IEEE Standard for Metal-Enclosed Low-Voltage Power Circuit Breaker Switchgear*[133] as ”LV switchgear of multiple or individual enclosures, including the following equipment as required:

- Low-voltage power circuit breakers (fused or unfused) in accordance with IEEE Std. C37.13-2015 or IEEE C37.14-2015
- Bare bus and connections
- Instrument and control power transformers
- Instruments, meters, and relays
- Control wiring and accessory devices

Low-voltage power switchgear is the preferred equipment for medium to large industrial systems where the advantages of low-voltage power circuit breakers, discussed in System Protection, page 69, can be utilized to enhance coordination and reliability. It is typically used as the highest level of low-voltage equipment in a facility of this type and, if the utility service is a low-voltage service, the service entrance switchgear as well. Low-voltage Switchgear, page 171 shows an example of low-voltage switchgear.

Low-voltage switchgear, although it performs the same functions and has comparable availability of voltage and ampacity ratings as switchboards, represents a different mode of development from switchboards and is, in general, more robust, both due to the construction of the switchgear itself and due to the characteristics of low-voltage power circuit breakers versus. molded-case circuit breakers. For this reason, it is preferred over switchboards where coordination, reliability, and maintenance are of primary concern.

133. IEEE Std. C37.20.1-2001, October 2002.

Low-voltage switchgear is typically built as “rear accessible” meaning the access to load cabling and connections are from the rear of the equipment. In situations where space is limited, low-voltage switchgear may be built as “front accessible” where the access load cabling and connections are from the front of the equipment. This allows the low-voltage switchgear lineup to be placed against a wall. This configuration is also useful in electrical house applications where no exterior doors are necessary to access the back side of the equipment.

Figure 100 - Low-voltage Switchgear

Low-voltage switchgear is compartmentalized to reduce the possibility of internal fault propagation. ANSI C37.20.1 (see *IEEE Standard for Metal-Enclosed Low-Voltage Power Circuit Breaker Switchgear*[134]) requires each breaker to be provided with its own metal-enclosed compartment. Optional barriers are usually available to separate the main bus from the cable terminations, forming separate bus and cable compartments within a section, as well as side barriers to separate adjacent cable and bus compartments.

All low-voltage switchgear is required to pass an AC withstand test of 2.2 kV for one minute (see *IEEE Standard for Metal-Enclosed Low-Voltage Power Circuit Breaker Switchgear*[134]).

As with switchboards, low-voltage switchgear is available with many options. The options are generally more numerous than those for switchboards due to the nature of switchgear service conditions.

134. IEEE Std. C37.20.1-2001, October 2002.

Low-voltage Transformer

“A transformer is a static electrical device that transfers energy between two or more circuits through electromagnetic induction” (https://www.se.com/). The main applications of a transformer include converting utility voltage to building distribution voltage, and converting distribution voltage to application voltage requirements. These units can be classified into multiple types: Dry-type, Control Power, and Mini Power-zone.

Table 33 - Low-voltage Transformers: Quick Reference

Available Primary Voltage Ratings	208, 240, 480, 600 Vac Delta
Available Secondary Voltage Ratings	208Y/120, 240 Vac Delta 120V, 480Y/277, 204/120
Available kVA Rating	15–1000 kVA
Major Industry Standards	NEMA ST-20 UL1561 and CSA22.2 No.47 Energy Efficient Registration – Department of Energy 10 CFR 429 CE Marking (Control Power) EN 60 204 and EN 61 558 (Control Power)
Typical Enclosure Types	Type 1, Type 2, Type 3R, Type 4X

Dry-Type: Dry-type distribution transformers are designed to transform voltages for supplying electrical power to a building or load center. For classification as a low voltage dry-type distribution transformer, the transformer must have an input voltage of 34.5 kV or less, have an output voltage of 600 V or less, be rated for operation at a frequency of 60 Hz, and have the capacity of 15-2500 kVA (see 0100CT1901 Low-voltage Transformers).

Dry-type transformers windings are air-cooled; and are not permitted to use oil as a coolant. When voltage is applied to the input winding of the transformer, there can be a brief period of inrush current until the transformer core stabilizes, which lasts for about six power cycles (0.1 seconds). The magnitude of the inrush varies depending on when the switch closes on the power wave, meaning the inrush can range from zero to greater than the full load current rating of the transformer (7400CT1901).

Figure 101 - Low Voltage Dry-type Transformers. Left to right: Dry-type Ventilated Enclosure, Dry-type Non-ventilated Enclosure, Open Core and Coil

Additionally, the impedance of the supply system can influence the amount of inrush current the transformer can draw. To avoid tripping circuit breakers or blowing fuses on the primary side of the transformer during energizing, it is essential to carefully coordinate fuse sizes or breaker handle ratings, and magnetic trip settings. To provide optimal coordination and minimize inrush nuisance tripping, adjust the primary overcurrent protection based on the maximum inrush current. This results in the primary overcurrent protection exceeding the 125% allowance in the NEC for primary-only protection, and secondary protection is required (see 7400CT1901).

Due to concerns regarding the impact on the efficiency of the transformers and market needs for improvements in energy consumption, low voltage distribution transformers are regulated through the Energy Policy and Conservation Act (7400CT1901). The Department of Energy (DOE) evaluates and sets minimum efficiency standards for low voltage dry-type distribution transformers. Transformer efficiency can be defined as the percentage of power out compared to the percentage of power in. A perfect zero loss transformer would have the same power in as out and would be 100% efficient (see 7400CT1901). The efficiency of the transformers shall be no less than that which is required for their kVA rating, as shown in Energy Conservation Standards for Low Voltage Dry-type Distribution Transformers, page 173.

Table 34 - Energy Conservation Standards for Low Voltage Dry-type Distribution Transformers

Single Phase		**Three Phase**	
kVA	**Efficiency %**	**kVA**	**Efficiency %**
15	97.70	15	97.89
25	98.00	30	98.23
37.5	98.20	45	98.40
50	98.30	75	98.60
75	98.50	112.5	98.74
100	98.60	150	98.83
167	98.70	225	98.94
250	98.80	500	99.14

Table 34 - Energy Conservation Standards for Low Voltage Dry-type Distribution Transformers (Continued)

—	—	750	99.23
—	—	1000	99.28

The following low-voltage dry-type transformers must comply with the DOE efficiency standards as shown in Energy Conservation Standards for Low Voltage Dry-type Distribution Transformers, page 173:

- Three- and single-phase transformers
- Step-up and step-down transformers
- General purpose ventilated transformers
- Harmonic-mitigating transformers
- General purpose open core and coil transformers

The following low-voltage dry-type transformers are not required to comply with the efficiency standards as shown in Energy Conservation Standards for Low Voltage Dry-type Distribution Transformers, page 173:

- Auto-transformers
- Drive-isolation transformers
- Non-ventilated transformers
- Resin-encapsulated transformers
- Buck-boost transformers
- Control-power transformers
- Medical isolation panel transformers

Control Power: Industrial control power transformers are designed with low impedance windings for voltage regulation and can accommodate the high inrush current associated with contractors, starters, solenoids, and relays. Their function is to meet the diverse needs of panel builders and machinery OEMs. They are typically 50/60 Hz rated and are designed with various temperature classes as shown in Temperature Rises for Low-voltage Transformers, page 174.

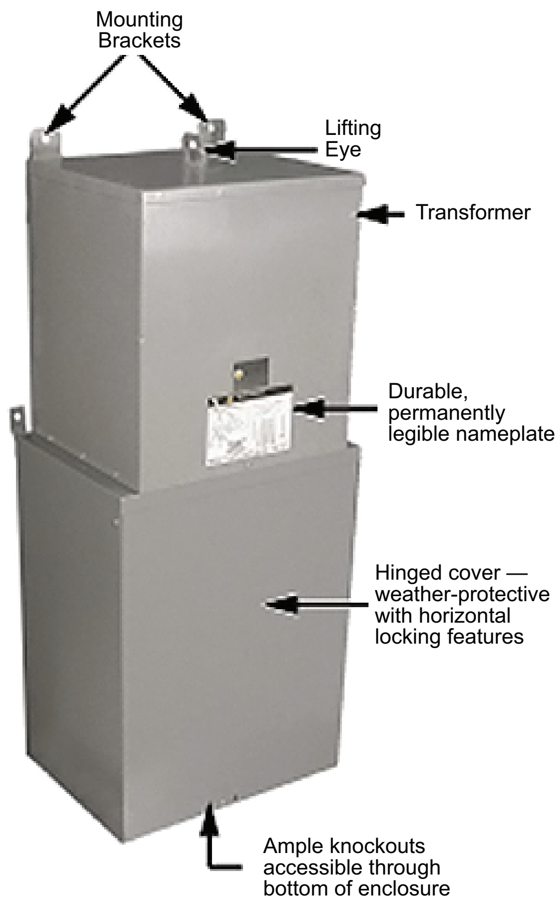
Table 35 - Temperature Rises for Low-voltage Transformers

Transformer Type	Temperature Rise (°C)
Dry-type Distribution	55, 80, 115, or 150
Control Power	55, 80, 115
Mini Power-Zone	80, 115

Figure 102 - Control Power Transformer

Mini Power-Zone: Mini Power-Zone combines a transformer and circuit breaker distribution panel into a single wall mounted substation. The substation includes a primary main circuit breaker, sealed step-down transformer, secondary main circuit breaker, and distribution panelboard. They are typically built in a NEMA Type 3R enclosure, making them suitable for indoor and outdoor use, but can also be built for Type 4X applications. Typical applications for these units can include assembly lines, emergency power, temporary power, areas with limited space, and more.

Figure 103 - Mini Power-Zone



Medium-voltage Advanced Design Guide

For information on medium-voltage basics according to IEC and IEEE standards please reference Medium Voltage Technical Guide.

Medium-voltage Power and Distribution Transformers

Table 36 - Medium-voltage Power and Distribution Transformers: Quick Reference

Available Primary Voltage Ratings	2400–38 kV
Available Secondary Voltage Ratings	120–15 kV
Available kVA Ratings	Through 10,000 kVA

Table 36 - Medium-voltage Power and Distribution Transformers: Quick Reference (Continued)

Major Industry Standards	ANSI/IEEE C57 Series (All types) UL 1562 (Dry and Cast-resin types)
Typical Enclosure Types	1, 3R

Medium-voltage power and distribution transformers are used for the transformation of voltages for the distribution of electric power. They can be generally classified into two different types:

Dry-Type: The windings of this type of transformer are cooled via the circulation of ventilating air. The windings may be one of several types, including Vacuum Pressure Impregnated (VPI), Vacuum Pressure Encapsulated (VPE), and cast-resin. The cast-resin types generally are more durable and less likely to absorb moisture in the windings than the VPI or VPE types. In some cases, the primary windings are cast-resin and the secondary windings are VPI or VPE.

Liquid-Filled: The windings of this type of transformer are cooled via a liquid medium, usually mineral oil, silicone, or paraffinic petroleum-based fluids.

Liquid-filled units have a generally low in first-cost, but the requirements in NEC The National Electrical Code, NFPA 70[135] Article 450 must be reviewed so that installation requirements can be adequately met, and maintenance must be taken under consideration since fluid levels should be monitored and the condition of the fluid examined on a regular basis. They have an expected service life of approximately 20 years. VPE and VPI dry-type transformers also generally have low first-costs, have longer lifetimes than liquid-filled units, and are much easier than liquid-filled types to install indoors; however, give consideration to the absorption of moisture by the windings if these are used outdoors. Installed indoors, these have expected service lifetimes of around 30 years. Cast-resin dry-type transformers have generally high first-costs compared to the other types but have the same installation requirements as dry-type transformers and have the longest expected service life (around 40 years).

Enclosure styles may also be divided into two basic types: pad-mounted, which is a totally-enclosed type generally mounted outdoors and with specific tamper-resistance features to minimize inadvertent access by the general public, and unit substation type, which is an industrial-type enclosure suitable for close-coupling into an integrated unit substation lineup with primary and secondary equipment (unit substation-style transformers may also be equipped with cable termination compartments as well).

Medium Voltage Power and Distribution Transformers, page 177 shows typical examples of medium-voltage power and distribution transformers.Top to bottom: cast-coil dry type with unit substation-style enclosure, VPI dry-type with unit substation-style enclosure, liquid-filled type with unit substation-style enclosure, and dry-type with pad-mounted enclosure.

135. The National Fire Protection Association, Inc., 2005 Edition.

Figure 104 - Medium Voltage Power and Distribution Transformers

Medium-voltage power and distribution transformer capacities may be increased with the addition of fans. Cooling types are listed as AA (ambient air) for dry-type transformers without fans, and AA/FA (ambient air/forced air) for dry-type transformers with fans, for an increase of 33% in kVA capacity. The cooling type for a liquid-filled transformer is listed as OA for units without fans, OA/FA for units with fans, with an increase of 15% kVA capacity for units 225 - 2000 kVA, and 25% for units 2,500 – 10,000 kVA. “FFA” (future forced air) options are usually available for both dry and liquid-filled types, although experience has shown that the fans are almost never added in the field.

Typical BIL Levels for Medium-voltage Power and Distribution Transformers, page 177 gives typical BIL levels for medium-voltage power and distribution transformers. These apply to both the primary and secondary windings. Typical Design Temperature Rises for Medium-voltage Power and Distribution Transformers, page 177 gives typical design temperature rises.

Table 37 - Typical BIL Levels for Medium-voltage Power and Distribution Transformers

kV Class	VPI/VPE Dry-type BIL (kV)	Liquid-filled and Cast- resin Dry-type BIL (kV)
1.2	10	30
2.5	20	45
5.0	30	60
7.2	30	60
8.7	45	75
15.0	60	95
25.0	110	125
35.0	N/A[136]	150

Table 38 - Typical Design Temperature Rises for Medium-voltage Power and Distribution Transformers

Transformer Type	Temperature Rise (°C)
VPI/VPE Dry-type	80, 115, or 150
Cast-coil Dry-type	80 or 115
Liquid-filled	55/65 or 65

Impedance levels vary; the manufacturer must be consulted for the design impedance of a specific transformer. In general, units 1000–5000 kVA typically have 5.75% impedance ± 7.5% tolerance.

136. VPI/VPE dry-type transformers are typically not available above 25.0 kV Class.

Medium-voltage power and distribution transformers are typically available with several types of accessories, including connections to primary and secondary equipment, temperature controllers and fan packages, integral fuses for transformers with padmount-style enclosures.

Medium-voltage Metal-enclosed Interrupter Air-insulated Switchgear

Table 39 - Medium-voltage Metal-enclosed Switchgear: Quick Reference

Available Voltage Ratings	2400 V–38 kV
Available Current Ratings	600–2000
Available Short-circuit Ratings	Through 65 kA
Major Industry Standards	ANSI/IEEE C37.20.3
Typical Enclosure Types	1, 3R

Metal-enclosed power switchgear is defined by IEEE Standard for Metal-Enclosed Interrupter Switchgear[137] as "a switchgear assembly enclosed on all sides and top with sheet metal (except for ventilating openings and inspection windows) containing primary power circuit switching or interrupting devices, or both, with buses and connections and possibly including control and auxiliary devices. Access to the interior of the enclosure is provided by doors or removable covers." Metal-enclosed interrupter switchgear is defined by IEEE Standard for Metal-Enclosed Interrupter Switchgear[137] as "metal-enclosed power switchgear including the following equipment as required:

- Interrupter switches (or vacuum circuit breaker)
- Power fuses (current-limiting or noncurrent- limiting)
- Bare bus and connections
- Instrument transformers
- Control wiring and secondary devices

Metal-enclosed interrupter switchgear is typically used for the protection of unit substation transformers and as service-entrance equipment in small- to medium-size facilities. Metal-enclosed Interrupter Switchgear, page 179 shows an example of metal-enclosed interrupter switchgear.

137. IEEE Std. C37.20.3-2001, August 2001.

Figure 105 - Metal-enclosed Interrupter Switchgear

In the case of fusible equipment, overcurrent protection flexibility is limited, however with current-limiting fuses this equipment has high (up to 65 kA rms symmetrical) short-circuit interrupting capability. The load interrupter switches in this class of switchgear are designed to interrupt load currents only and may use air as the interrupting medium or SF_6. They may be arranged in many configurations of mains, but ties, and feeders as required by the application.

As for Vacuum-circuit breaker Metal-enclosed gear, all use a combination of vacuum circuit breaker and protective relays; design features like compartmentalization, bus insulation and for breakers to be withdrawable Is not required by IEEE standards.

This type of switchgear is frequently used as the primary equipment of a unit substation line-up incorporating primary equipment, a transformer, and secondary equipment.

Voltage Withstand Levels for Metal-enclosed Interrupter Switchgear, page 179 shows the BIL levels of metal-enclosed interrupter switchgear, per [138]. The power frequency withstand is a one-minute test value. Momentary (ten cycle) and short-time (two seconds) current ratings are also assigned for this type of switchgear.

Table 40 - Voltage Withstand Levels for Metal-enclosed Interrupter Switchgear

Rated Maximum Voltage (kV)	Power Frequency Withstand (rms) (kV)	Impulse Withstand (kV)
4.76	19	60
8.25	36	95
15.0	36	95
27.0	60	125
38.0	80	150

138. IEEE Standard for Metal-Enclosed Interrupter Switchgear, IEEE Std. C37.20.3-2001, August 2001.

Internal barriering requirements for medium-voltage areas within the switchgear are minimal. All low-voltage components are required to be separated by grounded metal barriers from all medium-voltage components. Interlocks are required to minimize access to medium-voltage fuses while their respective switch is open and to minimize closing their respective switch while they are accessible. In the rare case that this type of switchgear contains drawout devices, shutters must be provided to minimize accidental contact with live parts when the drawout element is withdrawn.

Available options for this type of switchgear include shunt trip devices for the switches, motor operators for the switches, blown fuse indication. Relaying of any type, including voltage relaying, must be carefully reviewed to avoid exceeding the limits of the switches. The application of overcurrent relaying to this type of switchgear is not recommended unless a short-circuit interrupting element is included, such as a vacuum interrupter.

Medium-voltage Motor Control Centers

Table 41 - Medium-voltage Motor Control Centers

Available Voltage Ratings	2400 V–7.2 kV
Available Current Ratings	Through 3000 A
Available Short-circuit Ratings	Through 50 kA
Major Industry Standards	NEMA ICS-3, UL 347
Typical Enclosure Types	1, 3R

Medium-voltage motor controllers are used to control the starting and protection for medium-voltage motors. They generally utilize vacuum contactors rated up to 400 A continuous, in series with a non-load-break isolation switch and R-rated fuses, fed from a common power bus. The motor starting methods in Arc Flash Hazard, page 150 are all generally supported, including soft-start capabilities. Class E2 units per Industrial Control and Systems: Medium Voltage Controllers Rated 2001 to 7200 Volts AC[139], which employ fuses for short-circuit protection, are generally the most common. Medium-voltage MCC, page 181 shows a typical example of a medium-voltage MCC.

Medium-voltage MCC's are generally available with several options depending upon the manufacturer, including customized control and multi-function microprocessor-based motor protection relays The contactors are generally of roll-out design to allow quick replacement.

Above 7200, metal-clad switchgear is generally used for motor starting.

139. NEMA Standards Publication ICS 3-1993.

Figure 106 - Medium-voltage MCC

Medium-voltage Metal-clad Switchgear

Table 42 - Medium-voltage Metal-clad Switchgear

Available Voltage Ratings	2400 V–38 kV (27 kV for SE)
Available Current Ratings	Through 3000 A (4000 A for SE)
Available Short-circuit Ratings	Through 50 kA
Major Industry Standards	ANSI/IEEE C37.20.2
Typical Enclosure Types	1, 3R

Metal-clad switchgear is defined by[140] as “metal-enclosed power switchgear characterized by the following necessary features:

- The main switching and interrupting device is of the removable (drawout type) arranged with a mechanism for moving it physically between connected and disconnected positions and equipped with self-aligning and self-coupling primary disconnecting devices and disconnectable control wiring connections.
- Major parts of the primary circuit, that is, the circuit switching or interrupting devices, buses, voltage transformers, and control power transformers, are completely enclosed by grounded metal barriers that have no intentional openings between compartments. Specifically included is a metal barrier in front of, or a part of, the circuit interrupting device so that, when in the connected position, no primary circuit components are exposed by the opening of a door.
- All live parts are enclosed within grounded metal compartments.
- Automatic shutters that cover primary circuit elements when the removable element is in the disconnected, test, or removed position.
- Primary bus conductors and connections are covered with insulating material throughout.
- Mechanical interlocks are provided for proper operating sequence under normal operating conditions.
- Instruments, meters, relays, secondary control devices, and their wiring are isolated by grounded metal barriers from all primary circuit elements except for short lengths of wire such as at instrument transformer terminals.

140. IEEE Standard for Metal-Clad Switchgear, IEEE Std. C37.20.2-1999, July 2000.

- The door through which the circuit interrupting device is inserted into the housing may serve as an instrument or relay panel and may also provide access to a secondary or control compartment within the housing.

Medium-voltage metal-clad switchgear is generally used as the high-level distribution switchgear for medium- to large-sized facilities. It is also the preferred choice for service entrance equipment for these types of facilities.Metal-clad Switchgear, page 182 shows an example of metal-clad switchgear.

Figure 107 - Metal-clad Switchgear

Metal-clad switchgear uses high-voltage circuit breakers, as described in System Protection, page 69, fed from a common power bus. It is configurable in many different arrangements of main, bus tie, and feeder devices to suit the application. Relays are usually required since the circuit breakers generally do not have integral trip units. This type of switchgear is the preferred means for accomplishing automatic transfer control and complex generator paralleling applications; the control may be placed in the switchgear itself or in a separate panel, depending upon the application and specific end-user preferences.

A new generation of Metal-clad switchgear with narrower footprint, offers an average space saving of 25% when compared to traditional metal-clad. Its native digital operation and monitoring enhances safety and efficiency.

The construction requirements per[141] ensure that metal-clad switchgear is the safest type of switchgear in terms of operator safety.

The BIL and withstand voltage requirements for this switchgear are the same as for metal-enclosed switchgear as given in Medium-voltage Metal-clad Switchgear, page 181.

This type of switchgear has many options available to suit the application, such as electric racking for circuit breakers, ground and test units that allow the grounding/ testing of stationary contacts with a circuit breaker withdrawn.

Retrofit Solutions

Retrofit solutions are pre-engineered solutions that are designed with a new breaker element truck and carriage used to be installed in the existing switchgear. The interfaces with the existing structure maintain all safety interlocks inherent with the original design. The interior of the existing cell is not modified. These types of solutions work well with any brand of legacy switchgear.

141. IEEE Standard for Metal-Clad Switchgear, IEEE Std. C37.20.2-1999, July 2000.

- For low-voltage switchgear a cradle-in-cradle design is utilized as replacement to make a connection to the existing cell bus connections. The retrofit solutions allow interchangeability of the breaker element with other OEM switchgear of the same rating.
- For medium-voltage switchgear a new truck element is designed to match the existing cell. Design the electrically operated mechanism to match the existing air-magnetic circuits. The mechanism utilized in the design have a passive interlock to block the insertion or removal of a closed breaker.
- The solutions are designed and tested to IEEE Std C37.59 or to ANSI C37.50 standards.

Medium-voltage Gas Insulated Switchgear

Table 43 - Medium-voltage Gas Insulated Switchger: Quick Reference

Available Voltage Ratings	2400 V–38 kV
Available Current Ratings	Through 2500 A
Available Short-circuit Ratings	Through 40 kA
Major Industry Standards	ANSI/IEEE C37.20.9
Typical Enclosure Types	1, 3R

Gas Insulated switchgear is a relatively compact, multi-component assembly, enclosed in a grounded metallic housing in which the primary insulating medium is a compressed gas. It is typically characterized by the following features:

- 1-high or Single-high construction
- Fixed vacuum circuit breaker
- Front-access only design
- Front cable connections and testing
- Internal disconnect and grounding mechanism
- Bottom and top cable entry, with T-body connectors
- Arc resistant and seismic design
- CTs and VTs accessible outside the gas tank
- VTs are isolated with integrated grounding switch
- Modular design of switchgear sections

Medium-voltage gas-insulated switchgear is generally used as the high-level distribution switchgear for medium- to large-sized facilities. It is also the preferred choice for Power or E-houses and power distribution rooms where gas-insulated switchgear's compact design maximizes equipment space savings.

Figure 108 - GHA and CBGS-0

Retrofills for Upgrade and Modernization

A retrofill solution is a custom engineered solution that involves modifying the cell and bus to accept the new low or medium voltage circuit breaker. The new circuit breaker provides new racking mechanism, primary and secondary disconnects, as well as new doors. For low-voltage switchgear a cradle-in-cradle design is utilized as replacement to make a connection to the existing cell bus connections. The retrofit solutions allow interchangeability of the breaker element with other OEM switchgear of the same rating:

- For medium-voltage switchgear a new truck element is designed to match the existing cell. Design the electrically operated mechanism to match the existing air-magnetic circuits. The mechanism utilized in the design have a passive interlock to block the insertion or removal of a closed breaker.
- The solutions are designed and tested to IEEE Std C37.59 or to ANSI C37.50 standards.

Emergency Power Distribution Equipment

Introduction

Emergency and standby power systems are designed to provide an alternate source of power if the normal source of power, typically the electric utility service, should fail. Reliability of these types of systems is critical and good design practices are essential.

Codes and Standards

Classification of Emergency and Standby Power Systems

- **Emergency Power System:** NEC Article 700 specifies electrical safety requirements for circuits and equipment that must operate to enable the evacuation of buildings where large numbers of people assemble, such as hotels, theaters, areas, and healthcare facilities. Circuits and equipment that provide emergency illumination are covered by Article 700. Examples of other systems to which Article 700 may apply include ventilation systems, fire alarm systems, elevators, fire pumps, and industrial processes where interruption of power could result in a serious safety risk or health hazard. For instance, if power interruption could result in a release of a hazardous material from industrial process machinery, the associated circuits and equipment could be subject to the provisions of Article 700. The systems are also classified as Level 1, critical to life safety. When power is lost, emergency systems are required to provide alternate power within ten seconds or less.
- **Legally Required Standby Systems:** NEC Article 701 specifies electrical safety requirements for legally required standby systems circuits and equipment that must operate when the normal supply or system is interrupted. Article 700 addresses equipment and systems that are needed to provide required illumination for building egress or power for equipment essential for safety of life, Article 701 specifies the requirements to provide power to aid support personnel responding to emergencies or supporting recovery from emergency events. For example, while emergency circuits under Article 700 powers lighting required to exit a building, legally required circuits may power lighting that enables responders to view controls for critical building equipment, such as controls for valves, transfer switches, power distribution panels, and other electrical or safety equipment. When power is lost, legally required standby systems are required to provide alternate power within 60 seconds or less.
- **Optional Standby Systems:** NEC Article 702 specifies requirements for the "installation and operation of optional standby systems, both those that are permanently installed in their entirety and those arranged for connection to a portable supply …. where life safety does not depend on the performance of the system." [702.1, 702.2] Examples of systems covered by Article 702 include those in (1) residences provided to avoid inconvenience or discomfort; (2) business facilities installed to avoid interruption in the operation of revenue-generating equipment, and (3) warehouses where loss of refrigeration would result in product spoilage and business losses.

The National Electrical Code

The National Electrical Code contains requirements for emergency systems in Article 700, legally required standby systems in Article 701, optional standby systems in Article 702 and critical operations power systems in Article 708. In addition, Article 445 (Generators), 517 (Health Care Facilities), 665 (Integrated Electrical Facilities), 705 (Interconnected Electrical Power Production Sources) and Article 240.87 (Arc Energy Reduction) are all of particular interest for emergency and standby power systems.

NFPA 110

NFPA 110 *Standard for Emergency and Standby Power Systems*, defines how emergency and standby power systems are to be installed and tested. It contains requirements for energy sources, transfer equipment, and installation and environmental considerations. It divides Emergency Power Supply Systems (EPSS) into Types, Classes, and Levels.

The Type refers to the maximum time that an EPSS can remain unpowered after a loss of the normal source. The types are listed in NFPA 110 Emergency Power Supply System Types NFPA 110 Table 4.1(b), page 186.

Table 44 - NFPA 110 Emergency Power Supply System Types NFPA 110 Table 4.1 (b)

Type	Power Restoration Time
U	Basically Uninterruptible (UPS Systems)
10	10 seconds
60	60 seconds
120	120 seconds
M	Manual stationary or nonautomatic – no time limit

The Class of an EPSS refers to the minimum time, in hours, for which the system is designed to operate at its rated load without being refueled or recharged. The classes for emergency power systems are shown in NFPA 110 Emergency Power System Classes NFPA 110 Table 4.1(A), page 186.

Table 45 - NFPA 110 Emergency Power System Classes NFPA 110 Table 4.1(A)

Class	Power Restoration Time
0.083	0.083 hour (5 minute)
0.25	.25 hour (15 minute)
2	2 hour
6	6 hour
48	48 hour
X	Other time, in hours, as required by the application, code, or user.

The Level of an EPSS refers to the level of equipment installation, performance, and maintenance requirements. The levels for emergency power systems are shown in NFPA Emergency Power System Levels, page 186.

Table 46 - NFPA Emergency Power System Levels

Level	When Installed
1	When loss of the equipment to perform could result in loss of human life or serious injuries (A4.4.1)
2	When loss of the equipment to perform is less critical to human life and safety and where the authority having jurisdiction shall permit a higher degree of flexibility than that provided by a Level 1 system (A4.4.2)

NFPA 101

NFPA 101 [4], Life Safety Code, addresses those construction, protection, and occupancy features necessary to minimize danger to life from fire, including smoke, fumes, or panic. It defines the requirements for what systems the Emergency Power System supplies.

NFPA 99

NFPA 99 defines establishes criteria to minimize the hazards of fire, explosion, and electricity in health care facilities. It defines several specific features of electric power systems for these facilities.

Power Sources

Generators are the most prevalent source of power for emergency and standby power systems. For most commercial and industrial power systems these are engine-generator sets, with the prime-mover and the generator built into a single unit. For reciprocating engines, diesel engines are the most popular choice of prime-mover for generators, due to the cost of the diesel engines as compared to other forms of power and the relative ease of application. Engine generator sets can also run on natural gas, however natural gas engines typically have slower response times, than diesel units.

Another option available is the turbine generator, typically powered by natural gas. Gas-turbine generator sets are generally lighter in weight than diesel engine-generator sets, run more quietly, and generally require less cooling and combustion air, leading to lower installation costs. Turbine generators typically are utilized in large capacity applications, when lengthy continuous operation is required and in combined heat and power (CHP) applications. Gas-turbine generator sets are more expensive and typically less efficient than diesel engine-generator sets. They have more complex controls and require longer starting times (normally around 30 seconds compared to the 10-15 seconds or less for diesels). The long starting-time requirement, cost, and lack of available small sizes (< 500 kW) makes the gas-turbine generators infeasible in most emergency and standby power applications.

Considerations for generator installations include the combustion and cooling air required by the generator and prime mover, provisions for the removal of exhaust gases, noise abatement, expected run time hours and emissions. These considerations can increase the installation costs, especially for diesel engines. Fuel supply must also be considered; building code and insurance considerations may force the fuel storage tank to be well removed from the generator(s), usually forcing the addition of a fuel transfer tank near the generator(s).

Engine-generator sets must be sized properly for the application. Several ratings exist for the output capability of an engine generator set. The continuous rating is typically the output rating of the engine-generator set on a continuous basis with a non-varying load. The prime power rating is typically the continuous output rating with varying load. The standby rating is typically the output rating for a limited period of time with varying load. The manufacturer must be consulted to define the capabilities of a given unit.

Automatic-transfer Switches

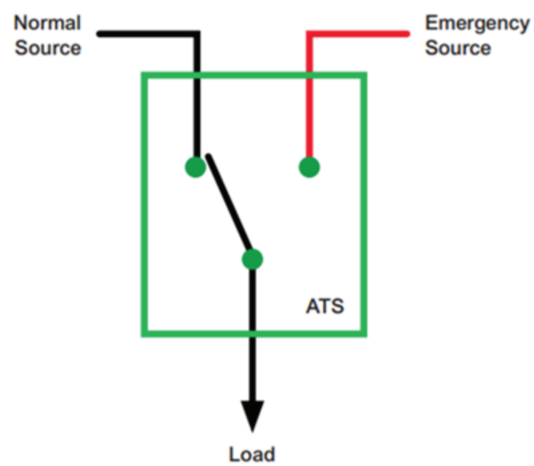
A means must be provided to switch the critical loads from the normal utility source to the standby power source. Several types of devices are available for this.

An Automatic Transfer Switch (ATS) is defined as “self-acting equipment for transferring one or more load conductor connections from one power source to another” [1]. Automatic-transfer switches are the most common means of transferring critical loads in Emergency Power Supply Systems (EPSS). An automatic-transfer switch consists of a switching means and a control system that senses both normal and emergency supply voltage and frequency. The major functions of an automatic-transfer switch include the following:

- Carry current continuously
- Detect power failures
- Initiate the alternate source (Send a start signal to an engine generator)
- Transfer load
- Sense restoration of the normal source
- Retransfer load to the normal source
- Withstand and close on fault currents – ATS Withstand Current Rating (WCR)

An automatic-transfer switch determines when an outage occurs and after an adjustable time delay (Typically one to six seconds in the event of a momentary outage) sends a start signal to the emergency generator. Upon sensing the generator has achieved acceptable voltage and frequency the automatic-transfer switch transfers the load to the alternate source. When the normal source returns and after an adjustable time delay the automatic-transfer switch controls sense the normal source voltage and frequency and transfer the load back to the normal source when it has achieved acceptable voltage and frequency levels. automatic-transfer switches are available in ratings from 30 - 4000 A, and up to 600 V [1]. Low Voltage Transfer Switches are listed to UL1008. There are options for medium-voltage transfer switches up to 15 kV that are listed to UL 1008A. Because automatic-transfer switches are designed to continuously carry the loads they serve, even under normal conditions, take care in sizing these so that the potential for loss is minimized. Similarly, pay attention to available short circuit current at each transfer switch so that proper Withstand Current Rating (WCR) capability is provided. Automatic-test switches with adjustable pickup and dropout setpoints and integral testing capability should be included.

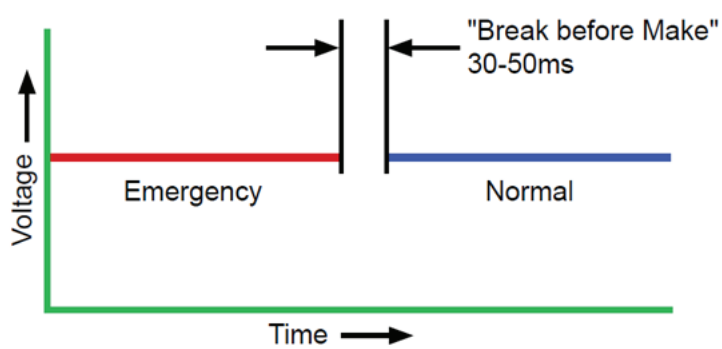
Figure 109 - Automatic-transfer Switch One-line Diagram Representation



Automatic-transfer switches can be provided in open-transition, closed-transition or delayed-transition modes.

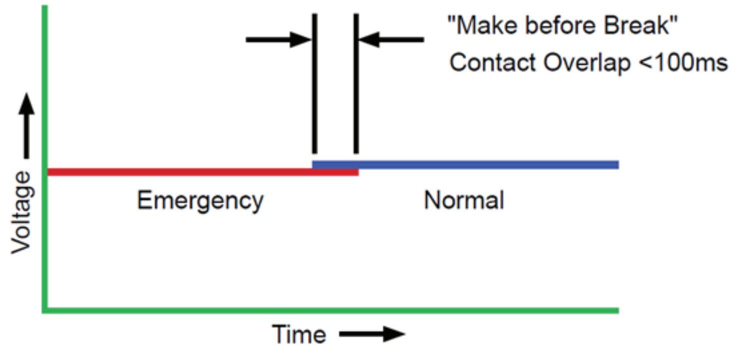
Open-transition is the simplest mode of transferring load between two power sources. Open-transition operates in a “Break before Make” sequence which results in a momentary interruption of power, typically 30 to 50 milliseconds.

Figure 110 - Open-transition Sequence



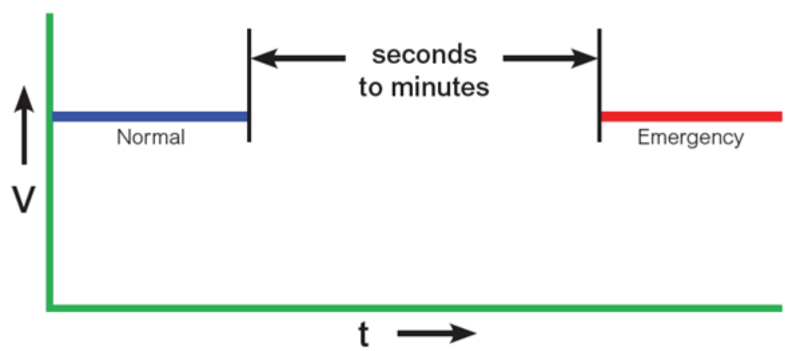
Closed-transition operation transfers between two acceptable power sources without interrupting power to the load in a “Make before Break” sequence. Closed-transition operation connects the normal and alternate sources together for a short (100 milliseconds or less) time when switching between two acceptable sources. Closed—transition switches are typically applied in critical applications to avoid interruption to load when switching between two acceptable sources. Examples include returning to normal after an outage, when load transfers are planned or in test mode. Take special care when transferring motor loads or high inrush current loads.

Figure 111 - Closed-transition Sequence



When power is disconnected from a motor it can become self-excited, delivering energy until they slow to a stop. In addition, if connection to a source were to occur when the motor is 180° out of phase with the source it is transferring to the motor and motor coupling could be subjected to potential damage. There are two methods that can be used to manage transfer of motor loads. One is inphase monitoring which measures the real time phase angle difference between the sources and allows transfer to occur when the sources approach synchronism. This approach is typically used with Open-transition transfer switches. A second method is a Delayed-transition mode of operation. Delayed Transition operation includes an automatic-transfer Switch with a center-off position for the switching contacts. In this mode of operation, the ATS disconnects all loads from both power sources for a brief user adjustable time period, allowing voltage from inductive loads to decay. At the expiration of the time period the ATS transfers to the alternate source.

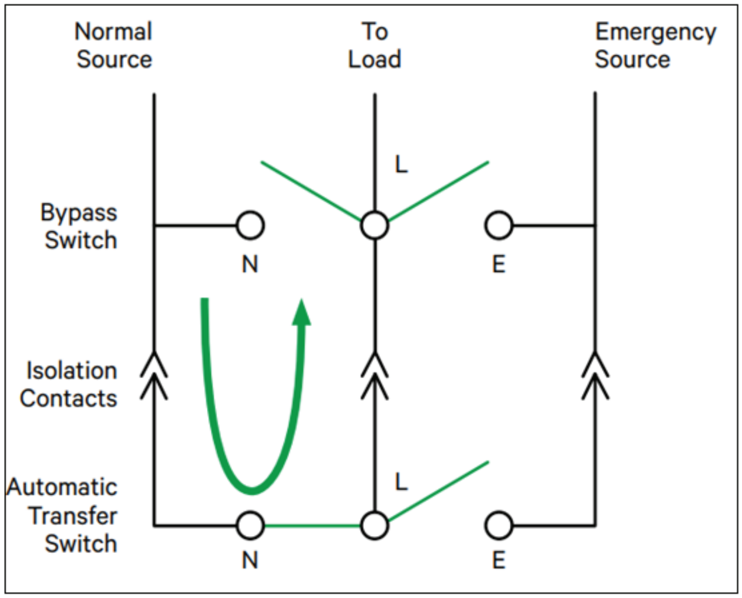
Figure 112 - Delayed-transition Sequence



Manual versions of transfer switches are also available. A one-line representation of an automatic-transfer switch is shown in Automatic-transfer Switch One-line Diagram Representation, page 188.

In critical applications when loads cannot be de-energized for long periods of time, combined Automatic-transfer/Bypass-isolation switches (ATS/BPS) are used to bypass the automatic-transfer switch and connect the source to the load via the bypass switch. This allows isolation of the transfer switch for maintenance purposes. Because emergency power circuits must always be available to serve life-safety equipment, NEC Article 700.5(B) specifies that “Means shall be permitted to bypass and isolate the transfer equipment.” Automatic transfer switches equipped with bypass isolation provide continuous power to loads when the ATS is removed from service for inspection, testing, and maintenance. Bypass/isolation Switch Application, page 190 shows a typical automatic-transfer/bypass - isolation switch arrangement.

Figure 113 - Bypass/isolation Switch Application



In Bypass/isolation Switch Application, page 190 the bypass switch contacts bypass the automatic-transfer switch, and isolation contacts serve to isolate the automatic-transfer switch. The Bypass/isolation switch is typically manually operated. Bypass/ isolation switches are available with a "make before break" feature allowing bypass of the automatic-transfer switch to be completed without disconnecting the load. Automatic-transfer/Bypass-isolation switches are available in Open-transition, Closed-transition and Delayed-transition configurations as described above.

Figure 114 - Automatic-transfer- Bypass/isolation Swtiches

Uninterruptible Power Supplies

Definition

An Uninterruptible Power Supply (UPS) is an electrical device that supplies temporary power to a load when the input power source fails. This differs from a standby generator in that the UPS provides near-instantaneous protection from power interruptions such that the load is not subject to any power interruption. Energy is provided via a stored energy source discussed later in this document. Continuous power is provided by an upstream generator / ATS source, or through resumption of utility power.

Application

UPS products can range from 200 VA single-phase up to over 1.5 MW three-phase, with a variety of voltages and frequencies available for global applications. They are typically installed in applications that require continuous power so as not to lose critical data, such as financial information, critical process information, sensitive electronics, and lighting, manufacturing, specific health care (MRI, CT, etc.) and other applications that are highly desired to keep up through a temporary power disruption. A byproduct of most larger UPS products is that they provide tightly controlled, highly conditioned power to those sensitive loads, by nature of the double conversion process.

Types of UPS

The three most common types of UPS are offline/standby; line-interactive; and double conversion. The type is typically indicative of the power level and criticality of the load, that is offline/standby are normally small VA capable devices, from 200 W - 2 KW single phase, line-interactive 500 W - 5 kW single phase, and double conversion from 5 KW single phase to the largest sizes of double conversion. The bulk of the discussion in this paper focuses on the three-phase double conversion market:

- **Offline/standby:** This product offers surge protection and battery backup, but is normally in a standby condition, allowing utility to pass through to the critical load during normal operations. These are most commonly used on a personal desktop, at point-of-sale systems in stores, and other small applications.

- **Line Interactive:** This product is similar to standby, with the additional feature of an autotransformer that adjusts to ongoing sag and surge conditions to provide conditioned power. These are a lower cost options to compared to double conversion and are typical implemented in small back office computer rooms, to keep small servers and network switches energized during brief outages.

Figure 115 - Line-interactive

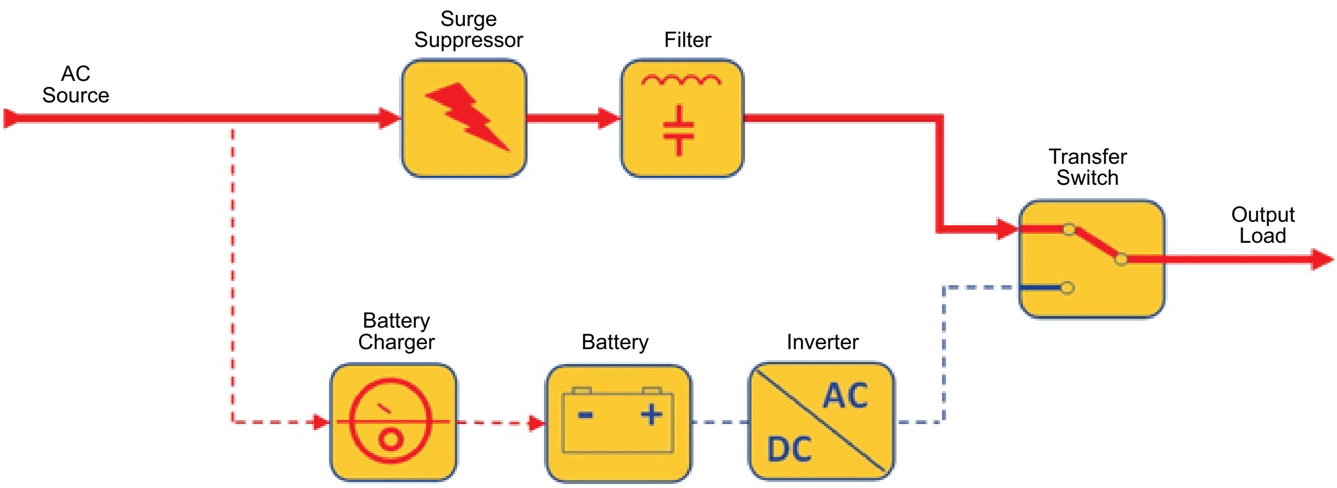
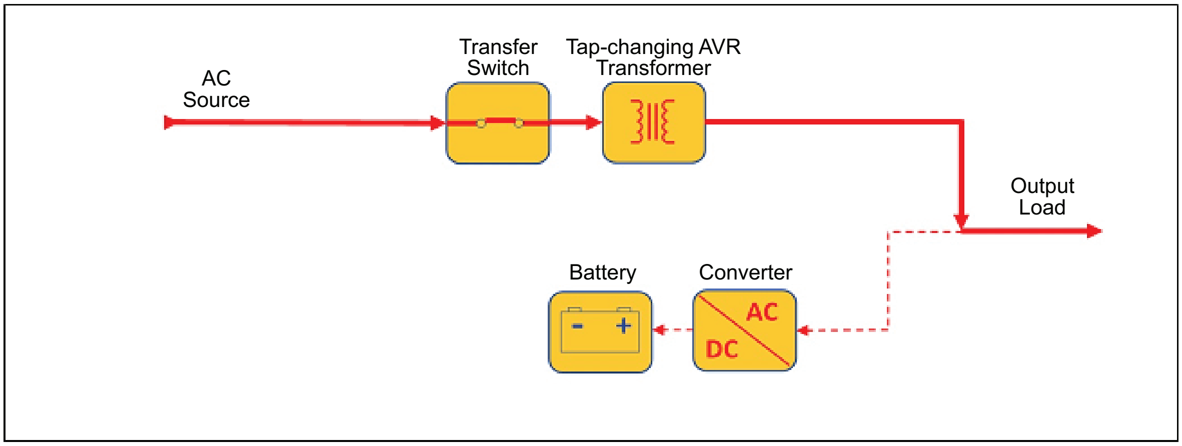
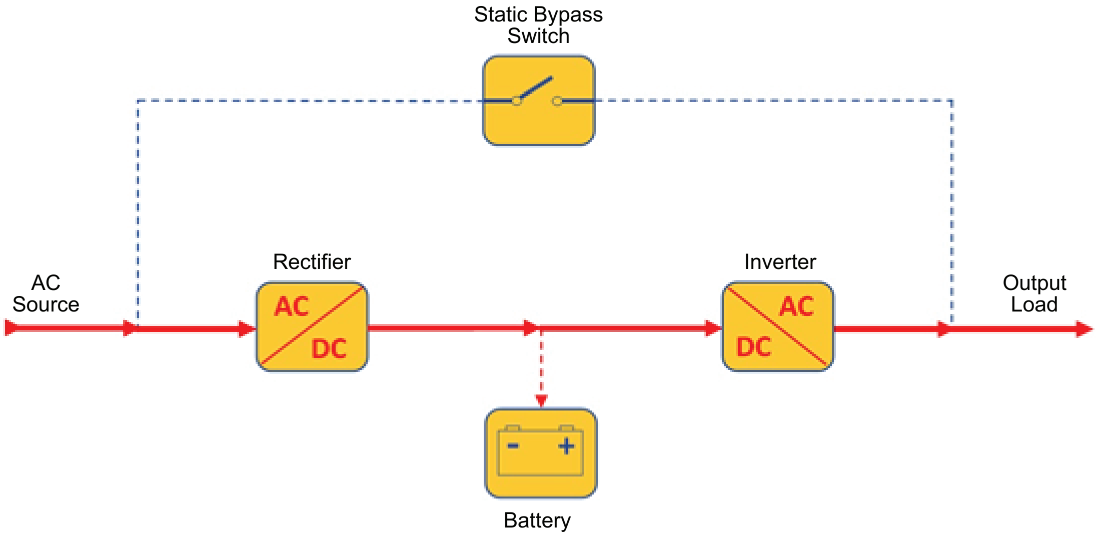


Figure 116 - Line-interactive 2



- **Double Conversion:** The majority of large scale three-phase UPS in the world utilize double conversion systems. As the name suggests, takes input utility, converts it to DC via a rectifier and charges the Direct Current (DC) source while simultaneously converting back to AC off the DC bus via an inverter. This system provides highly conditioned and controlled AC power to more susceptible critical loads. A bypass static switch allows for continuous power to the load in the case of power train loss in the double conversion system. These UPS modules typically start at five - ten KVA single-phase and can be as large 1.5 MW. Additional system capacity can be achieved by paralleling multiple units together. Total system capacity is limited to paralleling bus and breaker sizes as well as limiting control capabilities. Rarely are system capacities see greater than 3.2 MW.

Figure 117 - Double Conversion



Use Examples

UPS systems are used in a wide variety of locations. In the home, personal desktop computers may be backed up by a small offline/standby system. In small business operations, the back-office server, phone switch, network equipment, and other business critical components may be protected by a line-interactive UPS. Typically, units are placed in the bottom of the two-post rack.

In larger applications, double-conversion UPS are used for a variety of purposes. Applications include lighting inverter support for emergency lighting, CT/MRI/PET scanning systems, data centers to back up the critical computing facility, and manufacturing processes to prevent production losses. Many times, a UPS is used to back up the controls portion of whatever process is occurring. This allows for the PLC, computer, or whatever is controlling, for example, the manufacturing process to stay energized through a temporary outage, and thus knows where the process left off until power is restored for the process to continue.

Codes and Standards

Uninterruptible Power Supplies are UL listed conforming to UL1778. Special application standards include UL924 for emergency lighting. Recent DC storage adoptions have seen the rise of UL1973 for lithium batteries, and large-scale fire testing to UL9540A test standards. DC Energy sources are directly coupled with the UPS. They are governed by International Building Code (IBC), International Fire Code (IFC), and National Fire Protection Agency (NFPA) standards, addressed later in this document.

Design Considerations

The use of UPS topologies for different applications also requires specific design considerations. This is specifically true for larger double-conversion UPS. The following sub-sections outline the most common design considerations.

- **Transformer versus Transformer-less:** Double-conversion UPS have seen a fundamental transformation over the last ten years. Prior generations of UPS included output transformers (a transformer in series with the inverter) for waveform shaping and electrical isolation. Some also included an input isolation transformer, either for galvanic isolation, or to allow for special rectifier configurations. With inverter technology improvements, transformers on both input and output have been all but eliminated. The only common remaining transformer is in UL924 lighting inverter systems at 480 V. Since lighting is many times at 277 V off a 480/277 V system, the UPS takes 480 V 3 W+G input and provides an output isolation transformer, 480-480/277 V 4 W+G, developing the neutral to support lighting loads.
- **Bypass:** A second major design improvement has been in the static bypass switch technology. Higher efficiency requirements have driven more efficient modes, such as ECO or E-Conversion, whereby power is transferred to the load via the static bypass. In the event of a power outage, the UPS transfers back to double conversion mode. This requires the static bypass to be a 100% continuous duty rated component. Previous components were typically momentary duty rated with wraparound contractors.
- **Power Factor**: Power factor and power capability of UPS have been transformed in the last decade as well. In the 1990s, UPS were typically .8 power factor (pf). For example, a 500 kVA UPS could only provide 400 kW of usable power. In the early 2000s, these were improved to .9 pf (500 kVA/450 kW). Power electronics improvements have now made unity power factor the de facto standard, where kVA equals kW (kVA/kW).
- **Input Voltages:** Input versus output voltage of data center UPS remains a common confusion point. Incoming utility transformation is typically to 480/277 V main switchboard use. From here, lighting panels, mechanical loads, and the UPS are fed. While the other equipment (lighting and mechanical loads) might use the neutral and require it to be pulled, the UPS typically does not require, nor desire, a neutral to be run. Downstream of the UPS, in the data center, or point of use, most IT loads utilizes 208/120 V, or something similar. Therefore, a Power Distribution Unit (PDU) incorporates a transformer to develop the 208/120 V required. Thus, a UPS can be 480 V 3 W+G input and output, feeding the 480 V input of the PDU to provide appropriate transformation. This can be a significant cost saver in not requiring a neutral run, four-pole breakers for bypass operation, complexity of operation, and other issues.

  208 V is a common voltage for double conversion in the range between 10 kVA and 150 kVA, and frequently used in small to medium size data centers, as well as Medium Distribution Facilities (MDF) and larger edge computing deployments.

- **Redundancy and Reliability:** UPS design configurations are often described by nomenclatures using the letter “N” in a calculation stream. For instance, a parallel redundant system may also be called an N+1 design, or a system plus system design may be referred to as 2N. “N” can simply be defined as the “need” of the critical load. In other words, it is the power capacity required to feed the protected equipment. An N system is a system comprised of a single UPS module, or a paralleled set of modules whose capacity is matched to the critical load projection. This type of system is by far the most common of the configurations in the UPS industry. Schneider Electric’s White Paper 75 is available for further information on this topic: https://www.apc.com/us/en/support/resources-tools/white-papers/.

  In large data centers, reliability is a key metric. Mean Time Between Failure (MTBF) has historically been a key indicator of consistent performance. This metric measures the number of hours between component failures within a UPS that resulted in a load loss. Mean Time To Repair (MTTR) is another key metric that determines the amount of time in hours from onset of component loss to complete repair and return of that UPS to operation. While both metrics are key, in modern UPS topologies with modularized design implementations, MTBF values continue to extend while MTTR continues to be reduced dramatically. Schneider Electric’s White Paper 96 is available for further information on this topic: https://www.apc.com/us/en/support/resources-tools/white-papers/.

- **Breaker and Generator Sizing:** UPS input breaker sizing is an important topic. UPS sizes are stated for their output capacity. They are considered a constant kW device. As such, it is necessary to provide a larger input breaker than expected. This is due to the losses experienced through the UPS, as well as the additional load required on the input to charge the DC voltage source. A typical rule of thumb is to use a breaker that is 125% of nominal UPS output. UPS manufacturers provide detailed breaker sizing information in their literature.

  Generator and Automatic Transfer Switch (ATS) components must also be oversized to account for this additional input load, and to account for UPS input filters that can present leading power factors at low load levels. A 1.5 rating factor was common in previous generations of UPS topologies. With the introduction of power factor corrected rectifier assemblies, Insulated Gate Bipolar Transistor (IGBT) input technology, and other advancements, that generator rating factor can be reduced to 1.1-1.25 in modern UPS installations.

Direct Current Energy Sources

UPS modules can use a variety of DC energy storage systems to provide the necessary energy during outages. These vary from different battery technologies to flywheels. In large data center grade UPS, as the most common voltage is 480 Vac in/out, and the DC bus voltages is 480 Vdc to connect to the DC energy storage source.

- **Battery Technologies:** Battery technologies that are most commonly seen: Flooded Lead Acid, Valve Regulated Lead Acid, Lithium, and Nickel-Zinc. Each is discussed in the following paragraphs.

  Flooded Lead Acid (FLA) batteries are by far the most space consuming and most expensive choice, which also must include spill containment and room ventilation measures. They were the most common battery types up until the mid-2000s. Since then, they have seen a sharp decline in use, mainly due to size and cost. They are a 20-year product, with a common life expectancy of 13-15 years in UPS applications. They require quarterly maintenance to keep the electrolyte levels constant.

  Valve Regulated Lead Acid (VRLA) have been a common second choice to FLA for decades, due to space savings as well as significant initial cost savings. However, VRLA are a ten-year product, with three-five year life expectancy. They require semi-annual maintenance, and it is recommended to use a battery monitoring system to be alerted when they begin to fail.

  Lithium batteries (LiB) are a recent addition (2016) to the large UPS market. Initially at a significant price disadvantage to VRLA, volume of sales has driven their price point to or on par with VRLA. Due to their longevity of 15 service years, size and weight savings, they are a very attractive choice in modern data center and other designs. Recently, IFC/IBC and the NFPA have all provided updated standards (IFC/IBC 2018, and NFPA855), which require limitations on lithium battery technology. The most common lithium offerings have received UL1973 listings for stationary application and have passed large scale fire testing as required under those standards (UL9540A test standard).

  Nickel-Zinc batteries (Ni-Zn) are a relatively recent addition to battery technology used in UPS applications. They offer similar savings to weight and footprint compared to LiB. As this is an emerging technology, they come at a significant price disadvantage. However, they do not pose the same fire concerns, and can be placed in greater quantities without restrictions.

- **Flywheel:** In some applications, frequently seen in hospital installations, flywheels are also being used as an available energy source. Flywheels allow for very short ride through times of 20-40 seconds, just sufficient to get to generator on the UPS input. Flywheels are relatively expensive, yet use only a very small amount of space, rivaling LiB and Ni-Zn. They do require extensive maintenance periodically, such as bearing and oil replacements. Service support and availability needs to be considered when considering flywheels as an energy source.

- **Warranted Life:** Warranty for batteries has also evolved over the last 15 years. FLA typically carries a three - five year full warranty, with a pro-rated value over the remaining 15 years. VRLA commonly carry a three-year full warranty, without subsequent pro-ration. Previously, both technologies offered a cycle life warranty. This required a battery monitoring system to provide the required data. Cycle life warranties have been mostly eliminated in the current battery market. LiB and Ni-Zn commonly carry 10-year performance guarantees, with offerings for full warranty coverage.

- **UPS Backup Time:** UPS back up times vary widely. Specialty applications such as UL924 have a mandated 90 minute required run time.

  Smaller facilities are typically limited by space and cost, which leads to backup times such as five minutes or less.

  Data Centers are typically in a range of 5-15 minutes on the longer end. However, data centers are nearly always provided with a backup generator, and the actual run time on the UPS is in the 15-40 second timeframe, regardless of actual battery installation.

An additional design consideration is the battery technology used and its limitations, as well as the overall design of the electrical infrastructure. If a generator exists, consider minimal battery run time, as the additional run time is never needed. However, battery chemistries may limit just how short that time can be. A chemical phenomenon known as “coup de fouet” limits VRLA batteries to be not less than five minutes, unless a thin plate pure lead style of VRLA is used, then one - two minutes are common. LiB have a specific amount of energy available (one jar style with a specific amp-hour), therefore they have very specific run times available, from as little as two minutes to commonly five-seven minutes, depending on UPS KW. Ni-Zn will have similar considerations to LiB.

These LiB installations are typically referred to as using “Power” batteries. As described, they can discharge the entire stored energy rapidly (min. versus hours). Energy batteries, also LiB, on the other hand, allow to discharge the stored energy over a much longer period (hours vesus minutes). Just recently are these types of implementation considered to support additional use cases, such as Demand Reduction and Energy Arbitrage to reduce overall electrical utility charges.

Conclusion

UPS implementations are used to protect against power disruptions in many diverse applications. The two main reasons are to protect against financial losses or life-safety concerns. This includes data centers and hospitals or control systems and entire manufacturing processes. While those fundamentals of the different UPS technologies have not changed dramatically over the last decades, what has changed, due to advancements in power electronic components, are improvements in the overall efficiency, energy storage systems, and the reduction of physical size of the UPS. We have witnessed the use of mainly transformerless UPS in system designs, the use of Li-Ion batteries, and the shift from monolithic to modular UPS architectures. The most used UPS technologies are offline/standby, line interactive and double conversion. They range from a few hundreds of watts to multiple megawatts.

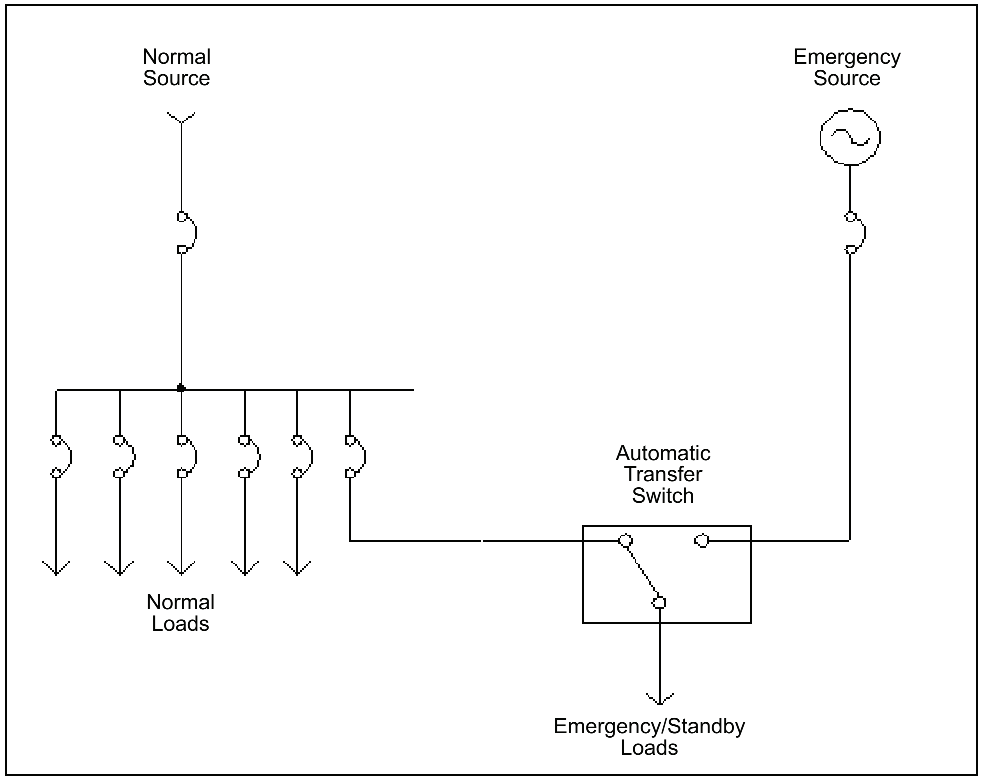
Power System Configurations

Standby and Emergency Power Systems can be configured in customizable bus configurations including single isolated bus, segmented bus, common utility/ emergency, main-tie-main bus and ring bus. Several operational modes, including open transition, closed transition and soft load operation can be provided. Configurations include single engine applications and multiple generator paralleling applications. Examples of some of the most common arrangements are shown here.

Basic Single Engine Configuration

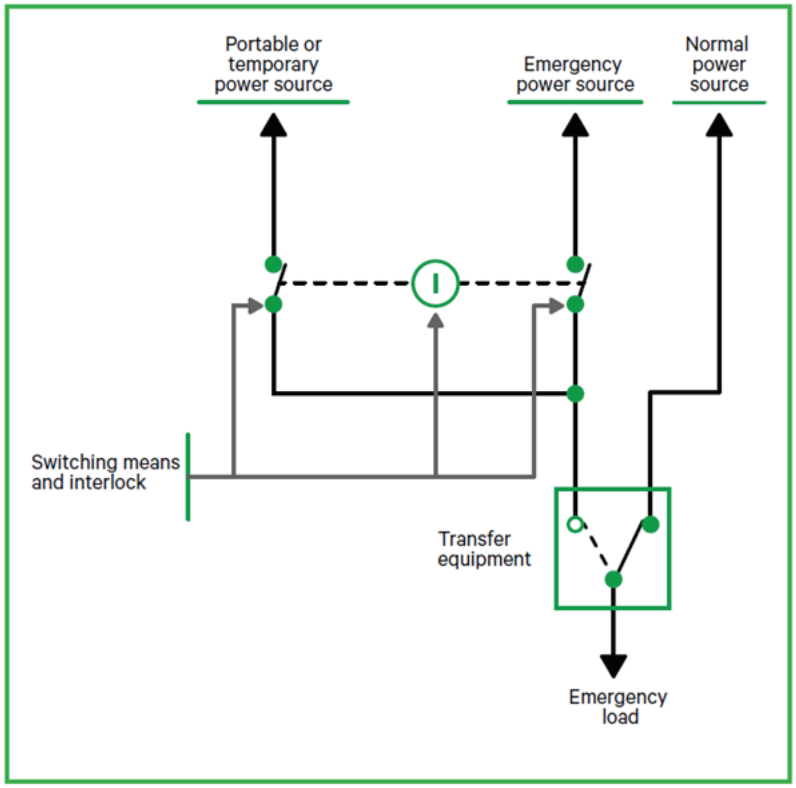
The most basic configuration of an emergency or standby power system is a single engine with single or multiple transfer switches shown in Simple Emergency/Standby System Arrangement, page 198. The transfer switch(es) transfer the emergency/ standby loads to the alternate source upon loss of the normal source. This configuration is the most cost effective emergencny system however a loss of the engine generator or any single component can result in loss of service to the emergency/standby loads.

Figure 118 - Simple Emergency/Standby System Arrangement



For Emergency Power Systems with a single alternate power source, NEC Article 700.3(F) requires a means of connecting temporary or portable power, an example is shown in Provisions for Connection of a Temporary or Portable Power Source, page 199.

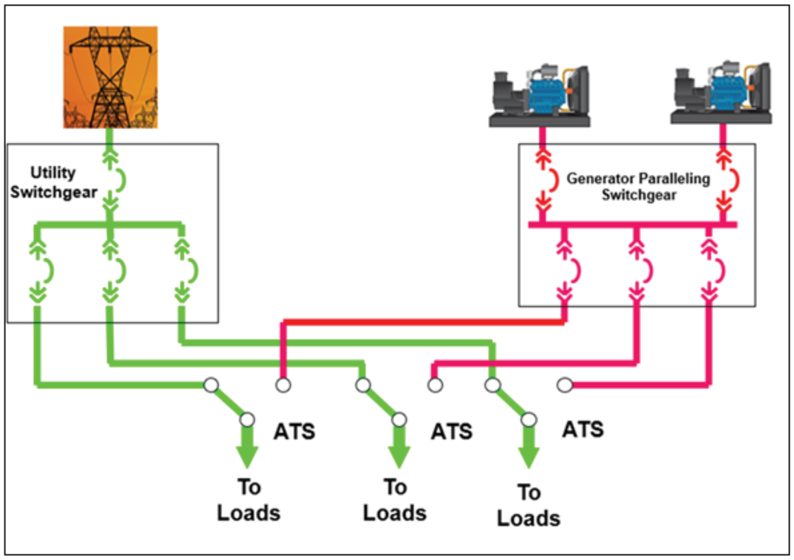
Figure 119 - Provisions for Connection of a Temporary or Portable Power Source



Multiple Generator Paralleling System Configuration

Multiple engine generator paralleling paralleling/synchronizing switchgear refers to the controls and equipment required for connection of multiple sources, usually generators to a common bus and/or a utility source and the load control necessary for the specific application in the event of a power outage. Utilizing multiple generators inherently provides redundancy and a higher degree of reliability by design compared to a single larger generator. N+1 configurations can be provided for capacity and maintainability. For example, a three-engine generator N+1 Emergency System is designed so that any two-engine generators can support the full system load. If one engine generator were to stop functioning, the full load is still supported by the remaining two engine generators. In these applications, system priority load control for load adding and shedding is implemented to so that the most critical loads are connected to backup power when required. Generator paralleling systems are available for a low voltage system up to 600 V and medium voltage systems up to 15 kV. An example of a typical low voltage multiple generator paralleling system with multiple automatic transfers is shown in Low Voltage Multiple Generator Paralleling System with Multiple Automatic Transfer Switches, page 200.

Figure 120 - Low Voltage Multiple Generator Paralleling System with Multiple Automatic Transfer Switches

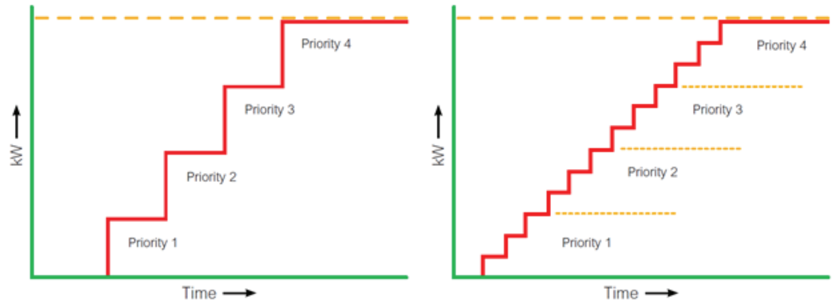


Synchronizing: Paralleling/synchronizing engine generators requires additional controls and attention must be paid to the engine generator selection. An engine typically is provided with the same kW size rating and with the same pitch. Voltage regulators and speed controls should also be matched. An automatic synchronized device is required for each engine generator. Synchronization matches a generator's speed. frequency and voltage with another source, typically another engine generator. Synchronization is necessary when connected generators together to control power surges, avoid reverse power conditions, reducing electrical stress on generators and switchgear and reduces mechanical stress and damage to prime movers. Several conditions must be met to synchronize sources:

- The number of phases must be the same.
- The direction of rotation must be the same.
- The voltage amplitudes must be closely matched (±5%).
- The frequencies must be closely matched (±5 Hz).
- The phase angles must be closely matched (±5°).

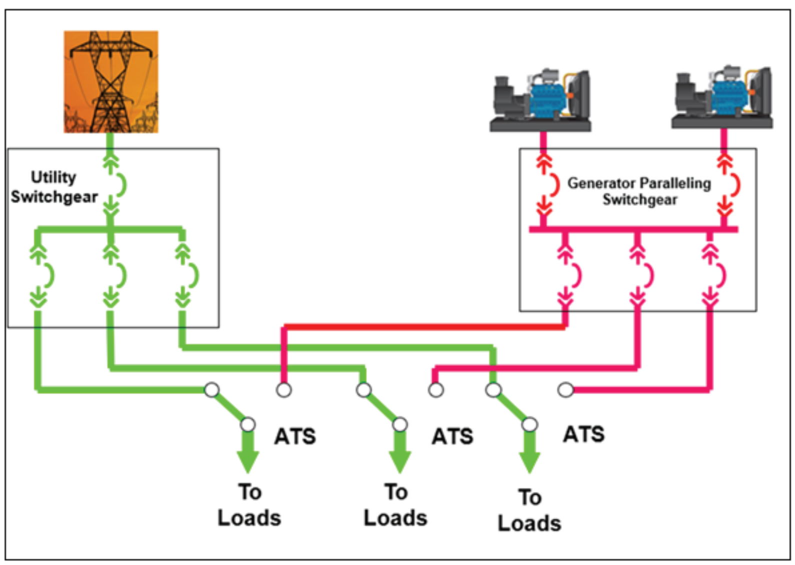
Automatic Priority Load Control: In paralleling swtichgear applications loads are assigned priorities so that they are added to the Emergency or Standby Power System in priority order. The highest priority loads are added first following by second highest. Typically priorities are sized in blocks to match the capacity of a single engine generator. For example, a two-engine paralleling system as shown in Low Voltage Multiple Generator Paralleling System with Multiple Automatic Transfer Switches, page 200 with two 1000 kW engines would have two priority blocks each sized to the capacity of one of the engines. If load shedding is required due to bus overload or engine loss, the lowest priority loads are shed first. Load control can be provided by operating prioritized automatic transfer switches or electrically operated circuit breakers. Automatic transfer switch load control is most common in low voltage applications. Medium voltage applications typically utilize electrically operated circuit breakers for load control. Prioritized load can be added in blocks or steps as shown in Prioritized Block Load Control and Prioritized Step Load Control, page 201.

Figure 121 - Prioritized Block Load Control and Prioritized Step Load Control



Modes of Operation: Emergency and Standby Power Systems as shown in Low Voltage Multiple Generator Paralleling System with Multiple Automatic Transfer Switches, page 200 can operate in open transition or closed transition modes. In the example shown open transition or closed transition automatic transfer switches as described in System Arrangements, page 36 can be provided. Closed transition transfer switches provide no interruption to load when transferring between two acceptable sources. Closed transition operation occurs on return to the normal source after an outage and during transfer switch test mode. Closed transition operation occurs at each automatic transfer switch as shown in Low Voltage Generator Paralleling System with Closed Transition Automatic Transfer Switches, page 201.

Figure 122 - Low Voltage Generator Paralleling System with Closed Transition Automatic Transfer Switches

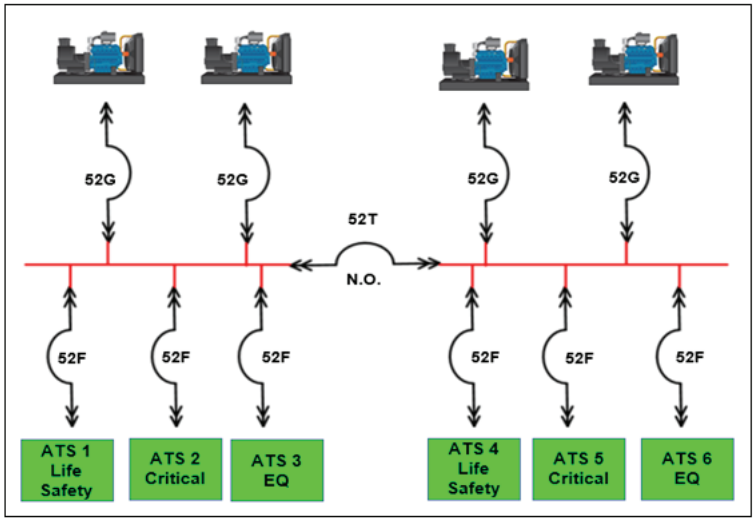


Multiple Generator Paralleling System with Segmented Bus and Tie Circuit Breaker

Tie circuit breakers can be employed in Emergency and Standby Systems to achieve connection of loads in ten seconds for Emergency Systems per NEC Article 700. In this configuration the highest priority loads are split between the two bus segments. In Segmented Bus Configuration, page 202 the tie circuit breaker 52T is normally open. When the transfer switches sense a normal power outage all engine generators are signaled to start. Individual generators are concurrently connected to isolated segments of the bus without the need for synchronizing first, bringing multiple engine generators online simultaneously and connecting the highest priority loads within the ten second requirement. As additional engines become available, they are synchronized with the connected generators, connected to the bus and the lower priority loads are transferred to the emergency system. After all the generators are connected and all the transfer switches have transferred their loads to the emergency system the tie breaker can be signaled to close by the emergency system Master

Controls. Because the tie circuit breaker 52T is connecting sources together a synchronizing device is required across the tie circuit breaker to synchronize the bus segments prior to it closing. Configurations of this type are common in healthcare applications.

Figure 123 - Segmented Bus Configuration



Medium Voltage Main-Tie-Tie-Main Configuration with Multiple Engine Generators

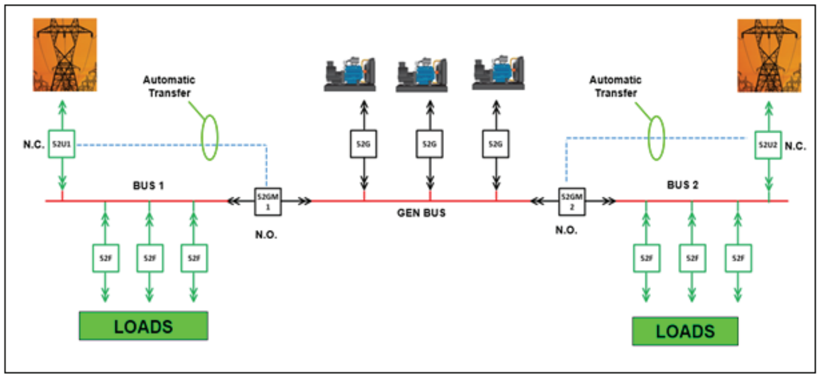
A medium voltage Main – Tie – Main or Main – Tie – Tie Main system can integrate an emergency/standby system into the overall design. More Complex Medium Voltage Main-Tie-Tie-Main system with Multiple Generators Configuration, page 203 illustrates the integration of a multiple engine paralleling system into a Main – Tie – Tie – Main configuration. There are different variations of the configuration shown below, however all are more complex than a single common bus or a segmented bus with a single tie circuit breaker. The additional complexity however adds additional redundancy to the system design by introducing a second utility connection.

In this application the ties, shown as main breakers 52GM1 and 52GM2, are normally open and the utility circuit breakers 52U1 and 52U2 are normally closed feeding loads on their respective buses. Utility sensing via a protective relay is provided on each utility circuit breaker. Size each utility to carry the system full load. In the event one utility were to go offline as detected by the utility protective the system master controls open the offline utility circuit breaker, close both 52GM1 and 52GM2 allowing the remaining utility to power the entire facility load.

Additionally, the engine generators can be started in the event one utility is lost and operate as reserve capacity in the event the remaining utility were to go offline. In the event the remaining utility were to go offline, the engine generators are already running and available to assume load. Take care when running engines without load connected to avoid wet stacking. In this type of sequence, with one utility available, the engines can be run for set period of time, typically 20 minutes. At the expiration of a time delay and with the remaining utility serving the load the engines are shutdown.

In the event both utilities go offline as sensed by their respective protective relays, the system master controls open both utility circuit breakers 52U1 and 52U2 and the engine generators are signaled to start. When the first engine generator is connected to the dead bus circuit breakers, 52GM1 and 52GM2 are closed, and the highest priority loads are connected via operation of electrically operated feeder circuit breakers shown as 52F. As subsequent engines are synchronized and connected additional loads are connected via their respective feeder circuit breakers, until all loads are connected to the emergency bus. If load shedding is required due to a bus overload or engine loss the lowest priority loads are shed first.

Figure 124 - More Complex Medium Voltage Main-Tie-Tie-Main system with Multiple Generators Configuration



When normal power is restored, several options are available to retransfer load back to the normal source. Retransfer sequences can be open transition, closed transition or closed transition/soft load. In the example shown in More Complex Medium Voltage Main-Tie-Tie-Main system with Multiple Generators Configuration, page 203 all retransfer sequences occur between the respective utility and main breakers as follow:

Open Transition Retransfer: When normal power is restored main circuit breakers 52GM1 and 52GM2 are opened and utility circuit breakers 52U1 and 52U2 are then closed in a “Break before Make” operation, assuming facility load. The engine generator circuit breakers are opened, the engine generators enter a cooldown period and then shutdown. Provide electrical Interlocks so that the respective main and utility circuit breaker pairs from both cannot be closed at the same time.

Closed Transition Retransfer: When normal power is restored main circuit breakers 52GM1 and 52GM2 remain closed. Both utilities are synchronized with the live bus via additional synchronizing devices provided for each utility. Once in synchronism circuit breakers 52U1 and 52U2 are then closed in a “Make before Break” operation. Closed transition overlap time is typically 100 milliseconds or less. Both main circuit breakers 52GM1 and 52GM2 are opened and each utility assumes facility load on its respective bus segment. The engine generator circuit breakers are opened, the engine generators enter a cooldown period and then shutdown. Additional synchronizing controls are required at each utility for closed transition operation. Benefits of closed transition operation include no interruption to loads when transferring between two acceptable sources or during system test modes.

Soft Load/Closed Transition Retransfer: Soft load sequence is similar to the closed transition sequence however the overlap time is extended, allowing load to be ramped off of the generators on onto the utility. Interconnection can be approximately 30 seconds to several minutes. Benefits are similar to closed transition but also include less wear and tear on circuit breakers and UPS systems. Utility company approval is required for soft load operation and may require specific utility approved protective relaying at each utility circuit breaker. Synchronizing devices are required at each utility circuit breaker.

Figure 125 - Three-Generator Medium Voltage Emergency/Standby System

Hospital Applications and Configuration

Hospital Emergency Systems are code driven and have very specific requires. Applicable codes are NEC Article 700 “Emergency Systems” and Article 517 “Health Care Facilities, NFPA 99 “Health Care Facilities and NFPA 110 “Emergency & Standby Systems. NEC Article 700 requires emergency systems to be designed to automatically supply power for exit lighting, fire detection and alarm systems, elevators, fire pumps, and public safety communications systems and may also provide power for ventilation where it is essential to maintain life.

The emergency system is classified as an Essential Electrical System and is described in NFPA 99 as “A system comprised of alternate sources of power and all connected distribution systems and ancillary equipment, designed to allow for continuity of electrical power to designated areas and functions of a health care facility during disruption of normal power sources, and also to minimize disruption within the internal wiring system.” Essential Electrical Systems are also divided into two types. Type 1 are Critical Care Spaces and Type 2 are General Care Spaces. Additionally, there are areas of a hospital that are classified as Non-Essential were an Essential Electrical System is not required. These areas include waiting rooms, general lighting and non-critical service equipment.

NFPA 99 assigns a risk category to each space within the healthcare facility based on the risk associated with a loss of the power distribution system serving that space. A summary of risk categories from NFPA 99, Chapter 4 is shown inFrom NFPA 99, Chapter 4, page 205. Most hospitals are Risk Category 1.

Figure 126 - From NFPA 99, Chapter 4

Risk Category	Failure of Such Equipment or System is Likely to Cause
Category 1	Major Injury or Death to patients or caregivers
Category 2	Minor Injury to patients or caregivers
Category 3	Patient Discomfort
Category 4	No Impact on patient care

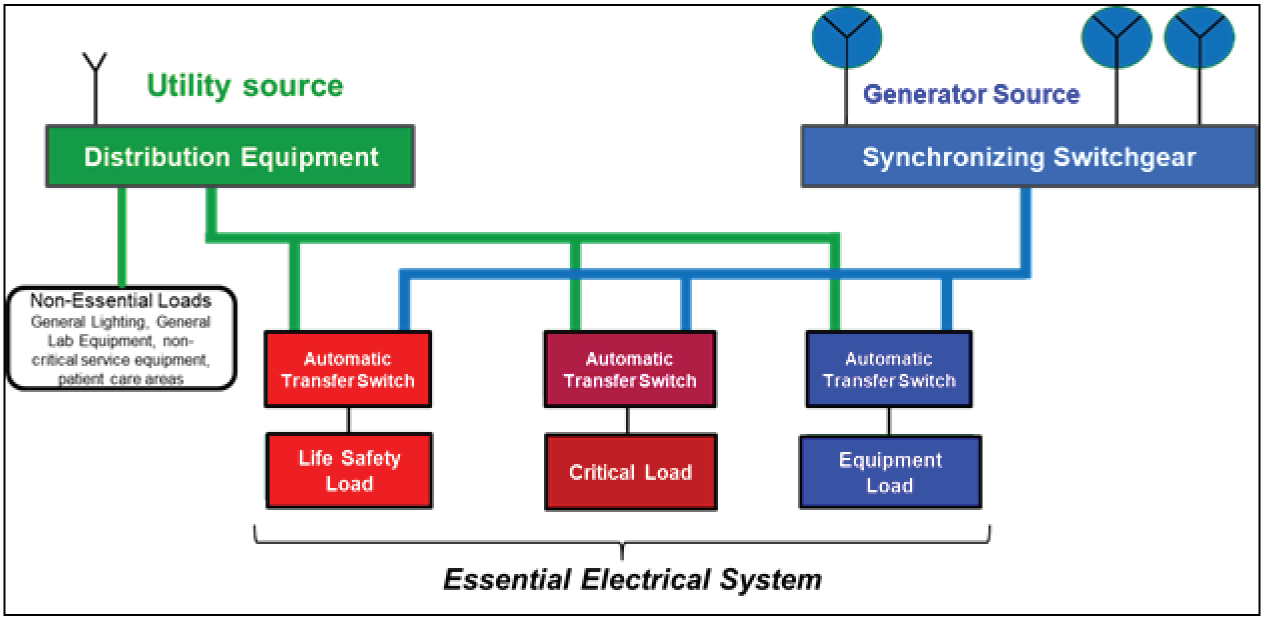
From NFPA 99 Chapter 4

Essential Electrical Systems for hospitals are separated into three distinct branches as described in NEC Article 517.32-34 as follows:

- **Life Safety Branch:** The Life Safety Branch of the EES provides power for lighting, receptacles to those functions or warning systems that are required to allow building occupants to safely leave the building in an emergency. Transfer switches feeding the Life Safety Branch must be automatic and must be non-delayed. Emergency power must be supplied to the life safety branch within ten seconds of a normal source power outage. Typically, these loads are served by automatic-transfer/bypass-Isolation switches. Often these switches are provided with Closed Transition features. Wiring for the Life Safety Branch is kept independent of all other wiring.
- **Critical Branch:** The Critical Branch serves loads that either have immediate impact on patient well-being or are essential to the clinical functionality of the health care facility. Transfer switches feeding the critical branch must be automatic. Emergency power to the critical branch must be supplied within 10 seconds of a normal source power outage. Typically, these loads are served by automatic-transfer/bypass-Isolation switches. Often these switches are provided with Closed Transition features. Wiring for the Critical Branch is kept independent of all other wiring.
- **Equipment Branch:** The Equipment Branch serves loads for major electrical equipment required for patient care. The equipment branch of the EES consists of large electrical equipment loads can include chillers, compressed air systems, exhaust systems and sump pumps needed for patient care and basic facility operation facility. Transfer switches feeding equipment loads are configured for delayed connection to the emergency system.

An example of an Emergency System for a Hospital Application is shown below in Hospital Essential Electrical System with Life Safety, Critical and Equipment Branches, page 206.

Figure 127 - Hospital Essential Electrical System with Life Safety, Critical and Equipment Branches



Essential Electrical Systems are required to have two independent sources of power, the normal utility source and a backup generator or multiple paralleled generators. When normal source power is lost the generator(s) must be started and Life Safety and Critical Branch Automatic Transfer Switches must transfer to the emergency system and provide power to their loads within ten seconds of the normal source power outage. Life Safety Branch transfer switches must transfer to the emergency source immediately upon sensing the availability of emergency power without a delay. Life Safety automatic transfer switches are always considered Priority 1 loads. Critical Branch automatic transfer switches may have a delay to allow the Life Safety automatic transfer switches to connect to emergency power first but must be connected to emergency power within ten seconds of a normal power source outage. Equipment Branch automatic transfer switches can be delayed and are always considered a lower priority than Life Safety or Critical Branch ATS. Automatic transfer switches are required for equipment loads that serve suction.

Hospital Essential Electrical Systems have specific testing requirements as follow:

- NFPA 110 Chapter 8 specifies that an Essential Power Supply System (EPSS) including its transfer switches "shall be exercised under load at least monthly”.
- System testing is required 12 times a year, at intervals not less than 20, or more than 40 days – All ATS must be tested monthly.
- The essential electrical system must be maintained to supply emergency power within 10 seconds of loss of normal power. If the ten second criteria is not met during regular testing, the organization must have a process to confirm on an annual basis that the ten second criteria can be met. Joint Commission requirement based on NFPA 99.
- Tests must be run in accordance with NFPA 110 Requirements.

Distributed Energy Resources

Microgrids

Introduction

With the proliferation of distributed energy resources (DERs) like solar PV and other clean energy generation, battery energy storage systems (BESS), emergency generator arrays etc., the entire landscape of electrical distribution is undergoing a radical transformation. “Microgrids” – as defined by the U.S. Department of Energy, “a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid” – are becoming an integral part of the modern electrical distribution domain. The connection of local microgrids to larger capacity utility grids brings a whole host of design challenges to engineering and operations, both at individual facilities and at utilities. These parameters can be broadly classified in two categories:

- **Electrical:** The rise of “prosumers” (proactive consumers) means that protection and control, grid stability etc. must now be designed with a distributed microgrid infrastructure in mind.
- **Data (Digitization):** Design of a modern digital system architecture warrants a thorough understanding of requirements in terms of data models, software interfaces and interchange of data between various sub-systems.

Market Drivers for Microgrid Adoption

Three factors are responsible for accelerating the adoption of microgrids. Firstly, the economics of deploying distributed energy resources, especially renewables like solar photovoltaic (PV) and battery energy storage systems (BESS), has changed dramatically over the last decade. The installed cost of solar PV has fallen significantly, and many vendors now offer packaged BESS solutions. Many states and local governments offer incentives for “net zero” energy consumption or other economic incentives to export generation capacity back to the utility grid. Facilities can get significant savings by optimizing their local generation to take advantage of rate tariffs or reduce peak demand charges.

Secondly, many companies now embrace sustainability directives to evolve to “green” consumption. ESG (Environmental, Social, and Governance) metrics for many companies now include sustainability and renewable energy targets, driving microgrid projects.

Finally, the importance of facility resilience and dependable power has magnified enormously. Costs of power interruptions are astronomical at mission-critical facilities, driving microgrid projects to increase local generation to ride out natural disasters like the California wildfire related power shutoffs of 2019 and the Texas winter storm disruptions of 2021. Additionally, there is a strong impetus for all backup generation (both existing and new) to switch to low carbon sources like solar PV.

The scale and size of microgrids varies widely, ranging from commercial and industrial microgrids (very large) serving smart cities, municipalities, manufacturing plants, large military bases. all the way to the small and medium microgrids serving individual buildings, gas stations, supermarkets, schools, supermarkets. This scale/size factor influences design criteria such as the complexity of controls, resilience, or the need to operate in islanded mode, and the interconnection with utilities.

Industry Standards

Industry standards related to microgrids (both ANSI and IEC) are evolving rapidly and can be classified roughly as operating at three different levels.

- **Individual DER, or component level:** These include microgrid related language within component-level switchboard or panelboard standards, solar PV inverter standards.
- **System level:** These include explicit microgrid system standards relating to energy management or controls that involve multiple DERs operating as a synchronized unit. For example, the IEEE 2030.7 standard includes control functions for microgrid as a system that can manage itself, operate autonomously or grid connected, and seamlessly connect to and disconnect from the main distribution grid.
- **Interconnection level:** These focus specifically on the interconnection and interoperability between local microgrids or DERs with utility electric power systems (EPSs). These standards provide requirements relevant to the performance, operation, testing, safety considerations, and maintenance of the interconnection. For example, California Rule 21 has specific requirements on the types of data to be shared between microgrids or local smart DERs and the utility energy management system. Architectural details about the interconnection such as protocols of data interchange (IEEE2030.5), frequency of data updates, are also specified in California Rule 21.

Microgrid Standards, page 209 classifies the various standards pertinent to the deployment of microgrids but is not intended to be comprehensive. Many local, state, and regional jurisdictions may also be relevant.

Table 47 - Microgrid Standards

Standard/ Recommended Practical Guide	Title	Description
IEEE 1547	Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces	Establishes criteria and requirements for interconnection of distributed energy resources (DER) with electric power systems (EPS), and associated interfaces.
IEEE 1547.1	IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Energy Resources with Electric Power Systems and Associated Interfaces	The type, production, commissioning, periodic tests, and evaluations that shall be performed to confirm that the interconnection and interoperation functions of equipment and systems interconnecting distributed energy resources with the electric power system confirm to IEEE 1547 are specified here.
IEEE 1547.2	IEEE Application Guide for IEEE Std 1547, IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems	Provides tips, techniques, and common practices to address issues related to DER project implementation.
IEEE 1547.3	IEEE Guide for Cybersecurity of Distributed Energy Resources Interconnected with Electric Power Systems	Provides guidelines for Cybersecurity of DER’s interconnected with Electric Power Systems.
IEEE 1547.4	Guide for Design, Operation, Integration, and Interoperability of Intentional Electric Power Systems Islands	Provides approaches and good practices for the design, planning, maintenance, and operation of Intentional Island Systems and their integration and interoperability with other EPSs.
IEEE 1547.6	IEEE Recommended Practice for Interconnecting Distributed Resources with Electric Power Systems Distribution Secondary Networks	Provides an overview of distribution secondary network systems design, components, and operation. Describes considerations for interconnecting DR with networks and provides potential solutions for the interconnection of DR on network distribution systems.
IEEE 1547.7	IEEE Guide for Conducting Distribution Impact Studies for Distributed Resource Interconnection	This guide provides alternative approaches and good practices for engineering studies of the potential impacts of a DR or aggregate DR interconnected to the electric power distribution system. This guide describes criteria, scope, and extent for those engineering studies.
IEEE 1547.9	IEEE Guide for Using 1547 for Interconnection of Energy Storage Distributed Energy Resources with Electric Power Systems	Addresses interconnection of energy storage distributed energy resources to electric power systems. Provides examples of such interconnection, guidance on prudent and technically sound approaches to these interconnections.
UL1741, UL1741-SB	Standard for Inverters, Converters, Controllers, and Interconnection System Equipment for Use with Distributed Energy Resources	Describes manufacturing (including software) and product testing requirements to specify inverters more capable of riding through grid excursions and actively managing grid reliability functions.
UL891, UL1558	Standards for Switchboards and Switchgear	Supplements ANSI switchgear standards C37.20.1 and C37.51. Used in conjunction with NFPA70/ NEC.
NFPA99	Healthcare Facilities Code	Covers aspects of emergency power systems and associated testing in healthcare facilities.
UL3001* (evolving)	Standard for safety and performance of distributed energy systems	Covers DER system design, integration, and operation.
IEEE 2030.5	IEEE Standard for Smart Energy Profile Application Protocol	Defines the application layer with TCP/IP providing functions in the transport and Internet layers to enable utility management of the end user energy environment, including demand response, load control, time of day pricing, management of distributed generation, and electric vehicles.
IEEE 2030.7	IEEE Standard for the Specification of Microgrid Controllers	Address functions at the microgrid system level (above the component control level) to enable control functions to manage themselves, operate autonomously or grid-connected and seamlessly connect/disconnect from the grid.
IEEE 2030.8	IEEE Standard for the Testing of Microgrid Controllers	Testing procedures to enable verification, performance quantification and comparison of different functions of microgrid controllers.
IEEE 2030.9	IEEE Recommended Practice for the Planning and Design of the Microgrid	Best practices for the planning and design, including system configuration, electrical system design, safety, power quality monitoring and control, electric energy measurement and scheme evaluation.
California Rule 21	Tariff document describing the interconnection, operating, and metering requirements for generation facilities to be connected to a utility’s distribution system.	Rules for the performance, function, metering, and communications of generation and energy storage systems.

Table 47 - Microgrid Standards (Continued)

IEEE P2030.11 (Project started)	DER Management Systems Functional Specification	Guides the development of functional specifications for DER management systems. It includes guiding principles for the application and deployment of DER management systems.
IEEE P2030.12 (Project started)	Draft Guide for the Design of Microgrid Protection Systems	Design and selection of protective devices and the coordination for various modes of microgrid operation, including grid-connected and islanded modes and related transitions between modes.

Microgrid Functions

Typical microgrid functions can be classified into two main categories – microgrid operation, and microgrid optimization - as described below.

Microgrid Operation

- **Monitoring:** Many microgrids require monitoring from remote network operation centers (NOCs). Dependable monitoring of microgrids require the measurement and display of energy, power, and other metrics for individual DERs and loads. If microgrid sites have on-site operators, factor into the design a local HMI to display microgrid loads, generation and status information.
- **Alarming and notification:** Many microgrids require monitoring from remote network operation centers (NOCs). Dependable monitoring of microgrids require the measurement and display of energy, power, and other metrics for individual DERs and loads. If microgrid sites have on-site operators, factor into the design a local HMI to display microgrid loads, generation and status information.

  Alerting on abnormal operating conditions or malfunctions of microgrid components is an essential component of microgrid design.
- **Export management:** In some microgrid deployments, utilities may prohibit or limit export of active power to the grid. In these cases, use excess PV production to charge BESS or curtailed to minimize exceeding export thresholds. In addition to the basic control-limiting functions, export management can be extended to include optimization functions. For example, BESS may be preemptively discharged in preparation to absorb the expected excess PV based on weather forecasts.
- **Grid connection management:** When the microgrid is islanded (off-grid mode), many islanding sequences of operation must be safely managed. Balancing various generation sources optimally while islanded is another control function. For example, PV production and BESS charging or discharging may need to be orchestrated precisely to avoid imbalanced conditions. Conversely, when the utility grid is restored, the restoration sequences may need to be tuned to safely manage state transitions. These grid connection and disconnection sequences must be designed into the microgrid control algorithms.
- **Load management:** Both when islanded or when connected to utility grids, loads must be monitored and either shed or reconnected automatically based on the generation-consumption balance. For example, lower priority non-critical loads may be disconnected when islanded and only restored last after utility restoration. Even when connected to the utility grid, some local loads may need to be disconnected for certain operating conditions. Prioritization and control capabilities for loads is usually an important design criterion for microgrid operation.

Microgrid Organization

- **Forecasting:** Forecasting of both generation and loading is a fast-evolving R&D area with many applications. For example, weather forecasts can be used effectively to optimize microgrids. When stormy conditions or natural disasters like wildfires are forecasted, microgrids can be directed towards charging BESS in preparation, to improve system resilience during outages.

- **Energy optimization:** By controlling DERs optimally, significant savings can be achieved, especially at locations where rate tariffs vary substantially. For example, using local DER production (such as previously charged BESS or solar PV) during expensive on-peak tariff periods and by charging BESS during less expensive off-peak periods. More advanced applications can also optimize local generation to respond to real-time rate changes.
- **Demand charge reduction:** By controlling DERs appropriately, sites can avoid expensive peak demand charges. Using trends and analytics, software may also predict approaching peak demand values and make operational decisions in advance. For example, BESS may be charged in anticipation of predicted peaks and discharged to avoid them.
- **Net zero management:** By intelligently controlling energy storage and solar PV, utility consumption may be partially offset to facilitate "net zero" initiatives. For example, during sunny periods when local PV production is higher than site consumption, energy storage systems may be charged. Later in the day or at night, when solar PV production is low to zero, then the energy storage system can be discharged to meet local site loads.
- **Demand response programs:** Many utilities offer financial incentives to reduce or shift electricity usage during peak periods. Demand response programs are used as dynamic options for balancing supply and demand through mechanisms like real time pricing, and critical peak rebates. When utilities issue demand response signals to customers with microgrids, controls can increase local PV or BESS production to shift loads away from utility. Such participation in demand response programs can be financially attractive to customers.

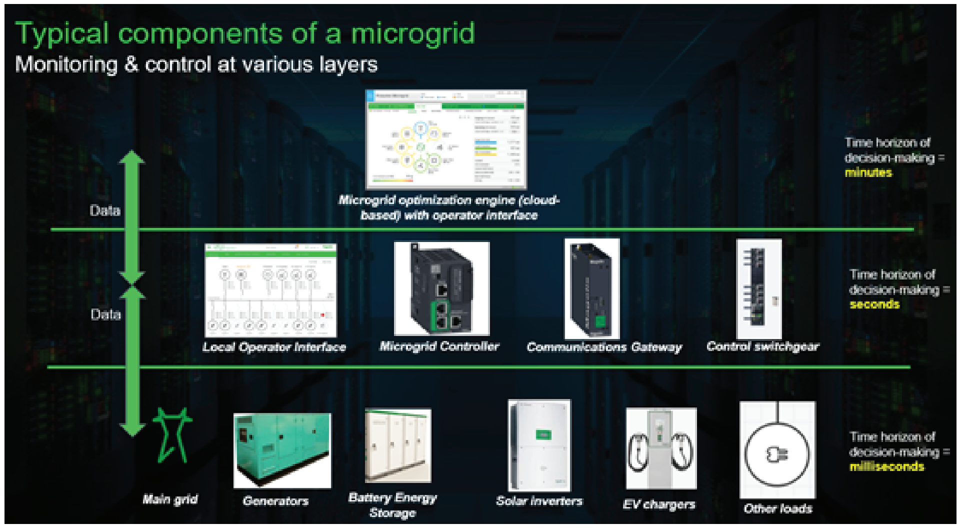
Typical Microgrid System Components

Typical components of a microgrid can be categorized into three layers:

- **Connected devices layer:** These comprise "smart" devices and associated communications such as generator controls, battery energy storage systems, inverters, EV chargers, communicating circuit breakers.
- **Edge layer:** This layer comprises of controllers and software associated with orchestrating the coherent operation of the microgrid as a system.
- **Analytics layer:** This layer typically comprises of optimizing and analytics software that sends decision data to the edge layer. For example, predictive software may send down control signals to control individual DERs.

Cybersecure communications are an integral transverse function of data flow between the components of these three layers.

Figure 128 - Typical Microgrid Components



Design and Specification Considerations

Geographies – differing tariffs, incentives, government initiatives

Clearly, microgrids provide energy users with a variety of benefits, ranging from providing energy resilience, to offering cost savings and carbon emission reductions. However, different entities may value these benefits very differently, depending on the mission and objective of the specific project. To determine an optimal system design, the local market and resource conditions must be carefully considered.

Geographical and regional considerations influence microgrid project development and design in the following ways:

- **Availability or local suitability of energy resources:** Some areas have a variety of energy resources readily accessible, including strong solar (such as, southern U.S.), consistent wind (such as, regions of the Midwestern U.S.), or built-out natural gas infrastructure. Other regions may be limited in infrastructure or natural resources that can be harnessed. Another dimension of geographic evaluation is urban versus. rural. For instance, urban locations may have space limitations for outdoor equipment because of high real-estate costs or zoning requirements. Urban locations may also be subject to solar PV shading from surrounding buildings. In contrast, rural customers may seemingly have ample land to locate resources like ground-mounted solar PV but may be in flood plains or be situated across public rights-of-way. Resource availability is highly site-specific and therefore requires consideration on a local level for optimal microgrid design.
- **Energy rates:** Energy customers are served by hundreds of electric utilities across the US and are charged for that energy using very different tariff structures. A simple tariff may use only the total energy used (quantity of kWh) a site consumes. Other tariffs may include a peak demand per kW charge, reactive power, power factor penalties and other billing determinants. Time-of-Use (TOU) rates where the cost per kWh of energy varies between off-peak, mid-peak and on-peak rates, depending on the time-period of use. Given that factors such as the competitive environment at the local level, the degree of renewables penetration, local politics. all impact the cost for utilities to produce and deliver electricity, customers face a variety of prices and mechanisms for how they are charged. These mechanisms greatly impact microgrid project development and ROI calculations.

- **Federal, state, and local incentive programs:** Federal incentives like the Investment Tax Credit (ITC) are key enablers of microgrids and apply to all U.S. geographies, reducing solar PV and BESS capital costs. Additional local incentive programs at the state, local or municipal level may further subsidize the upfront expense of onsite generation. For example, state-wide incentives like the Self Generating Incentive Program (SGIP) in California and the DEEP Microgrid Grant Program in Connecticut have proven to be highly effective mechanisms for deploying more distributed, clean, and resilient energy systems. Successful program references and an uptick of large policy measures such as the 2021 Federal Infrastructure Bill have prompted more state and local emphasis and funding for microgrids. The commercial and technical requirements that are applicable to take advantage of these incentives must be evaluated and applied for on a project-by-project basis.
- **Market participation:** Additional programs applicable to specific regions may also be available, enabling microgrids to offer unique benefits to the local Utility or Regional Transmission Organizations (RTOs) via participation in market programs like Demand Response or Frequency Regulation. This type of market participation is highly location-specific and is typically oriented around specific outcomes that DER technology or microgrid operational mode can drive.

All the above geography-specific factors impact the design, cost, and ultimately the functionality of a microgrid system. These factors are evaluated carefully during initial project development. With increased emphasis on dependable, efficient, and sustainable energy systems, the local market landscape for microgrids is a fast-evolving one. Staying informed on geographic-specific conditions remains an important factor in implementing successful microgrid solutions.

Space and footprint considerations

Many physical space and footprint considerations impact the feasibility and design of microgrids. As previously mentioned, site location is a critical factor that helps to identify the size of DERs that can be installed and the potential locations for these resources. Once site location has been selected, by analyzing the electrical drawings and infrastructure maps, the available physical space can be determined for the required electrical distribution, microgrid controls infrastructure, and the desired DERs (such as solar PV, BESS, and generator sets). It is important to discuss these physical space considerations with the site decision makers early in the design phase.

The space footprint of the electrical distribution equipment and controls cabinets is a key consideration in microgrid design. Some of the design parameters impact the space footprint are the main bus amperage rating, the number of sections needed to fit all the required breakers and devices, and whether the electrical distribution equipment is going to be located indoors or outdoors. Physical space is also a key factor when determining potential options for the size, type and mix of DERs (solar PV, BESS, generator sets) to be installed on site.

For solar PV systems, the type of available space (rooftop, land, or parking lot space) is an important criterion. This dictates whether rooftop PV, ground mount PV, carport PV, or some combination of the three can be designed into the system. Once PV type is determined, the amount of space dictates the size of the solar system that can be installed. Typically, physical space is a restricting factor with PV - meaning the system capacity that can fit within the available space is often insufficient to meet site demand. The design challenge is that of maximizing the size of the PV system based on the available space. A rough estimate of space for one MW of ground-mount PV is about four acres. Non-ground mount systems have additional considerations. Rooftop PV systems must factor in existing rooftop equipment such as HVAC and sprinklers and incorporate row spacing and rooftop setbacks for maintenance and safety. Carport systems must factor in the parking lot set up and incorporate fire lane widths. Additionally, local zoning and safety codes also impact the placement of PV systems.

For a BESS, the physical space requirements and performance varies widely depending on the type of system and battery chemistry selected. A common battery chemistry integrated into microgrid systems is Lithium-Ion Iron Phosphate (LFP). Depending on the specific BESS, the power blocks can vary in size which impacts the overall power and energy density of a system. Therefore, the physical space for a BESS is dependent upon the power and energy capacity needed. For example, a typical 300 kW/745 kWh BESS has an energy density of 12.4 kWh/sq. ft. and a system power density of 5 kW/sq. ft. A typical footprint for this BESS is 90 inches H x 52 inches D x 155 inches L. In addition to required system size of a BESS, the depth increases if the system needs to be outdoor rated. For other battery chemistries, footprint and space design constraints vary widely.

Physical space requirements for generator sets vary depending on the fuel and particular system selected. Two common generator fuel types are natural gas and diesel. For example, a two MW Natural Gas Generator set has dimensions of 291 inches L x 84 inches W x 95 inches H, or a power density of 11.8 kW/sq ft. Comparatively, an example two MW Diesel Generator Set maximum dimensions are 404 inches L x 99.62 inches W x 156.6 inches" H, or a power density of 10.6 kW/sq ft. On-site fuel storage must be factored into the design. A typical fuel oil storage tank with a capacity of 1000 gallons has a diameter of 48 inches and a length of 130 inches. There may be also local safety requirements for on-site fuel storage. Additionally, certain mission-critical sites (like hospitals) may have minimum on-site fuel storage capacities specified in corporate guidelines and safety codes.

In addition to PV, Lithium-Ion BESS and generators, there are many other technologies that can be implemented for energy generation and storage in a microgrid system. A few of these other technologies include fuel cell, flow battery, Uninterruptable Power Supply (UPS), and wind turbines. Each of these technologies vary widely in footprint and density, and physical space availability need to be considered when designing the microgrid system.

Building Information Modeling (BIM) and other automated layout software tools are typically used during the early design phase of microgrids to optimize the asset locations and positions appropriately.

Economic analysis and project return-on-investment (ROI) tools

One of the main influences driving the adoption of Behind-The-Meter (BTM) microgrid systems in Commercial and Industrial (C&I) facilities is lowering the net cost of energy they purchase from utilities. Through the appropriate use of on-site Distributed Energy Resources (DERs) to at least partially offset consumption and optimizing the remaining utility usage, microgrid can significantly lower facility bills. Several key components of data are needed during the early project assessment phase to complete a complete economic analysis to estimate the potential return-on-investment (ROI) of microgrid projects.

First, the site geographical location is very critical, and helps identify the size of DERs that can be installed, their types, and potential locations. Estimates of the solar irradiance (power per unit area of energy from the Sun) at a given location helps determine the potential for solar PV deployment. As labor rates vary regionally, location also helps determine the expected installation and operations and maintenance (O&M) costs, which impacts ROI calculations.

Next, a comprehensive analysis of past (or projected, in the case of greenfield projects) utility bills are needed to understand site energy usage and current tariffs. A minimum of twelve months of utility bills is typically needed to establish a site load baseline. Additional years of data helps minimize projection errors due to any year-to-year variability. Using utility bill kWh rates, the impact of kWh's delivered from on-site DERs can be financially quantified. Time-of-use tariffs with on-peak, mid-peak and off-peak rates can also be factored into the analysis. Other energy management strategies such as demand-shifting, demand compensation, power factor penalty compensation, can also be analyzed within the economic analysis.

Fifteen-minute interval data helps to size dispatchable DERs by modeling the daily load profile of the site, rather than monthly averages. For example, a Battery Energy Storage System (BESS) can be sized to avoid costly demand peaks and reduce energy usage during expensive on-peak periods. If a Combined Heat and Power (CHP) system is also within scope, usage data from the gas utility can help with proper sizing and operation relative to thermal load. Generally, CHP tends to be attractive when there are high and coincident peaks in electrical and thermal demand, and when the price of electricity ($/kWh) is roughly three times or more than the unit price of natural gas ($/therm). This unit price disparity is commonly referred to as "Spark Spread."

Fortunately, there are many open-source and commercial software tools available to optimize microgrid deployment and provide recommendations for DER types and sizing. These tools typically require the input data discussed above (such as site location, utility tariff structures, load profile, installation costs). In addition to DER sizing, these software tools may also produce a Discounted Cash Flow (DCF) model to simulate incentive programs like the Investment Tax Credit (ITC), Modified Accelerated Cost Recovery System (MACRS) for accelerated depreciation, and any local or regional incentives. This DCF model outputs important metrics like the Net Present Value (NPV) and payback period, which are critical values in determining if the project is a worthy investment. Running these ROI calculations is typically an iterative process – making best-guess estimates, examining the outputs, adjusting the inputs, and repeating the exercise. By leveraging these analysis tools, iterative changes to design and cost inputs can be run quickly and reliably, accelerating the critical timeline between project development, and securing financing.

Protection considerations

Requirements for the system topology are designed to increase both the reliability of the overall utility system and with the reliability of service to the installation in question. These requirements typically take the following forms:

- Restrictions on the size of services.
- Restrictions on, or requirements for, normal and alternate services and transfer equipment between the two.
- Restrictions or requirements for the configuration of emergency and standby power systems.
- Restrictions on the types of service disconnecting devices allowed.
- Restrictions on the types of service overcurrent protection allowed.
- Requirements for service cable compartments in service equipment.
- Requirements or restrictions on the number and types of protective relaying.
- Overall requirements for the service switchgear.

The requirement that is applied to virtually every utility installation, is that the service overcurrent device must coordinate with the upstream utility overcurrent device, typically a recloser or utility substation circuit breaker. If there is standby power on the premises, the utility typically requires that paralleling the alternate power source with the utility source not be possible unless stipulated in the rate agreement for the service in question.

Requirements for restricted access to service cable termination and service disconnect compartments in the service switchgear are another common. In some cases, these must be in a dedicated switchgear or switchboard section, increasing the service equipment footprint. In many cases grounding means must be provided with the equipment to allow the utility's preferred safety grounding equipment to be installed. In some cases, requirements may be imposed on the entire service switchgear, such as electrical racking for circuit breakers or barriers that are not standard for the equipment type used.

In some cases, the control power for the service switchgear, such as a battery, must be designed to the utility's specifications. Additional protective relaying may be required to minimize abnormal conditions which, although not harmful to the system being served, affect the reliability of the utility system. In some cases, the makes and models of protective relays for the service overcurrent protection are restricted to those the utility has approved.

Metering considerations

Measurement of load and system performance are critical to the functionality of the microgrid, both while grid connected and while islanded from the grid. This section does not address specific meter hardware but does address the information that meters may need to collect, and their interaction with other devices, including edge control systems and local or remote energy management systems.

Metering considerations must cover both functional and financial operation of microgrids. Grid-connected metering and grid-independent metering requirements must reflect the nature of the overall system, including possibly divided responsibilities between owner and operator. Some microgrid systems are components within larger power distribution systems, while others are self-contained, so the architecture of the system influences the metering choices and options.

The following measurements are typical for most microgrid systems:

- Metering variables like energy, voltage, frequency, active power, reactive power. at the Point of Common Coupling (POCC) that is, interconnection point with utility.
- State/status for each DER.
- Instantaneous and historical load profiles for the full system as well as secondary and tertiary loads.

Functional considerations for grid-connected operations typically includes metering and monitoring the grid reference, and individual DERs. The financial opportunities and constraints of the system dictate the location and type of metering. For example, revenue grade metering may be required for PV and BESS systems to comply with Investment Tax Credit verification, utility billing/credit for renewable energy delivered to the customer and the grid, and for ancillary services performance, such as participation in demand response or frequency response programs. Measurement of loads typically does not require revenue grade metering unless there is a specific need for sub-billing or tenant metering functions.

Metering sample rates and the volume of historical data collected from metering (through various devices such as dedicated meters, LV trip units, relays, or revenue grade meters) influence the performance of the edge layer and analytics layer software. There is an implicit tradeoff between volume of data captured and the performance of these software packages. Optimization software processes multiple streams of data such as BESS state of charge, metered PV production, CHP utilization, metered grid data, to output control signals that meets the system and customer goals. Production versus consumption decisions utilize meter data that is optimal for the algorithm being processed. Typically, cloud optimization software samples averaged metering values to send DER optimization signals to the site microgrid.

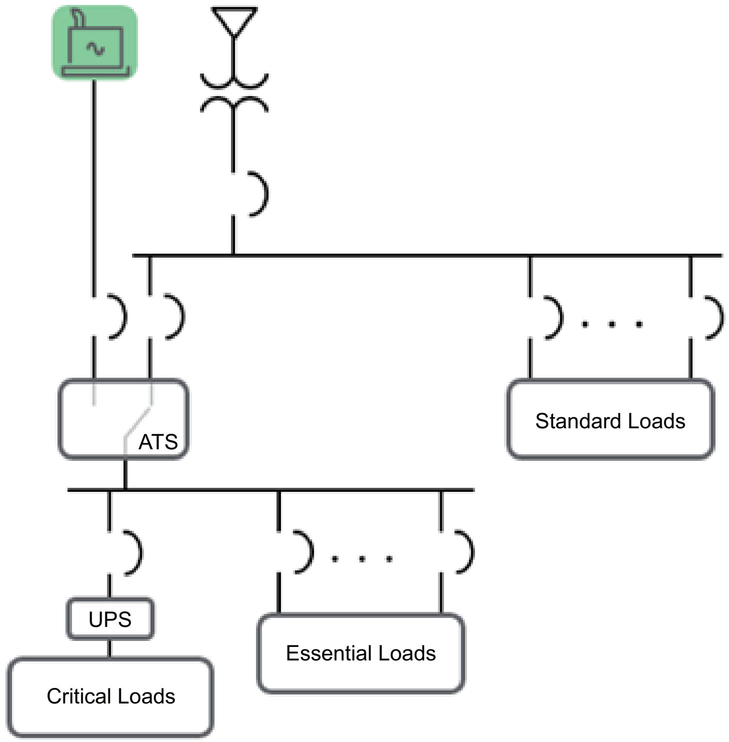
To meet resilience goals, accurately monitoring the state of the grid reference is crucial. Edge layer software monitors the POCC, establish and stabilize local grid forming resources, and execute load management (shed/add) decisions based on the collected metering data. The methodology and decision making related to sequence of operations related to grid transitions relies on appropriate metering of loads and sources.

Many sites and customers are likely not be mindful of the importance of power quality in microgrids; however, this is an important design criterion. Initial microgrid assessments and power system studies dictate the necessity to include power quality metering or even power quality correction equipment. Appropriate power quality metering help maintain system uptime (resilience) through awareness of changes of DER or other system component performance prior to system malfunction.

Load management

A traditional model of backup power involves transferring full or partial site load to a fixed diesel or natural gas generator, using an automatic transfer switch (ATS). The ATS both senses the loss in utility voltage and signals the generator to engage.

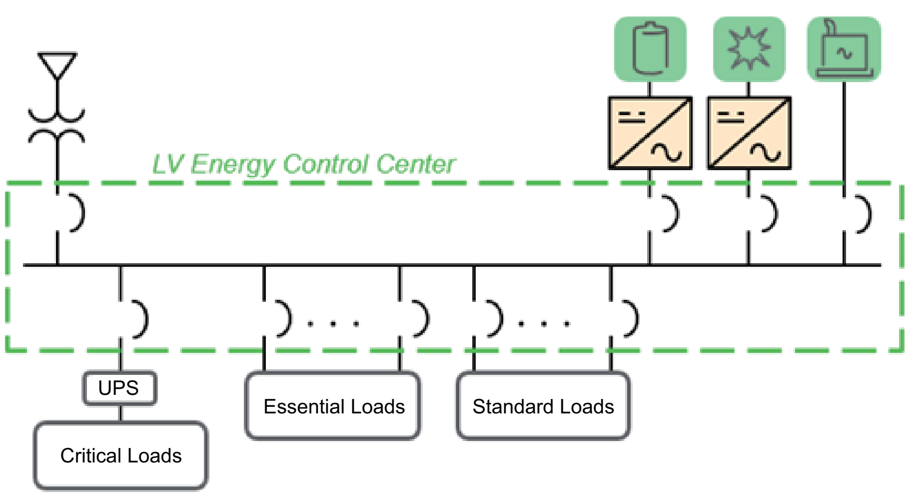
Figure 129 - Load Management



In the configuration above, there is typically no way to control individual loads. The source simply supports loads on its own circuit and loading that exceeds source capacity simply trips the source offline.

In contrast, in a behind-the-meter microgrid, multiple sources (Solar PV, Battery Storage, Combined Heat and Power, Fuel Cells, Generators to name common assets) may be combined in parallel, where the microgrid controller manages loading and power stability between sources. In addition to active source management, microgrids may also manage site loads directly and indirectly. The ability to manage both sources and loads introduces a range of economic and functional project design options.

Figure 130 - Behind-the-meter Microgrid



- **Direct load management:**

  Example 1: the microgrid controller communicates with a site building management system (BMS), which has several predefined energy profiles. The BMS may adjust HVAC, chiller, and boiler setpoints to reduce load.

  Example 2: the microgrid controller communicates with one or more Motor Control Centers (MCCs), to run high horsepower pumps at reduced output.

- **Indirect load management:** Example: the microgrid controller operates breakers that serve the loads, in order of increasing load criticality. In general, this tier of load management occurs after direct management has been attempted, as it is more abrupt in suddenly cutting power.

Managing loads actively has both economic and functional benefits. When sizing certain resources, such as battery energy storage, the ability to manage loads may reduce the need to oversize resources. Consider a site with a 500 kW peak that occurs once in a 12-month data set, and where the next highest peak is 300 kW. In that case, the ability to shed non-critical loads during an edge case may allow for a reduced size of expensive backup power that would see low annual utilization. By actively managing load usage and schedules, consumption can be optimized for specific tariffs by avoiding peak price loading for example.

Functionally, managing loads actively has several benefits. The ability to manage loads at multiple levels of load criticality allow maximum utilization of energy sources at a site. In a fixed system, a degraded condition of source capacity (below the site load) would simply trip the site offline. However, with the capability to shed loads selectively, a microgrid controller maintain loads to the maximum extent possible. During a utility outage, managing loads provides extra resilience (sometimes referred to as “load preservation systems”). Non-critical loads may be shed up to level of source capacity (this is a typically a configurable sequence, that may be modified as site needs change over time). With controllable breakers, and with some foresight at the design stage, the microgrid load management sequence may be modified as site needs change over time (a “Future Proof” design). For example, if a new source is added at a future date under similar loading conditions, the load shedding scheme may be modified to optimize the new total source capacity. If site load increases with no new sources, the load shedding scheme may be modified to reduce additional load during an outage, to continue to maximally leverage available source capacity.

Resilience and response time

A key benefit of microgrids is providing resilience - powering a site even when the main electrical grid has suffered an outage. The cost of full or even partial outages has risen astronomically. In addition to directly measurable business costs, intangible “brand damage” is a major factor driving decisions by business and government entities to implement resilience through microgrids. The capability of a microgrid to isolate from the grid and provide power to a site through local DERs — “islanding” — is especially crucial for critical infrastructure like hospitals, military bases, datacenters, and college campuses.

The architectural details of the islanding process, balancing of power flow amongst DERs and loads when islanded, and sequence of reconnection back with the grid greatly impact system complexity in relation to the microgrid’s overall configuration, architecture, and operational intent. A full assessment of loads with particular attention to arranging them into tranches or tiers of critical, essential, and normal, is an important design step. For example, critical loads or life support systems likely needs UPS coverage so this decision has implications on UPS sizing, ATS configuration, generator capacity. In contrast, normal (or non-essential) loads may be able to withstand extend outages, reducing DER sizing.

Response time, that is, how quickly power is restored to loads when power is lost, is typically a significant determining factor in the complexity and cost of a microgrid project. During an unplanned outage, the microgrid controller can transition from grid-connected to islanding mode in many ways. The simplest option, a basic open transition, results in a momentary loss of power and blackout of the site. A more complex option is to engineer a seamless closed transition or fast transition microgrid, with the advantage of very minimal disruption upon outages or restoration. Particularly sensitive loads (mission-critical IT loads, semiconductor processes) require routing into the critical loads tier to help with adequate UPS coverage. Microgrid control code must be designed to provide all the sequences of operations associated with islanding, restoration, load and source management.

Microgrids must be carefully designed with load characteristics, as well as generation capacity in mind to provide a solution that best accomplishes the site's specific response time needs and requirements.

Microgrid Interconnection Requirements

As more utilities either embrace or are forced to contend with distributed generation, many standards and regulations are evolving to specify interoperability requirements. These interconnection agreements and standards typically involve requirements for both electrical connectivity and data connectivity. Electrical interconnectivity requirements may include more traditional topics such as revenue metering, relay settings, no-export conditions, demand response clauses. Data connectivity requirements are a fast-evolving area and prescribe both the data interchange and communications between utilities and microgrid systems.

IEEE1547.1-2018 covers guidance for microgrids and individual DERs connected to typical primary or secondary distribution voltage levels for voltage/power control, islanding, power quality. IEEE2030.5 covers specific guidance for interconnectivity communications including data model, messaging model, communication protocol and security. There are a wide variety of architectural choices covered in the standard and allied documents such as the Sunspec CSIP Implementation Guide. For example, direct DER communications through either an embedded Smart Inverter Control Unit (SMCU) or DER with Generating Facility Energy Management System (GFEMS). Potentially, DER aggregator software at the edge or cloud-based may be an intermediary node for communications between the utility and the local microgrid. For design and architectural details on these topics, see *IEEE Std. 1547-2018*[142]. *Common Smart Inverter Profile (CSIP) IEEE 2030.5 Implementation Guide for Smart Inverters* [143] and *IEEE Std. 2030.5*[144].

Functionally, the data connectivity requirements may be codified by local regulatory bodies. California Rule 21 for example specifies IEEE2030.5 based protocols and requires:

- Specific expected responses to control actions transmitted from the utility for grid support. For example, anti-islanding, dynamic Volt-var, fixed power factor control.
- Periodic data reporting. For example, polling of active/reactive power, instantaneous measurements, status information, alarms.
- Security mechanisms. For example, “heartbeat” handshaking, authentication, authorization.

A detailed discussion of these interconnection requirements is beyond the scope of this section. Please refer to the additional references provided below:

- *IEEE Std. 1547-2018*, IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces. Revision of IEEE Std 1547-2003.
- *Common Smart Inverter Profile (CSIP) IEEE 2030.5 Implementation Guide for Smart Inverters*, March 2018 (Version 2.1).
- *IEEE Std. 2030.5*, IEEE Standard for Smart Energy Profile Application Protocol.

142. IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces. Revision of IEEE Std 1547-2003.
143. March 2018 (Version 2.1).
144. IEEE Standard for Smart Energy Profile Application Protocol.

Electrical Energy Management

Introduction

Electricity is a powerful form of energy that is essential to the operation of virtually every facility in the world. It is also an expensive form of energy that can represent a significant portion of a manufacturing facility's cost of production.

This energy management primer is intended to introduce applications that that can be performed by and values that can be derived from a well-designed EPMS (Electrical Power Monitoring System). Additionally, it covers some electricity billing fundamentals, especially focusing on the two major aspects of the electric bill, demand, and energy. This section also highlights key aspects of identifying energy-saving opportunities among major industrial processes and equipment.

Figure 131 - Power Meter

Electrical Distribution and Alarming

Just like any other process in a facility, electrical distribution systems are complex with many devices, and potential detected failures can occur at different locations.

Considering the critical nature of the continuity of an electrical power supply, having the capacity to quickly view, analyze, and understand where the loss has occurred, like our car dashboards, is key for facility managers.

The facility manager needs to:

- Gain visibility of the status and relevant information of the entire electrical system.
- Receive alarms on abnormal conditions or events.
- Monitor and report on peak demand, loading of equipment like transformers, generators, breakers, UPSs.
- Know, analyze, and understand and quickly pinpoint where issues of the electrical distribution network come from.

The Electrical Distribution Monitoring and Alarming application collects data from connected products to provide on-site access to consolidated views of electrical measurements, status information, and individual device details. It also provides remote control actions.

The digital architecture of the Electrical Distribution Monitoring and Alarming application involves collecting the input data from the different products, either directly over Ethernet or via gateways. This data is then used by the local monitoring software package for on-premises visualization analysis and reporting.

A properly designed Electrical Distribution Monitoring and Alarming application includes the following suggested outputs:

Live Data Display

- Native support for a wide range of devices and communication protocols.
- Electrical network Single-Line Diagrams (SLD).
- SLD color animation for visual discernment.
- Energized/de-energized sections and energy source (Utility A, Utility B, Generator).
- Elevation drawings.
- Real time data values of each connected device, such as electrical parameters, device settings, and status information.
- Animated floor plans and riser diagrams of power equipment status and alarms.
- Available capacity of various equipment such as breakers, transformers.

Alarms and Events

- Chronological display of alarms/events with sorting and filtering capabilities.
- Intelligent alarm grouping into summary incidents.
- Simplified operator alarm dashboard.
- Remote even notification via email or SMS.
- Disturbance direction detection to help quickly identify the root cause of power quality incidents.
- High-speed waveform capture and analysis.

Trends

- Real-time and historical data can be viewed on a trend viewer.
- Thresholds to indicate when trend is getting close or exceeding a setpoint.

Dashboards

- Configurable dashboards for visualizing historical power system data.

Reports

- Historical data reporting.

Notifications

- SMS notification and/or email can be sent for fast analysis and action.
- Email notifications are also available to send reports and noncritical information.

Analysis Tools

Electrical Distribution Monitoring and Alarming provides an incident timeline with advanced functions:

- Alarm/event data according to their date and time.
- Detailed breakdown and sequence of alarms, waveforms and trends involved in the incident.
- Disturbance direction detection to indicate upstream / downstream root cause of an incident.

Cloud-Based Analytics and Services

As an option, a connected advisory service can perform cloud-based analytics for electrical network health, with recommendations from expert service engineers.

BMS Integration

EcoStruxure Power enables integration of electrical data and alarms at the Edge Control layer with BMS software for better decision making.

Continuous Thermal Monitoring

One of the leading causes of electrical fires in low and medium voltage installations are non-operational cable power connections, busbars, and withdrawable circuit breakers, in particular when the connections are made on site. A non-operational power connection can lead to an increase of its electrical contact resistance which induces a thermal runaway that can lead, in the worst case, to destruction of switchgear and severe injury to the operator.

Increase of contact resistance can result from:

- Loose connections due to improper installation or maintenance (improper tightening torque, connection loosening due to vibrations).
- Damaged surface (due to corrosion, excessive pressure, excessive friction).

A common remedy is provided by infrared inspections which must be performed manually, are tedious, and only identify issues on a periodic basis.

A properly designed Continuous Thermal Monitoring system provides the following: live data display, alarms and events, notifications, trends, and reports 24/7 without the need for external infrared inspections.

Asset Performance and Maintenance

In the past, equipment maintenance for circuit breakers, UPSs, and motors, was performed using a preventative approach. This means, circuit breakers were serviced periodically, typically every one to two years.

By leveraging asset diagnostics data, preventative and condition-based maintenance models can help facilitate maintenance planning to reduce risk of early degradation, optimize maintenance activities and optimize maintenance related spending.

The Facility Manager needs to:

- Move from reactive or preventative to condition based (predictive) maintenance strategies for critical assets like circuit breakers, gensets, transformers.
- Gain visibility into critical assets health and maintain them when necessary.
- Enhance their maintenance strategy with expert services to determine the optimal time to maintain critical assets.
- Streamline and optimize maintenance spending.

This application helps the Facility Manager by providing the following:

Live Data Display

- Circuit breaker asset monitoring diagram (% of electrical and mechanical wear, % of environmental and control unit aging, number of operations, load and temperature profiles).
- UPS monitoring diagrams (measurements, UPS status, battery information, pre-alarms and alarms).
- Power Quality mitigation equipment, generator status diagrams.

Reports and Dashboards

- Circuit Breaker Aging report
- UPS Health report
- Generator Battery Health report

These reports provide the right information to help decide when to maintain circuit breakers, UPSs and generator start batteries.

Cloud-based Analytics Services

- Remote notifications in case of electrical asset condition anomalies.
- Predictive analytics to determine equipment remaining lifetime and other health indicators.
- Asset matrix to visualize asset health risks.
- Pro-active asset maintenance optimization support by the vendor’s Service Bureau.

Capacity Management

Many facilities are in a constant state of flux. Areas are being renovated, equipment is being moved, new production lines are brought online, old equipment is being upgraded.

Capacity of the electrical distribution infrastructure must evolve per these changing environments while not exceeding the rating of electrical distribution equipment.

This is a problem for circuit breakers, UPSs, generators, ATSs, transformers, capacitor banks, bus bars, conductors, fuses. Often, exceeding the rated capacity means nuisance trips, but it can also result in overheating or fires.

The Facility Manager needs to:

- Understand the capacity needs of the electrical distribution infrastructure to plan for expansions or modifications of the facility environment.
- Upgrade the facility while not exceeding the rated capacity of equipment and mitigating potential risks to the electrical infrastructure (For example, Nuisance trips, overheating, fires).

This application provides the following for the Facility Manager:

Live Data Display

- Electrical Health diagram

Trends

- Real-time and historical data can be viewed on a trend viewer.

Reports

- Branch Circuit Capacity report
- Generator Power report
- UPS Power report
- Equipment Capacity report
- Generator Capacity report
- Power Losses report

Backup Power Testing

Critical buildings such as hospitals and data centers rely on emergency power systems to supply the facility with power during an interruption of the utility incomer(s). During an interruption, power is transferred from the utility supply to the alternate power source using automatic transfer switches (ATS).

In fact, according to the Electric Power Research Institute (EPRI), backup power systems fail to start 20% to 30% of the time. Common causes include starter battery issues, low fuel levels, wet-stacking, controls in wrong state.

Also, the Joint Commission (also known as JCAHO) requires healthcare facility to test their emergency power supply system monthly with specific guidelines on the test procedure as well as data collection and reporting the results.

The Facility Manager needs to:

- Ensure the reliability and availability of backup power supply systems in the event of unexpected power outages.
- Save time, improve productivity, and ensure accuracy of testing process and documentation per standards or manufacturer recommendations.

Purpose of Backup Power Testing application is to provide the following:

- Centralized remote operator control and testing:
- Remotely test Automatic Transfer Switch transfer, re-transfer and bypass
- Start, run, stop, and cool down emergency generators
- Remotely control Load Banks for engine-generator and UPS loading
- Conduct system test of emergency generator paralleling
- Remotely test Fire Pump Controls emergency power
- Monitor, automatically record and report backup power tests
- Automatic transfer switches
- Back-up generators
- UPS
- Emergency generator paralleling system
- Load Banks
- Fire Pump Control Systems
- Record key legislated parameters for compliance reports including:
- Transfer time for Automatic Transfer Systems and generators.
- Generator run time, engine loading, exhaust and engine temperature, fuel levels and battery health.
- UPS's ability to sustain critical loads during power outage, and UPS battery health.
- Load bank loading on emergency generator paralleling, engine-generators and UPS systems.

This application provides the following outputs:

Live Data Display

- Animated device diagrams with status and analog values of ATS, generators, power control systems, load banks, fire pump controls system and UPS.

Reports

- Generator Test (EPSS) report
- Generator Battery Health report
- Generator Load Summary report
- UPS Auto-test report
- UPS Battery Health report
- Automatic Transfer Switch performance report
- Utility power outage report

Power Quality Monitoring

There are many different power quality disturbances which can adversely affect critical or sensitive equipment, processes and buildings. To promote seamless and uninterrupted functioning of these assets, it is very important to continuously measure, understand and act on any power quality issues that could affect uninterrupted operation.

The Facility Manager needs to:

- Understand which power quality events could adversely affect their processes or operations.
- Be able to monitor persistent power quality disturbances.
- Analyze and determine actions needed to correct issues.

Power Quality Monitoring application helps with the following:

- Monitor steady-state and event-based disturbances.
- Harmonics, current unbalance, flicker and over/under voltage conditions, transients, interruptions.
- Better understand power quality disturbances.
- Trends and reports to understand potential issues that could affect operations.
- Capture and study event details such as waveforms.
- Disturbance Direction Detection to locate the directionality of events.
- Deep-dive analysis of power quality issues.
- Advanced dashboards and reports.
- Analytics-based advisory services to improve performance across the system.

The following are the outputs of the Power Quality Monitoring application:

Live Data Display

- Steady state disturbances such as harmonics, unbalance, and frequency, can be visualized in real time.

Events and Alarms

- Onboard events and alarms with timestamps.

Trends

Steady state disturbances such as harmonics, unbalance, frequency can be visualized as trends to monitor their evolution over time.

Analysis Tools

- Power Events Incident Timeline
- Waveform viewer

Dashboards

- Power Quality Status Panel diagrams
- Power Quality dashboards

Reports

- Power Quality report, Power Quality Analysis, and Impact reports.
- Harmonics Compliance report, IEC 61000-4-30 report, EN 50160-2000 and EN 50160-2010 reports.

Cloud-based Analytics and Services

- Cloud-based advisory service can perform cloud-based analytics on power quality data.

Electricity Billing Basics

Most electric utilities serve a designated geographic territory, largely without other competitors having access to their customers. As such, utility prices have often been set by local, state, or federal regulators, entities that review electric utility costs, revenues, investment decisions, fuel prices, and other factors to arrive at a target rate of return. This approved rate of return, coupled with the utility's cost structure, determine prices customers pay.

These prices are established in electric utility tariffs, or rate schedules. Rate tariffs are usually established for different classes or sizes of customers. Common class types may include industrial, commercial, residential, municipal, and agricultural. Each customer class may have one or more rate schedules available, and it is common for the electric utility to allow a facility to choose the rate schedule within its class that offers the lowest price.

Electricity Metering

Electric utilities meter both the real and reactive power consumption of a facility. The real power consumption, and its integral -- energy, usually comprise the largest portion of the electric bill. Reactive power requirements, usually expressed in power factor, can also be a significant cost and is discussed later.

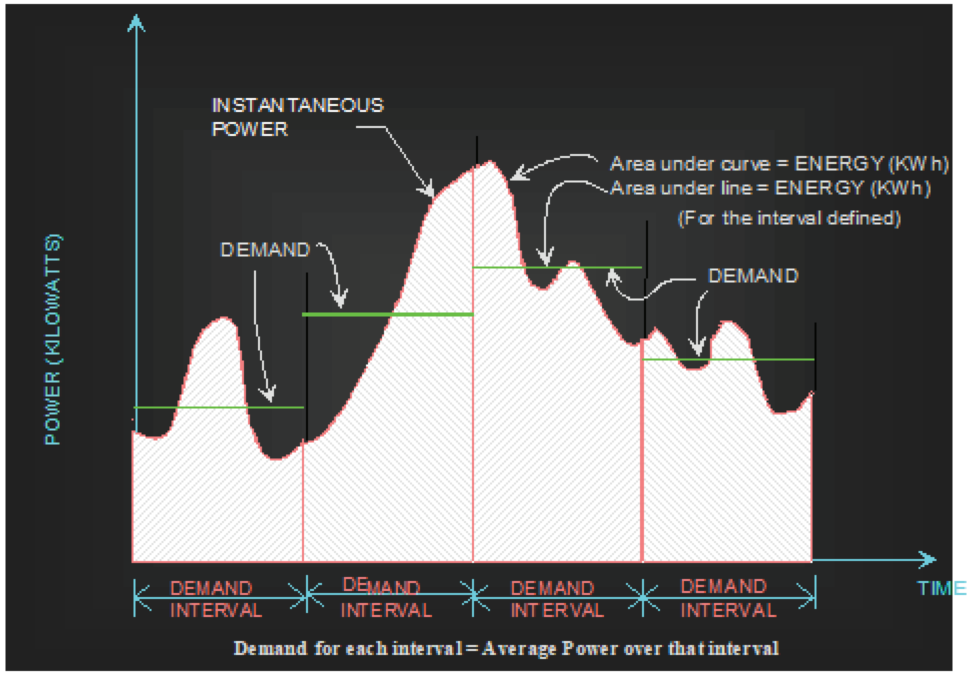
Demand

Real power consumption, typically expressed in kilowatts or megawatts, varies instantaneously over the course of a day as facility loads change. While instantaneous power fluctuations can be significant, electric utilities have found that average power consumption over a time interval of 15, 30, or 60 minutes is a better indicator of the "demand" on electrical distribution equipment.

Transformers, for example, can be selected based on average power requirements of the load. Short-duration fluctuations in load current may cause corresponding drops in load voltage, but these drops are within the normal operating tolerances of typical machines and within the design parameters of the transformer.

The demand rate, in $/kW, may also be referred to as a capacity charge, since it has historically been related to the necessary construction of new generating stations, transmission lines, and other utility capital projects. Demand charges often represent 40% or more of an industrial customer's monthly bill.

Figure 132 - Demand Curve



"Demand" is the average instantaneous power consumption over a set time interval, usually 15, 30, or 60 minutes.

Energy

The other major component of an electric bill is energy. The same metering equipment that measures power demand also records customer energy consumption. Energy consumption is reported in kilowatt-hours or megawatt-hours. Unlike power demand with its capacity relationship, customer energy consumption is sometimes related to fuel requirements in electric utility generating stations. The cost per kilowatt-hour in each electric utility rate structure, therefore, is often influenced by the mix of generating plant types in the utility system. Coal, fuel oil, natural gas, hydroelectric, and nuclear are typical fuel sources on which power generation is based.

Load Factor – Demand/Energy Relationship

One useful parameter to calculate each month is the ratio of the average demand to the peak demand. This unit-less number is a useful parameter that tracks the effectiveness of demand management techniques. A load factor of 100% means that the facility operated at the same demand the entire month, a so-called "flat" profile. This type of usage results in the lowest unit cost of electricity.

Few facilities operate at a load factor of 100%, and that is not likely to represent an economical goal for most facilities. But a facility can calculate its historical load factor and seek to improve it by reducing usage at peak times, moving batch processes to times of lower demand, and so forth. Load factor can be calculated from values reported on practically every electric bill:

LF = kWh / (kW * days * 24);

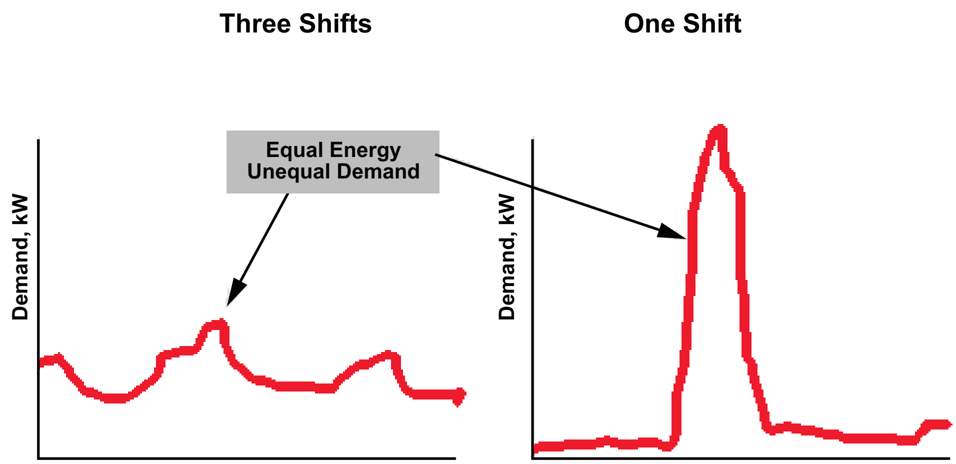
Where LF is Load Factor, kWh is the total energy consumption for the billing period, kW is the peak demand set during the billing period, and days is the number of billing days in the month (typically 28-32). "24", of course is the number of hours in a day.

Time-of-Use customers may prefer to track load factor only during on-peak time periods. In that case, the kWh, kW, days, and hours/day in the formula are changed to reflect the parameters established only during the on-peak periods.

Typical load factor for an industrial facility depends to a great degree on the number of shifts the plant operates. One shift, five-day operations typical record a load factor of

20-30%, while two-shifts yield 40-50%, and three shift, 24/7 facilities may reach load factors of 70-90%.

Figure 133 - Demand Curve: Multiple Shifts



Load Factors, page 228 gives a graphical comparison of facilities with dramatically different load factors. The three-shift facility produces an average demand that is nearly equal to its peak demand, while the average and peak demand for the one shift facility is much less than one.

Table 48 - Load Factors

Load Factor	30%	50%	70%
Peak Demand kW	1142	685	489
Energy Usage kW%	250,000	250,000	250,000
Demand Cost	$11,420	$6,850	$4,890
Energy Cost	$10,000	$10,000	$10,000
Total Monthly Bill	$21,420	$16,850	$14,890
Average Cost/kWh	$8.57	$6.74	$5.96
Demand Cost as Percent of Total	53%	41%	33%

Power Factor

The relationship of real, reactive, and total power has been introduced previously, and described as the “power triangle”. For effective electricity cost reduction, it is important to understand how the customer’s electric utility recoups its costs associated with reactive power requirements of its system. Many utilities include power factor billing provisions in rate schedules, either directly in the form of penalties, or indirectly in the form of real-power billing demand that is higher than the actual measured peak.

Even if a utility does not charge directly for poor power factor, there are at least three other reasons that a customer may find it economical to install equipment to improve power factor within its facility, thereby reducing the reactive power requirements of the utility:

- Reduce power factor penalties.
- Release capacity of an existing circuit.
- Reduce heating losses associated with power distribution (often called I^2R losses).
- Improve voltage regulation.

Fixed capacitor banks are best suited for use on electrical systems with no voltage or current harmonics. In the presence of harmonics, Active Harmonic Filters (AHF) are a better solution.

Figure 134 - Capacitor Banks

Typical Energy Auditing Process

1. Evaluate the current rate schedule.
2. Determine if other rate schedules are available.
3. Complete the Facility Energy Profile.
4. Assess no-cost/low-cost energy saving options.
5. Complete feasibility analysis of energy management project options.
6. Recommend Energy Action Plan.

Facility Energy Profile — Where's the Energy Going?

An important initial step in evaluating energy saving opportunities is to estimate both:

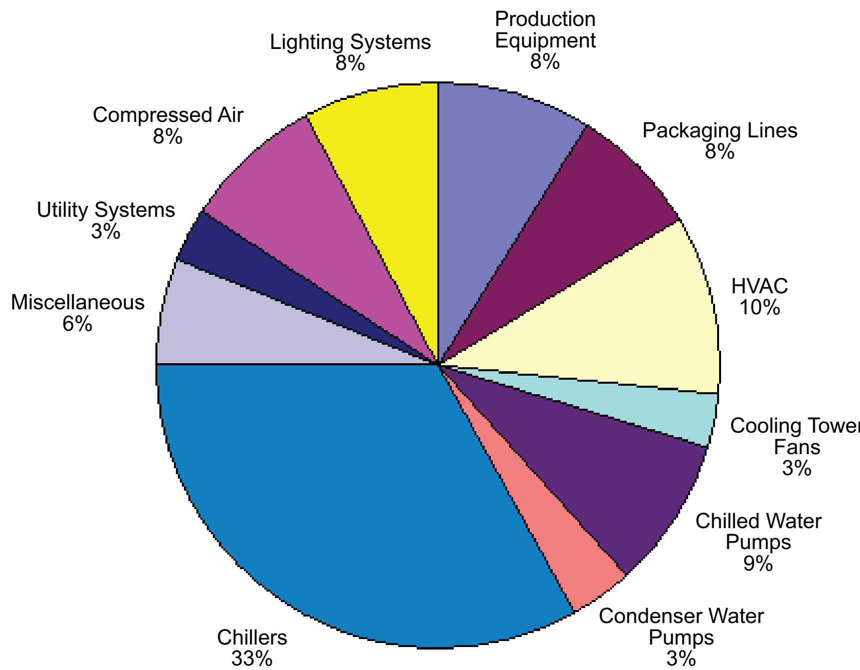
- The contribution to peak billing demand, and
- The amount of energy consumption.

Of each major load or process within the facility being evaluated.

This Facility Energy Profile helps to focus the energy optimization efforts on those processes or loads that have the most savings potential. This profile also may identify batch processes or discretionary loads that may be scheduled at times of low demand for the rest of the facility, or during times of off-peak utility prices.

The Facility Energy Profile identifies the major energy consuming processes and equipment in the facility.

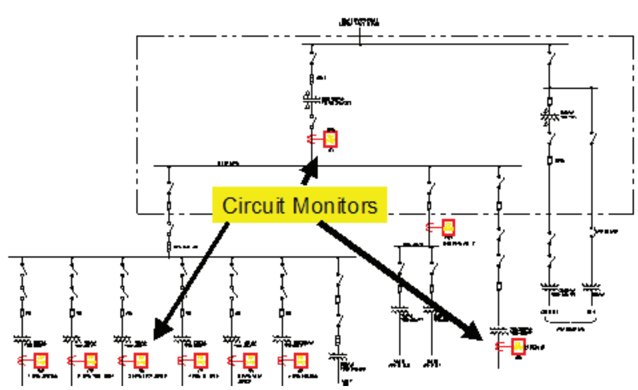
Figure 135 - Facility Energy Profile



The FEP is best developed using actual power measurements from existing facility-wide monitoring systems. Some types of loads, lighting, for instance, may comprise part of the usage of every major circuit in the facility. This fact would suggest that the meter measuring the power consumption of a feeder serving the building's centrifugal water chillers.

Actual power monitoring data from existing Circuit Monitors measuring the power consumption of individual feeders is the best basis for establishing the Facility Energy Profile.

Figure 136 - Circuit Monitors



Demand Analysis Techniques

Demand analysis is the methodology used to determine if there are opportunities for a given facility to reduce peak demand charges. Demand analysis involves manipulation of historical demand interval data to determine which major processes or loads are operating at times of highest demand; how "steep" or "flat" the facility's load profile appears; and what times of day these peaks are occurring. Armed with this information, the energy auditor can better evaluate the potential for a variety of demand reduction techniques.

The Demand Sort Table, page 231 is produced by rearranging individual integrated demand readings for a given billing period. Meters record demand readings chronologically, 3000 or so readings for a 30-day billing period at 15-minute demand intervals; the demand sort utilizes a software tool to distribute the readings from highest to lowest, so that times and values of peak usage are easily analyzed.

Figure 137 - Integrated Demand Readings

July		August		Sept	
Date/Time	kWD	Date/Time	kWD	Date/Time	kWD
7/17/03 13:15	2,252.60	8/28/03 13:15	2,322.20	9/18/03 13:30	2,240.96
7/8/03 13:30	2,250.96	8/28/03 11:15	2,279.28	9/18/03 13:15	2,236.44
7/29/03 13:15	2,242.40	8/28/03 11:00	2,277.52	9/3/03 12:15	2,235.72
7/16/03 13:15	2,234.32	8/28/03 13:30	2,271.32	9/18/03 13:45	2,212.68
7/29/03 13:30	2,232.48	8/29/03 12:00	2,264.88	9/19/03 13:30	2,212.16
7/30/03 13:00	2,231.12	8/28/03 13:00	2,256.36	9/3/03 13:00	2,204.80
7/30/03 13:15	2,229.44	8/27/03 12:15	2,247.20	9/3/03 11:15	2,192.36
7/16/03 11:15	2,221.56	8/28/03 11:30	2,246.24	9/3/03 11:30	2,181.20
7/17/03 13:30	2,218.60	8/27/03 13:15	2,243.56	9/19/03 13:15	2,178.36
7/8/03 13:15	2,217.68	8/27/03 13:30	2,242.40	9/4/03 10:00	2,174.72
7/16/03 13:30	2,214.32	8/28/03 12:15	2,240.76	9/3/03 11:45	2,173.84
7/23/03 12:30	2,211.32	8/29/03 12:15	2,237.80	9/5/03 13:30	2,168.64
7/29/03 13:00	2,207.56	8/27/03 11:30	2,237.44	9/2/03 13:30	2,167.84
7/9/03 11:15	2,206.52	8/13/03 13:30	2,230.96	9/3/03 11:00	2,166.84
7/17/03 13:00	2,201.60	8/28/03 10:45	2,230.60	9/3/03 13:15	2,165.40
7/17/03 9:15	2,190.84	8/27/03 13:00	2,226.12	9/4/03 9:45	2,159.48
7/30/03 12:45	2,190.36	8/26/03 13:30	2,226.08	9/4/03 13:30	2,158.28
7/17/03 12:30	2,189.92	8/28/03 12:00	2,224.60	9/3/03 9:45	2,157.76
7/17/03 13:45	2,187.24	8/25/03 12:30	2,223.56	9/3/03 12:30	2,153.64
7/9/03 12:15	2,186.68	8/29/03 11:45	2,220.36	9/3/03 10:00	2,152.96
7/16/03 13:00	2,184.68	8/7/03 13:00	2,219.28	9/2/03 11:30	2,152.24
7/15/03 13:30	2,183.96	8/26/03 13:00	2,217.76	9/4/03 12:30	2,149.44
7/29/03 12:45	2,178.12	8/28/03 12:45	2,213.72	9/3/03 12:45	2,146.44
7/18/03 12:30	2,172.04	8/7/03 13:15	2,209.00	9/2/03 13:15	2,146.04
7/28/03 13:00	2,171.52	8/27/03 11:15	2,204.04	9/4/03 10:30	2,145.44
7/9/03 9:15	2,170.68	8/27/03 10:45	2,199.96	9/4/03 12:15	2,139.96

The Demand Sort Table, page 231 facilitates demand analysis by depicting the number of intervals (or hours) during which the plant's peak electrical demand exceeded certain levels.

Table 49 - Demand Sort Table

15–Minute Intervals Above Given Demand Level						
kWD	May	June	July	Aug	Sept	kWD
2400						2400
2350						2350
2300		1		1		2300
2250	2	5	2	6		2250
2200	7	31	15	25	6	2200
2150	15	73	53	92	21	2150

Table 49 - Demand Sort Table (Continued)

15–Minute Intervals Above Given Demand Level						
kWD	**May**	**June**	**July**	**Aug**	**Sept**	**kWD**
2100	26	129	126	164	52	2100
2050	52	206	235	282	110	2050
2000	114	287	380	400	189	2000
1950	177	383	477	495	292	1950
1900	257	473	551	599	409	1900
1850	352	580	634	698	510	1850

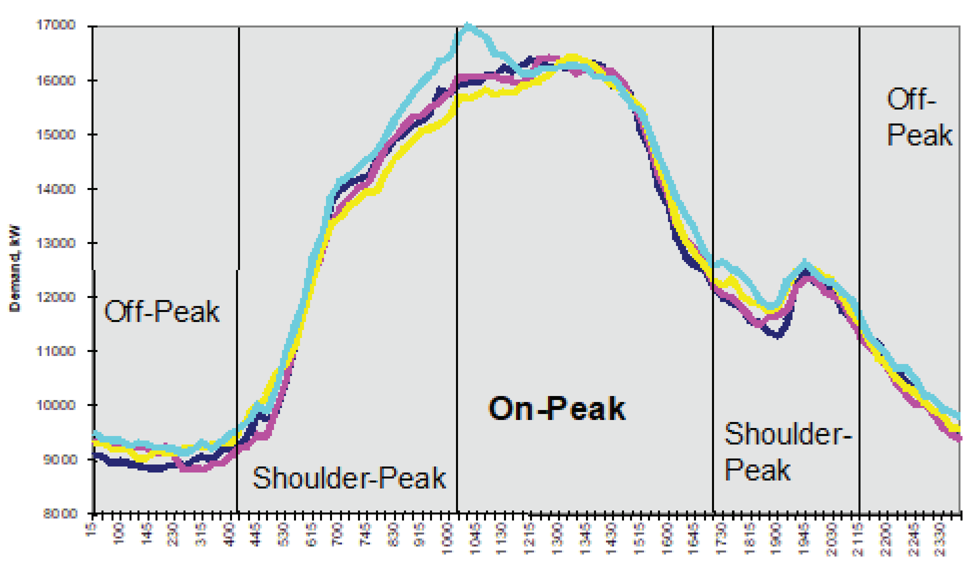
Using the Demand Reduction Table, page 232, the engineer can determine that a reduction in peak demand to 2200 kW at this example facility would have required a demand reduction of 122 kW for 25 fifteen-minute intervals, or 6.25 hours, in August of the sample year.

Table 50 - Demand Reduction Table

Month	Former Peak kW	Proposed Peak kW	Load Required kW	Time Required Hours	Demand Reduction kW	Demand Savings $
Non-Summer	2322	2200	0	0	122	8540.00
May	2265	2200	65	1.75	65	650.00
June	2305	2200	105	7.75	105	1050.00
July	2253	2200	53	3.75	53	530.00
August	2322	2200	122	6.25	122	1220.00
September	2241	2200	41	1.5	41	410.00
						12,400.00

Peak-day Load Profiles, page 232 from actual power monitoring data can show consistency, or, as in this case, a single-day aberration in peak demand that set the demand minimum billing level (ratchet) for the remainder of the year.

Figure 138 - Peak-day Load Profiles



Demand Control

Demand controls systems are available that perform these basic functions:

- Measure power consumption (demand) in real time.
- Predict demand level based on rate of instantaneous usage.
- Compare predicted value to target setpoint.
- Transmit signals to pre-determined equipment to turn off or curtail power usage if demand is predicted to exceed target kW.

These demand controls systems are intended to reduce peak demand for a facility to some predetermined level.

The design engineer’s foremost demand control system challenge is to identify loads in the facility that can be controlled effectively. Ideal load candidates include those machines or processes that are (1) currently contributing to the facility’s load at peak times, and (2) whose function can be delayed or curtailed at times of peak.

Most facilities lack equipment or processes that fit this ideal description, despite the numerous machines and processes that may be operating at peak times. In fact, successful demand control is usually the exception rather than the rule.

One common candidate for the demand control system is the air conditioning system. Buildings equipped with multiple packaged direct-expansion air conditioning systems are typical targets of demand control sales efforts. Unfortunately, demand control of air conditioning compressors usually leads to loss of temperature or humidity control within the conditioned space, or lack of demand savings.

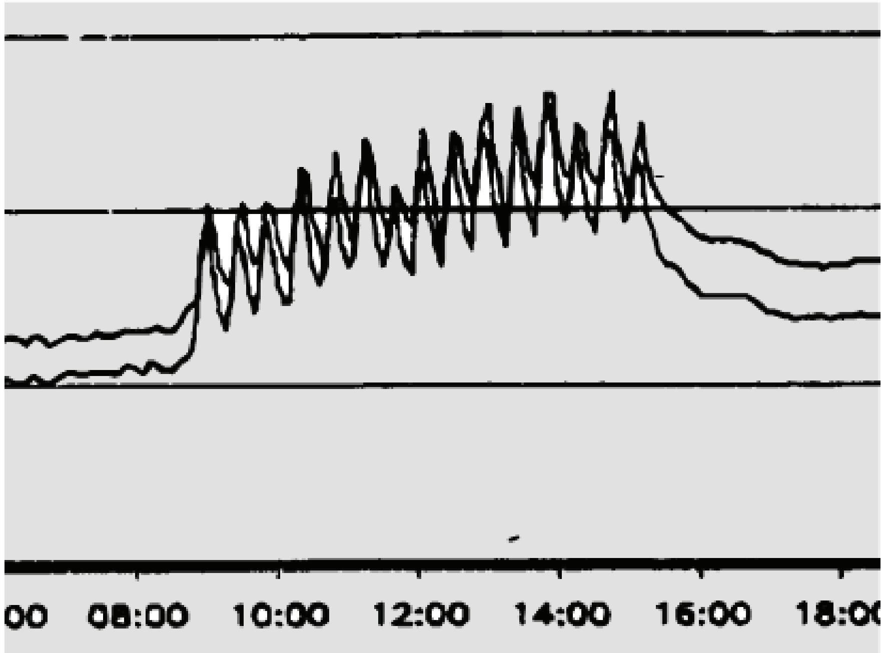
The reason for this paradox is twofold. One, natural diversity among multiple air conditioning compressors maximizes the chance that all compressors are not operating at full load at the same time. Strangely, this fact is often highlighted in the demand control system sales pitch: “Not all compressors are running at the same time, so you should turn some off for short periods of time”.

Secondly, basic thermodynamic principles of moist air and vapor-compression refrigeration systems require compressor power consumption to reduce air temperature and condense moisture. This process is controlled by thermostats and humidistats within the facility. When cooling or dehumidification is removed or reduced at times when these devices are “calling for” them, temperature and humidity rises in the conditioned space.

So, if not air conditioning equipment, what loads have been successful demand control candidates? An electrolysis process providing chemicals for a paper mill was able to reduce peak demand and flatten the demand profile for the overall facility. A battery-charging system for forklift vehicles in an automotive facility could produce real demand savings during peak times. Finally, a large induction furnace melting scrap metal proved to be an effective candidate for the rolling mill at a steel plant.

Chilled Water Supply and Return Temperatures, page 234 increase over the course of a day due to demand control of inlet guide vanes on a centrifugal water chiller. Space conditions could not be maintained because of the demand control.

Figure 139 - Chilled Water Supply and Return Temperatures



Peak Shaving with Onsite Generation

How, the engineer might ask, can a facility save money by producing their own energy (PV, battery, diesel generator.) that costs more per kWh than the energy they purchase from the utility? Very carefully, is the expected – and accurate - response.

The key to economic peak shaving is to understand and optimize the demand savings associated with onsite generation operation. That is, the onsite generation must be operated the absolute minimum time necessary to reduce peak demand the maximum amount. Because the overall average unit price of electricity is not necessarily equivalent to the effective price of electricity at the plant's peak.

For example, the facility that pays an overall average unit price of 8 ¢/kWh probably pays only about 3-4 ¢/kWh for actual energy consumption, yet an additional $10-$20/kW for demand. At the end of the month, the total billing amount divided by the total kWh usage might yield 8 ¢/kWh average, but the actual cost of power at its peak – when demand charges are included – may equate to an effective unit price of 20 ¢/kWh or higher. For the facility with a sharp demand peak, when the peak for the month is set in a few hours or less and the remainder of the time demand is low, peak-shaving at 12 ¢/kWh can be preferable to paying 20 ¢/kWh.

Costs of Generated Power

Onsite generators typically utilize natural gas, wood, fuel oil, or steam derived from a fossil fuel or as a part of a production process. Unit fuel costs for fossil fuels are usually calculated based on the fuel's heating value, an estimated efficiency of the generator system, and the fuel cost.

Cost/kWh = fuel price/gal * 3413 / HV / efficiency

In the equation above, HV is the heating value of fuel oil in BTU/gal, and 3413 is the conversion from BTU to kWh. Internal combustion diesel generators typically range in efficiency from 25-30%.

For a typical example, #2 fuel oil may be burned in an IC engine. For a fuel-oil price of $3.00/gal, and a generator efficiency of 25%, the fuel cost/kWh is:

Cost/kWh = $3.00 * 3413 / 108,000 BTU/gal / 0.25

Cost/kWh = 38 ¢/kWh.

Obviously, peak-shaving is much less attractive at a fuel cost of $3.00/gal, unless required generator operation can be predicted accurately and electricity charges are comparably high as well.

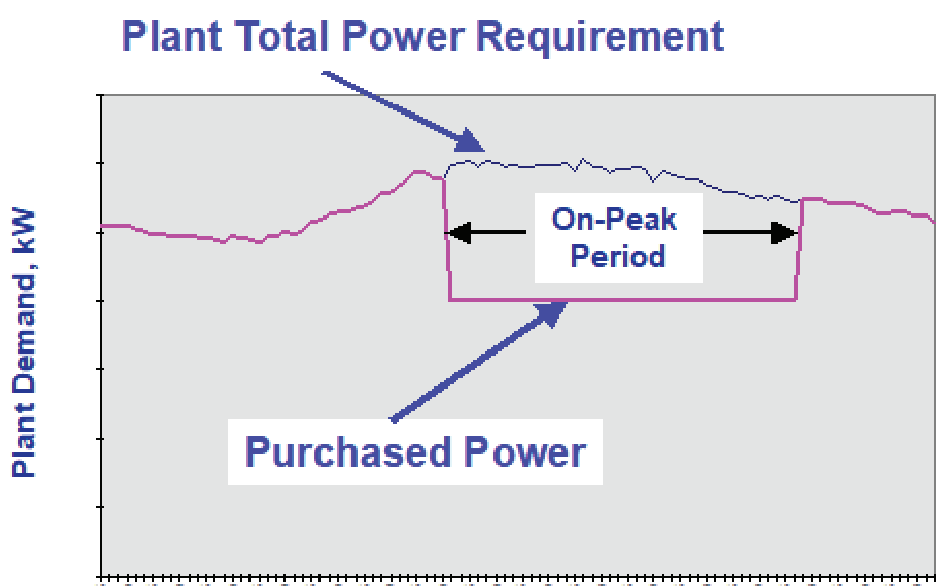
Utility Rates Affecting Peak-shaving Generation

Electric utility rates must be analyzed carefully prior to implementing peak shaving or cogeneration opportunities. Some utilities have special interconnection and protective relaying requirements so that onsite generation does not pose a safety hazard for utility workers. In addition, many utility rate schedules impose standby charges for onsite generation.

These charges are intended to recoup the utility's investment in transformers and other equipment necessary to serve the facility's entire load when the onsite generation equipment is not operating. Without this standby equipment, utilities often reserve the right to replace service equipment with smaller facilities, at risk to the facility of overloading the smaller equipment when onsite generation is not operating.

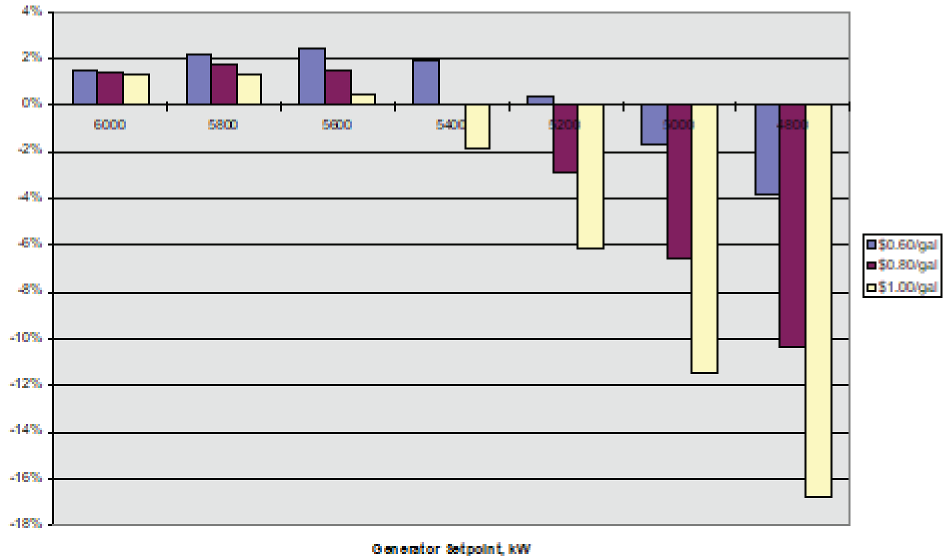
Facilities with onsite generation may be able to operate this equipment to reduce purchased power requirements during periods of high demand, or high utility prices.

Figure 140 - On-peak Period



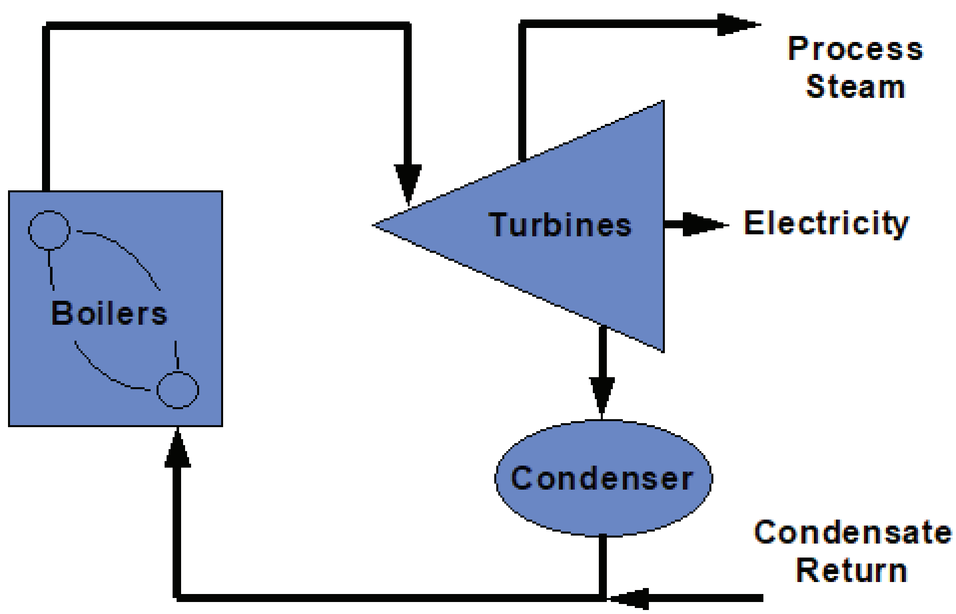
Savings, or losses, associated with operation of peak-shaving generators is dependent on fuel prices, on-peak electricity prices, the amount of time the generator must operate for a given peak-reduction target, and, most importantly, the accuracy with which plant personnel can predict these variables.

Figure 141 - Peak-shaving Generators Savings or Losses



Electricity generation and peak shaving can also be accomplished with steam cogeneration systems typical of paper mills, refineries, and other large industrial processes.

Figure 142 - Steam Cogeneration Peak-shaving

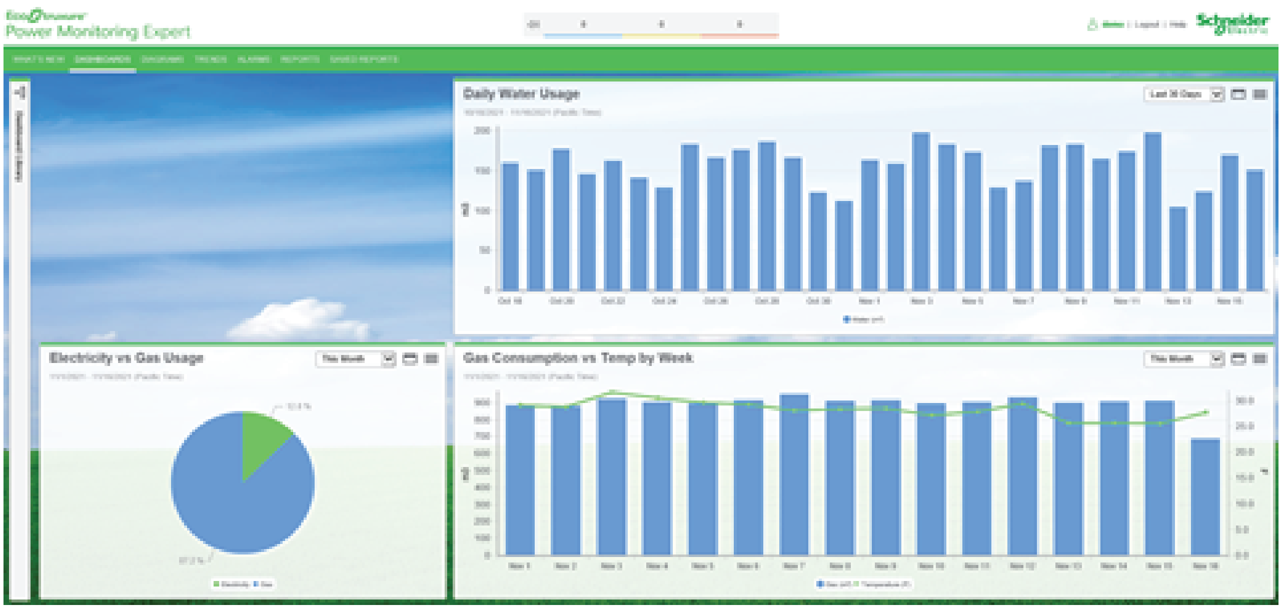


Water, Air, Gas, Electric Steam (WAGES)

WAGES is the acronym for the complete power and energy monitoring system in a typical industrial facility. Industrials are concerned about the costs of Water, Air (compressed), Gas (natural gas), Electricity, and Steam. These systems are often interrelated to the degree that reductions in one utility can increase usage in another. The power monitoring system used by industrials must have the capability of monitoring each of these parameters accurately, and of posting this information in a common, preferably web-based, format for use by the local site and by remote engineers and managers.

Web-based power monitoring systems allow energy managers to monitor all their utilities (Water, Air, Gas, Electricity, Steam) and verify the results of their energy reduction techniques to facilitate identification of new opportunities. Such systems can also convert the energy consumption to dollars by applying a tariff.

Figure 143 - Web-based Power Monitoring Systems



Energy Survey Checklist

Lighting

TBD: Fix non standard bullets

- Lighting operating more hours than needed.
  - Reduce operating hours with lighting control system.
- Areas over lit for task performed.
  - Reduce light levels by disconnecting or replacing lamps or fixtures.
- Incandescent or quartz lamps operating more than 2,000 hours per year.
  - Convert to fluorescent or other energy efficient source.
- Mercury vapor lamps.
  - Convert to energy saving fluorescent, metal halide, or high-pressure sodium.
- Standard fluorescent lamps operating one shift.
  - Convert to energy saving fluorescent lamps and ballasts.
- Standard fluorescent lamps operating two or three shifts.
  - Convert to energy saving fluorescent lamps and ballasts.
- Fluorescent at 18 feet or higher mounting heights.
  - Convert to high pressure sodium.
- VHO fluorescent fixtures.
  - Convert to energy saving fluorescent, metal halide, or high-pressure sodium.
- Standard fluorescent ballasts.
  - Replace with energy savings electronic ballasts at loss.

Induction Motors

- Motors operating 75%+ full load, more than 6,000 hours per year.
  - Replace with energy efficient motors at loss.
- Standard V-belts on pumps or fans.
  - Convert to cog V-belts.
- Fans or pumps that are throttled with dampers or control valves.
  - Consider variable speed drives.

Demand Management

- Sharp demand peaks of short duration (low load factor).
  - Identify loads to shed or reschedule to off-peak.
- Batch processes.
  - Shift to off-peak.
- Consider Time-of-Use savings opportunities.

Exhaust, Ventilation, and Pneumatic Conveying

- Transport velocities or exhaust flows higher than minimum required.
  - Consider changing belts and sheaves to reduce air velocity.
- Consider variable speed or inlet vane control.
- Consider exhaust air heat recovery.
- Make-up air properly provided for all exhaust.
- Fume hoods designed to minimize exhaust.
- Properly designed stack heads (no Chinese hats or caps on outlets).

Fan-coil Unit Air Handling Units

- Consider air side economizers.
- Considered chilled water reset.
- Consider water side economizer.

Centrifugal Water Chillers

- Multiple chillers operating on a common header.
  - Fully load one chiller before starting another.
  - Consider chilled water reset.
- Consider water side economizer.
- Consider variable speed chiller control (long hours at light loads).
- Excessive approach temperatures - Check trends or design data.
  - Clean condenser and evaporator tubes.
- Adding cooling load or chillers.
  - Consider thermal energy storage.

Cooling Towers

- Consider variable speed drives for fan motors.
- Consider PVC fill to replace wood fill material.
- Consider velocity recovery stacks.

Boilers

- Stack gas temperature > 400° (Ideal temperature: 100 degrees plus saturation temperature of the steam).
  - Consider economizer to preheat feedwater or combustion air.
- Manual or intermittent blowdown.
  - Consider automatic blowdown system.
- Continuous blowdown.
  - Consider blowdown heat recovery system.
- Excess air high or unburned combustibles.
  - Consider boiling tuning.
- Large amounts of high-pressure condensate.
  - Consider high pressure condensate receiver.
- Increase amount of condensate returned.
- Improve boiler chemical treatment.
- Maintain steam traps.

Heat Recovery

- Waste-water streams > 100°F.
  - Consider heat exchanger and/or heat pump.
- Waste air or gas stream > 300°F.
  - Consider heat exchanger.

Cogeneration

- Boiler rated pressure 100 psi greater than pressure required by process.
- Concurrent steam and electrical demands.
  - Consider back-pressure turbine.

Refrigeration

- Consider hot gas heat recovery.
- Consider thermal storage.

Compressed Air

- Provide additional small air compressor for loads.
- Provide outside air intake.
- Eliminate air leaks.

EcoStruxure™ Power Digital Applications

For more information, see EcoStruxure Power Digital Applications (IEC) for IEC applications, and EcoStruxure Power Digital Applications (NEMA) for NEMA applications.

Electrical Vehicle Charging

Abstract: Electric vehicle (EV) adoption has rapidly increased in the past decade and is projected to continue growing exponentially. With it comes the need for a new fueling paradigm that adds heavy loading to the electrical system. EV drivers interact with different types of chargers based on the application. System designers need to consider how the user will interact with the charger, what charging behavior should be encouraged, the overall size of the system, effective power distribution equipment, and charge management software with monitoring and control capabilities to specify the optimal EV charging site.

Introduction

Electric Vehicle Supply Equipment (EVSE, commonly referred to as electric vehicle chargers or EV chargers) is becoming a more common electrical load as EV demand rises. Most top automakers who sell to the US market have made commitments to dramatically increase production of electric vehicles within the next two decades. Designing systems with EVSE as a load requires several special considerations. This section will examine NEC requirements for electric vehicle supply equipment installations, types of electric vehicle chargers, an overview of standards to consider when specifying a charger or designing a system to support it, power distribution equipment to support EVSE installations, smart charging and charge management systems, and the emerging application of bidirectional charging.

NEC 625 Electric Vehicle Power Transfer System

NEC National Electric Code® Article 625 covers the electrical conductors and equipment connecting an electric vehicle to premises wiring for the purposes of charging, power export, or bidirectional power flow. To understand these requirements, the basic NEC definitions of Electric Vehicle Supply Equipment and related terms as provided in Article 100 must be understood.

> **NOTE:** This guide is not intended as a substitute for familiarity with the NEC, nor is it intended as an authoritative interpretation of every aspect of the NEC articles mentioned.

Electric Vehicle: An automotive-type vehicle for on-road use, such as passenger automobiles, buses, trucks, vans, neighborhood electric vehicles, and electric motorcycles, primarily powered by an electric motor that draws current from a rechargeable storage battery, fuel cell, photovoltaic array, or other source of electric current. Plug-in hybrid electric vehicles (PHEV) are electric vehicles having a second source of native power.

Electric Vehicle Connector: A device that, when electrically coupled (conductive or inductive) to an electric vehicle inlet, establishes an electrical connection to the electric vehicle for power transfer and information exchange.

Electric Vehicle Power Export Equipment (EVPE): The equipment, including the outlet on the vehicle, that is used to provide electrical power at voltages greater than or equal to 30 Vac or 60 Vdc to loads external to the vehicle, using the vehicle as the source of supply.

Electric Vehicle Supply Equipment (EVSE): Equipment for plug-in charging, including the ungrounded, grounded, and equipment grounding conductors, and the electric vehicle connectors, attachment plugs, personnel protection system, and all other fittings, devices, power outlets, or apparatus installed specifically for the purpose of transferring energy between the premises wiring and the electric vehicle.

Wireless Power Transfer Equipment (WTPE): Equipment installed specifically for transferring energy between the premises wiring and the electric vehicle without physical electrical contact.

> **NOTE:** The general form of WTPE consists of two physical packages: a control box and a primary pad.
>
> **NOTE:** Electric vehicle power export equipment and wireless power transfer equipment are sometimes contained in one set of equipment, sometimes referred to as a bidirectional WPTE.

DCFC: DC Fast Charger, also referred to as Level 3.

Battery Management System (BMS)

- Regulates the current and voltage supplied to the battery and optimizes the charging process.
- Communicates with the vehicle's onboard computer in-regards to the charging process.
- Monitors the charging process.

Electromagnetic Interference (EMI): EMI can disrupt the normal functioning of electronic systems in an EV, such as the audio, GPS, engine control unit, and more. It can also interfere with other electronic equipment nearby. Filters and shielding can be employed.

BESS: Battery Energy Storage System - Captures energy from renewable and non-renewable sources and stores it in rechargeable batteries for later use.

DER: Distributed Energy Resources - A distributed energy resource is any resource or technology that generates, stores, or manages energy at a local level, typically close to the point of consumption.

With these definitions in mind, NEC 625 includes standards for design considerations for power distribution equipment and energy management software, both of which will be discussed in greater detail later in this design guide. A selection of relevant sections is included in the following.

625.40 Electric Vehicle Branch Circuit. Each outlet installed for the purpose of supplying EVSE greater than 16 amperes or 120 volts shall be supplied by an individual branch circuit. Exception: Branch circuits shall be permitted to feed multiple EVSEs as permitted by 625.42(A) or (B).

625.41 Overcurrent Protection. Overcurrent protection for feeders and branch circuits supplying EVSE and WTPE, including bidirectional EVSE and WPTE, shall be sized for continuous duty and shall have a current rating of not less than 125 percent of the maximum load of the equipment. Where noncontinuous loads are supplied from the same feeder, the overcurrent device shall have a current rating of not less than the sum of the noncontinuous loads plus 125 percent of the continuous loads.

625.42 Rating. The EVSE shall have sufficient rating to supply the load served. Electric vehicle charging loads shall be considered to be continuous loads for the purposes of this article. Service and feeder shall be sized in accordance with the product ratings, unless the overall rating of the installation can be limited through controls as permitted by 625.42(A) or (B).

A. **Energy Management System (EMS**). Where an EMS in accordance with 750.30 provides load management of EVSE, the maximum equipment load on a service and feeder shall be the maximum load permitted by the EMS. The EMS shall be permitted to be integral to one piece of equipment or integral to a listed system consisting of more than one piece of equipment. When one or more pieces of equipment are provided with an integral load management control, the system shall be marked to indicate this control is provided.
B. **EVSE with Adjustable Settings.** EVSE with restricted access to an ampere adjusting means complying with 750.30(C) shall be permitted. If adjustments have an impact on the rating label, those changes shall be in accordance with manufacturer's instructions, and the adjusted rating shall appear on the rating label with sufficient durability to withstand the environment involved. EVSE as

references shall be permitted to have ampere ratings that are equal to the adjusted current setting.

625.43 Disconnecting Means. For EVSE and WPTE rated more than 60 amperes or more than 150 volts to ground, the disconnecting means shall be provided and installed in a readily accessible location. If the disconnecting means is installed remote from the equipment, a plaque shall be installed on the equipment denoting the location of the disconnecting means. The disconnecting means shall be lockable open in accordance with 110.25.

625.48 Interactive Equipment. EVSE or WTPE that incorporates a power export function and that is part of an interactive system that serves as an optional standby system, an electric power production source, or a bidirectional power feed shall be listed and marked as suitable for that purpose. When used as an optional standby system, the requirements of Parts I and II of Article 702 shall apply; when used as an electric power production source, the requirements of Parts I and II of Article 705 shall apply. EVPE that provides a receptacle outlet as its point of power export shall be in accordance with 625.60.

625.49 Island Mode. EVPE and bidirectional EVSE that incorporate a power export function shall be permitted to be a part of an interconnected power system operating in island mode.

625.50 Location. The EVSE shall be located for direct electrical coupling of the EV connector (conductive or inductive) to the electric vehicle. Unless specifically listed and marked for the location, the coupling means of the EVSE shall be stored or located at a height of not less than 450 mm (18 in.) above the floor level for indoor locations or 600 mm (24 in.) above the grade level for outdoor locations. This requirement does not apply to portable EVSE constructed in accordance with 625.44 (A).

625.54 Ground-Fault Circuit-Interrupter Protection for Personnel. All receptacles installed for the connection of electric vehicle charging shall have ground-fault circuit-interrupter protection for personnel.

Types of Electric Vehicle Chargers

Electric vehicles (EVs) use batteries as a power source for locomotion. The battery in the EV is a direct current (DC) device and must be recharged with DC power. However, most power distribution systems run on AC power. To get power from a traditional site's electrical system to the EV battery, it must be rectified from AC to DC before reaching the battery. This can be accomplished in one of two ways: the power conversion can happen inside the vehicle using its onboard charger (AC charging) or externally to the vehicle (DC charging). The following diagrams illustrate how EV batteries can be charged.

Figure 144 - DC Charging Power Flow

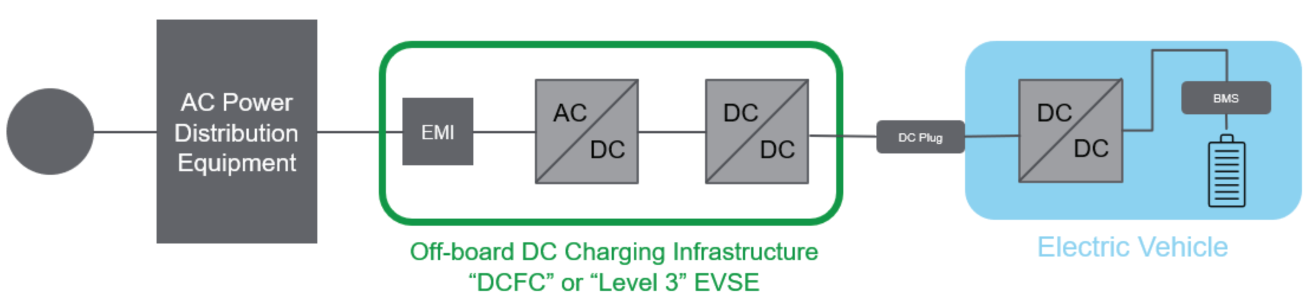
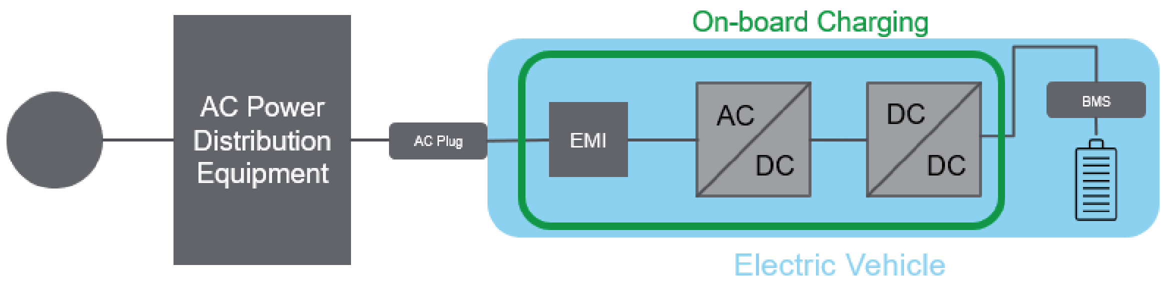


Figure 145 - AC Charging Power Flow



The charging speed of an electric vehicle is determined by the limiting factor (lower kW rating) of the onboard and offboard charging systems.

Charging Type	Maximum charge rate is the lesser rating of these	
AC Charging	On-board Rectifier	AC EVSE
DC Charging	Max. Battery Acceptance Rate	DC EVSE

The true instantaneous charging rate will vary depending on the battery's charging curve, state of charge, internal and ambient temperature, and other factors. However, an approximation of total time to charge may be calculated thusly:

$$\text{Time to charge} = \frac{\text{Battery Rating (kWh)}}{\text{EVSE Rating (kW)}}$$

Two main considerations for EV charger selection will be discussed in this section. First, the power level of the EVSE, which determines how long it will take to recharge the EV battery. Second, the connector type, which is the interface for power and communications between the EVSE and the vehicle.

There are three widely used rates of EV charging: Level 1 AC, Level 2 AC, and Level 3 DCFC. Electric vehicles can be used with different EVSE depending on the rate of charge / charging dwell-time desired.

Level 1 provides charging through a standard 120 V outlet. It is common in residential applications. AC power travels to the vehicle's on-board charger, which rectifies it to DC power to charge the EV battery. Level 1 charging adds two to five miles to the battery range per hour of charge, taking 40–50 hours to completely fill a vehicle battery.

Level 2 charging follows the same path as Level 1 charging (AC power -> onboard charger -> vehicle battery) through electric vehicle supply equipment (EVSE) rather than a standard 120 V outlet. The EVSE may be applied at 208/120 V or 240 Vac. The upstream overcurrent protective device for a Level 2 EVSE will be a two-pole breaker rated at least 125% of the rated EVSE current (e.g., a Level 2 EVSE rated for 30 A would be fed from a 40 A 2P breaker). Level 2 EVSE is commonly seen in residential, workplace, and public charging applications. They can fill an all-electric battery in 4–10 hours.

Common Level 2 ratings and their upstream overcurrent protective device ratings:

AC Level 2 EVSE	Charger Output	Upstream OCPD
7.2 kW	30 A	40 A 2P
7.6 kW	32 A	40 A 2P
9.6 kW	40 A	50 A 2P
11.5 kW	48 A	60 A 2P
16.8 kW	70 A	90 A 2P
19.2 kW	80 A	100 A 2P

The following table approximates different dwell times and corresponding range added to an EV plugged into an AC Level 2 charger.

Site Application	Residential	Workplace	Shopping Mall	Stores
Charge Time	8–12 hours	8 hours	1–2 hours	30–60 minutes
Extra Range	30–200 miles	30–100 miles	10–60 miles	10–40 miles

Average charging time of a typical electric passenger vehicle for a 25-mile trip:

22 kW charging station — 20 min

7 kW charging station — 1 h

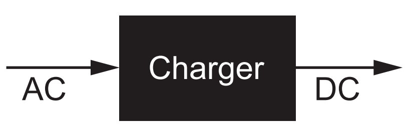
Domestic socket — +4 h

DCFC Level 3 Direct Current Fast Charge (DCFC) equipment is the fastest way to charge an EV battery due to its higher kW rating. DCFC EVSE power ratings range from 20 kW up to 350 kW. Instead of using the vehicle's onboard charger to convert from AC to DC, the DCFC EVSE takes care of the power conversion and pushes DC power to an onboard DC/DC converter then directly to the vehicle battery.

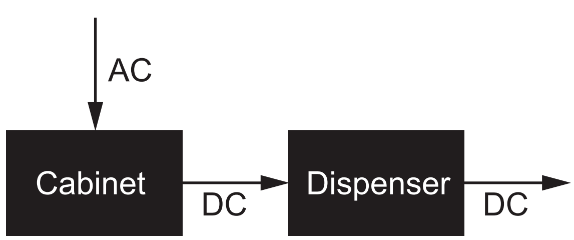
DCFC is typically fed from 480 V 3P breakers. DC fast chargers are typically installed along highways for public use, or for fleet vehicles or car dealerships that need a quick charging turnaround. DCFC can get a battery from zero to 80% in as little as 20 minutes.

There are two commonly available configurations for DCFC: Standalone or "All In One" systems and Split systems.

Standalone (SA): or "All in One" systems normally < 240 kWpp (max around 480 kW). Modules combined with charger.



Split systems: Separated dispenser and power module cabinet. Normally 150 kW-360 kW max pp (max 500 kW) but similar architecture for MW. Shared power amongst multiple dispensers, normally (1–8 ports), some systems are scalable with additional modules or cabinets.



The following is a list of common DCFC ratings. Upstream overcurrent protection device sizes should be confirmed with the manufacturer's datasheet.

DCFC EVSE Ratings:

- 30 kW
- 50 kW
- 60 kW
- 75 kW
- 100 kW
- 120 kW
- 150 kW
- 180 kW
- 250 kW
- 350 kW

Connectors

In addition to different rates of charging, connector type is a consideration when selecting an EV charger. In North America, the most common standards are SAE J1772 for AC charging and Combined Charging Standard 1 (CCS1) for DC charging, or the North American Charging Standard (NACS, formerly known as Tesla) for both AC and DC charging. Some vehicles, like older models of the Nissan Leaf, use a CHAdeMO connector, but these are being phased out.

Nearly one million EVs on the road at the beginning of 2024 use J1772 for AC charging and CCS1 for DC charging. However, now that NACS is available for vehicles other than Tesla, many automakers will be switching to the NACS connector and standard. Ford, GM, VW Group (including Audi and Porsche), BMW Group, Mercedes-Benz, Hyundai, Genesis, Kia, Mazda, Nissan/Infiniti, Toyota/Lexus, Subaru, Volvo, Polestar, Lucid, Fisker, and Rivian have all committed to using the NACS configuration in 2025.

Type 1–SAE J1772

This is the standard for Level 1 and 2 charging in North America and Asia, where the source is a single-phase alternating current (AC). It is a 5-pin plug that can draw power up to 19.2 kW.

Type 2–Mennekes

This is the standard in Europe where triple-phase alternating current is the default power source for Level 1 and 2 charging. The 7-pin plug allows up to 43 kW and (unlike the Type 1) features an automatic locking mechanism to prevent accidental disconnection.

CCS1

This 7-pin EV plug is used for DCFC charging (up to 350 kW) in North America, although it can also be used for slow AC charging. Essentially, the CCS1 is a SAE J1772 plug with two additional high-speed DC charging pins added.

CCS2

The European counterpart of the CCS1 is a 9-pin enhancement of the Mennekes plug. It allows charging of up to 350 kW. As with the CCS1, this plug can deliver both AC and DC charging.

CHAdeMO

Initially developed in Japan, the 10-pin CHAdeMO was one of the first fast-charging DC plug types on the market. The first generation offered up to 50 kW, and the second generation expanded to 400 kW. Despite its popularity in Japan, the plug is being phased out internationally, particularly since the European Commission mandated CCS2 for DC charging in Europe.

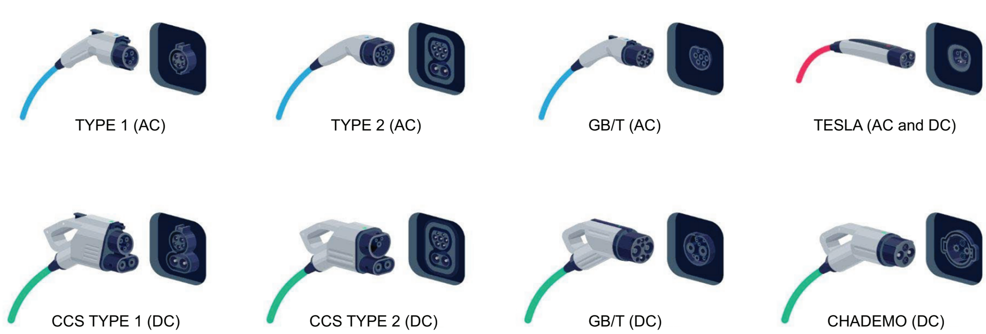
GB/T

GB/T is the standard AC and DC plug in China, delivering 7.4 kW for AC and 237.5 kW for DC. It is used by around half the electric vehicles in the world today but is not used in North America.

North American Charging Standard (NACS)

Tesla’s formerly proprietary EV plug accommodates Level 1, 2 and 3 AC and DC charging. In other words, there is just the one plug. In Europe, Tesla cars now use CCS2 charging.

Figure 146 - EV Charging Connector Types



As manufacturers switch their plug standard and the industry evolves, adaptors and cable kits help drivers use a multitude of EV chargers. All Tesla vehicles come with an adapter that connects to the J1772 plug. An adaptor that goes the other way, allowing J1772/CCS1 vehicles to use NACS chargers, is also available. Many charging companies are also offering the option to retrofit their stations with a new cord to keep up with the industry's increased adoption of NACS.

Electric Vehicle Charging Standards

Industry standards are changing rapidly as this growing industry evolves. There are published and developing standards regarding conductive and inductive charging, unidirectional charging and bidirectional power transfer, charger construction and safety, communication, cybersecurity, and more. The Electric Vehicle Charging Standards table below classifies various standards pertinent to electric vehicle charging systems but is not intended to be comprehensive. Many local, state, and regional jurisdictions may also be relevant.

Standard/Recommended Practical Guide	Title	Description
NFPA 70 (NEC) Article 625	Electric Vehicle Charging System	Covers the installation of equipment and devices external to an electric vehicle related to electric vehicle charging.
International Building Code (IBC)	2021 Electric Vehicles and Building Codes: A Strategy for Greenhouse Gas Reductions	Provides example code language for municipalities to set their own policies. Notably, it defines the minimum EV circuit size as 40 A and 208/240 V. Provides table for municipalities to define percentage of parking stalls as EVSE installed, EV-capable, and EV-ready for new construction.
IEEE C62.230-2022	IEEE Guide for Surge Protection of Electric Vehicle Infrastructure	Outlines the application of surge-protective devices for electric vehicle infrastructure including power, data acquisition, and communications-related circuitry.
IEEE 2030.5	IEEE Standard for Smart Energy Profile Application Protocol	Defines the application layer with TCP/IP providing functions in the transport and Internet layers to enable utility management of the end user energy environment, including demand response, load control, time of day pricing, management of distributed generation, and electric vehicles.
UL 2202	DC Charging Equipment for Electric Vehicles	Covers off board electric vehicle conductive charging equipment that converts from AC to DC (DC output devices) to recharge the propulsion batteries in over-the-road electric vehicles. Does not cover on board EV chargers.
UL 2594	Electric Vehicle Supply Equipment	Covers off board electric vehicle conductive charging equipment that does not convert voltage (AC in – AC out) and provides power to an onboard EV charger.
UL 2231	Standard for Personnel Protection Systems for Electric Vehicle (EV) Supply Circuits	Includes general requirements for EV supply circuits to reduce the risk of electric shock to the user from accessible parts in grounded or isolated circuits for charging electric vehicles. These circuits are external to or on board the vehicle. This standard also includes particular requirements for protection devices for use in charging systems, including requirements for isolated circuit capacitor switching transient testing and harmonic distortion immunity testing.
UL 2251	Standards for Safety: Plugs, Receptacles, and Couplers for Electric Vehicles	Standard for safety regarding EV plugs, EV receptacles, vehicle inlets, vehicle connectors, and EV breakaway couplings under conditions of continuous use. These devices are intended for use with conductive EVSE and are intended to facilitate the conductive connection from the EVSE to the vehicle.
UL 2252	Outline of Investigation for Adapters for use with Electric Vehicle Couplers	Investigates adapters for conductive EV power transfer to the vehicle. The adapters are not used to convert voltages. They are only used to convert the physical configuration of the interfaces and provide for continued communication protocols.
UL 2263	Electric Vehicle Cable	This standard specifies the requirements for electric vehicle cables rated up to 1000 Vac and DC intended to be part of a cord set carried in the vehicle for connection to a charging station or for permanent or temporary connection to Electric Vehicle Supply Equipment (EVSE) or for connection to the branch circuit supplying the EVSE or vice versa.
SAE J1772	SAE Standard for Electric Vehicle and Plug-in Hybrid Electric Vehicle Conductive Charge Coupler	This SAE standard covers physical, electrical, functional, safety, and performance requirements for conductive power transfer to an electric vehicle, including operational requirements and the functional and dimensional requirements for the vehicle inlet and mating connector.

Standard/Recommended Practical Guide	Title	Description
SAE J3400	North American Charging System (NACS) for Electric Vehicles	This standard is currently a work in progress. It will cover physical, electrical, functional, safety, and performance requirements for conductive power transfer to an electric vehicle using a connector capable of transferring either DC or AC single-phase power using two current-carrying contacts.
SAE J2344	Guidelines for Electric Vehicle Safety Equipment (EVSE)	This SAE Information Report identifies and defines the preferred technical guidelines relating to safety for vehicles that contain high voltage, such as Electric Vehicles (EV), Hybrid Electric Vehicles (HEV), Plug-In Hybrid Electric Vehicle (PHEV), and Fuel Cell Vehicles (FCV) during normal operation and charging. Guidelines in this document do not necessarily address maintenance, repair, or assembly safety issues
NECA 413-2019	Installing and Maintaining Electric Vehicle Supply Equipment (EVSE)	Procedures for installing and maintaining AC and DC EVSE.
Inductive Wireless EV Charging		
UL 2750	Wireless Power Transfer Equipment for Electric Vehicles	Wireless Power Transfer (WPT) Equipment for transferring power to a stationary electric vehicle. WPT equipment consists of at least two devices, the power source, and a ground assembly. The WPT equipment may also be provided with a third device, the mating vehicle assembly. These requirements are also suitable for covering each individual device as a stand-alone product.
SAE J1773	SAE Recommended Practice for Electric Vehicle Inductively Coupled Charging	This SAE Recommended Practice establishes the minimum interface compatibility requirements for electric vehicle inductively coupled charging for North America that transfers power at frequencies significantly higher than power line frequencies. It is not applicable to inductive coupling schemes that employ automatic connection methods or that transfer power at power line frequencies.
Bidirectional EV Charging		
UL 9741	Electric Vehicle Power Export Equipment (EVPE)	UL9741 covers off-board unidirectional and bidirectional equipment that transfers electrical energy between an electric vehicle and off board loads as well as operating in parallel with an electric power system, such as the electric utility grid, using a permanently attached vehicle connector. Equipment that has optional bidirectional functionality serves as both Electric Vehicle Power Export Equipment (EVPE) and electric vehicle supply equipment (EVSE). The power export functionality includes enable and disable functions to limit or prevent export to the utility grid for locations that are not capable of or permitted to receive back feed power. This functionality is addressed using requirements of **UL 1741**. The equipment performs power conversion and Interconnection Systems Equipment (ISE) functionality. These functions may be located within one piece of equipment or within multiple pieces of equipment.
Megawatt Charging		
UL 2278	Outline of Investigation for Megawatt Charging Configured Electric Vehicle Couplers	These requirements cover vehicle connectors and vehicle inlets designated as, and configured as, megawatt charging couplers. These devices are rated up to 1500 Vdc, 1000 A under conditions of continuous use. Vehicle connectors may be actively cooled, such as with liquid cooling, when operating. These devices are intended for use with conductive DC charging equipment for electric vehicles and intended to facilitate conductive connection from the charging equipment to the vehicle.
SAE J3271	Megawatt Charging System for Electric Vehicles (Work In Progress)	This document describes the megawatt-level DC charging system requirements for couplers/inlets, cables, cooling, communication, and interoperability. The intended application is for commercial vehicles with larger battery packs requiring higher charging rates for moderate dwell time. Improving charging session reliability while maintaining existing number of contacts/conductors can be achieved by superimposing communication signals over “connection-detection” analog signals.
Historical / Stabilized Standards		

Standard/Recommended Practical Guide	Title	Description
SAE J2293/1	SAE Recommended Practice for Energy Transfer System for Electric Vehicles Part 1: Functional Requirements and System Architectures	SAE J2293 establishes requirements for Electric Vehicles (EV) and the off-board Electric Vehicle Supply Equipment (EVSE) used to transfer electrical energy to an EV from an Electric Utility Power System (Utility) in North America. This document defines, either directly or by reference, all characteristics of the total EV Energy Transfer System (EV-ETS) necessary to insure the functional interoperability of an EV and EVSE of the same physical system architecture. The ETS, regardless of architecture, is responsible for the conversion of AC electrical energy into DC electrical energy that can be used to charge the Storage Battery of an EV, as shown in Figure 1. The different physical ETS system architectures are identified by the form of the energy that is transferred between the EV and the EVSE, as shown in Figure 2. It is possible for an EV and EVSE to support more than one architecture. This document does not contain all requirements related to EV energy transfer, as there are many aspects of an EV and EVSE that do not affect their interoperability. Specifically, this document does not deal with the characteristics of the interface between the EVSE and the Utility, except to acknowledge the Utility as the source of energy to be transferred to the EV. The functional requirements for the ETS are described using a functional decomposition method. This is where requirements are successively broken down into simpler requirements and the relationships between requirements are captured in a graphic form. The requirements are written as the transformation of inputs into outputs, resulting in a model of the total system. Each lowest level requirement is then allocated to one of four functional groups (FG) shown in Figure 2. These groups illustrate the variations of the three different system architectures, as the functions they represent will be accomplished either on an EV or within the EVSE, depending on the architecture. Physical requirements for the channels used to transfer the power and communicate information between the EV and the EVSE are then defined as a function of architecture. System architecture variations are referred to as follows: Type A—Conductive AC System Architecture—Section 7.2.1 Type B—Inductive System Architecture— Type C—Conductive DC System Architecture—Section 7.2.3 The requirements model in Section 6 is not intended to dictate a specific design or physical implementation, but rather to provide a functional description of the system's expected operational results. These results can be compared against the operation of any specific design. Validation against this document is only appropriate at the physical boundary between the EVSE and EV.
SAE J2293/2	SAE Recommended Practice for Energy Transfer System for Electric Vehicles Part 2: Communication Requirements and Network Architecture	See part 1 but for communications and networking. Stabilized 2014, intended to be a historical document (same as part 1).

Power Distribution Equipment Requirements for EVSE

The integration of EV charging supply equipment requires the integration of several high-power loads and an adaptation to the existing electrical infrastructure. This section presents basic principles for designing the EV charging infrastructure and its integration into an existing electrical installation.

For more information on power distribution equipment options, please see the Power Distribution Equipment section of this design guide. For EVSE applications, the focus will be on low voltage equipment: panelboards, switchboards, and dry-type transformers.

The first consideration for power distribution equipment is how the EVSE will get their power.

Different charging levels require different power distribution equipment.

Figure 147 - Level 1

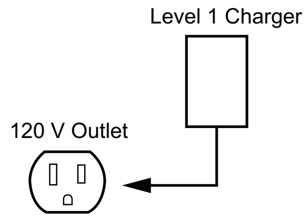


Figure 148 - Level 2

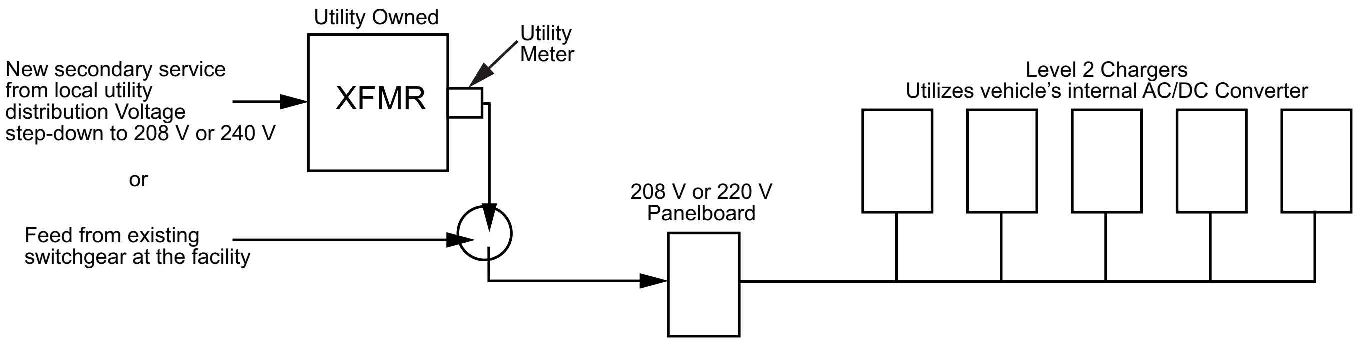


Figure 149 - Level 3

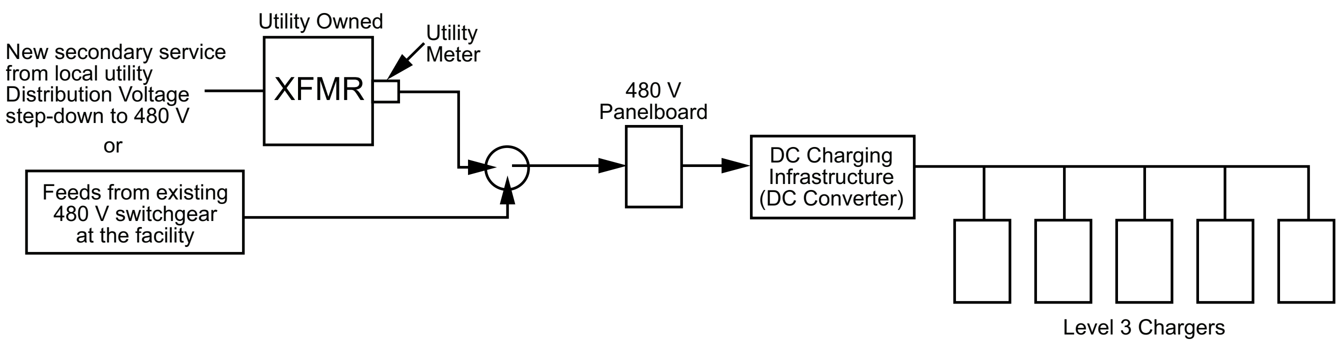


Figure 150 - Level 2 and 3

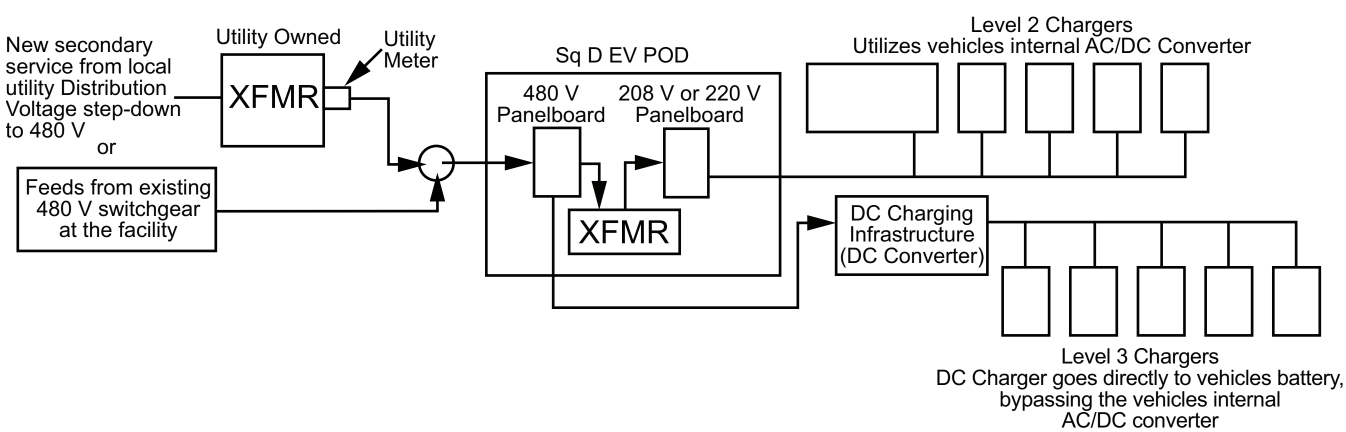
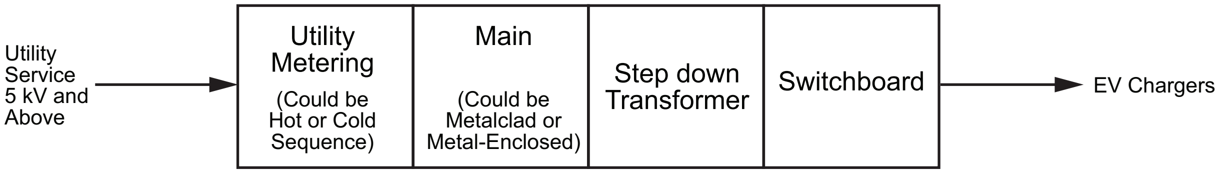


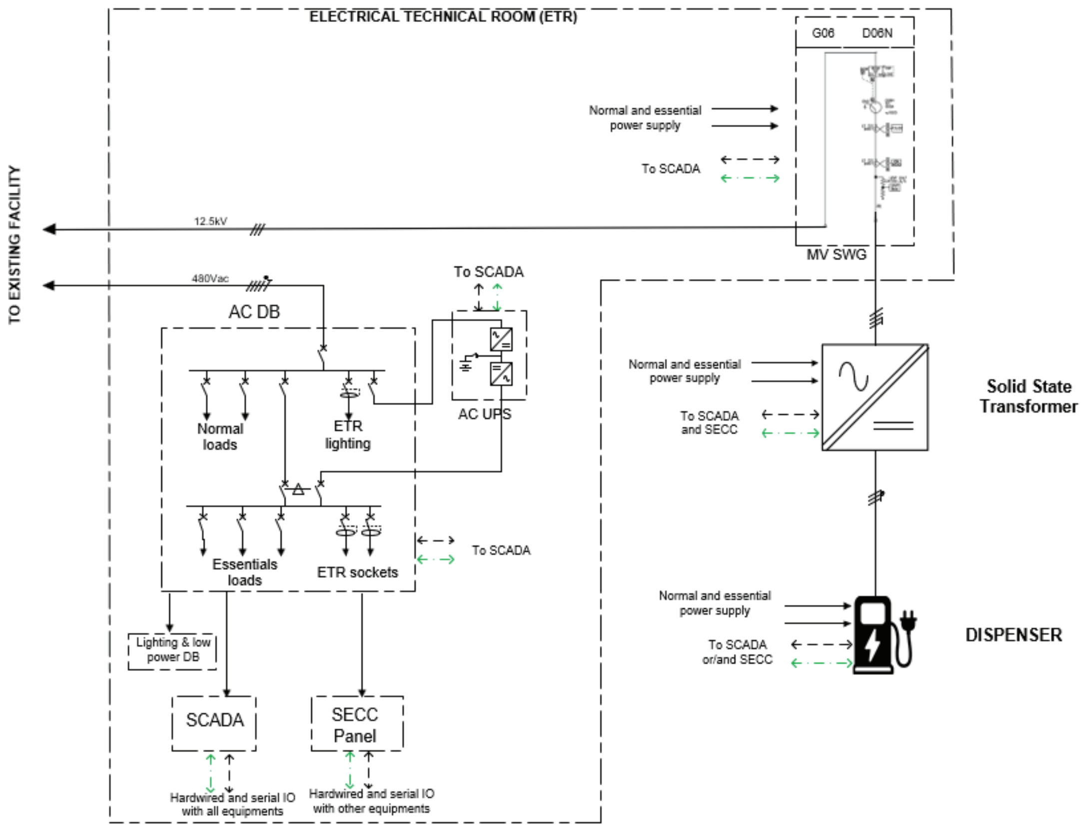
Figure 151 - Large Installations



Utility metering required, unless fed from internal facility feeder.

Figure 152 - Megawatt Charging

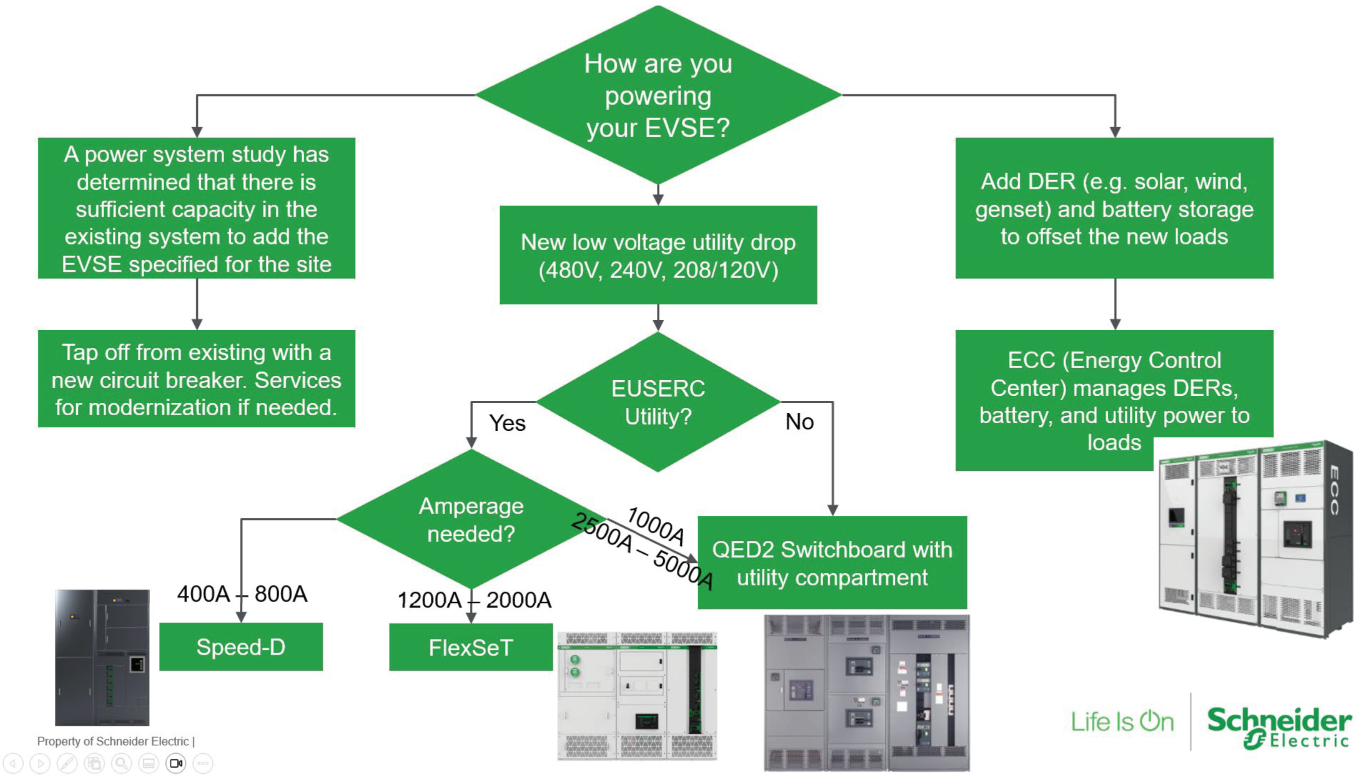
One promising architecture for extra-large megawatt charging applications is to utilize a solid state transformer with a medium voltage AC input and a DC output for power distribution to the MW dispenser(s).



EV Charger Applications

Common use cases:

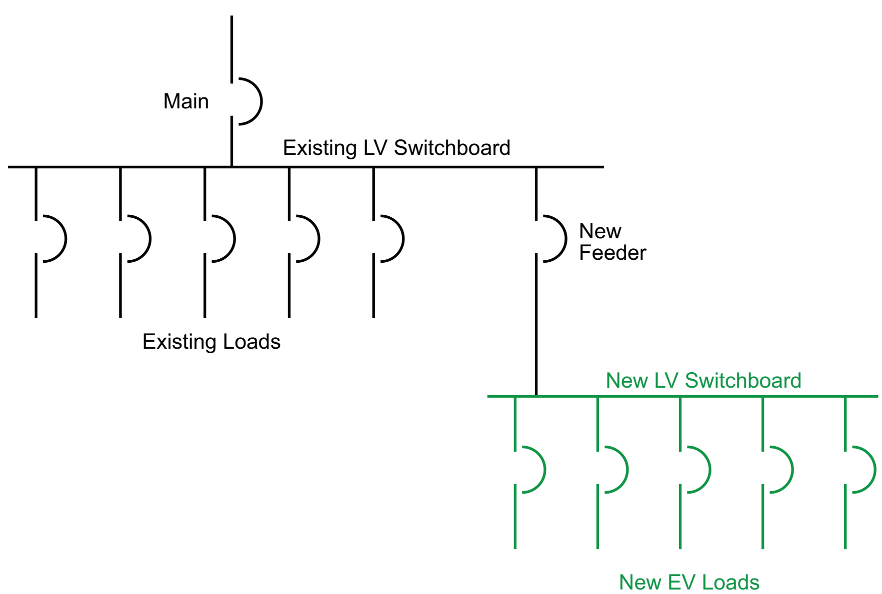
	Residential	Multifamily	Fleet Charging
Typical use case	Single-family homes (residential and/ or commercial contractors)	Housing complexes that serve multiple families with dedicated or shared charging	Centralized depot charging for fleet vehicles (light-duty or medium-duty)
Power requirement	≤19.2 kW (AC Level 2)	≤19.2 kW (AC Level 2)	DCFC and/or AC Level 2
EV charger	Schneider Charge Pro AC	Schneider Charge Pro AC	DCFC and/or Schneider Charge Pro AC
Power distribution	Square D Energy Center OR Schneider Pulse OR QO Load Center	QED2 Switchboard FlexSeT Switchboards IPC2 EV Pod NQ Panelboard EZM Metering	QED2 Switchboard IPC2 EV Pod LV Transformer NQ Panelboard For larger installations: MV Switchgear MV Distribution Transformers LV Switchgear or Switchboards ECC for DERs BESS
Software	Schneider Home	EV Connect Multifamily Software	EV Connect Energy Fleet Management
	At Work	**Destination**	**In Transit**
Typical use case	Corporate or commercial EV charging sites where commuters park their EVs while at work	Public, non-DCFC charging sites where people spend an extended time	Public DCFC sites, such as gas stations, convenience stores, etc.
Power requirement	≤19.2 kW (AC Level 2)	≤19.2 kW (AC Level 2)	≥150 kW DCFC
EV charger	Schneider Charge Pro AC	Schneider Charge Pro AC	≥150 kW DCFC
Power distribution	QED2 Switchboard FlexSeT Switchboards IPC2 EV Pod NQ Panelboard LV Transformer	QED2 Switchboard FlexSeT Switchboards IPC2 EV Pod NQ Panelboard LV Transformer	QED2 Switchboard IPC2 EV Pod LV Transformer NQ Panelboard For larger installations: MV Switchgear MV Distribution Transformers LV Switchgear or Switchboards ECC for DERs BESS
Software	EV Connect Energy Management EcoStruxure Energy Hub EcoStruxure Power	EV Connect Multifamily Software	EV Connect Network EcoStruxure Energy Hub



Scenario 1: A power system study has determined that there is sufficient capacity in the existing system to add the EVSE specified for the site.

If the number of charging points and their capacity is significantly lower than the installed power, an option to investigate could be to integrate the EV chargers into the existing electrical installation, as shown in the following.

Figure 153 - EV Loads Integrated into the Existing Electrical Infrastructure



It is important to perform a power system study to ensure the power load can be added to the existing electrical infrastructure. Energy efficiency measures could be proposed to reduce the existing consumption and therefore increase the power demand that can be added. Local power supplies and storage could be proposed to compensate for the impact of integrating the EV charging equipment. If the existing LV switchboard cannot accommodate the additional power and/or devices required, the option described in next paragraph is recommended.

As specified in NEC Section 625, the power distribution equipment feeding the EVSE shall have sufficient rating to supply the load served. Overcurrent protection for feeders and branch circuits supplying electric vehicle supply equipment shall be sized for continuous duty and shall have a rating of not less than 125 percent of the maximum load of the electric vehicle supply equipment. Electric vehicle charging loads shall be considered continuous loads unless an automatic load management system is used, in which case the maximum equipment load on a service and feeder shall be the maximum load permitted by the automatic load management system. This section assumes that an automatic load management system is not present. More information about automatic load management systems and smart charging may be found in the Charge Management Software section.

Municipal guidelines should be consulted for new construction projects involving parking to determine the minimum number of spaces that need EVSE. Some utilities offer special rates for EV charging installations. To be eligible for the EV tariff, utility requirements may specify a dedicated meter for the EV chargers.

Remembering charger types:

- AC Level 2 chargers are typically rated for installation in 208/120 V systems or 240 V systems. Most require a 2P breaker as OCPD.
- DCFC will typically be fed from a 480 V 3P breaker.

For example, consider a site with (10) Level 2 chargers rated 7.2 kW / 30 A. For each breaker rating, find 125% of the EVSE’s current rating:

30 A * 1.25 = 37.5 A

The OCPD for each of the chargers will be the next highest available standard size: 40 A.

A 208/120 V panelboard to feed these (10) chargers may have a panel schedule like this:

CKT #	Load Desc.	Trip	Pole	A		B		C		Pole	Trip	Load Desc.	CKT #
				L BUS	R BUS	L BUS	R BUS	L BUS	R BUS				
1	7.2 kW Charger	40 A	2	3120	3120					2	40 A	7.2 kW Charger	2
3						3120	3120						
5	7.2 kW Charger	40 A	2					3120	3120	2	40 A	7.2 kW Charger	2
7				3120	3120								
9	7.2 kW Charger	40 A	2			3120	3120			2	40 A	7.2 kW Charger	2
11								3120	3120				
13	7.2 kW Charger	40 A	2	3120	3120					2	40 A	7.2 kW Charger	2
15						3120	3120						
17	7.2 kW Charger	40 A	2							2	40 A	7.2 kW Charger	2
19				3120	3120								
21													
23													
25													
27													
29													
			Total Load (VA):	24960		18720		18720					

The total connected load is 62400 VA, or 173.2 A. The next highest main breaker size would be 200 A.

Schneider Electric NQ Panelboard

Schneider Electric NQ Panelboards have 400 A and 600 A options with main circuit breakers. These panels can be applied at 208 V or 240 V, either alone or in an IPC2 unit. If more Level 2 chargers are required, they may be fed from additional panels.

The following quantities use a continuous current rating for the EVSE loads (no LMS)

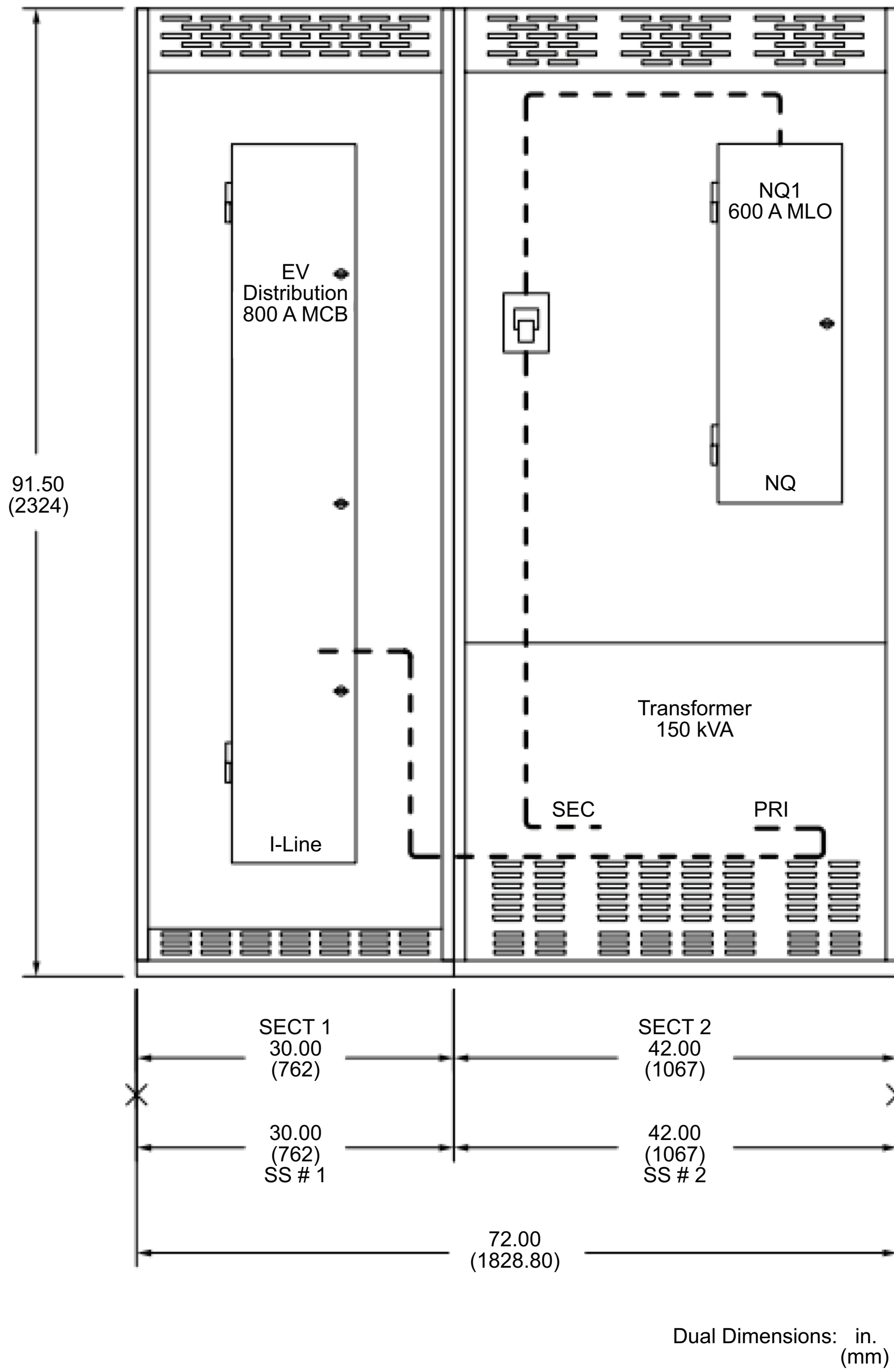
Charger	NQ 208 V 400 A	NQ 208 V 600 A	NQ 240 V 400 A	NQ 240 V 600 A
	Quantity	Quantity	Quantity	Quantity
7.2 kW L2	18	26	16	24
7.6 kW L2	17	25	15	22
9.6 kW L2	13	20	12	18
11.5 kW L2	11	17	10	15
19.2 kW L2	6	10	6	9

NOTE: 70 A to 100 A 2P breakers are limited to 11 breakers per panel due to the neutral connection limitations.

IPC2 "EV Pod"

Available Voltage (utility xfmr sec or point in system where to tap off for EVSE addition)	Type of EVSE Needed	Recommended Equipment
480 V	DCFC Chargers	Switchboard with breakers to DCFC OR Switchboard to I-Line panels to DCFC
480 V	AC L2 Chargers	480 V switchboard to step-down transformer to panel(s) to L2 EVSE OR 480 V switchboard to IPC2 "EV Pod" integrated step-down transformer and panels to L2 EVSE
480 V	Mix of DCFC and L2 Chargers	IPC2 "EV Pod" with a 480 V panelboard, step-down transformer, and 240 V or 208 V panelboard
208/120 V	DCFC Chargers	Step-up transformer to 480 V I-Line panelboard or QED2 switchboard
208/120 V	AC L2 Chargers	NQ Panelboard
208/120 V	Mix of DCFC and L2 Chargers	IPC2 "EV Pod" with a 208/120 V panelboard, step-up transformer, and 480 V panelboard

Figure 154 - IPC2 “EV Pod” elevation with 480 V, 800 A I-Line panelboard, step-down transformer, and 208 V, 600 A NQ panelboard



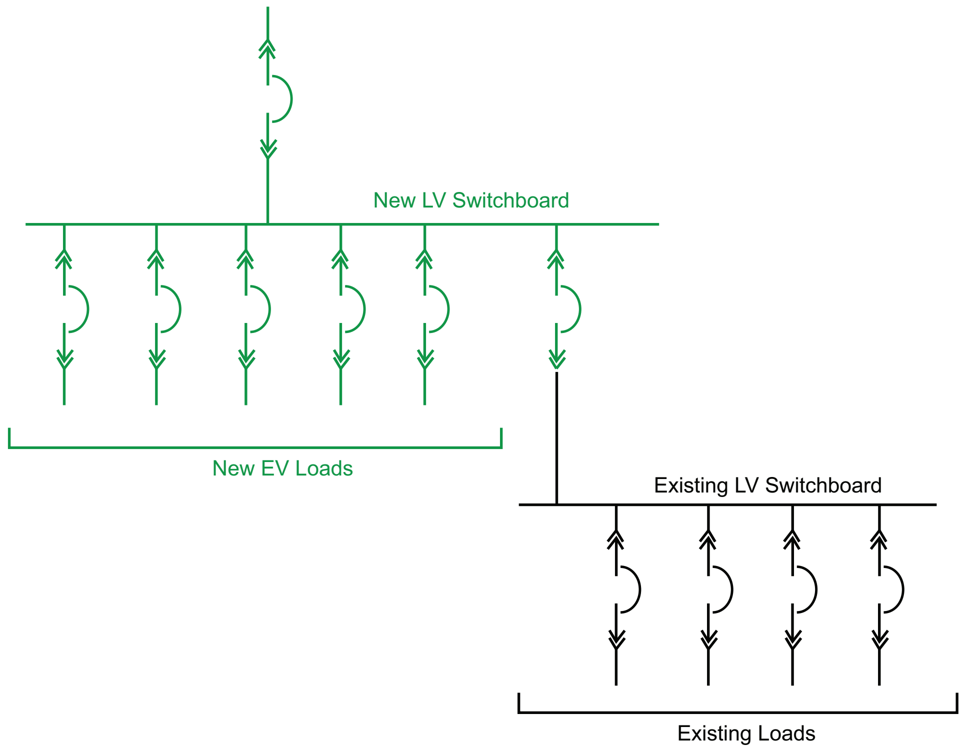
The Scenario 1 example and variations presented below cover the addition of EVSE to sites with existing power distribution systems. Many existing businesses and sites are retrofitting and/or adding to their existing systems to accommodate the demand for EVSE.

If the power demand of the new EV loads is equivalent to or higher than that of the existing electrical installation, it could be preferable to install a new main LV switchboard to integrate all EV loads. The existing electrical infrastructure will be connected to this new main LV switchboard. A power system study should be performed to ensure overcurrent protective device coordination between the existing installation feeder and the new main incoming device.

If there are several EV chargers located at the same area, secondary LV switchboards or panelboards could be installed close to the EV charging area to minimize the cable length.

The creation of a new main LV switchboard presents the advantage of minimizing the changes to the existing electrical installation. In addition, it offers the opportunity to coordinate protection devices and thus optimize the power availability.

Figure 155 - EV Loads Integrated into a New Main Low Voltage Switchboard



The integration of EV loads increases the power demand of the electrical installation significantly. An extension of the local energy infrastructure is often required. A switch from a LV grid connection to a MV grid connection could be necessary in certain cases.

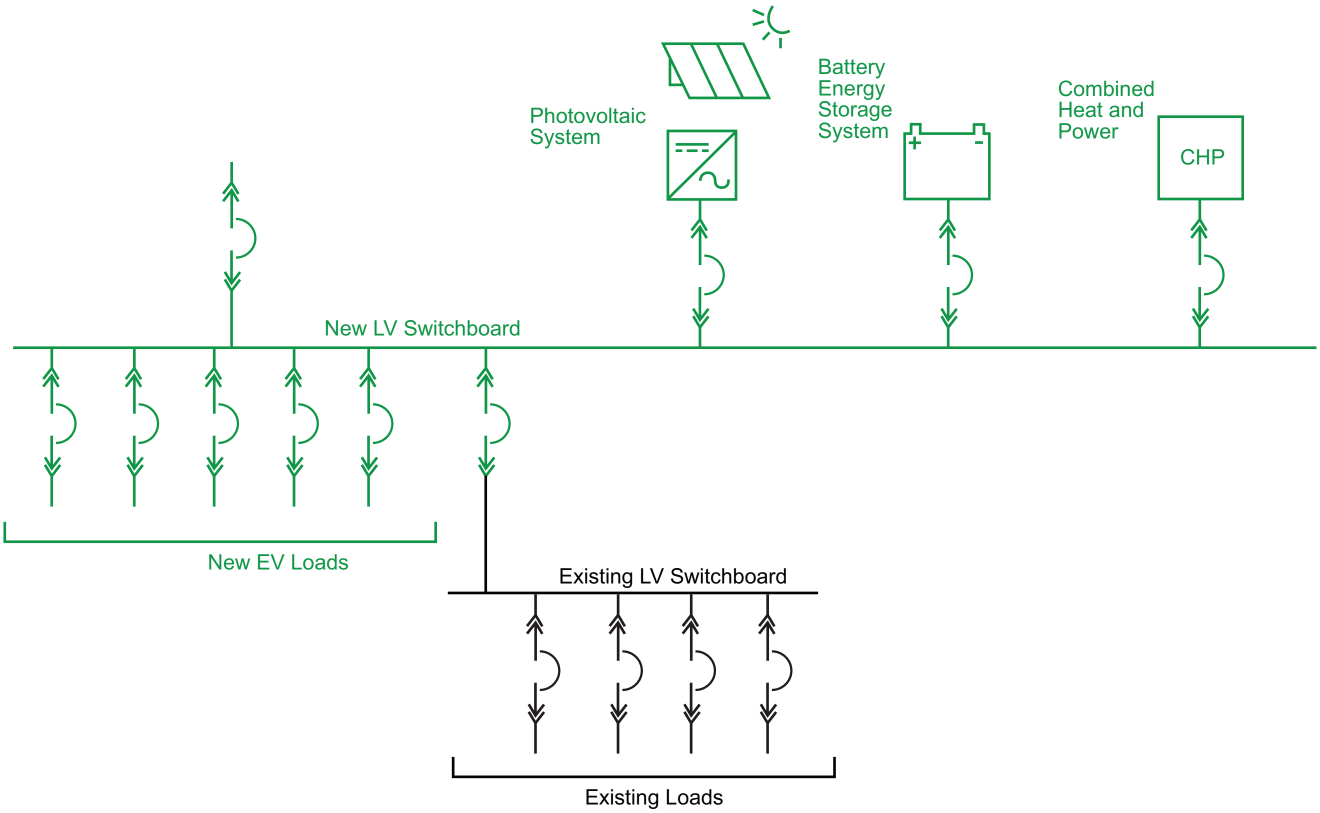
In addition to the electrical infrastructure, the electricity contract with the energy provider needs to be reviewed.

To limit or avoid these types of significant modifications to the existing local installation, local energy power supplies can be added, such as:

- Photovoltaic system: for local energy production and a commitment to sustainability.
- Energy storage system: to avoid power demand peaks and optimize solar production use.
- Combined heat and power (CHP): combined heat and power production if relevant.

Local power supplies can be connected to the new main LV switchboard. Their integration into an existing electrical infrastructure requires a preliminary audit.

Figure 156 - EV Loads and Local Power Supplies Integrated into a New Main Low Voltage Switchboard



Busduct

Example solution for a parking structure.

I-Line Busway

800–5000 A busway

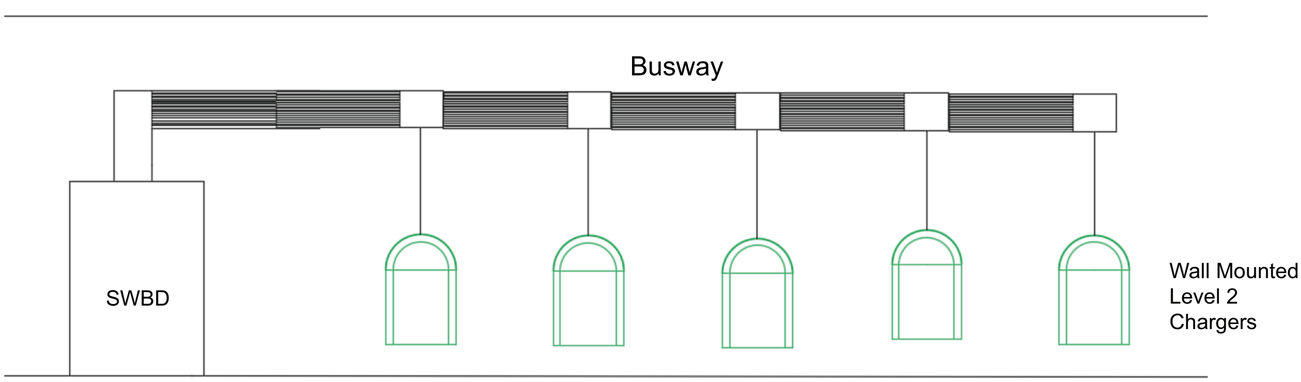
Aluminum and/or Copper

Plug-in or bolt-on disconnects

30 A, 60 A, 100 A, 200 A, 400 A, 600 A + plug-in circuit breaker disconnects

Fusible or circuit breaker plug-in units

Circuit breakers with electronic trip unit (ETU), communications (Ethernet or Modbus)



Charge Management Software

Charge Management Software (CMS) communicates directly with the EV chargers for monitoring and control. Automatic load management systems can alleviate the impact of EV installations by setting a maximum power limit for a group of EVSE. This software is also how equipment owners can bill for charger usage and drive ROI on their EVSE investment.

Key terms:

- **Smart chargers** are internet enabled hardware units that work with software management to provide the best driver and owner experience. Smart chargers are also required hardware when applying for incentives.
- **Software management** enables you and your clients to have complete control of your charging program, reduce costs, capture incentives, and ensure a positive ROI and driver experience.
- **Load Management Software** balances the existing output capability among the energy-consuming assets in a building or business. Linked directly to a site's electrical capacity. Works with smart charging and demand response.
- **Demand Response** is implemented at the power company level.

As illustrated in the following, there are different communication protocols between the electric vehicle (EV) and the electric vehicle supply equipment (EVSE), and between the EVSE and the CMS.

ISO 15118 is a set of protocols that allow EVs to communicate with charging stations. ISO 15118-2 pertains to network and application protocol requirements for communication between electric vehicles and charging stations.

- **Plug & Charge** – A standardized, secure authentication process where an EV automatically identifies itself to the charging station, initiating and authorizing charging without requiring user interaction (such as RFID cards or apps).
- **AutoCharge** – A simpler method for automatic charging session initiation based on the vehicle's MAC address. AutoCharge starts charging when the vehicle is recognized by the charging station.

Feature	Plug and Charge	AutoCharge for Level 2
Communication	ISO 15118–2	ISO 15118–2
Standard	ISO 15118	Proprietary (no universal standard)
Security	High (uses encrypted certificates)	Moderate
Setup	Complex (requires EV, charger, and CPO support)	Simple (requires MAC address registration)
Vehicle Requirement	ISO 15118 compliant vehicles	ISO 15118 compliant vehicles
Primary Use Case	Public charging, fleets	Commercial fleets

Open Charge Point Protocol (OCPP) is an open communication protocol that allows EV charging stations to communicate with central management systems. There are several versions currently available and in development.

- **OCPP 1.6** – Widely used, supports basic smart charging and device management.
- **OCPP 2.0.1** – Introduces enhanced security, plug-and-charge, and better support for energy management.
- **OCPP 2.1 –** Vehicle-to-grid (V2G) support.

Feature	OCPP 1.6	OCPP 2.0.1	OCPP 2.1
Security	Standard	Advanced	Further Refined
Smart Charging	Device Level Control	Hierarchical Control	V2G
Diagnostics	Limited	Improved	Enhanced
Plug and Charge	Yes	Yes	Yes
V2G Support	No	Limited	Yes
Compatibility	Not Compatible with 2.0.1 or 2.1	Compatible with 2.1 but not 1.6	Compatible with 2.0.1 but not 1.6

It is important to specify the correct OCPP firmware revision on the charger to ensure that the desired EVSE and CMS are compatible. Typical language may read, “must support OCPP 1.6J or later with smart charging profiles. To ensure compatibility, charger must undergo certification testing with EVConnect.”

Smart chargers must be able to communicate via internet, wired or wireless, and support web socket communication. Commonly specified communications capabilities are WiFi 802.11 at 2.4 GHz for wireless network communication, Ethernet 10/100, and 4G LTE Cellular connectivity with a sim card that may or may not be swappable in the field. Some users prefer to also specify EVSE that is capable of a local list support or freevend offline/non-network mode fallback configuration.

Cybersecurity is an important consideration with any connected product. One way to ensure safety when specifying a smart charger is to specify that the EVSE must include a trusted platform module (TPM) developed using an IEC 62443 compliant reference framework for cybersecurity.

In order to provide accurate data to the CMS, the EVSE should include an imbedded submeter for measurement and reporting of electricity delivered to the EVSE. ±1% accuracy is a commonly specified value for the internal meter.

There are extensive possibilities for monitoring, control, and logging with charge management software. Commonly specified features include remote monitoring and control, cost calculations, and charge history. Knowing what you can manage and how is key to helping your clients understand why software management is necessary with their EV charging program if full ownership of the solution with complete visibility and control is desired.

There are many ways you and/or your clients may want to manage charging. You may want to manage unique driver groups differently, encourage increased utilization by implementing overstay fees, know when it is time to add more stations because the current allotment is being fully used, or address issues quickly to optimize the driver experience.

You will also want to bill drivers correctly for the energy they use and save money by managing on and off-peak energy utilization. Many energy providers charge you significantly more according to the peak amount you consume in a given time period. As such, doing things that spike the site’s load will cause a jump in the bill.

Managing all of this can sound daunting, but it does not need to be. You can provide a solution that does not take hours and hours each week to monitor and adjust. A good software management platform will enable you to set it up, track progress, understand utilization, view revenue, and track key metrics you and/or your clients need for reporting in a simple, easy to understand dashboard.

The management system will need to enable your EV charging program to operate within your site's current electrical capacity and with your local energy provider's capacity, not against it.

The electric grid is fragile and as climate change increases, we are seeing more failures. How will a shift to electric vehicles affect this? In 2019, Americans drove roughly 9 billion miles per day. A "high efficiency" electric vehicle gets about 4 miles per kilowatt-hour. So, that is an average nationwide daily energy use of 2.25 billion kilowatt-hours. Meanwhile, nationwide energy use comes to about 10.6 billion kilowatt-hours per day. In other words, EVs would up demand on the grid by 20%.

Moreover, vehicle charging is more difficult to manage. The grid needs to be able to "predict" high demand times to stay stable. An additional 2.25 billion kilowatt-hours of consumption spread across people's varied schedules creates substantial difficulty.

Demand pricing and grid balancing are about when electricity is consumed, along with how much is consumed. Demand will go up with electric vehicles, so load management focuses on controlling the "when." But load management systems also take on another issue: distribution of electricity through all EVs plugged into a system.

By managing these two variables in tandem, load management systems reduce costs for the person using them and protect the local grid, all by managing when electricity is consumed, how much is used and where those amounts go. The ability to manage how much power is being used is critical in minimizing grid failures and optimizing a positive driver experience.

Load management ensures clients avoid costly infrastructure and services upgrades by managing how much electricity they need to bring to their panel to power their chargers. This is critical for setting yourself and clients up for a shorter ROI.

Let us say there is a need for 30 chargers, but only enough room on the panel for 6. Load management will enable you install all 30 chargers by oversubscribing the panel without fear of going over electrical limits. You and your clients can avoid service upgrades, new transformers, panel upgrades or replacements, etc., saving 10's or 100's of thousands of dollars and streamlining the project timeline. This also makes your bids more competitive than others who do not have a firm grasp of this concept.

Load management systems operate in different ways. Most focus on three qualities: controlling when electricity is used, where it goes and how much goes to each vehicle, all with minimal effort on the part of the user.

Types of Load Limits: EV Connect supports both current and power limits in setting charging profiles.

- Current Limit (A): Limiting the maximum amperage of a group of stations based on the size of the upstream circuit breaker or panel.
- Power Limit (kW): Limiting the maximum power (kW) of a group of stations served by one transformer.
- Some sites are also subject a utility rate that requires aggregate load stay below a power threshold.

Load Balancing Logic: Load is balanced in near real time using two mechanisms: Proportional or Fleet.

- Proportional Load Sharing - Each active session is provided a proportional percentage of the available power limit, scaled by the rated capacity of charging stations.

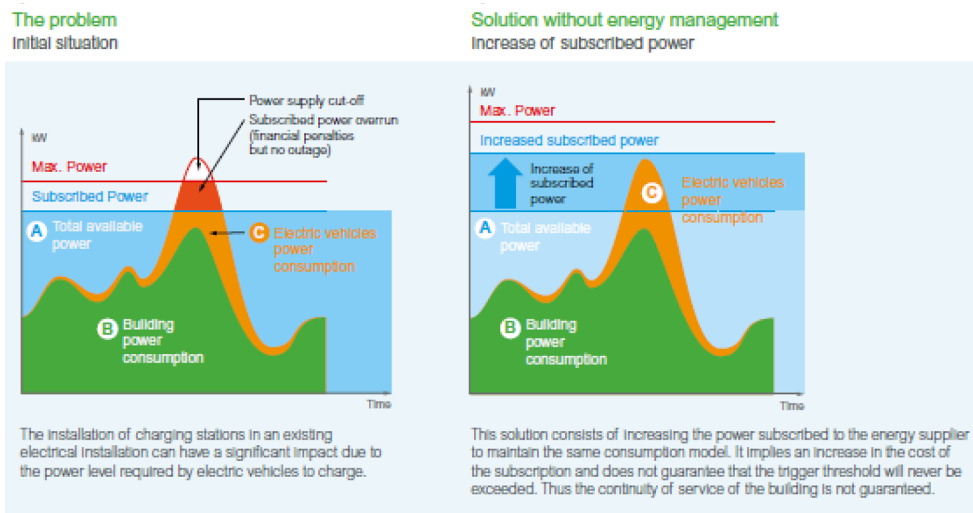
In general, a client will be able to prioritize different elements. For instance, you can prioritize reducing energy cost by instructing the system to charge vehicles separately throughout the night, with a maximum consumption limit. This allows you to ensure that each vehicle is charged as much as possible without threatening the electrical grid or risking high demand charges. Some can even be programmed to consume more electricity when the grid has more capacity than demand, allowing users to make use of that gap while assisting the electrical grid.

Using the example above, let us say your client has all 30 chargers installed off 6 circuits – each with capacity for 1 charger. When driver 1 plugs in, they will get 100%

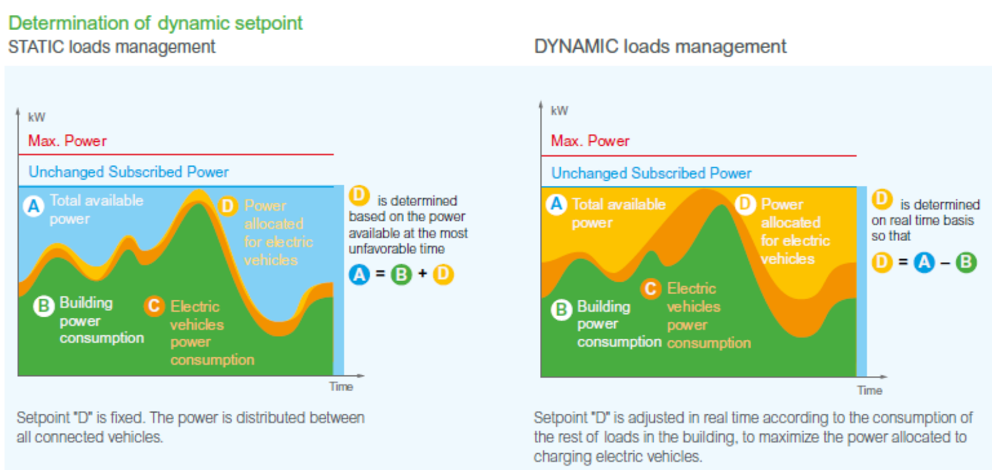
of the power. When driver 2 plugs in, both cars will get 50%. When driver 3 plugs in, all three get 33%, and so on for each circuit. Ideal for scenarios where drivers are parked for long duration, you can see how this has a positive impact on your client's infrastructure costs and charging capacity.

These systems are remarkably simple to use, too. You select peak power or energy usage and tell the system how to judge that amount: either by the total amount consumed or amount used over a specific period of time or make the amount responsive to grid demand. You then set power-sharing settings, picking certain amounts for each vehicle, or using a first-in, first-out system.

Here's how load management uses software to maximize the site's current infrastructure:



If such solution is not installed, the installation should be sized for the maximum power demand without considering charging period and usage coefficient. As consequence, the installation will be oversized versus the real need, and the costs of the EV charging infrastructure will be higher.



So, as you can see, without software, you cannot design an optimal charging program, and therefore cannot maximize a charging program for yourself or a client. ROI is contingent on reducing your up-front infrastructure costs, capturing incentives, managing pricing or time of use, enabling driver groups, and billing them accurately, tracking utilization, increasing uptime, and operating within the grid capacity you have.

With software, all of this is possible. With EV Connect, all of this easy.

By partnering with EV Connect, you are choosing a partner who empowers you to power your client's EV charging programs. We put you in the driver's seat to build, manage, service, track and grow the right solution for your clients and prospects. We understand that your success is directly tied to your ability to easily provide competitive quotes, limit time needed to set-up, service and manage chargers, and be the expert your clients are looking to when they want to offer EV charging.

While there are basic power management software platforms for any building site, it makes the most sense to communicate with the experts at EV Connect to discuss your power management needs. Working in tandem with demand response from the power company, smart charging, software management and power management have the potential to significantly reduce your site costs. Not to mention this helps ensure a sustainable future for EVs if sites can continue to maximize the potential of their existing power infrastructure.

Sources

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3. Select Car Leasing – Miles Per KwH - The New MPG
4. Energy Information Administration (EIA) – Electricity Consumption in the United States Was About 3.9 Trillion Kilowatthours (kWh) in 2021
5. Schneider Electric – What Is a Power Management System, and How Does It Help Optimize Uptime and Efficiency?
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8. McKinsey – Charging electric-vehicle fleets: How to seize the emerging opportunity

Bidirectional Charging

Bidirectional Charging refers to systems that are capable of power flow in two directions: the power to charge the battery in an electric vehicle, as discussed earlier in this section, and reverse power flow from the electric vehicle battery back to the rest of the system. Bidirectional charging requires an EV capable of reverse power flow, EVSE capable of bidirectional power flow, and software to communicate with and manage all the components.

ISO 15118-20 is the ISO 15118 standards document that pertains to vehicle to grid communication standards.

Bidirectional charging is sometimes referred to as V2X or "vehicle to everything" charging. There are also specific types of bidirectional charging discussed in the following.

- **Vehicle to grid (V2G)**: Through a converter that is usually present in the charger, vehicles can send energy directly back to the grid. This can facilitate more energy efficiency for a local power grid and lead to cost savings by enabling charger owners to get paid for helping maintain grid reliability.
- **Vehicle to home (V2H)**: Bidirectional V2H charging turns a car battery into a backup power source for a home. This also allows for more efficient energy usage and potential cost savings and typically relies on technology that is built into the charger.
- **Vehicle to load (V2L)**: The EV battery can be used to power appliances and tools on the go. This type of charging relies on vehicles that have built-in converters and 120-volt plugs for charging appliances and devices.
- **Vehicle to vehicle (V2V):** A specific application of V2L charging where the load is another electric vehicle. V2L allows the transfer of energy from one car to another.

By creating this two-way energy stream, bidirectional charging offers several benefits to EV owners, both in terms of potential savings and energy efficiency.

1. **Save Money on Energy Use**

   Bidirectional charging unlocks potential savings for vehicle owners in two ways. First, smart-charging technology, coupled with bidirectional charging, can turn a car into an efficient power source for a home or business. The vehicle charging can be set to charge during off-peak hours or when renewable sources are available.

   Second, with vehicle-to-grid technology, you can sell energy back to the utility company for redistribution. This can further reduce your utility costs. One study by the University of Rochester found that V2G chargers can save EV owners $120 to $150 per year.

2. **Store Backup Power for Your Home or Business**

   Beyond cost savings, bidirectional charging can also provide peace of mind for homeowners and business owners. If you are caught in a power outage, V2H charging allows your vehicle to serve as a backup power source while the utility company conducts repairs. The typical electric car battery holds about 60 kilowatt-hours of electricity, which is enough to power a home for roughly two days.

3. **Create a Portable Power Source**

   Thanks to bidirectional technology, in some cases, that same battery that can power your home can also go on the road with you to serve as a mobile power source. If you take your EV camping or out on the job, for instance, you can use it to power appliances. In a pinch, you could even use it to provide energy for someone else's car.

Sources:

1. Autotrends – What Is Bidirectional Charging?
2. University of Rochester – Can Electric Cars Help Strengthen Electrical Grids?
3. World Resources Institute – How California Can Use Electric Vehicles To Keep the Lights On
4. Clean Energy Reviews – Bidirectional Chargers Explained - V2G Vs V2H Vs V2L

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