7

Faults

Faults kill. Faults start fires. Faults force interruptions. Faults create voltage sags. Tree trimming, surge arresters, animal guards, cable replacements: these tools reduce faults. We cannot eliminate all faults, but appropriate standards and maintenance practices help in the battle. When faults occur, we have ways to reduce their impacts. This chapter focuses on the general characteristics of faults and specific analysis of common fault types with suggestions on how to reduce them. One of the definitions of a fault is (ANSI/IEEE Std. 100-1992):

Fault: A physical condition that causes a device, a component, or an element to fail to perform in a required manner; for example, a short circuit or a broken wire.

A fault almost always involves a short circuit between energized phase conductors or between a phase and ground. A fault may be a bolted connection or may have some impedance in the fault connection. The term "fault" is often used synonymously with the term "short circuit" defined as (ANSI/IEEE Std. 100-1992):

Short circuit: An abnormal connection (including an arc) of relatively low impedance, whether made accidentally or intentionally, between two points of different potential. (*Note:* The term *fault* or *short-circuit fault* is used to describe a short circuit.)

When a short-circuit fault occurs, the fault path explodes in an intense arc. Local customers endure an interruption, and customers farther away, a voltage sag; faults cause most reliability and power quality problems. Faults kill and injure line operators. Crew operating practices, equipment, and training must account for where fault arcs are likely to occur and must minimize crew exposure.

7.1 General Fault Characteristics

There are many causes of faults on distribution circuits. A large EPRI study was done to characterize distribution faults in the 1980s at 13 utilities mon-

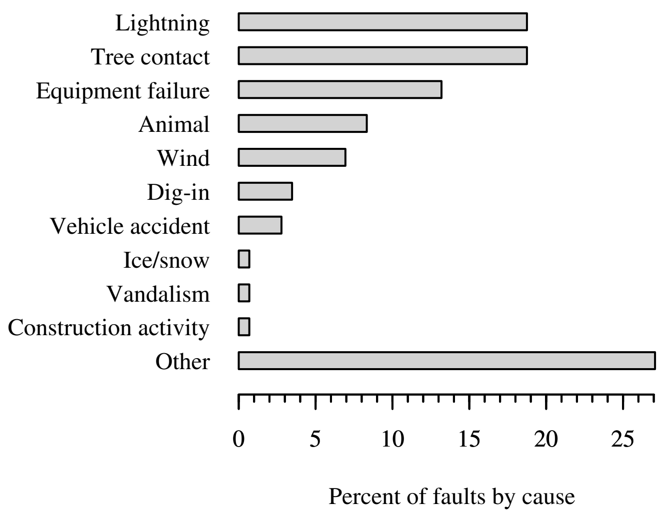


FIGURE 7.1
Fault causes measured in the EPRI fault study. (Data from [Burke and Lawrence, 1984; EPRI 1209-1, 1983].)

itoring 50 feeders (Burke and Lawrence, 1984; EPRI 1209-1, 1983). The distribution of permanent fault causes found in the EPRI study is shown in Figure 7.1. Many of the fault causes are discussed in more detail in this chapter. Approximately 40% of faults in this study occurred during periods of adverse weather which included rain, snow and ice.

Distribution faults occur on one phase, on two phases, or on all three phases. Single-phase faults are the most common. Almost 80% of the faults measured involved only one phase either in contact with the neutral or with ground (see Table 7.1). As another data point, measurements on 34.5-kV

TABLE 7.1
Number of Phases Involved in Each Fault Measured in the EPRI Fault Study

Fault	Percentage
One phase to neutral	63%
Phase to phase	11%
Two phases to neutral	2%
Three phase	2%
One phase on the ground	15%
Two phases on the ground	2%
Three phases on the ground	1%
Other	4%

Source: Burke, J. J. and Lawrence, D. J., "Characteristics of Fault Currents on Distribution Systems," *IEEE Transactions on Power Apparatus and Systems*, vol. PAS-103, no. 1, pp. 1–6, January 1984. EPRI 1209-1 (1983).

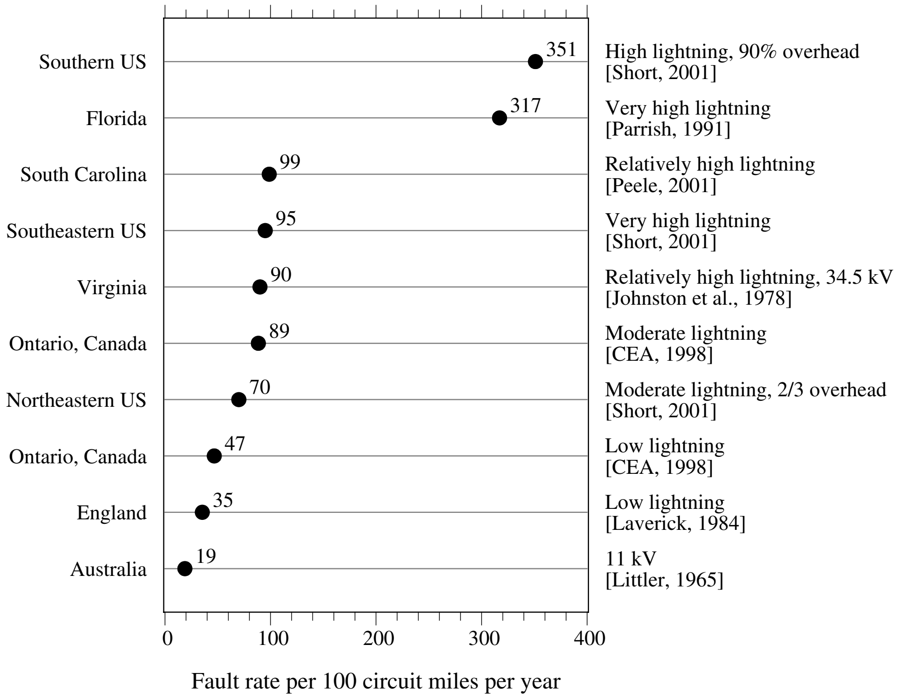


FIGURE 7.2
Fault rates found in different studies. (Data from [CEA 160 D 597, 1998; Johnston et al., 1978; Laverick, 1984; Littler, 1965; Parrish, 1991; Peele, 2001; Short, 2001].)

feeders found that 75% of faults involved ground (also 54% were phase to ground, and 15% were phase to phase) (Johnston et al., 1978). Most faults are single phase because most of the overall length of distribution lines is single phase, so any fault on single-phase sections would only involve one phase. Also, on three-phase sections, many types of faults tend to occur from phase to ground. Equipment faults and animal faults tend to cause line-to-ground faults. Trees can also cause line-to-ground faults on three-phase structures, but line-to-line faults are more common. Lightning faults tend to be two or three phases to ground on three-phase structures.

Figure 7.2 shows fault rates found in various studies for predominantly overhead circuits. Ninety faults per 100 mi per year (55 faults/100 km/year) is common for utilities with moderate lightning. Fault rates increase significantly in higher lightning areas. This type of data is difficult to obtain. Utilities more commonly track faults that cause sustained interruptions, interruptions that contribute to reliability indices such as SAIDI (some data on these faults is shown in Figure 7.3). The actual fault rates are higher than this because many temporary faults are cleared by reclosing circuit breakers or reclosers.

Faults are either *temporary* or *permanent*. A permanent fault is one where permanent damage is done to the system. This includes insulator failures,

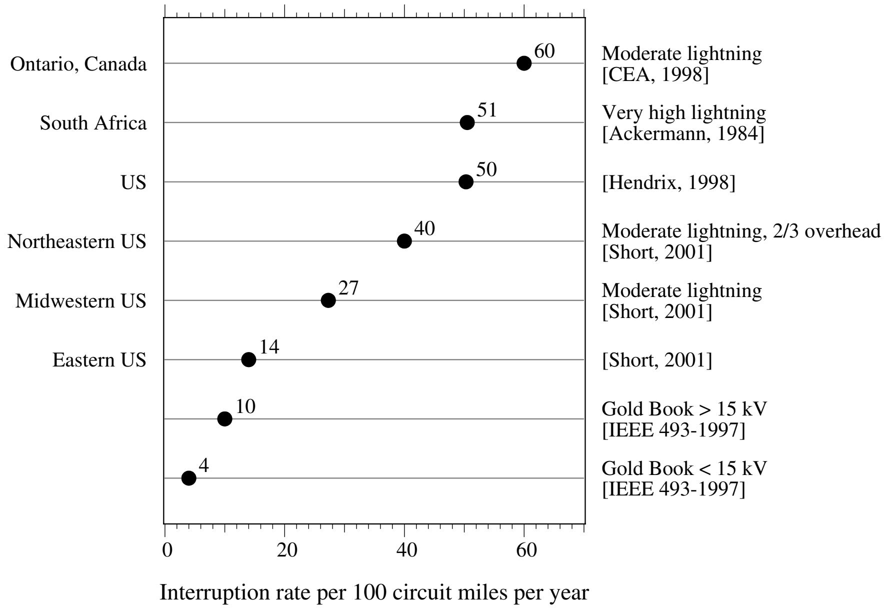


FIGURE 7.3
Fault rates for faults that cause sustained interruptions. (Data from [Ackermann and Baker, 1984; CEA 160 D 597, 1998; Hendrix, 1998; IEEE Std. 493-1997; Johnston et al., 1978; Parrish, 1991; Short, 2001].)

broken wires, or failed equipment such as transformers or capacitors. Virtually all faults on underground equipment are permanent. Most equipment fails to a short circuit. Permanent faults on distribution circuits usually cause sustained interruptions for some customers. To clear the fault, a fuse, recloser, or circuit breaker must operate to interrupt the circuit. The most critical location is the three-phase mains, since a fault on the main feeder will cause an interruption to all customers on the circuit. A permanent fault also causes a voltage sag to customers on the feeder and on adjacent feeders. Permanent faults may cause momentary interruptions for a customer. A common example is a fault on a fused lateral (tap). With *fuse saving* (where an upstream circuit breaker or recloser attempts to open before the tap fuse blows), a permanent fault causes a momentary interruption for customers downstream of the circuit breaker or recloser. After the first attempt to save the fuse, if the fault is still there, the circuit breaker allows the fuse to clear the fault. If a fault is permanent, all customers on the circuit experience a momentary — and the customers on the fused lateral experience a sustained interruption.

A temporary fault does not permanently damage any system equipment. If the circuit is interrupted and then reclosed after a delay, the system operates normally. Temporary (non-damage) faults make up 50 to 90% of faults on overhead distribution systems. The causes of temporary faults include lightning, conductors slapping together in the wind, tree branches that fall across conductors and then fall or burn off, animals that cause faults and

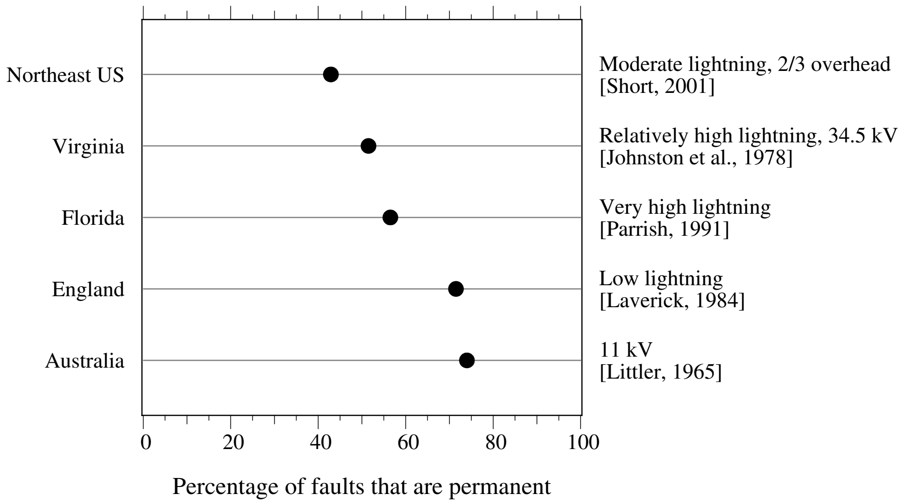


FIGURE 7.4
Percentage of faults that are permanent (on predominantly overhead circuits). (Data from [Johnston et al., 1978; Laverick, 1984; Littler, 1965; Parrish, 1991; Short, 2001].)

fall off, and insulator flashovers caused by pollution. Temporary faults are the main reason that reclosing is used almost universally on distribution circuit breakers and reclosers (on overhead circuits). Temporary faults will cause voltage sags for customers on the circuit with the fault and possibly for customers on adjacent feeders. Temporary faults cause sustained interruptions if the fault is downstream of a fuse, and fuse saving is not used or is not successful. For temporary faults on the feeder backbone, all customers on the circuit are momentarily interrupted. Faults that are normally temporary can turn into permanent faults. If the fault is allowed to remain too long, the fault arc can do permanent damage to conductors, insulators, or other hardware. In addition, the fault current flowing through equipment can do damage. The most common damage of this type is to connectors or circuit interrupters such as fuses.

The majority of faults on overhead distribution circuits are temporary. The data in Figure 7.4 confirms the widely held belief that 50 to 80% of faults are temporary. This very limited data set shows high lightning areas with lower percentages of temporary faults. This contradicts the notion that temporary faults are higher in areas with more lightning. Storms with lightning and wind should cause more temporary faults.

Determining the percentage of faults that are temporary versus permanent is complicated. For faults that operate fuses, it is easy. If it can be successfully re-fused without any repair, the fault is temporary:

$$\text{Percent permanent} = \frac{\text{Fuses replaced after repair}}{\text{Total number of fuse operations}} \times 100\%$$

Circuit breaker or recloser operations are difficult. If *fuse blowing* is used, where tap fuses always operate before the circuit breaker or recloser, the percentage of temporary faults cleared by circuit breakers and reclosers is:

$$\text{Percent permanent} = \frac{\text{Number of lockouts}}{\text{Number of lockouts} + \text{Number of successful reclose sequences}} \times 100\%$$

A SCADA system produces these numbers, but if this information is not available, the percentage can be approximated using circuit breaker count numbers:

$$\text{Percent permanent} = \frac{l}{n\text{-}r \cdot l} \times 100\%$$

where

n = total number of circuit breaker (or recloser) operations
r = number of reclose attempts before lockout (there are r+1 circuit breaker operations during a lockout cycle)
l = number of lockouts

If *fuse saving* is used, where the circuit breaker operates before lateral fuses, then it is more difficult to estimate the number of temporary faults. For the whole circuit (it is not possible to separate the faults on the mains from the faults on the taps), we can estimate the percentage as follows:

$$\text{Percent permanent} = \frac{l + f}{l + s + f_2} \times 100\%$$

where

s = number of successful reclose sequences
f = number of fuses replaced following repair (not including nuisance fuse operations)
f_2 = number of fuse operations that are not coincident with circuit breaker trips

f_2 should be close to zero, since the circuit breaker should operate for all faults. Assuming f_2 is zero (which may have to be done, since this is a difficult number to obtain) implies no nuisance fuse operations without a circuit breaker operation. It is difficult for an outage data management system to properly determine the number of temporary faults.

Faults frequently occur near the peak of the voltage waveform as shown in Figure 7.5. About 60% of the faults in the EPRI fault study occurred when the voltage was within 5% of the peak prefault voltage (where the angle was

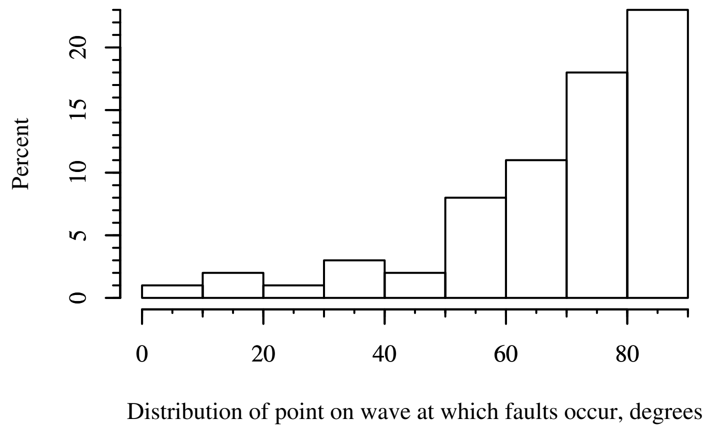


FIGURE 7.5
Point of fault on the voltage waveform. (Data from [Burke and Lawrence 1984; EPRI 1209-1, 1983].)

70 to 90°). This is reasonable. Any insulation failure, whether it be a squirrel breaching a bushing or a failure in a cable, more likely strikes with the voltage at or near its peak. Some faults defy this pattern. Lightning faults happen at any point on the voltage waveform because the fault occurs when the lightning strikes (although lightning can cause a flashover but not a fault if the voltage is very close to a zero-crossing of the power-frequency voltage). Two-phase and three-phase faults create more instances in which the voltage is not near its peak.

7.2 Fault Calculations

The magnitude of fault current is limited only by the system impedance and any fault impedance. The system impedance includes the impedances of wires, cables, and transformers back to the source. For faults involving ground, the impedance includes paths through the earth and through the neutral wire. The impedance of the fault depends on the type of fault.

Most distribution primary circuits are radial, with only one source and one path for fault currents. Figure 7.6 shows equations for calculating fault currents for common distribution faults.

The equations in Figure 7.6 assume that the positive-sequence impedance is equal to the negative-sequence impedance. As an example, the impedance term due to the sequence components for a line-to-line fault is (Z_1 + Z_2), which simplifies to $2Z_1$ when the impedances are assumed to be equal. This is accurate for virtually all distribution circuits. With a large generator nearby, the equivalent circuit may have different positive- and negative-

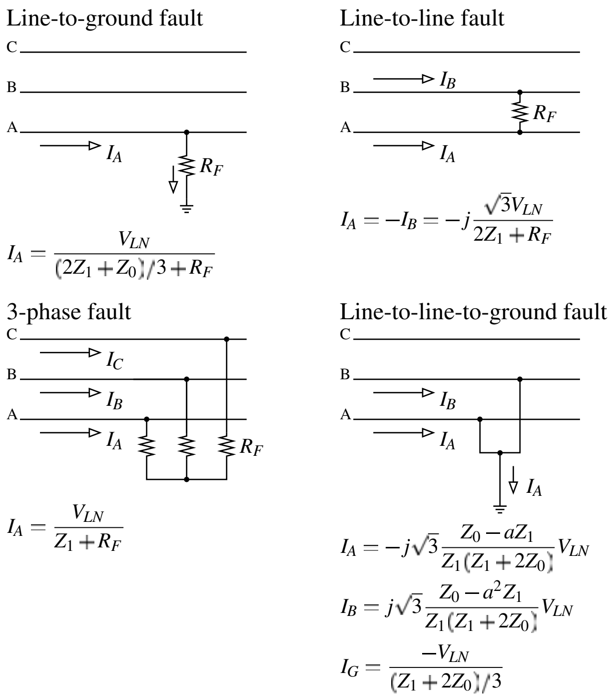


FIGURE 7.6
Fault-current calculations.

sequence impedances (but that case is usually done on the computer and not with hand calculations). The maximum currents occur with a bolted fault where R_F is zero. The maximum current for a line-to-line fault is 86.6% of the maximum three-phase fault current. In all cases, the load current is ignored. In most cases, load will not significantly change results.

The three-phase fault current is almost always the highest magnitude. On most circuits, the zero-sequence impedance is significantly higher than the positive-sequence impedance. One important location where the line-to-ground fault current may be higher is at the substation. There are two reasons for this:

1. A delta – wye transformer is a zero-sequence source. The positive-sequence impedance includes the impedance of the subtransmission and transmission system. The zero-sequence impedance does not. Figure 7.7 shows the sequence diagrams for the positive and zero sequences. The delta-wye connection forms a zero-sequence source while the positive-sequence impedance includes the subtransmission equivalent impedance.
2. If the substation transformer has three-legged core-form construction, the zero-sequence impedance is lower than its positive-

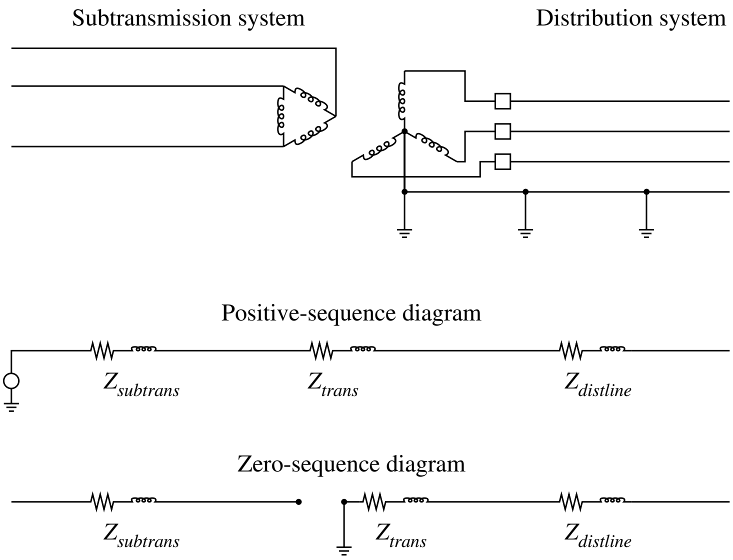


FIGURE 7.7
Positive and zero-sequence diagrams for a delta – wye substation transformer.

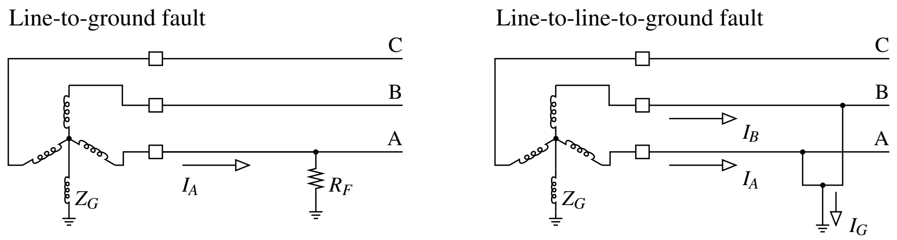
sequence impedance. Typically, the zero-sequence impedance is 85% of the positive-sequence impedance, which increases ground-fault currents by 5.2%.

In cases where the zero-sequence impedance is less than the positive-sequence impedance, the line-to-ground fault gives the highest phase current. The double line-to-ground fault produces the highest-magnitude ground current.

In order to reduce fault currents for line-to-ground faults, a neutral reactor on the station transformer is sometimes used. Figure 7.8 shows the equations for faults involving ground for circuits with a neutral reactor (the line-to-line fault and the three-phase fault are not affected). A common value for a neutral reactor is 1 Ω for 15-kV class distribution circuits.

The impedance seen by line-to-ground faults is a function of both the positive and the zero sequence impedances. This important loop impedance is $Z_S = (2Z_1 + Z_0)/3$. The sequence impedances, Z_1 and Z_0, used in the fault calculations include the sum of the impedances with both resistance and reactance along the fault current path. Some of the common branch impedances are given below including some rule-of-thumb values that are useful for hand calculations:

- Overhead lines:
  - $|Z_1| = 0.5\ \Omega/\text{mi}\ (0.3\ \Omega/\text{km})$
  - $|Z_S| = 1\ \Omega/\text{mi}\ (0.6\ \Omega/\text{km})$



$$I_A = \frac{V_{LN}}{(2Z_1 + Z_0)/3 + R_F + Z_G}$$

$$I_A = -j\sqrt{3}\,\frac{Z_0 + 3Z_G - aZ_1}{Z_1(Z_1 + 2Z_0 + 6Z_G)}V_{LN}$$

$$I_B = j\sqrt{3}\,\frac{Z_0 + 3Z_G - a^2Z_1}{Z_1(Z_1 + 2Z_0 + 6Z_G)}V_{LN}$$

$$I_G = \frac{-V_{LN}}{(Z_1 + 2Z_0 + 6Z_G)/3}$$

FIGURE 7.8
Fault-current calculations with a neutral reactor on the substation transformer.

- Underground cables:
  - $|Z_1|$ = 0.6 Ω/mi (0.35 Ω/km)
  - $|Z_S|$ = 0.5 Ω/mi (0.3 Ω/km)
- Substation transformer:
  - $|Z_1|$ = $|Z_S|$ = 1 Ω
  - A typical 15-kV substation transformer impedance is 1 Ω, which corresponds to a bus fault current of 7.2 kA for a 12.47-kV circuit.
- Subtransmission equivalent: often can be ignored

See Smith (1980) for an excellent paper on fault calculations for additional information. Include impedances for step-down transformer banks, series reactors, and voltage regulators. Use the rule-of-thumb numbers above for back-of-the-envelope calculations and as checks for computer modeling.

The simplified equation for a transformer impedance is

$$Z_1 = Z_0 = j\frac{kV^2}{MVA}Z_{\%}$$

where

kV = line-to-line voltage
MVA = transformer base rating — open air (OA) rating
$Z_{\%}$ = transformer impedance, per unit

We ignore the resistive component since the X/R ratio of station transformers is generally greater than 10 and often in the range of 20 to 30. The transmission/subtransmission equivalent is usually small, and we often ignore it (especially for calculating maximum fault currents). Include the transmission system impedance for weak subtransmission systems such as 34.5-, 46- or 69-kV circuits, or for very large substations. Find the transmission equivalent from the per unit impedances (r_1, x_1, r_0, and x_0) on a given MVA base referred to the distribution voltage (Smith, 1980) as

$$Z_1 = (r_1 + jx_1)\frac{kV_s^2}{MVA_b}\left(\frac{kV_{pb}}{kV_p}\right)^2$$

$$Z_0 = (r_0 + jx_0)\frac{kV_s^2}{MVA_b}\left(\frac{kV_{pb}}{kV_p}\right)^2$$

where

MVA_b = base MVA at which the r and x impedances are given
kV_s = line-to-line voltage in kV on the secondary side of the station transformer
kV_p = line-to-line voltage in kV on the primary
kV_{pb} = base line-to-line voltage on the primary used to calculate MVA_b (often equal to kV_p)

If the transmission impedances are available as a fault MVA with a power factor, find the transmission equivalent (Smith, 1980) with

$$Z_1 = \frac{kV_s^2}{MVA}(pf + j\sqrt{1-pf^2})\left(\frac{kV_{pb}}{kV_p}\right)^2$$

$$Z_0 = \frac{\sqrt{3}kV_s^2}{kI_g \cdot kV_{pb}}(pf_g + j\sqrt{1-pf_g^2})\left(\frac{kV_{pb}}{kV_p}\right)^2 - 2Z_1$$

where

MVA = 3-phase short-circuit MVA at the primary terminals of the station transformer (see Table 7.2 for typical maximum values)
kI_g = available ground fault current in kA at the primary terminals of the station transformer
pf = power factor in per unit for the available three-phase fault current
pf_g = power factor in per unit for the available single-phase fault current

While almost all distribution circuits are radial, there may be other fault current sources. We ignore these other sources most of the time, but occasionally, we consider motors and generators in fault calculations. Synchronous motors and generators contribute large currents relative to their size. On a typical 15-kV class distribution circuit, one or two megawatts worth

TABLE 7.2

Typical Maximum Transmission/Subtransmission Fault Levels

Transmission Voltage, kV	Maximum Symmetrical Fault, MVA
69	3,000
115	5,000
138	6,000
230	10,000

of connected synchronous units are needed to significantly affect fault currents. On weaker circuits, smaller units can impact fault currents. Induction motors and generators also feed faults. Inverter-based distributed generation can contribute fault current, but generally much less than synchronous or induction units. Of course, on feeders that have network load, current through network transformers backfeeds faults until the network protectors operate.

7.2.1 Transformer Connections

The fault current on each side of a three-phase transformer connection can differ in magnitude and phasing. In the common case of a delta – grounded-wye connection, the current on the source side of the transformer differs from the currents on the fault side for line-to-ground or line-to-line faults (see Figure 7.9). For a line-to-ground fault on the primary side of the transformer, the current appears on two phases on the primary with a per unit current of 0.577 (which is $1/\sqrt{3}$).

These differences are often needed when coordinating a primary-side protective device and a secondary-side device. In distribution substations, this is commonly a fuse on the primary side and a relay controlling a circuit breaker on the secondary side. The line-to-line fault must be considered — this gives more per-unit current on one phase in the primary, 1.15 per unit

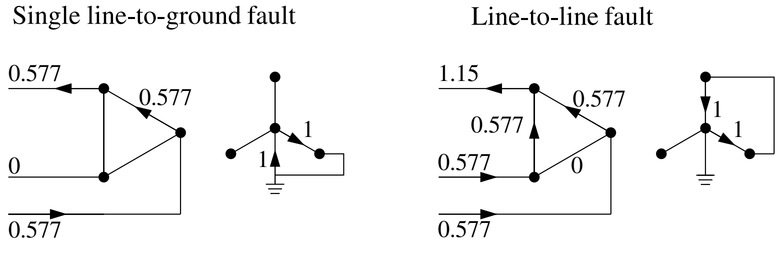


FIGURE 7.9
Per-unit fault-currents on both sides of a delta – grounded-wye transformer.

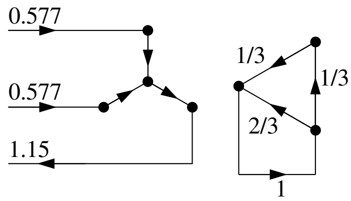


FIGURE 7.10
Per-unit fault-currents on both sides of a wye – delta transformer.

($2/\sqrt{3}$) in one of the phases (see Figure 7.9). To make sure a primary fuse coordinates with a secondary device, shift the minimum-melting time-current curve of the primary-side fuse to the left by a factor of 0.866 = $\sqrt{3}/2$ (after also adjusting for the transformer turns ratio). The current differences also mean that the transformer is not protected as well for single-phase faults; a primary-side fuse takes longer to clear the single-phase fault since it sees less current than for a three-phase or line-to-line fault.

Fault currents are only different for unbalanced secondary currents. For a three-phase secondary fault, the per-unit currents on the primary equal those on the secondary (with the actual currents related by the turns ratio of the transformer). A wye – wye transformer does not disturb the current relationships; the per-unit currents on both sides of the transformer are equal.

In a floating wye – delta, similar current relationships exist; a line-to-line secondary fault shows up on the primary side on all three phases, one of which is 1.15 per unit (see Figure 7.10). For a floating wye – delta transformer with a larger center-tapped lighting leg and two power legs, fault current calculations are difficult. Faults can occur from phase to phase and from phase to the secondary neutral, and the lighting transformer will have a different impedance than the power leg transformers. For an approach to modeling this, see Kersting and Phillips (1996).

7.2.2 Fault Profiles

Fault profiles show fault current with distance along a circuit. Determining where thermal or mechanical short-circuit limits on equipment may be exceeded, helping select or check interrupting capabilities of protective equipment, and coordinating protective devices are important uses of fault profiles. Figure 7.11 and Figure 7.12 show typical fault current profiles of distribution circuits.

Some general trends that the fault profiles show are:

- *Distance* — The fault current drops off as the inverse of distance ($1/d$).
- *Ground faults* — On overhead circuits, the ground fault current falls off faster (and the ground fault current is generally lower)

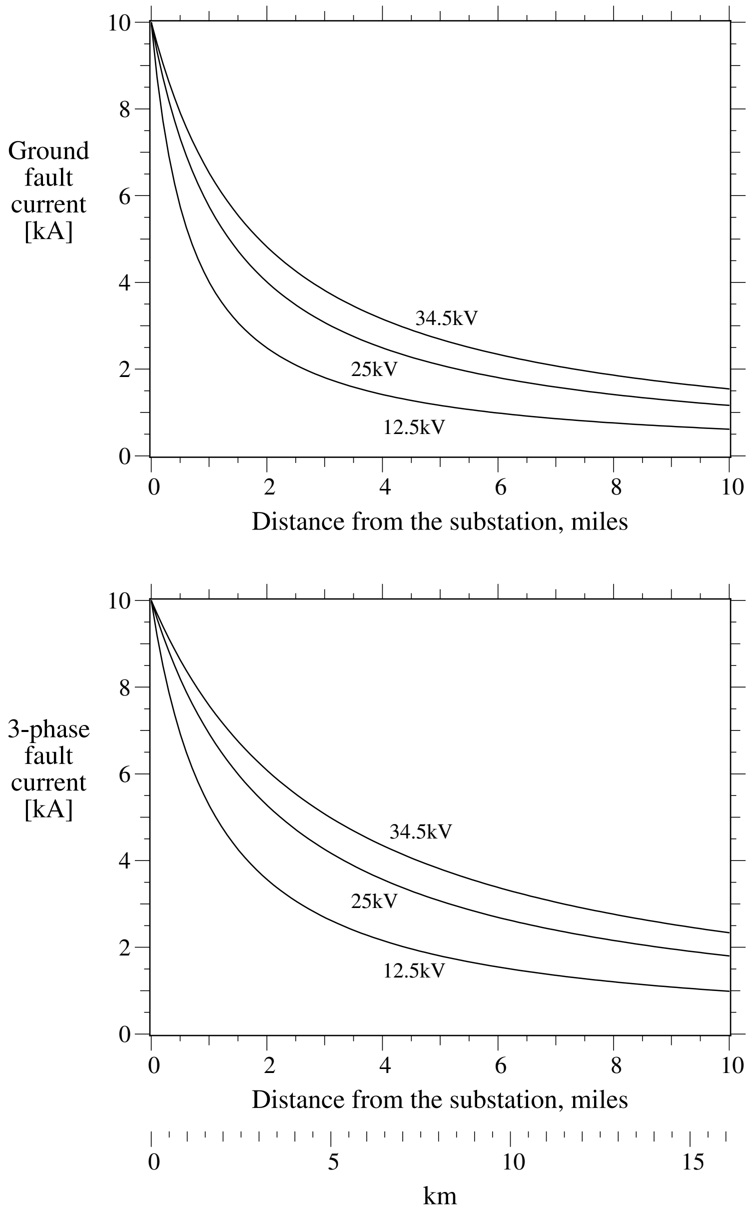


FIGURE 7.11
Fault-current profiles for line-to-ground faults and for three-phase faults for an overhead circuit. Phase characteristics: 500 kcmil, all-aluminum, GMD = 4.69 ft (1.43 m). Neutral characteristics: 3/0 all-aluminum, 4-ft (1.22-m) line-neutral spacing. $Z_1 = 0.207 + j0.628\ \Omega$/mile ($0.1286 + j0.3901\ \Omega$/km), $Z_0 = 0.720 + j1.849\ \Omega$/mile ($0.4475 + j1.1489\ \Omega$/km), $Z_S = 0.378 + j1.035\ \Omega$/mile ($0.2350 + j0.6430\ \Omega$/km).

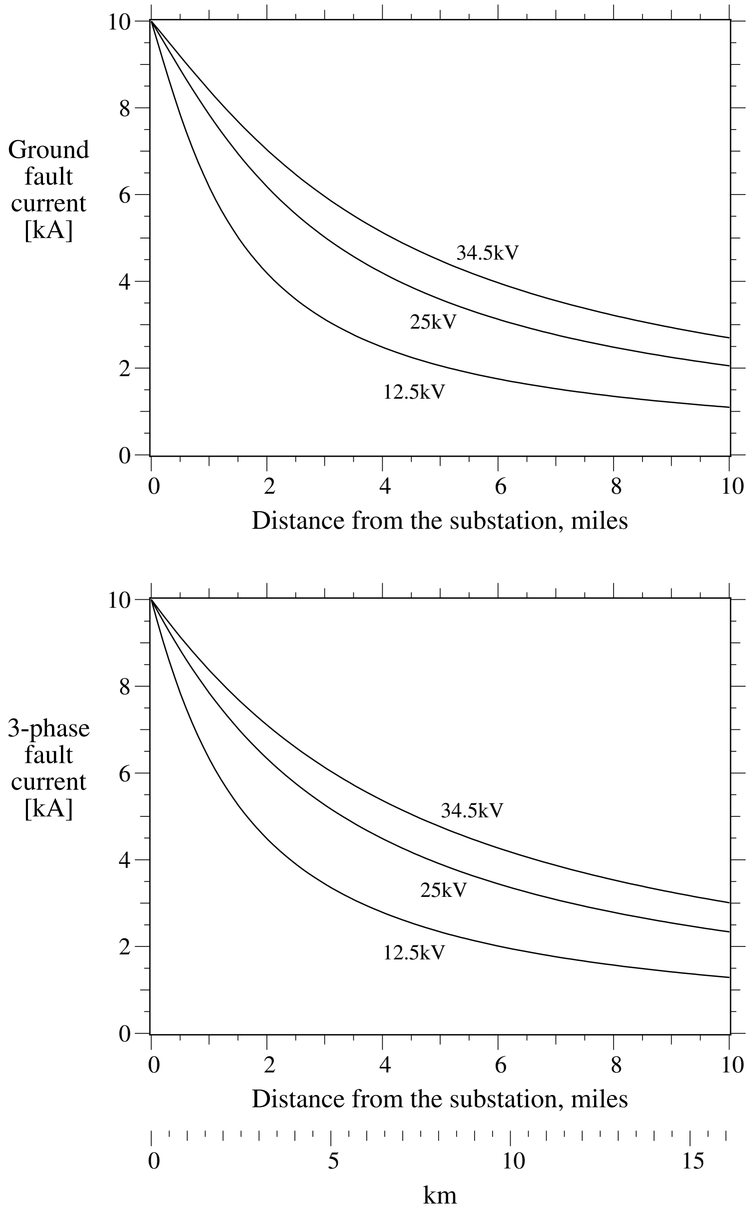


FIGURE 7.12
Fault-current profiles for line-to-ground faults and for three-phase faults for an underground cable circuit. 500-kcmil aluminum conductor, 220-mil XLPE insulation, 1/3 neutrals, flat spacing, 7.5 in. between cables. $Z_1 = 0.3543 + j0.3596\ \Omega/\text{mile}$ $(0.2201 + j0.2234\ \Omega/\text{km})$, $Z_0 = 0.8728 + j0.2344\ \Omega/\text{mile}$ $(0.5423 + j0.1456\ \Omega/\text{km})$, $Z_S = 0.5271 + j0.3178\ \Omega/\text{mile}$ $(0.3275 + j0.1975\ \Omega/\text{km})$.

than the three-phase fault current. The zero-sequence reactance is generally over three times the positive-sequence reactance, and the zero-sequence resistance is also higher than the positive-sequence resistance.

- *System voltage* — On higher-voltage distribution systems, the fault current drops off more slowly. The actual line impedance does not change with voltage ($Z_S \approx 1\ \Omega/\text{mi}$), and since $I = V_{LN}/Z$, it takes more impedance (more circuit length) to reduce the fault current.
- *Cables* — Underground cables have much lower reactance than overhead circuits, so the fault current does not fall off as fast on underground circuits. Also, note that *X/R* ratios are lower on cables.
- *Profiles* — The three-phase and ground-fault profiles of underground cables are similar. The zero-sequence reactance can actually be smaller than the positive-sequence reactance (but the zero-sequence resistance is larger than the positive-sequence resistance).

7.2.3 Effect of *X/R* Ratio

In a reactive circuit (high *X/R* ratio), it is naturally more difficult for a protective device such as a circuit breaker to clear a fault. Protective devices clear a fault at a current zero. Within the interruptor, dielectric strength builds up to prevent the arc from reigniting after the current zero. In a resistive circuit (low *X/R* ratio), the voltage and current are in phase, so after a current zero, a quarter cycle passes before the voltage across the protective device (called the *recovery voltage*) reaches its peak. In a reactive circuit, the fault current naturally lags the voltage by 90°; the voltage peaks at a current zero. Therefore, the recovery voltage across the protective device rises to its peak in much less than a quarter cycle (possibly in 1/20th of a cycle or less), and the fault arc is much more likely to reignite.

Another factor that makes it more difficult for protective devices to clear faults is asymmetry. Circuits with inductance resist a change in current. A short circuit creates a significant change in current, possibly creating an offset. If the fault occurs when the current would naturally be at its negative peak, the current starts at that point on the waveshape but is offset by 1.0 per unit. The dc offset decays, depending on the *X/R* ratio. The offset is described by the following equation:

$$i(t) = \underbrace{\sqrt{2}I_{rms}\sin(2\pi ft + \beta - \theta)}_{\text{ac component}} - \underbrace{\sqrt{2}I_{rms}\sin(\beta - \theta)e^{-\frac{2\pi ft}{X/R}}}_{\text{decaying dc component}}$$

where

i(t) = instantaneous value of current at time *t*

I_{rms} = root-mean square (rms) value of the ac component of current,

$$I_{rms} = V / \sqrt{R^2 + X^2}$$

β = the closing angle which defines the point on the waveform at which the fault is initiated

θ = system impedance angle = $\tan^{-1} \frac{X}{R}$

f = system frequency, Hz

t = time, sec

Asymmetry is higher with higher X/R ratios. The worst case offset with $X/R = \infty$ is 2 per unit. Figure 7.13 shows an example of an offset fault current.

If a phase faults at the natural zero crossing ($\beta = \theta$), no offset occurs. The highest magnitude of the dc component occurs when the fault happens 90° from the natural zero crossing of the circuit (when $\beta = \theta \pm \pi/2$). The highest

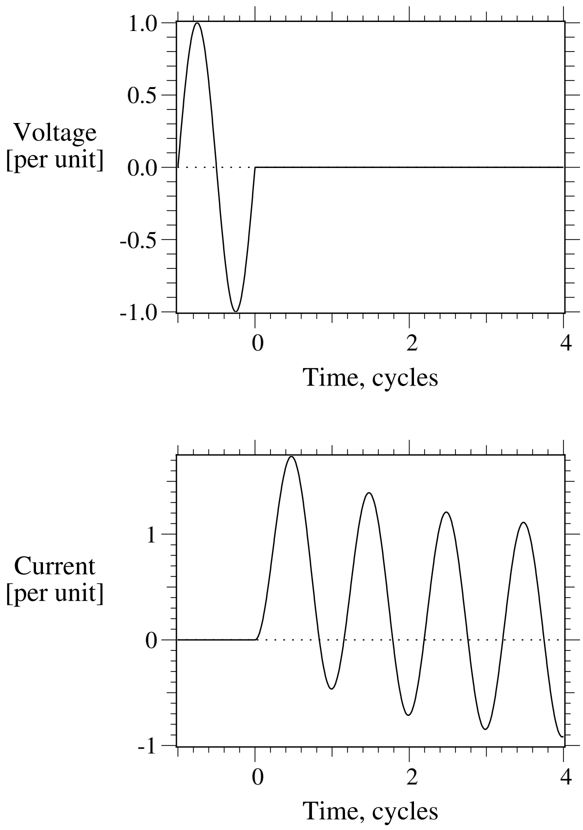


FIGURE 7.13
Example of an asymmetric fault with X/R = 10 which initiated when the closing angle β = 0, which is when the voltage crosses zero.

dc offset does not align with the highest peak asymmetric current (which is the sum of the ac and decaying dc component). The peak current occurs when the closing angle β= 0 for all X/R ratios (β = 0 when the fault occurs at a voltage zero crossing). The ratio of the peak current I_p to the rms current I_{rms} can be approximated by

$$\frac{I_p}{I_{rms}} = \sqrt{2}\left[1 + e^{-(\theta+\pi/2)\frac{R}{X}} \sin\theta\right] = \sqrt{2}\left[1 + e^{-\pi\frac{R}{X}}\right] \quad \text{for } \theta = \pi/2$$

This is the most industry-accepted approximation that is used, but it gives an approximation that is slightly low. A more accurate approximation can be found (St. Pierre, 2001) with

$$\frac{I_p}{I_{rms}} = \sqrt{2}\left[1 + e^{-2\pi\frac{R}{X}\tau}\right]$$

where τ is a fictitious time found with

$$\tau = 0.49 - 0.1e^{-\frac{1}{3}\frac{X}{R}}$$

In addition to causing a higher peak magnitude, asymmetry also causes a longer first half cycle (important for fuse operating time) and much higher first half cycle $\int I^2\,dt$. The occurrence of asymmetry is reduced by the fact that most faults occur when the voltage is near its peak (Figure 7.5). In a circuit with a high X/R ratio, when the voltage is at its peak, the fault current is naturally near zero. Therefore, for most faults, the asymmetry is small, especially for line-to-ground faults. For two- or three-phase faults where each phase is faulted simultaneously (as can happen with lightning), asymmetry is much more likely.

Asymmetry is important to consider for application of cutouts, circuit breakers, and other equipment with fault current ratings. Equipment is generally tested at a given X/R ratio. If the equipment is applied at a location where the X/R ratio is higher, then the equipment may have less capability than the rating indicates. Equipment often has a momentary duty rating which is the short-time (first-cycle) withstand capability. This is strongly influenced by asymmetry.

Other impacts of asymmetry include:

- Asymmetry can saturate current transformers (CTs). On distribution circuits, overcurrent relays should still operate although they could be more susceptible to miscoordination.
- Fuses respond to $\int I^2 dt$, so asymmetrical current melts the link significantly faster.

- Asymmetry can foul up fault-location algorithms in digital relays and fault recorders.

7.2.4 Secondary Faults

Secondary faults vary depending on the transformer connection and the type of fault on the secondary. For a standard single-phase 120/240-V secondary for residential service, two faults are of interest: a fault from a phase to the neutral and a fault from one of the hot legs to the other across the full 240 V. The impedance to the fault includes the transformer plus the secondary impedance. The secondary current for a bolted fault across the 240-V legs (between the two hot legs) is

$$I_{240} = \frac{240}{\sqrt{\left(R_T + \frac{R_S L}{1000}\right)^2 + \left(X_T + \frac{X_S L}{1000}\right)^2}}$$

where

I_{240} = Secondary current, symmetrical A rms for a 240-V fault (phase-to-phase)
R_T = Transformer full-winding resistance, Ω at 240 V (from terminals X1 to X3)
X_T = Transformer full-winding reactance, Ω at 240 V (from terminals X1 to X3)
R_S = Secondary conductor resistance to a 240-V fault, Ω/1000 ft
X_S = Secondary conductor resistance to a 240-V fault, Ω/1000 ft
L = Distance to the fault, ft

and

$$R_T = 0.0576 \frac{W_{CU}}{S_{kVA}^2}$$

$$Z_T = 0.576 \frac{Z_{\%}}{S_{kVA}}$$

$$X_T = \sqrt{Z_T^2 - R_T^2}$$

where

S_{kVA} = transformer rating, kVA
$W_{CU} = W_{TOT} - W_{NL}$ = load loss at rated load, W
W_{TOT} = total losses at rated load, W
W_{NL} = no-load losses, W
$Z_{\%}$ = nameplate impedance magnitude, %

For a short circuit from one of the hot legs to the neutral, both the transformer and the secondary have different impedances. For the transformer, the half-winding impedance must be used; for the secondary, the loop impedance through the phase and the neutral should be used.

$$I_{120} = \frac{120}{\sqrt{\left(R_{T1} + \frac{R_{S1}L}{1000}\right)^2 + \left(X_{T1} + \frac{X_{S1}L}{1000}\right)^2}}$$

where

I_{120} = Secondary current in symmetrical A rms for a 120-V fault (phase-to-neutral)
R_{T1} = Transformer half-winding resistance, Ω at 120 V (from terminals X1 to X3)
X_{T1} = Transformer half -winding reactance, Ω at 120 V (from terminals X1 to X3)
R_{S1} = Secondary conductor resistance to a 120-V fault, Ω/1000 ft
X_{S1} = Secondary conductor resistance to a 120-V fault, Ω/1000 ft
L = Distance to the fault, ft

In absence of better information, use the following impedances for transformers with an interlaced secondary winding:

$$R_{T1} = 0.375R_T \quad \text{and} \quad X_{T1} = 0.3X_T$$

And use the following impedances for transformers with noninterlaced secondary windings:

$$R_{T1} = 0.4375R_T \quad \text{and} \quad X_{T1} = 0.625X_T$$

Figure 7.14 shows fault profiles for secondary faults on various size transformers. The secondary is triplex with 3/0 aluminum conductors and a reduced neutral. It has impedances of

$$R_S = 0.211\ \Omega/1000\text{ ft} \qquad X_S = 0.0589\ \Omega/1000\text{ ft}$$

$$R_{S1} = 0.273\ \Omega/1000\text{ ft} \qquad X_{S1} = 0.0604\ \Omega/1000\text{ ft}$$

The secondary has significant impedances; fault currents drop quickly from the transformers. Close to the transformer, line-to-neutral faults are higher magnitude. At large distances from the transformer, the secondary impedances dominate the fault currents. Faults across 240 V are normally higher magnitude than line-to-neutral faults.

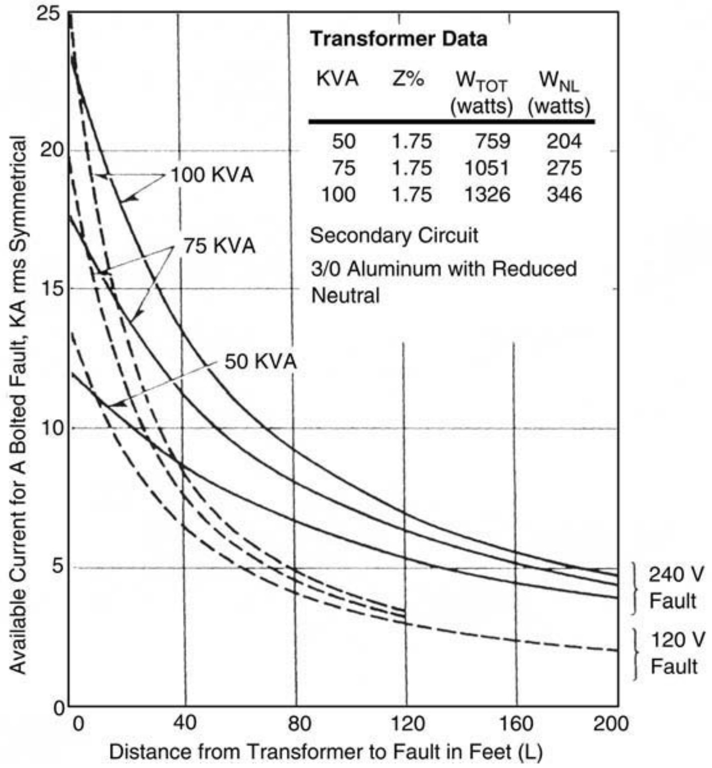


FIGURE 7.14
Fault profiles for 120/240-V secondary faults ($R_{T1} = 0.375R_T$, and $X_{T1} = 0.5X_T$). (From ABB Inc., *Distribution Transformer Guide*, 1995. With permission.)

Normally in secondary calculations, we can ignore the impedance offered by the distribution primary. The primary-system impedance is usually small relative to the transformer impedance, and neglecting it is conservative for most uses. On weak distribution systems or with large, low-impedance distribution transformers, the distribution system impedance plays a greater role.

7.2.5 Primary-to-Secondary Faults

Faults from the distribution primary to the secondary can subject end-use equipment to significant overvoltages. Figure 7.15 shows a circuit diagram of a fault from the primary to a 120/240-V secondary. This type of fault can occur several ways: a high-to-low fault within the transformer, a broken primary wire falling into the secondary, or a broken primary jumper. As we will discuss, the transformer helps limit the overvoltage. Having the primary fall on the secondary does not automatically mean primary-scale voltages in customers' homes and facilities.

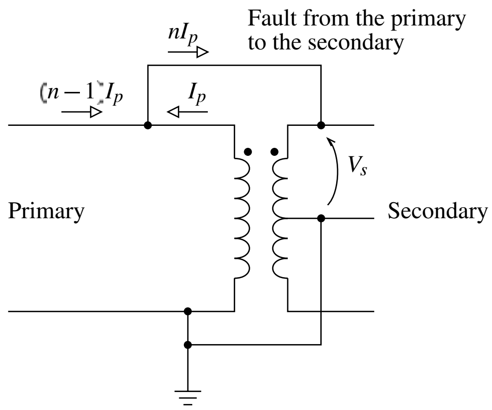


FIGURE 7.15
Fault from the primary to a 120/240-V secondary circuit.

The per-unit secondary voltage for a fault from the primary to the secondary (PTI, 1999) is

$$V_s = \frac{n}{1+(n-1)^2 \dfrac{S_{kVA}}{10\ V_{kV}\ I_{kA}\ Z_{\%}}}$$

where
V_s = secondary voltage, per unit at 120 V
n = transformer turns ratio from the primary voltage to the half-voltage secondary rating (normally 120 V)
I_{kA} = available primary fault current for a single line-to-ground fault, kA
S_{kVA} = transformer rating, kVA
$Z_{\%}$ = half winding impedance of the transformer, %
V_{kV} = primary line-to-ground winding rated voltage, kV

Figure 7.16 shows the per-unit overvoltage for various transformer sizes. Surprisingly, the primary voltage does not impact the overvoltage significantly. The overvoltage equation in per unit reduces (PTI, 1999) to approximately

$$V_s \approx \frac{1.2 Z_{\%} I_{kA}}{S_{kVA}}$$

The overvoltage increases with higher available fault current, higher impedance transformers, and smaller transformers. For all but the smallest transformers with the highest impedance, the overvoltage is not too hazardous. But, if a fuse operates to separate the transformer from the circuit but

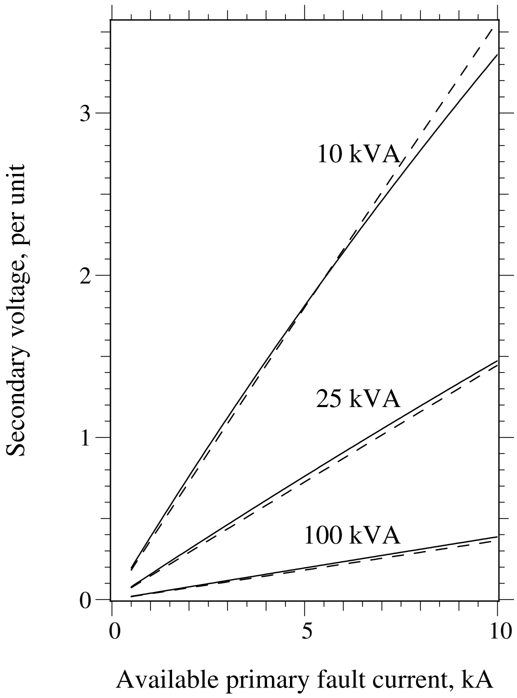


FIGURE 7.16
Secondary voltage during a fault from the primary to a 120/240-V secondary circuit. The solid lines are for a 4.8-kV circuit, and the dashed lines are for a 34.5-kV circuit. The results assume that $Z_{\%} = 3\%$.

leaves the primary-to-secondary fault, the fault imposes full primary voltage on the secondary (at least until the first failure on the secondary system). Such a condition can occur when the fault starts on the primary side above the transformer fuse (see Figure 7.17). If the transformer fuse blows before the upstream line fuse, the secondary voltage rises to the primary voltage. If the fault is below the transformer fuse, it does not matter which fuse blows first; either clears the fault.

The example in Figure 7.15 shows a fault to the secondary leg that is in phase with the primary (off of the *X*1 bushing of the transformer). A fault to the other secondary leg (off of *X*3) has very similar effects; the voltages and currents are almost the same, so the equations and graphs in this section also apply.

Although the transformer helps hold down the overvoltage, the primary-to-secondary fault may initiate a sizeable switching transient that could impact end-use equipment.

With most line fuses and transformer fuses used, the line fuse will clear before the transformer fuse and before the transformer suffers damage (good news on both counts). Even though the upstream fuse is larger, it sees $(n - 1)$

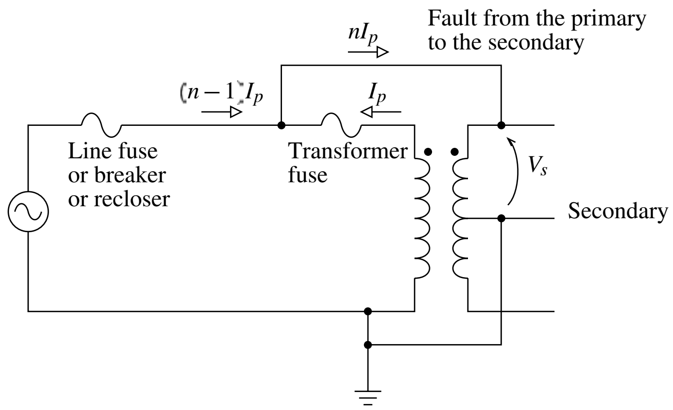


FIGURE 7.17
Fault from the primary to a 120/240-V secondary circuit.

times the fault current. With the primary fault above the transformer fuse, the transformer fuse is more likely to operate before the line fuse with

- *Small transformer fuses* — Another reason not to fuse transformers too tightly; smaller, fast transformer fuses are more likely to clear before an upstream device.
- *Upstream breaker or recloser* — If the upstream device is a circuit breaker or recloser instead of a fuse, the tripping time is much longer, especially on a time-delayed trip (but even a fast trip is relatively long). If a circuit breaker is upstream of the transformer, the transformer fuse is likely to blow before the circuit breaker for locations with high fault currents and with small transformer fuses.

A more detailed analysis of the coordination of the two devices requires using the time-current characteristics of each of the protective devices along with the currents. The current into the primary winding, I_p in kA is

$$I_p = \frac{I_{kA}}{(n-1) + \dfrac{10 I_{kA}}{(n-1)} \dfrac{V_{kV}}{S_{kVA}} Z_{\%}} \approx \frac{I_{kA}}{n}$$

Again, the upstream device sees $(n-1)I_p$, which is almost the full available current for a single line-to-ground fault, I_{kA}.

A transformer with a secondary circuit breaker (as in a completely self-protected transformer, a CSP) has another possible mode where the transformer separates. If the secondary circuit breaker opens before the upstream primary device, the high-to-low fault raises the secondary voltage to the primary voltage. The secondary circuit breaker may not be able to clear the

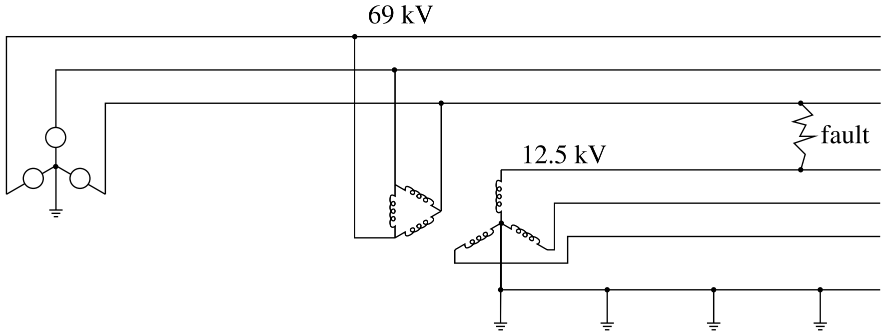


FIGURE 7.18
Example of a fault from a transmission conductor to a distribution conductor.

fault because the arc recovery voltage is much higher than the rating for the secondary circuit breaker; this is good news in that it helps protect end-use equipment from extreme overvoltages, but the secondary circuit breaker may fail trying to clear the fault. If the upstream device is a fuse, the fuse will probably clear before the secondary circuit breaker opens, but if the upstream device is a circuit breaker, the secondary circuit breaker will probably try to open first.

7.2.6 Underbuilt Fault to a Transmission Circuit

Faults from transmission circuits to distribution circuits are another hazard that can subject distribution equipment and customer equipment to extremely high voltages. Consider the example in Figure 7.18 of a fault from a subtransmission circuit to a distribution circuit.

As is the case for primary-to-secondary faults discussed in the previous section, overvoltages are not extremely high as long as the distribution circuit stays connected. But if a distribution interrupter opens the circuit, the voltage on the faulted distribution conductor jumps to the full transmission-line voltage. With voltage at several times normal, something will fail quickly. Such a severe overvoltage is also likely to damage end-use equipment. The distribution interrupter, either a circuit breaker or recloser, may not be able to clear the fault (the recovery voltage is many times normal); it may fail trying.

Faults further from the distribution substation cause higher voltages, with the highest voltage at the fault location. Current flowing back towards the circuit causes a voltage rise along the circuit.

While one can use a computer model for an exact analysis (but it is not possible with most standard distribution short-circuit programs), a simplified single-phase analysis (assuming a wye – wye transformer) helps frame the problem. The fault current is approximately

$$I = \frac{V_S}{\frac{(n-1)}{n} Z_A + \frac{n}{(n-1)} Z_B} \approx \frac{V_S}{Z_A + Z_B}$$

where

n = ratio of the transmission to distribution voltage (n = 69/12.5 = 5.5 in the example)

V_S = rms line-to-ground transmission source voltage (40 kV in the example)

Z_A = loop impedance from the transmission source to the high side of the distribution station

Z_B = loop impedance from the high-side at the distribution station out to the fault and back to the distribution low-side of the distribution substation

And, the 69-kV impedance often dominates, so the fault current is really determined by Z_A. For the distribution and transmission line impedances, Z_A and Z_B, you can use 1 Ω/mi for quick approximations. The worst case is with a small Z_A, a stiff subtransmission system.

The voltage at the fault is

$$V = I \frac{Z_B}{2} + V_d$$

where

V_d = line-to-ground voltage on the distribution circuit at the substation (as a worst case, assume that it is the nominal voltage; it will usually be less because of the sag that pulls down the voltages).

Figure 7.19 shows results from a series of computer simulations on a 12.5-kV circuit for various fault locations and subtransmission source stiffnesses. Results only modestly differ for other configurations: a 69-kV source in the opposite direction, a looped transmission source, a different substation transformer configuration, or different phases faulted. The worst cases are for stiff transmission systems.

If a distribution interrupter opens to leave transmission voltage on the distribution circuit, distribution transformers would saturate and metal-oxide arresters would move into heavy conduction. Transformer saturation distorts the voltage but may not appreciably reduce the peak voltage. Arresters can reduce the peak voltage, but they could still allow quite high voltages to customers. Arresters with an 8.4-kV maximum continuous operating voltage start conducting for power-frequency voltages at about 11 to 12 kV (1.5 to 1.6 times the nominal system line-to-ground voltage). At higher voltages, the arresters will draw more current. Depending on the number of arresters, a stiff transmission source can still push the voltage to between 3 and 4 per

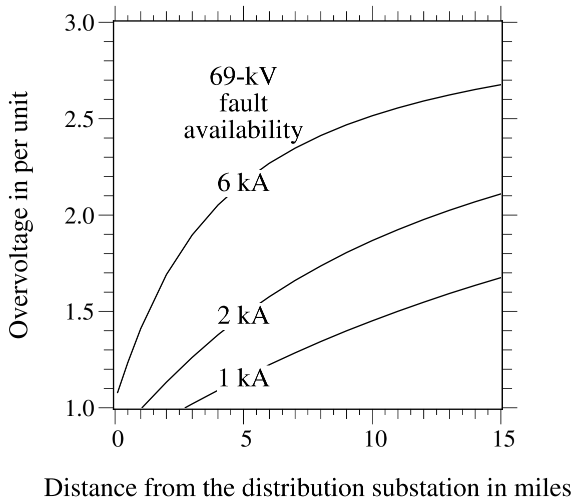
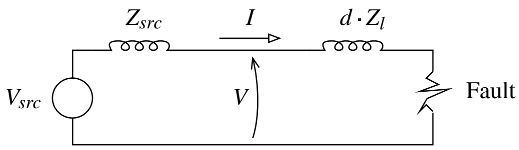


FIGURE 7.19
Results of simulations of a fault from a 69-kV circuit to a 12.5-kV circuit (before the distribution substation breaker trips).

unit, which is 20 to 30 kV (until an arrester or something else fails). In fact, the best protection happens when the arrester fails as fast as possible; the arrester becomes a sacrificial protector. Normal-duty arresters fail faster than heavy-duty arresters, which limits the duration of overvoltages. Goedde et al. (2002) propose using gapped arresters; their lab tests found that gapped arresters clip the overvoltage to a lower magnitude and fail faster during overvoltages.

To reduce the hazard of underbuilt distribution lines, consider the following experimental options:

- *Arresters* — Use normal-duty arresters and possibly gapped arresters.
- *Fuses* — Try to avoid using fuses or reclosers where it leaves significant downstream exposure underbuilt. The fast operation of fuses and reclosers are more likely to clear the distribution circuit before the overbuilt circuit.
- *Directional relays* — In faults to a transmission circuit, the power flows from the fault into the distribution station transformer (the opposite direction of power flow for normal faults). Tripping the distribution circuit breaker only for faults with forward power flow leaves the circuit breaker in for subtransmission faults.
- *Disable the instantaneous* — Without the instantaneous trip on the distribution feeder, the circuit breaker will wait longer before tripping. The transmission circuit is more likely to trip first.
- *Coordinate devices* — Coordinate the transmission-line protection to clear before the distribution circuit operates over the range of fault



$$d = \frac{V}{I \cdot Z_l}$$

FIGURE 7.20
Fault location calculations.

currents that can occur. Include the effects of multiple reclose operations on the transmission circuit. Evaluate the substation recloser or circuit breaker; and also, consider feeder protective devices (normally reclosers). Try to speed up clearing times on the transmission circuit as much as possible (both ends for looped subtransmission circuits).

- *Ground switch (very experimental)* — Whenever the distribution circuit breaker opens, engage a grounding switch on the load side of the distribution circuit breaker. This grounds the fault, preventing overvoltages and sustaining the fault on the transmission circuit.
- *Structures* — As much as possible, design the common structure to minimize the chance of faults between circuits. Use wide spacings between the two circuits, and build the subtransmission circuit to high mechanical standards to reduce the chance of broken conductors or crossarms or braces. More extreme protection could be provided by stringing a grounded conductor and placing it between the subtransmission and the distribution circuits. If the ground is involved in the fault, it will prevent overvoltages. These options are obviously difficult to retrofit, but these issues should be considered when designing new circuits.

Thoroughly review such options before implementation. Normally, utilities treat underbuilt circuits the same as any other circuit. These are experimental approaches; I do not know of any implementation of these options for circuits with overbuilt transmission. Also, most of these options do not help as much for distribution lines fed from a different transmission source.

7.2.7 Fault Location Calculations

If we know the voltages and currents during a fault, we can use these to estimate the distance to the fault. The equation is very simple, just Ohm's Law (see Figure 7.20):

$$d = \frac{V}{I \cdot Z_l}$$

where

V = voltage during the fault, V
I = current during the fault, A
Z_l = line impedance, Ω/length unit
d = distance to the fault, length unit such as mi

With complex values entered for the voltages and impedances and currents, the distance estimate should come out as a complex number. The real component should be a realistic estimate of the distance to the fault; the imaginary component should be close to zero. If not, then something is wrong.

While the idea is simple, a useful implementation is more difficult. Different fault types are possible (phase-to-phase, phase-to-ground, etc.), and each type of fault sees a different impedance. Fault currents may have offsets. The fault may add impedance. There are uncertainties in the impedances, especially the ground return path. Conductor size changes also make location more difficult.

Many relays or power quality recorders or other instruments record fault waveforms. Some relays have fault-locating algorithms built in.

The Ohm's Law equation is actually overdetermined. We have more information than we really need. The distance is a real quantity, but the voltages, currents, and impedances are complex, so the real part of the result is the distance, and the reactive part is zero. Most fault-locating algorithms use this extra information, allow the fault resistance to vary, and find the distance that provides the optimal fit (Girgis et al., 1993; Santoso et al., 2000). The problem with this approach is that the fault resistance soaks up the error in other parts of the data. It does not necessarily mean a better distance estimation. Most fault arcs have a resistance that is very close to zero. In most cases, we're better off assuming zero fault resistance.

The most critical input to a fault location algorithm is the impedance data. Be sure to use the impedances and voltages and currents appropriate for the type of fault. For line-to-ground faults, use line-to-ground quantities; and for others, use phase-to-phase quantities:

- Line-to-ground fault

$$V = V_a,\ I = I_a,\ Z = Z_S = (2Z_1 + Z_0)/3$$

- Line-to-line, line-to-line-to-ground, or three-phase faults

$$V = V_{ab},\ I = I_a - I_b,\ Z = Z_1$$

Remember that these are all complex quantities. It helps to have software that automatically calculates complex phasors from a waveform. Several methods are available to calculate the rms values from a waveform; a Fourier transform is most common. Some currents have significant offset that can add error to the result. Try to find the magnitudes and angles after the offset has decayed (this is not possible on some faults cleared quickly by fuses).

If potential transformers are connected phase to phase, we can still estimate locations for ground faults if we know the zero-sequence source impedance. Schweitzer (1990) shows that the phase-to-ground voltage is

$$V_a = 1/3(V_{ab} - V_{ca}) - Z_{0,src}I_0$$

where

$Z_{0,src}$ = zero-sequence impedance of the source, Ω

I_0 = zero-sequence current measured during the fault = $I_a/3$ for a single line-to-ground fault on phase A

Although the voltages and currents are complex, we can also estimate the distance just using the absolute values. Although we lose some information on how accurate our solution is because we lose the phase angle information, in many cases it is as good as using the complex quantities. So, the simple fault location solution with absolute values is

$$d = \frac{V}{I \cdot Z_l}$$

where

V = absolute value of the rms voltage during the fault, V

I = absolute value of the rms current during the fault, A

Z_l = absolute value of the line impedance, Ω/length unit

d = distance to the fault, length unit such as mi

With this simple equation, we can estimate answers with voltage and current magnitudes. For a ground fault, Z_l=Z_S is about 1 Ω/mi. If the line-to-ground voltage, V=5000 V, and the fault current, I=1500 A, the fault is at about 3.3 mi (5000/1500). Remember to use the phase-to-phase voltage and $|I_a - I_b|$ (and not $|I_a| - |I_b|$) for faults involving more than one phase.

We can calculate the distance to the fault using only the magnitude of the current (no phase angles needed and only prefault voltage needed) and the line and source impedances involved. If we know the absolute value of the fault current and the prefault voltage and the source impedance, the distance to the fault is a solution to the quadratic equation

$$d = \frac{-b + \sqrt{b^2 - 4ac}}{2a}$$

where

$a = Z_l^2$

$$b = 2R_l R_{src} + 2X_l X_{src}$$

$$c = Z_{src}^2 - \left(\frac{V_{prefault}}{I_{fault}}\right)^2$$

and

R_{src} = source resistance, Ω
X_{src} = source reactance, Ω
Z_{src} = absolute value of the source impedance, Ω
R_l = line resistance, Ω/unit distance
X_l = line reactance, Ω/unit distance
Z_l = absolute value of the line impedance, Ω/unit distance
I_{fault} = absolute value of the rms current during the fault, A
$V_{prefault}$ = absolute value of the rms voltage just prior to the fault, V

In this case, we are doing the same thing as taking a fault current profile (such as Figure 7.11) and interpolating the distance. In fact, it is often much easier to use a fault current profile developed from a computer output rather than this messy set of equations. If the prefault voltage is missing, assume that it is equal to the nominal voltage. If we have the prefault voltage, divide the current by the per-unit prefault voltage before interpolating on the fault current profile. Using a fault current profile also allows changes in line impedances along the length of the line. Carolina Power & Light used this approach, and Lampley (2002) reported that their locations were accurate to within 0.5 mi 75% of the time; and in most of the remaining cases, the fault was usually no more than 1 to 2 mi from the estimate.

We can also just use voltages. If we know the source impedance, we do not need current. The distance calculation is another quadratic formula solution, this time with

$$d = \frac{-b - \sqrt{b^2 - 4ac}}{2a} \qquad \text{(the negative root because } a \text{ is negative)}$$

where

$$a = Z_l^2 - Z_l^2\left(\frac{V_{prefault}}{V_{fault}}\right)^2$$

$$b = 2R_l R_{src} + 2X_l X_{src}$$

$$c = Z_{src}^2$$

and

V_{fault} = absolute value of the rms voltage during the fault, V

As with the fault current approach, rather than using this equation, we can interpolate a voltage profile graph to find the distance to the fault (such as those in Figure 10.6). Again, we are assuming that the arc impedance is zero.

Fault locations of line-to-line and three-phase faults are most accurate because the ground path is not included. The ground return path has the most uncertainties. The impedance of the ground return path depends on the number of ground rods, the earth resistivity, and the presence of other objects in the return path (cable TV, buried water pipes, etc.). The ground return path is also nonuniform with length.

This type of fault location is useful for approximate locations. For permanent faults, a location estimate helps shorten the lengths of circuit patrolled. Distance estimates can also help find those irksome recurring temporary faults that cause repeated momentary interruptions. Fault locations are most accurate when the fault is within 5 mi of the measurement; beyond that, the voltage profile and fault current profiles flatten out considerably, which increases error. Fault location is difficult if a circuit has many branches. If a fault is 2 mi from the source on phase B, but there are 12 separate circuits that meet that criteria, the location information is not as useful. Fault location is also difficult on circuits with many wire-size changes; it works best on circuits with uniform mainline impedances with relatively short taps. Impedance-based location methods produce close but not pinpoint results. For underground faults, we would like to know exactly where to dig, but these methods do not have that accuracy.

7.3 Limiting Fault Currents

Limiting fault current has many benefits, which improve the safety and reliability of distribution systems:

- *Failures* — Overhead line burndowns are less likely, cable thermal failures are less likely, violent equipment failures are less likely.
- *Equipment ratings* — We can use reclosers and circuit breakers with less interrupting capability and switches and elbows with less momentary and fault close ratings. Lower fault currents reduce the need for current-limiting fuses and for power fuses and allow the use of cutouts and under-oil fuses.
- *Shocks* — Step and touch potentials are less severe during faults.
- *Conductor movement* — Conductors move less during faults (this provides more safety for workers in the vicinity of the line and makes conductor slapping faults less likely).
- *Coordination* — Fuse coordination is easier. Fuse saving is more likely to work.

At most distribution substations, three-phase fault currents are limited to less than 10 kA, with many sites achieving limits of 7 to 8 kA. The two main ways that utilities manage fault currents are:

- *Transformer impedance* — Specifying a higher-impedance substation transformer limits the fault current. Normal transformer impedances are around 8%, but utilities can specify impedances as high as 20% to reduce fault currents.
- *Split substation bus* — Most distribution substations have an open tie between substation buses, mainly to reduce fault currents (by a factor of two).

Line reactors and a neutral reactor on the substation transformer are two more options used to limit fault currents, especially in large urban stations where fault currents may exceed 40 kA.

There are drawbacks of increasing impedance to reduce fault currents. Higher impedance reduces the stiffness of the system: voltage sags are worse, voltage flicker is worse, harmonics are worse, voltage regulation is more difficult.

A reactor in the substation transformer neutral limits ground fault currents. Even though the neutral reactor provides no help for phase-to-phase or three-phase faults, it provides many of the benefits of other methods of fault reduction. Neutral reactors cost much less than line reactors. Ground faults are the most common fault; and for many types of single-phase equipment, the phase-to-ground fault is the only possible failure mode. A neutral reactor does not cause losses or degrade voltage regulation to the degree of phase reactors. On the downside, a neutral reactor has a cost and uses substation space, and a neutral reactor reduces the effectiveness of the grounding system (see Chapter 13).

Several advanced fault-current limiting devices have been designed (EPRI EL-6903, 1990). Most use some sort of nonlinear elements — arresters, saturating reactors, superconducting elements, or power electronics such as a gate-turn-off thyristor — to limit the fault current either through the physics of the device or through computer control. Since most distribution systems have managed fault currents sufficiently well, these devices have not found a market. Given that, the EPRI study surveyed utilities and found evidence that a market for fault-current limiters exists if a device had low enough cost and was robust enough.

7.4 Arc Characteristics

Many distribution faults involve arcs through the air, either directly through the air or across the surface of hardware. Although a relatively good conductor, the arc is a very hot, explosive fireball that can cause further damage at the fault location (including fires, wire burndowns, and equipment damage). This section discusses some of the physical properties of arcs, along with the ways in which arcs can cause damage.

Normally, the air is a relatively good insulator, but when heavily ionized, the air becomes a low-resistance conductor. An arc stream in the air consists of highly ionized gas particles. The arc ionization is due to *thermal* ionization caused by collisions from the random velocities of particles (between electrons, photons, atoms, or molecules). Thermal ionization increases with increasing temperature and with increasing pressure. The heat produced by the current flow (I^2R) maintains the ionization. The arc stream has very low resistance because there is an abundance of free, charged particles, so current flow can be maintained with little electric field. Another type of ionization caused by acceleration of electrons from the electric field may initially start the ionization during the electric-field breakdown, but once the arc is created, electric-field ionization plays a less significant role than thermal ionization.

One of the characteristics that is useful for estimating arc-related phenomenon is the arc voltage. The voltage across an arc remains constant over a wide range of currents and arc lengths, so the arc resistance decreases as the current increases. The voltage across an arc ranges between 25 and 40 V/in (10 to 16 V/cm) over the current range of 100 A to 80 kA (Goda et al., 2000; Strom, 1946). The arc voltage is somewhat chaotic and varies as the arc length changes. More variation exists at lower currents. As an illustration of the energy in an arc, consider a 3-in. (7.6-cm) arc that has a voltage of about 100 V. If the fault current is 10 kA, the power in the arc is $P = V \cdot I = 100\text{ V} \cdot 10\text{ kA} = 1\text{ MW}$. Yes, 1 MW! Arcs are explosive and as hot as the surface of the sun.

An upper bound of roughly 10,000 to 20,000 K on the temperature of the arc maintains the relatively constant arc voltage per unit length. For larger currents, the arc responds by increasing the volume of gas ionized (the arc expands rather than increasing the arc-stream temperature). Higher currents increase the cross-sectional area of the arc, which reduces the resistance of the arc column; the current density is the same, but the area is larger. So, the voltage drop along the arc stream remains roughly constant. The arc voltage depends on the type of gas and the pressure. One of the reasons an arc voltage under oil has a higher voltage gradient than an arc in air is because the ionizing gas is mainly hydrogen, which has a high heat conductivity. A high heat conductivity causes the arc to restrict and creates a higher-density current flow (and more resistance). The arc voltage gradient is also a function of pressure. For arcs in nitrogen (the main ionizing gas of arcs in air), the arc voltage increases with pressure as $V \propto P^k$, where k is approximately 0.3 (Cobine, 1941).

Another parameter of interest is the arc resistance. A 3-ft (1-m) arc has a voltage of about 1400 V. If the fault current at that point in the line was 1000 A, then the arc resistance is about 1.4 Ω. A 1-ft (0.3-m) arc with the same fault current has a resistance of 0.47 Ω. Most fault arcs have resistances of 0

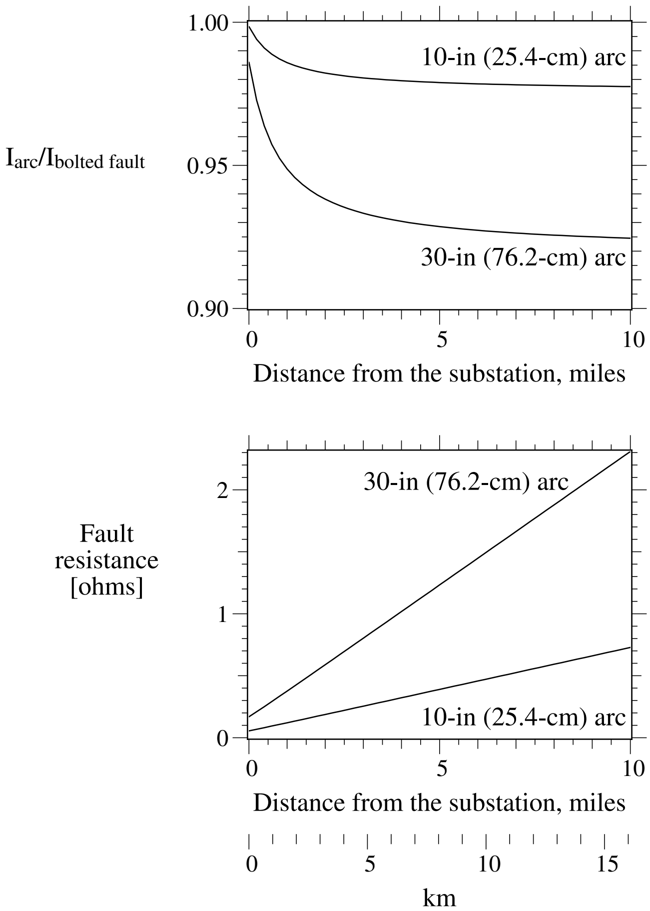


FIGURE 7.21
Ratio of fault current with and without an arc of the given length on a 12.47-kV circuit. This assumes the same system parameters as the fault profile in Figure 7.11 with the following additional assumptions: the arc voltage gradient equals 40 V/in. (16 V/cm), the arc voltage is all resistive, and the nonlinearity of the arc voltage is ignored.

to 2 Ω. Figure 7.21 shows that the impact of an arc on the fault currents along the line is fairly minor.

An arc voltage waveform has distinguishing characteristics. Figure 7.22 shows an arcing fault voltage that was initiated by tree contact on a 13-kV circuit measured during the EPRI DPQ project. The voltage on the arc is in phase with the fault current (it is primarily resistive). When the arc current goes to zero, the arc will extinguish. The recovery voltage builds up quickly because of the stored energy in the system inductance. Voltage builds to a point where it causes arc reignition. The reason for the blip at the start of the waveform (it is not a straight square wave) is that the arc cools off at the current zero. Cooling lowers the ionization rate and increases the arc resis-

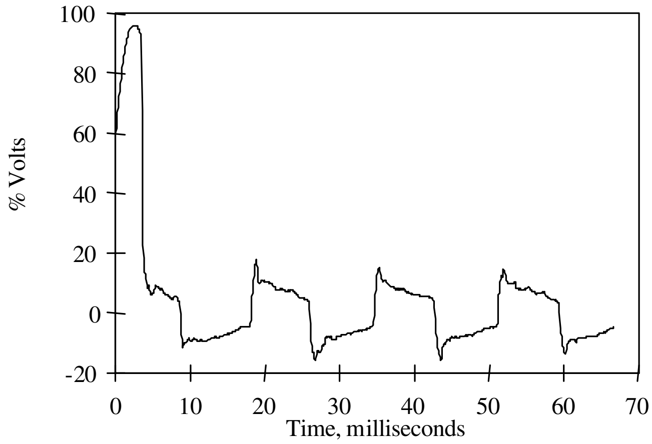


FIGURE 7.22
Arcing fault measured during the EPRI DPQ study. (Copyright © 1996. Electric Power Research Institute. TR-106294-V3. *An Assessment of Distribution System Power Quality: Volume 3: Library of Distribution System Power Quality Monitoring Case Studies.* Reprinted with permission.)

tance. Once it heats up again, the voltage characteristic flattens out. The waveform is high in the odd harmonics and for many purposes can be approximated as a square wave.

The movement and growth of an arc is primarily in the vertical direction. Tests at IREQ in Quebec showed that the primary reason that the arc elongates and moves vertically is the rising hot gases of the arc (Drouet and Nadeau, 1979). The magnetic forces ($J \times B$) did not dominate the direction or elongation. As a first approximation over a range of currents between 1 and 20 kA, arc voltages up to 18 kV, and durations up to 0.5 sec, the arc length can be expressed as a function of the duration only as

$$l = 30t$$

where
l = arc length, m
t = fault duration, sec

The arc movement is a consideration for underbuilt distribution and for vertical construction. The equation above can be used as an approximation to determine if an underbuilt distribution circuit could evolve and fault a distribution or transmission circuit above. It also gives some idea of how faults can evolve to more than one phase. Figure 7.23 shows an example of a fault evolving from one to three phases over the course of about 1.5 sec (the construction type is unknown, but it is probably a horizontal configuration). Given the vertical movement of a fault current arc, vertical designs are more prone to having faults evolve to more than one phase. We might

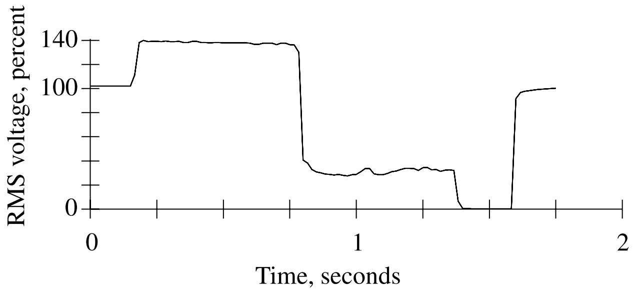


FIGURE 7.23
Voltage waveform from a fault that started as a single-phase fault (indicated by a swell on the phase shown), evolved to a double-line-to-ground fault (the voltage sags to about 35%), and finally evolved to a three-phase-to-ground fault (where the voltage sags to zero). (Copyright © 1996. Electric Power Research Institute. TR-106294-V3. *An Assessment of Distribution System Power Quality: Volume 3: Library of Distribution System Power Quality Monitoring Case Studies.* Reprinted with permission.)

think that a fault evolving to include other phases is not a concern since the three-phase circuit has to be opened anyway, whether it is a single- or three-phase fault. But, the voltage sag during the fault is more severe if more than one phase is involved, which is a good reason to use designs that do not tend to propagate to more than one phase (and to use relaying or fusing that operates quickly enough to prevent it from happening).

The temperature in the arc can be on the order of 10,000 K. This heat creates hazards from burning and from the pressure wave developed during the fault. The longer the arc, the more energy is created. NFPA provides guidelines on safe distances for workers based on arc blasts (NFPA 70E-2000). Several groups have worked to determine the appropriate characteristics of protective clothing (ASTM F1506-94, 1994). Because of the pressure wave, consider hearing protection and fall protection for workers who could be exposed to fault arcs. Arcs can cause fires: pole fires or fires in oil-filled equipment such transformers.

The pressure wave from an arc in an enclosed substation was the probable cause of a collapse of a substation building (important since many distribution stations are required to be indoors because of environmental considerations). Researchers found during tests that the pressure from a fault arc can be approximated (Drouet and Nadeau, 1979) by

$$A = 1.5\frac{I \cdot t}{l}$$

where
A = pressure, kN/m^2 (1 kN/m^2 = 20.9 lb/ft^2)
I = fault current magnitude, kA
t = duration of the fault, sec
l = distance from the source, m (for $l > 1$ m)

Although many electrical damage characteristics are a function of $\int I^2\, dt$, the pressure wave is primarily a function of $\int I\, dt$ (because the voltage along the arc length is constant and relatively independent of the arc current). Where arcs attach to wires, melting weakens wires and can lead to wire burndown. Most tests have shown that the damage is proportional to $\int I^k\, dt$, where k is near one but varies depending on the conductor type. For burndowns or other situations where the arc burns the conductor, the total length of the arc is unimportant, the small portion of the arc near the attachment point is important. The voltage drop near the attachment point is also very constant and does not vary significantly with current. The damage to conductors is very much like that of an electrical arc cutting torch.

Burndowns are much more likely on covered wire (also called tree wire). The covering restricts the movement of the attachment point of the arc to the conductor. On bare wire, the arc will move because of the heating forces on the arc and the magnetic forces (also called motoring).

On bare wire, burndowns are a consideration only on small conductors. Tests (Lasseter, 1956) have shown that the main cause of failure on small aluminum conductors is that the hot gases from the arc anneal the aluminum, which reduces tensile strength. The testers found little evidence of arc burns on the conductors. Failures can occur midspan or at a pole. Motoring is not fast enough to protect the small wire.

Arcs can damage insulators following flashover along the surface of the insulators. This was the primary reason for the development of arcing horns for transmission-line insulators. Arcing horns encourage a flashover away from the insulator rather than along the surface. Arcs can fail distribution insulators. During fault tests across insulators by Florida Power & Light (Lasseter, 1965), the top of the arc moved along the conductor. The point of failure was at the bottom of the insulator where the arc moved up the pin to the bottom edge of the porcelain. The bottom of the insulator gets very hot and can fail from thermal shock. The threshold of chipping was about 360 C (C = coulombs = A-sec = $\int I\, dt$), and the threshold of shattering was about 1125 C (see Figure 7.24). Adding an aluminum or copper washer (but not a steel washer) on top of the crossarm under the flange of the grounded steel pin reduced insulator shattering. The arc attaches to the washer rather than moving up along the pin, increasing the threshold of chipping by a factor of five. Composite insulators perform better for surface arcs than porcelain insulators (Mazurek et al., 2000). Some composite insulators have an external arc withstand test where $I{\cdot}t$ shall be 150 kA-cycles (2500 C for 60 Hz) (IEEE Std. 1024-1988).

Distribution voltages can sustain very long arcs, but self-clearing faults can occur such as when a conductor breaks and falls to the ground (stretching an arc as it falls). The maximum arc length is important because the longer the arc, the more energy is in the arc. For circuits with fault currents on the order of 1000 A and where the transient rise to the open-circuit voltage is about 10 μs, about 50 V may be interrupted per centimeter of arc length (Slepian, 1930). For a line-to-ground voltage of 7200 V, a line-to-ground arc

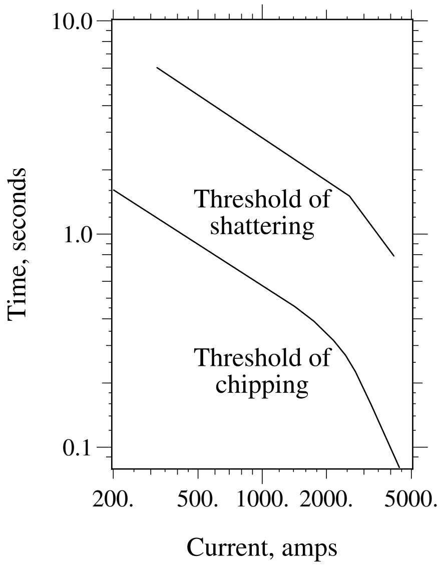


FIGURE 7.24
Insulator damage characteristics. (Data from [Lasseter, 1965].)

can reach a length of about 12 ft (3.7 m) before it clears. As another approximation, the length that an arc can maintain in resistive circuits is [from (Rizk and Nguyen, 1984) with some reformulation]:

$$l = V\sqrt{I}$$

where

l = arc length, in. (1 in. = 2.54 cm)
I = rms current in the previous half cycle, A
V = system rms voltage, kV (line to ground or line to line depending on fault type)

7.5 High-Impedance Faults

When a conductor comes in physical contact with the ground but does not draw enough current to operate typical protective devices, you have a *high-impedance* fault. In the most common scenario, an overhead wire breaks and falls to the ground (a *downed wire*). If the phase wire misses the grounded neutral or another ground as it falls, the circuit path is completed by the high-impedance path provided by the contact surface and the earth.

The return path for a conductor lying on the ground can be a high impedance. The resistance varies depending on the surface of the ground. Table

TABLE 7.3

Typical High-Impedance Fault Current Magnitudes

Surface	Current, A
Dry asphalt	0
Concrete (no rebar)	0
Dry sand	0
Wet sand	15
Dry sod	20
Dry grass	25
Wet sod	40
Wet grass	50
Concrete (with rebar)	75

Source: IEEE Tutorial Course 90EH0310-3-PWR, "Detection of Downed Conductors on Utility Distribution Systems," 1990. With permission. ©1990 IEEE.

7.3 shows typical current values measured for conductors on different surfaces (for 15-kV class circuits).

The frequency of high-impedance faults is uncertain. Most utilities responding to an IEEE survey reported that high-impedance faults made up less than 2% of faults while a sizeable number (15% of those surveyed) suggested that between 2 and 5% of distribution faults were not detectable (IEEE Working Group on Distribution Protection, 1995). Even with small numbers, high-impedance faults pose an important safety hazard.

On distribution circuits, high-impedance faults are still an unsolved problem. It is not for lack of effort; considerable research has been done to find ways to detect high-impedance faults, and progress has been made [see (IEEE Tutorial Course 90EH0310-3-PWR, 1990) for a more in-depth summary]. Research has identified many characteristics of high-impedance faults and have tested them for detection purposes. Efforts have been concentrated on detection at the substation based on phase and ground currents. High-impedance faults usually involve arcing, and arcing generally creates the lower odd harmonics. Arcing faults may also contain significant 2- to 10-kHz components. Arcing also bursts in characteristic patterns. High-impedance faults often cause characteristic changes in the load (for example, a broken conductor will drop the load on that phase). None of these detection methods is perfect, so some detection schemes use more than one method to try to detect high-impedance faults.

We can also detect broken conductors at the ends of radial circuits. Loss of voltage is the simplest method. Communication to an upstream protective device or to a control center is required. A difficulty is that it takes many devices to adequately cover a radial circuit (depending on how many branches occur on the circuit). Also, the "ends" of circuits could change during circuit reconfigurations or sectionalizing due to circuit interruptions. Also, if the loss-of-voltage detector is downstream of a fuse, another detector is needed at the fuse, so we can determine if the fuse operated or the conductor broke.

Practices that help reduce high-impedance faults include

- *Tight construction framings* — If a phase wire breaks, it is more likely to contact a neutral as it falls. (A drawback is that utilities have reported poorer reliability with tighter constructions like the armless design.) A vertical construction is better than a horizontal construction. Single-phase structures are better than three-phase structures.
- *Stronger conductors* — Larger conductors or ACSR instead of all-aluminum conductor are stronger and less likely to break for a given mechanical or arcing condition.
- *Smaller/faster fuses* — Faster fuses are more likely to operate for high-impedance faults. In addition, small fuses are likely to clear before arcing damages wires, which could burn down the wires.
- *Tree trimming* — Clearing trees and trimming reduces the number of trees or branches breaking conductors.
- *Fewer reclose attempts* — Each reclose attempt causes more damage at the fault location.
- *Higher primary voltages* — High-impedance faults are much less likely at 34.5 kV and somewhat less likely at 24.94 kV than 15-kV class voltages.
- *Public education* — Public advertisements warning the public to stay away from downed wires help reduce accidents when high-impedance faults do occur.

Practices to *avoid* include:

- *Covered wire* — Burndowns are more likely with covered wire. If a covered wire does contact the ground, it is less likely to show visible signs that it is energized such as arcing or jumping which would help keep bystanders away.
- *Unfused taps* — Burndowns are more likely with the smaller wire used on lateral taps.
- *Midspan connectors* — Flying taps can cause localized heating and mechanical stress.
- *Rear-lot construction* — Rear-lot construction is not as well maintained as road-side construction, so trees are more likely to break wires. If wires do come down, it is more hazardous since they are coming down in someone's backyard.
- *Neutral on the crossarm* — If a phase wire breaks, it is much less likely to contact the neutral as it falls if the neutral is on the crossarm. Other constructions that may have this same problem are overhead shield wires and spacer cables that do not have an additional neutral below.

Three-wire distribution systems have some advantages and some disadvantages related to high-impedance faults. The main advantage of three-wire systems is that there is no unbalanced load. A sensitive ground relay can be used, which would detect many high-impedance faults. The sensitivity of the ground relay is limited by the line capacitance. The main disadvantage of three-wire systems is that there is no multigrounded neutral. If a phase conductor breaks, there is a high probability that there will be a high-impedance fault. If there is underbuilt secondary or phone or cable TV under the three-wire system, then a high-impedance fault is less likely because a grounded conductor is below the phases.

Spacer cable has some mechanical strength advantages that could help keep phase wires in the air, and it has fewer faults due to trees. A downside is the covering which makes burndowns more likely. Also, it has a messenger wire that may act as the neutral; if it does not also have an underbuilt neutral, a phase conductor is more likely to fall unimpeded.

Backfeeds from three-phase transformer and capacitor installations can cause dangerous situations. If a wire breaks near a pole, at least half of the time, the load side (downstream side) will lie on the ground. Backfeed to the downed wire can occur through three-phase transformers downstream of the fault. The backfeed can provide enough voltage and current to the downed wire to be dangerous (but there will not be enough current to trip protective devices). Note that a grounded-wye – grounded-wye connection does not eliminate backfeeds. Another backfeed scenario is shown in Figure 7.25 where a three-phase load is fed from a fused tap. A bolted, low-impedance fault on one phase will blow the fuse, but backfeed current may flow through the three-phase connection. Even with a low-impedance fault, the backfeed current can be low enough that neither the remaining tap fuses nor the transformer fuses will operate. The fault can continue to arc until the wire burns down. An ungrounded capacitor bank can also provide a backfeed path.

Commercial relays that have high-impedance fault detection capabilities are available. One of the main problems with detection of high-impedance faults is false fault detections. If a detection system in the station detects a fault and a whole feeder is tripped for an event that is not really a high-impedance fault, reliability is severely hurt. Before reenergizing, crews patrol the circuit and make sure there was not a downed conductor. The sensitivity of a device must be traded off against its dependability. If it is too sensitive, many false operations will result. An alternative to tripping is alarming. Operators in control centers may always trip a circuit if it signals a high-impedance fault for fear of discipline if it really was a high-impedance fault and an accident occurred. Each time a high-impedance fault is detected, crews would have to patrol the circuit. If operators have too many false alarms, they may ignore the alarm.

A tree branch in contact with a phase conductor also forms a high-impedance fault. This is not as dangerous as a downed wire. Most of the time the circuit operates normally, without danger to the public (but see Chapter 13

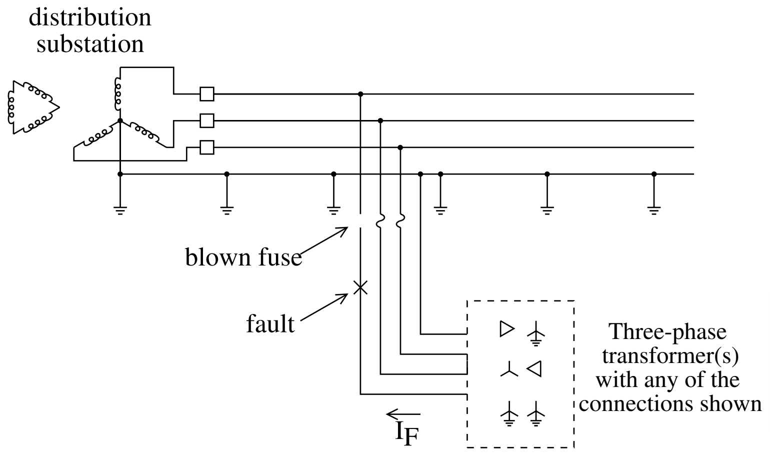


FIGURE 7.25
Backfeed to a fault downstream of a blown fuse.

for more analysis of this situation). A tree branch in contact with a phase conductor can draw enough current to trip a high-impedance fault detector. In a heavily treed area, crews could require many hours to find the location where the tree contact is taking place.

One of the main problems with substation detection is that each feeder usually covers many miles of line. With most faults, lateral fuses provide an effective way to isolate and identify the location of faults within a relatively small area. While it would be nice to have high-impedance fault detection capability on lateral taps, the costs have been prohibitive. Contrast a station detection scheme (one device) with detectors at taps — tens or hundreds of devices.

Another solution to falling conductors is using guards installed on poles below the phase wires to "catch" phase conductors. The guards are connected to the grounded neutral, so when a phase conductor breaks, a low-impedance fault is created. This would be a significant expense to install system-wide, but it may be suitable for isolated locations where it is critical not to have energized downed conductors (a stretch that runs across a school playground or a span that crosses a major road).

7.6 External Fault Causes

7.6.1 Trees

For many utilities, trees cause more faults and more interruptions than any other factor. Tree trimming is expensive — the largest maintenance item for most distribution companies. Tree trimming is also a contentious issue with the public. Residents hate to have their 100-year-old maple trees touched (or even their 30-year-old cottonwoods).

Faults caused by trees generally occur from three conditions:

1. Falling trees knock down poles or break pole hardware.
2. Tree branches blown by the wind push conductors together.
3. A branch falls across the wires and forms a bridge from conductor to conductor (or natural tree growth causes a bridge).

Tree-caused faults can be temporary or permanent. Falling trees or branches can cause permanent faults. Either falling across wires or pushing them together, tree branches can cause temporary faults. Broken tree branches account for the majority of interruptions. In one utility in the northeast U.S., 63% were caused by broken branches compared to 11% from falling trees and only 2% from tree growth (Simpson, 1997). Niagara Mohawk Corporation (NIMO) found that 86% of permanent tree-faults were outside of the right-of-way, and most were from major breakage (see Figure 7.26). Falling trees do the most damage; they often break conductors and even poles in some cases. Tree faults usually occur during storms, primarily from wind. Snow and ice additionally contribute to tree failures.

Several companies have done tests to evaluate the electrical properties of tree branches and how they cause faults (Goodfellow, 2000; Williams, 1999). For a tree branch to cause a fault, the branch must bridge the gap between two conductors, which usually must be sustained for more than 1 min. A tree touching just one conductor will *not* fault. The tree branch must cause a connection between two bare conductors (it can be phase to phase or phase to neutral). A tree branch into one phase conductor normally draws less than one amp of current under most conditions; this may burn some leaves, but it will not fault. On small wires in contact with a tree, the arcing to the tree may be enough to burn the wire down under the right conditions. While the tree in contact with one wire will not fault the circuit, there are some safety issues with trees in contact with overhead conductors (see Chapter 13).

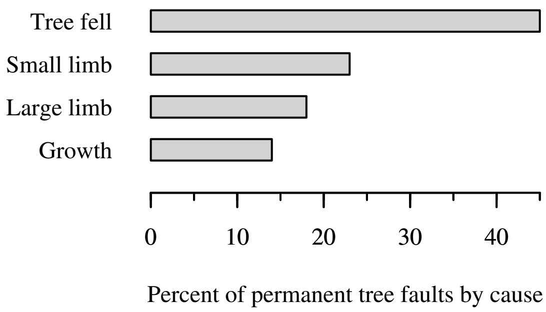


FIGURE 7.26
Tree failure causes for the Niagara Mohawk Power Corporation. (Data from [Finch, 2001].)

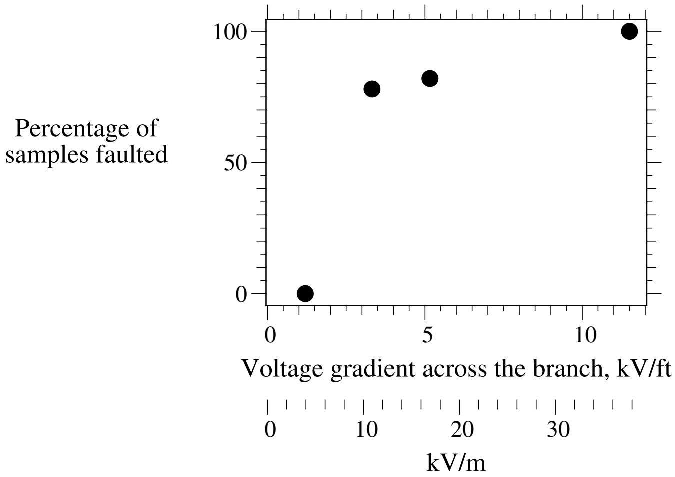


FIGURE 7.27
Percentage of samples faulted based on the voltage gradient across the tree branch. (Data from [Goodfellow, 2000].)

A fault across a tree branch between two conductors takes some time to develop. If a branch falls across two conductors, arcing occurs at each end where the wire is in contact with the branch. At this point in the process, the current is small (the tree branch has a relatively high impedance). The arcing burns the branch and creates carbon by oxidizing organic compounds. The carbon provides a good conducting path. Arcing then occurs from the carbon to the unburned portion of the branch. A carbon track develops at each end and moves inward.

Once the carbon path is established completely across the branch, the fault is a low-impedance path. Now the current is high; it is effectively a bolted fault. It is also a permanent fault. If a circuit breaker or recloser is opened and then reclosed, the low-impedance carbon path will still be there unless the branch burns enough to fall off of the wires.

Some other notable electrical effects include the following:

- It makes little difference if the branch is wet or dry. Live branches are more likely to fault for a given voltage gradient, but dead branches are more likely to break.
- Little branches can burn through and fall off before the full carbon track develops, so minor leaf and branch burning does not cause faults.
- The likelihood of a fault depends on the voltage gradient along the branch (see Figure 7.27).
- The time it takes for a fault to occur also depends on the voltage gradient (see Figure 7.28).
- Lower voltage circuits are much more immune to flashovers from branches across conductors. A 4.8-kV circuit on a 10-ft crossarm has

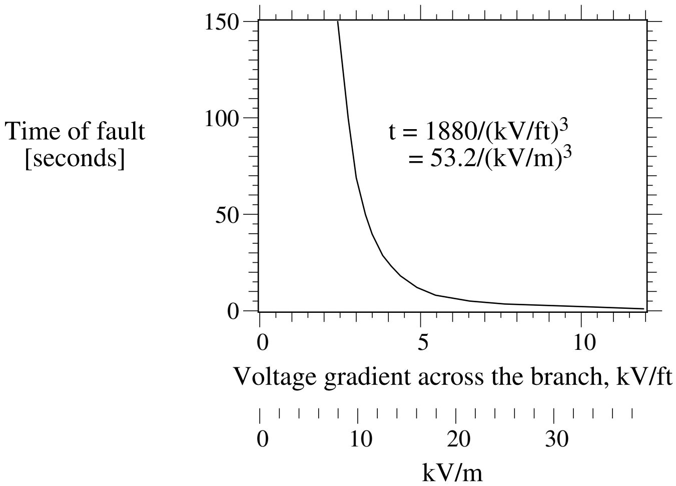


FIGURE 7.28
Time to fault based on the voltage gradient across the tree branch. (Data from [Goodfellow, 2000] with the curvefit added)

about a phase-to-phase voltage gradient of 1 kV/ft, very unlikely to fault from tree contact. A 12.47-kV circuit has a 2.7 kV/ft gradient, which is more likely to fault.

- Candlestick or armless designs are more likely to flashover because of tighter conductor-to-conductor spacings.

These effects reveal some key issues:

- Trimming around the conductors in areas with a heavy canopy does not prevent tree faults. Traditionally, crews trim a "hole" around the conductors with about a 10-ft (3-m) radius. If there is a heavy canopy of trees above the conductors, this trimming strategy performs poorly since most faults are caused by branches falling from above.
- Vertical construction may help since the likelihood of a phase-to-phase contact by falling branches is reduced.
- Three-phase construction is more at risk than single-phase construction.

Tree trimming is expensive. An EPRI survey found that utilities spend an average of about $10 per customer each year on tree trimming (EPRI TR-109178, 1998). Trimming can also irritate communities. It is always a dilemma that people do not want their trees trimmed, but they also do not want interruptions. Consider the following general tree-trimming guidelines:

- *Removal* — This is the most effective fault-prevention strategy, and many homeowners are willing to have trees removed.

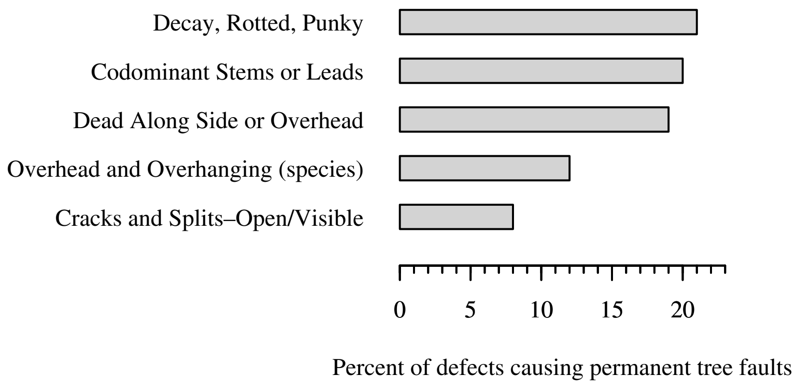


FIGURE 7.29
Defects causing tree failure for the Niagara Mohawk Power Corporation. (Data from [Finch, 2001].)

- *Danger trees* — Trimming/removal is most effective if trees and branches that are likely to fail are removed or trimmed to safe distances. This does take some expertise by tree trimming crews.
- *Target* — As with any fault-reduction program, efforts are best spent on the poorest performing circuits that affect the most customers. Along the same thought, spend more on three-phase mains than on single-phase taps.

Targeting danger trees is especially beneficial but requires expertise. In a careful examination of several cases where broken branches or trees damaged the system, 64% of the trees were living (Finch, 2001). Finch also advises examining trees from the backside, inside the tree line (defects on that side are more likely to fail the tree into the line). Finch describes several defects that help signal danger trees (see Figure 7.29). Dead trees or large splits are easy to spot. Cankers (a fungal disease) or codominant stems (two stems, neither of which dominates, each stem at a branching point is approximately the same size) require more training and experience to detect. It also helps to know the types of trees that are prone to interruptions (this varies by area and types of trees). For Niagara Mohawk, black locusts and aspens are particularly troublesome; large, old roadside maples also caused more than their share of damage (see Table 7.4).

Acceptable tree trimming (that is also still effective) is a public relations battle. Some strategies that help along these lines include:

- Talking to residents prior to/during tree trimming.
- Trimming trees during the winter (or tree-trimming done “under the radar”) — The community will not notice tree trimming as much when the leaves are not on the trees.

TABLE 7.4

Comparison of Trees Causing Permanent Faults with the Tree Population

Species	Percent of Outages	Percent of New York State Population
Ash	8	7.9
Aspen	9	0.6
Black Locust	11	0.3
Black Walnut	5	N/A
Red Maple	14	14.7
Silver Maple	5	0.2
Sugar Maple	20	12.0
White Pine	6	3.3

Source: Finch, K., "Understanding Tree Outages," EEI Vegetation Managers Meeting, Palm Springs, CA, May 1, 2001.

- Trimming trees during storm cleanups. Right after outages, residents are more willing to accept their beloved trees being hacked up (this is a form of the often practiced "storm-induced maintenance"; fix it when it falls down).
- Cleaning up after trees are trimmed/removed.
- Offering free firewood.

Choosing a tree-trimming cycle is tricky. Many utilities use a three- to five-year cycle. Longer tree-trimming cycles lead to higher fault rates (see Figure 7.30). The optimal trimming cycle depends on

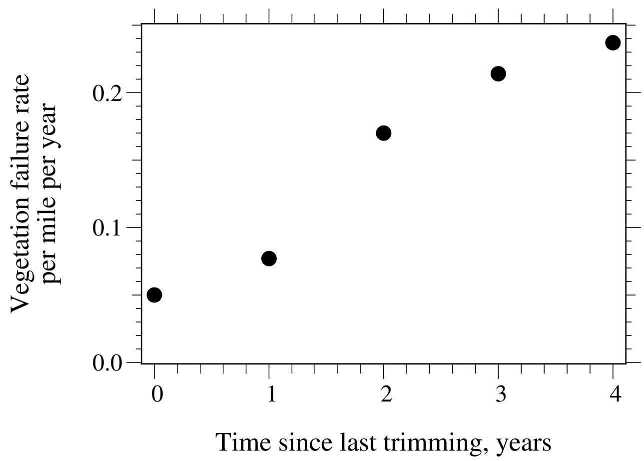


FIGURE 7.30
Tree failure rates vs. time since last trimming for one Midwestern utility. (Data from [Kuntz, 1999].)

TABLE 7.5

Interruption Rates in Outages per 100 Miles per Year Comparing Bare Wire, Tree Wire, and Spacer Cable at One Utility in the U.S. from 1995 to 1997

Fault Type	Bare	Tree Wire	Spacer Cable
Tree related	17.6	6.6	1.8
Animals	12.1	5.9	2.9
Lightning	3.4	1.9	1.0
Unknown	5.9	2.6	1.0
All other	11.3	4.6	5.9
Totals	50.3	21.7	12.5

Source: Hendrix, "Reliability of Overhead Distribution Circuits," Hendrix Wire & Cable, Inc., August 1998.

- Type of trees, growth rates, and growing conditions
- Community tolerance for trimming
- Economic assumptions, especially the chosen time value of money

In heavily treed areas, covered conductors help reduce tree faults. This "tree wire" provides extra insulation that reduces the chance of flashover for a branch between conductors. Good fault data is hard to find comparing fault rates of bare wire with covered wire. One utility whose results are provided in Table 7.5 has shown reductions in interruption rates of greater than 50% for covered wire and even more for spacer cable (the only caveat here is the data is published by a manufacturer, so it may not be unbiased). Tree and animal faults were also reduced by over 50%. European experience with covered conductors suggests that covered-wire fault rates are about 75% less than bare-wire fault rates. In Finland, fault rates on bare lines are about 3 per 100 km/year on bare and 1 per 100 km/year on covered wire (Hart, 1994). Covered wire helps with animal faults as well as tree faults.

Spacer cable and aerial cables are also alternatives that perform well in treed areas. Spacer cables are a bundled configuration using a messenger wire holding up three-phase wires that use covered wire. Aerial cables have fully-rated insulation just like underground cables. In South America, both covered wire and a form of aerial cable have been successfully used in treed areas (Bernis and de Minas Gerais, 2001). The Brazilian company CEMIG found that spacer cable faults were lower than bare-wire circuits by a 10 to 1 ratio (although the article did not specify if this included both temporary and permanent faults). The aerial cable faults were lower than bare wire by a 20 to 1 ratio. The effect on interruption durations is shown in Table 7.6. Several spacer cables or aerial cables can be constructed on a pole. Spacer cables and aerial cables have some of the same burndown considerations as covered wire. Spacer cable construction does have a reputation for being hard to work with. Both spacer cable and aerial cable costs more than bare

TABLE 7.6

Comparison of the Reliability Index SAIDI (Average Hours of Interruption per Customer per Year) of Bare Wire, Spacer Cable, and Aerial Cable in Brazil

Construction	SAIDI, h
Bare wire	9.9
Spacer cable	4.7
Aerial cable	3.0

Source: Bernis, R. A. O. and de Minas Gerais, C. E., "CEMIG Addresses Urban Dilemma," *Transmission and Distribution World*, vol. 53, no. 3, pp. 56–61, March 2001.

wire. CEMIG estimated that the initial investment was returned by the reduction in tree trimming. They did minimal trimming around aerial cable (an estimated factor of 12 reduction in maintenance costs) and only minor trimming around spacer cable (an estimated factor of 6 reduction in maintenance costs).

7.6.2 Weather and Lightning

Many faults on overhead circuits are weather related: icing, wind, and lightning. The fault rate during severe storms increases dramatically. Much of the physical and electrical stresses from these events are well beyond the design capability of distribution circuits.

Overhead circuits are designed to NESC (IEEE C2-1997) mechanical standards and clearances, which prescribe the performance of the line itself to the normal severe weather that the poles and wires and other structures must withstand. Most storm failures are from external causes, usually wind blowing tree limbs or whole trees into wires. These cause faults and can bring down whole structures.

Lightning causes many faults on distribution circuits. While most are temporary and do not do any damage, 5 to 10% of lightning faults permanently damage equipment: transformers, arresters, cables, insulators. Distribution circuits do not have any direct protection against lightning-caused faults since distribution insulation cannot withstand lightning voltages. If lightning hits a line, it causes a fault nearly 100% of the time. Since most lightning-caused faults do not do any permanent damage, reclosing is used to minimize the impact on customers. After the circuit flashes over (and there's a fault), a recloser or reclosing circuit breaker will open and, after a short delay, reclose the circuit.

It is important to properly protect equipment from lightning. Transformers and cables are almost always protected with surge arresters. This prevents most permanent faults caused by lightning. Equipment protection, arresters, and lightning protection are discussed in more detail in Chapter 12.

7.6.3 Animals

Faults caused by animals are often the number two cause of outages for utilities (after trees). Squirrels cause the most faults. Squirrels thrive in suburbs and love trees; utilities have noted increases in squirrel faults following development of wooded areas. Squirrels are usually active in the morning and sleep at night. Squirrel faults usually occur in fair weather. The patterns of animal-caused faults have been used to classify "unknown" faults (Mo and Taylor, 1995).

The two main ways to protect equipment against animals (particularly squirrels) are:

- Bushing protectors
- Covered lead wires

Both of these were rated "very good" at reducing animal-caused interruptions in an EPRI survey (EPRI TE-114915, 1999). Several survey respondents noted that the bushing protectors were susceptible to deterioration and tracking (they rated only "good" for durability). Some of the other comments regarding bushing protectors include:

- Insects nest in the bushing coverings, and birds probing for insects cause bird electrocutions and faults.
- Bushing covers hide loose connections and insulator damage and interfere with infrared inspections.

Bushing protectors and covered lead wires are inexpensive if installed with equipment (but expensive to retrofit). For transformer bushing protectors, have crews leave some room between the bottom of the bushing protector and the tank, so water does not build up and leak down through the bushing. Some additional items that also help include

- Trimming trees — Squirrels get to utility equipment via trees (pole climbing is less common). If trees are kept away from lines, utility equipment is less attractive.
- Good outage tracking — Many outages are repeated, so a good outage tracking system can pinpoint hotspots to identify where to target maintenance.
- Identifying animal — If outages are tracked by animal, it is easier to identify proper solutions.
- Maintaining proper clearances
- Avoiding metal crossarms

Animal faults vary by construction habits within a region. Some common problem areas that can lead to frequent animal faults include

- *Transformer bushings* — A very common animal fault is across a transformer bushing. Insulating paints are available for transformers, but it degrades quickly. Bushing guards and/or insulated lead wires offer the best protection.
- *Arresters* (especially polymer) — Another common animal fault is across an arrester, especially a tank-mounted arrester. Polymer-housed arresters have more problems than porcelain-housed arresters because they are much shorter. Use animal guards on tank-mounted arresters (especially on polymer-housed arresters).
- *Cutouts* — Cutouts are sometimes installed such that there is a low clearance between a phase conductor and a grounded object.

Fusing can also change the impact of animal-caused faults for faults across a distribution transformer bushing or a tank-mounted arrester. If the transformer is externally fused, only the customers on the transformer have an outage. If the transformer is a CSP with an internal fuse, then the tap fuse or upstream circuit breaker operates.

Birds rank second (behind squirrels) as far as the number of outages caused by animals (EPRI TE-114915, 1999; Frazier and Bonham, 1996). Many of the practices listed above can help with birds as well. Additionally, some bird-specific practices include:

- Get rid of nests.
- Track as a separate category.
- Remove nearby roosting areas.

The types of animals causing faults varies considerably by region, and there is also significant variation within a region. Animal faults also ebb and flow with animal populations. Animal population data can be used as one way to determine if "unknown" faults are really being caused by certain animals.

7.6.4 Other External Causes

Automobiles and poles do not always coexist nicely. It is difficult for utilities to prevent car accidents. Sometimes utilities can work with city engineers and police to try to lower speed limits and manage traffic better to avoid bad spots. Reflectors on poles may help. Siting poles further from roads also helps.

Balloons and other debris also cause many interruptions. Covered wire helps. Ladders, cranes, and other tall equipment into primary lines cause dangerous ground-level voltages as well as causing faults. Keep getting the word out. Public awareness campaigns help.

TABLE 7.7

Permanent-Fault Causes

Source	Rural	Urban
Equipment failures	14.1%	18.4%
Loss of supply	7.8%	9.6%
External factors	78.1%	72.0%

Source: Horton, W. F., Golberg, S., and Volkmann, C. A., "The Failure Rates of Overhead Distribution System Components," IEEE Power Engineering Society Transmission and Distribution Conference, 1991. With permission. ©1991 IEEE.

7.7 Equipment Faults

Equipment failures — transformers, capacitors, splices, terminations, insulators, connectors — cause faults. When equipment fails, it is almost always as a short circuit and rarely as an open circuit.

Equipment failures on overhead circuits are usually a small percentage of faults (see Figure 7.1). This is confirmed by another study at Pacific Gas & Electric Co. shown in Table 7.7. These are shown as a percentage of permanent faults. Since equipment faults are almost always permanent faults, the overall percentage of equipment failures is a low percentage of all faults (since most faults are temporary on overhead circuits). On underground circuits, most faults are due to equipment failures.

Distribution transformers are the most common major device, so their failure rate is important. Transformers generally fail at rates of about 0.5% per year. The most common failure mode starts as a breakdown of the turn-to-turn insulation.

Table 7.8 shows equipment failure rates recorded over a 5-year period at PG&E. This data is generic service-time failure rates, which is an estimate to the actual failure rate. Note that this is for California which has very little lightning and mild weather; other areas may have higher equipment failures. The rate of all permanent faults was 0.11 faults/mi/year for rural circuits (0.071 faults/km/year) and 0.16 faults/mi/year for urban circuits (0.102 faults/km/year). The only component where there was a statistical difference between urban and rural at the 90% confidence level was the difference in failure rates of transformers (the sample size for the rest of the numbers was too small to statistically determine a difference).

Another source for equipment failure rate data is the IEEE Gold Book (IEEE Std. 493-1997) (Table 7.9). Note that the Gold Book is for industrial facilities. Application and loading practices may be significantly different than typical utility applications. Still, they provide useful comparisons.

TABLE 7.8

Service-Time Overhead Component Failure Rates for PG & E

Component	Failure Rates per Year	
	Rural	Urban
Transformers	0.0271%	0.0614%
Switches	0.126%	0.0775%
Fuses	0.45%	0.374%
Capacitors	1.05%	0.85%
Reclosers	1.50%	1.44%
Voltage regulators	2.88%	n/a
Conductors	1.22/100 mi	1.98/100 mi

Source: Horton, W. F., Golberg, S., and Volkmann, C. A., "The Failure Rates of Overhead Distribution System Components," IEEE Power Engineering Society Transmission and Distribution Conference, 1991. With permission. ©1991 IEEE.

TABLE 7.9

Overhead Component Failure Rates in the IEEE Gold Book

Component	Failure Rate per Year
Transformers (all)	0.62%
Transformers (300 to 10,000 kVA)	0.59%
Transformers (>10,000 kVA)	1.53%
Switchgear bus (insulated)	0.113%[a]
Switchgear bus (bare)	0.192%[a]

[a] For each circuit breaker and connected switch.

Source: From IEEE Std. 493-1997. Copyright 1998 IEEE. All rights reserved.

7.8 Faults in Equipment

Failures in equipment pose special hazards with important safety ramifications. Transformers deserve extra attention because they are so common. One utility has reported one violent distribution transformer failure for every 270 transformers containing an internal fault, and 20% of re-energizations had internal faults, which is one violent failure every 1350 reenergizations (CEA 149 D 491A, 1997). Cuk (2001) estimated that between 2 and 5% of overhead transformers are re-fused every year (based on analyzing fuse purchases; this number varies with fusing practices). This section discusses failure mechanisms and the consequences of an internal failure.

Transformer insulation degrades over the life of the transformer. Heat drives the degradation of transformer insulation (this is a generality that applies to many other types of insulation as well). Overloading transformers will reduce a transformer's life. Most utilities will overload distribution transformers as it is the best economic way to operate them.

Heat degrades paper insulation at a relatively known rate. ANSI standards give guidelines on loss of life versus temperature. Heating can also cause generation of gas bubbles (Kaufmann and McMillen, 1983). Gas can be created by decomposition of the paper insulation. Prolonged overloading to 175% can cause gas generation. Gas can also be created when heated oil has a pressure drop; the most likely scenario is an overloaded transformer that is cooled quickly (the effect is most significant for overloads above 175%). Rainfall causes the quickest cooling; a loss of load also cools the transformer. The bubbles reduce the dielectric strength of the insulation system. Bubble generation starts when the temperature is near 145°C. Hotspot temperatures exceeding 200°C during overloading can reduce the insulation strength by a factor of two (Kaufmann, 1977). Once the transformer cools off and the bubbles disappear, the insulation recovers most of its initial strength (minus the amount of paper degraded). During overloading, failures can be caused by the power-frequency voltage or a voltage surge (the straw that breaks the camel's back).

Internal faults in equipment such as transformers and capacitors can cause violent damage. Of most concern, explosive failures endanger workers and the public. Figure 7.31 shows a thought-provoking picture of a failure of a recloser. It illustrates how important safety is. Buy quality equipment! Use effective fault protection! Knowing the characteristics of internal failures helps prevent such accidents. We must properly fuse equipment. Fusing should ensure that if equipment does fail internally, it is isolated from the system before it ruptures or ejects any oil.

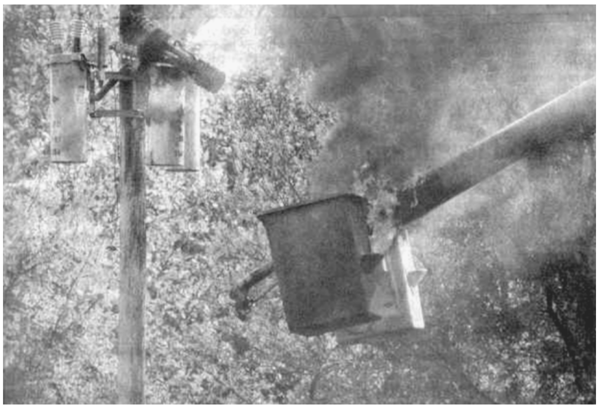


FIGURE 7.31
Explosion of a recloser that caused a fatality. (From Dalton Sullivan, Pocahontas (AR) Star Herald. With permission.)

During the 1970s, considerable work was done to investigate the failure mechanisms, withstand abilities of transformers, and ways to improve protection (Barkan et al., 1976; Goodman and Zupon, 1976; Mahieu, 1975). The voltage along an arc remains relatively constant regardless of the fault current magnitude when under oil just as it does in air. An arc voltage under oil is roughly 215 to 255 V/in. (85 to 100 V/cm) (Goodman and Zupon, 1976; Mahieu, 1975), which is higher than the voltage gradient of arcs in air. The arc voltage is higher because oil cools the arc, which reduces the ionization. Because the arc voltage is constant, the energy in the transformer is a function of $\int I\, dt$.

During a fault under oil, an arc creates a shock wave in the oil that can cause significant dynamic pressures. Also, considerable gas is generated at the rate of roughly 4.3 to 6.1 in.^{3}/kW (70 to 100 cm^3/kW) (Barkan et al., 1976; Goodman and Zupon, 1976). An arc in oil is hot enough to vaporize oil and ionize the gas. The gasses created by the arc include roughly 65 to 80% hydrogen and 15 to 25% acetylene with ethylene, methane, and higher molecular-weight gasses. The arc also produces considerable amounts of solids and free carbon. The arc generates combustible gasses, but combustion is uncommon because the oxygen level is generally low.

The pressure buildup and failure mode is fairly complicated and depends on the location of the fault. A fault in the windings generally causes less peak pressure on the top of the tank than a free-burning arc in oil even if the energy input is the same. The initial force on the transformer is a large downward force in the oil, but the top usually fails first since that is where the weakest structures are (although the downward force and resulting rebound can cause the transformer to buck violently which may break the supports). The transformer lid is the weakest structural portion, so with excessive pressure, the lid will be the first place to fail. Another common failure is a bushing ejection. For a given arc energy, larger transformers have less pressure buildup because a larger transformer has a larger air space [a 100-kVA transformer has 3.8 times the air volume as a 10-kVA transformer (Barkan et al., 1976)]. Padmounted transformers withstand more pressure buildup than overhead transformers (Benton, 1979). Padmounts have higher volume, and the square shape allows the tank to bulge out, which relieves some of the stress.

Many distribution transformers have pressure release valves. These are not fast enough to appreciably reduce the pressure buildup during high-current faults. The pressure release valves help for low-current faults due to interwinding failures. Most failures of distribution transformers start as interwinding faults, either from turn-to-turn or from layer-to-layer. Turn-to-turn faults on the primary winding draw less than load current, so they will not operate the primary fuse. Turn-to-turn faults on the secondary and layer-to-layer faults on the primary draw higher current that may be high enough to operate the primary fuse. Interwinding faults are low-current events where the pressure builds slowly, so the pressure release valves can effectively release the pressure for primary-winding faults although secondary winding faults may increase pressure faster than the pressure-relief valve can dissipate (Lunsford and Tobin, 1997). As an interwinding fault arcs and causes damage and melts additional insulation, the fault current will increase; usually current jumps sharply to the bolted fault condition (not a slow escalation of current).

Overhead completely self protected transformers (CSPs) and padmounted transformers with under-oil fuses have less withstand capability than conventional transformers. The reason for this is that the under-oil fuse (called a weak-link fuse) provides another arcing location. When the weak-link fuse melts, an arc forms in place of the melted fuse element. This arc is in addition to whatever arc may exist within the tank that caused the fault in the first place. The arc across the fuse location is generally going to be longer than normal arcs that could occur inside a transformer. The length of an under-oil weak-link fuse is 2 to 3 in. (5.1 to 7.6 cm) for a 15-kV class fuse. Higher-voltage transformers have longer fuses — a 35-kV class fuse has a length of about 5 in. (12.7 cm). Also, the voltage gradient along an arc in a fuse tube under oil is greater than a "free" arc in oil [the fuse tube increases the pressure of the arc, which increases the voltage drop (Barkan et al., 1976)].

Transformers with under-oil arresters have a special vulnerability (Henning et al., 1989). The under-oil arrester provides another possible failure mode which can lead to very high energy in the transformer if the arrester fails. If the arrester blocks fail, a relatively long arc results. A 10-kV duty-cycle rated arrester has a total block length of about 4.5 in. (11.4 cm). With such a long arc, the energy in the transformer will be very high. Industry tests and ratings do not directly address this issue. To be conservative, consider using a current-limiting fuse upstream of the transformer if the line-to-ground fault current exceeds 1 or 2 kA if under-oil arresters are used.

Stand-alone arresters are another piece of equipment where failure is a concern. If an arrester fails, a long internal arc may cause the arrester to explode, sending pieces of the housing along with pieces of the metal oxide. The move from porcelain-housed arresters to polymer-housed arresters was motivated primarily by the fact that the polymer-housing is less dangerous if the arrester fails. With a porcelain-housed arrester, the thermal shock from the arc can shatter the housing and forcefully expel the "shrapnel." Polymer-housed arresters are safer because the fault arc splits the polymer housing, which relieves the pressure buildup (although if the arc originates inside the blocks, the pressure can expel bits of the metal oxide). Arresters have caused accidents, and they got a bad name when metal-oxide arresters were first introduced because they occasionally failed upon installation.

Distribution arresters may specify a fault current withstand which is governed by IEEE standards (ANSI/IEEE C62.11-1987). To pass the test, an arrester must withstand an internal failure of the given fault current and all components of the arrester must be confined within the enclosure. The duration of the test is a minimum of 0.1 sec (manufacturers often specify other times as well) which is a typical circuit breaker clearing time when the instantaneous relay element operates. If the available fault current is higher than the rated withstand, then current-limiting fuses should be considered. With polymer-housed arresters, the fault-current withstand is usually sufficient with manufacturers specifying withstand values of 10 to 20 kA for 0.1 sec.

The failure of arresters (especially porcelain-housed arresters) is also a consideration for fusing. If an arrester is downstream of a transformer fuse and the arrester fails, the relatively small transformer fuse will blow. If an arrester is upstream of the transformer fuse then a larger tap fuse or the substation circuit breaker operates, which allows a much longer duration fault current. Arresters have isolators that disconnect the arresters in case of failure. Isolators do *not* clear fault current. After the fuse or circuit breaker operates, the disconnect provides enough separation to allow the circuit to reclose successfully. If the next upstream device is a circuit breaker and an instantaneous element is not used, fault currents could be much longer than the tested 0.1 sec, so consider adding a fuse upstream of the arrester on porcelain-housed units.

7.9 Targeted Reduction of Faults

Since faults are the *root cause* of interruptions and voltage sags, obviously, if faults are reduced, the incidence of interruptions and sags will be reduced (power quality and reliability improve) (Mo and Taylor, 1993). This can be done in several ways including

- Tree trimming
- Animal guards
- Arrester protection
- Tree wire (covered wire)
- Aerial or underground cable
- Identifying and replacing poorly performing hardware
- Line patrols including infrared thermography

One way to improve the fault-rate performance is to track the location and type of faults. It is relatively straightforward to track permanent faults since the failed equipment is obvious. They can be classified by category to help determine what types of maintenance need to be performed. The effort in tracking faults is paid back by targeting maintenance efforts to the most important sections.

Temporary faults are harder to pinpoint. If a circuit breaker or recloser operates and successfully recloses, the utility may be unaware of it (unless they get complaints of blinking clocks). A fuse may be blown by a temporary fault (especially if fuse blowing is used). If a fuse blows, the area narrows considerably. For areas with repeat fuse operations, careful patrols may identify areas where repeated faults occur. Still, if a tap fuse operates but is re-fused successfully, the cause may have been a squirrel across a bushing, a tree branch that fell onto then burned off of a line, or wind pushing two conductors together. It often takes a trained eye to determine the cause.

The most important sections are not necessarily the locations with the most faults per mile. The number of customers on a circuit and the type of customers on a circuit are important considerations. For example, a suburban circuit with many high-tech commercial customers should warrant different treatment from a rural circuit with fewer, mostly residential and agricultural customers. How this is weighted depends on the utility's philosophy.

On-site investigations can help reduce faults. Faults tend to repeat at the same locations and follow patterns. For example, one particular type and brand of connector may have a high failure rate. If these are identified, replacement strategies can be implemented. Another example is animal faults. One particular pole, which happens to be a good travel path for squirrels, may have a transformer with no animal guards. The same location may have repeated outages. These may be difficult to find if they cause temporary faults.

Faults are not evenly distributed along lines. Faults are not inevitable. Not all faults are "acts of God." Most are from specific deficiencies at specific structures. On overhead circuits, most faults result from inadequate clearances, inadequate insulation, old equipment, or from trees or branches extending into a line.

Consider faults as *preventable*, then go look for them. Crews can be trained to spot pole structures where faults might be likely. During restoration, crews can identify several common causes of faults including

- Poor jumper clearances
- Old equipment (such as expulsion arresters)
- Bushings or cable terminations unprotected against animals
- Poor clearances with polymer arresters
- Damaged insulators
- Damaged covered wire
- Bad cutout placement
- Danger trees/branches present

Crews can fix problems identified during the outage restoration or target them for future repair.

Implement training out in the field for best results; show examples of fault sources (Taylor, 1995). Walk the line and use binoculars; this is more effective than "riding the line." Some fault sources are not obvious and require looking at a structure from different angles. Taylor provides another good piece of advice: never assume that the lines are built according to specifications.

Characteristic fault patterns are different at different locations. Factors that influence these differences include types of trees, weather conditions, construction practices, and types of equipment purchased. Know the local trends; they can help identify ways to reduce faults.

The best way to reduce faults over time is to "institutionalize" fault-reduction practices. After identifying the most common fault sources, implement programs to address these so performance improves continually. Start with a good design that eliminates fault sources, especially at equipment poles; use sufficient electrical clearance. Separate grounded objects from phase conductors as much as possible. Then employ procedures to ensure that more fault-resistant designs are implemented. Train linemen and field engineers to do it right. If possible, implement programs to bring old construction up to specifications; replace old arresters, increase poor clearances, add covered jumper wires, add animal guards, and so on. An opportune time to clean up poor construction is when crews are already doing work on a structure. Perform quality audits during work and after work is done. Give crews and field engineers feedback.

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with appropriate analysis software. Analysis can be a challenge, based on part by environmental factors that influence the data, so a technician with level I or II thermography certification should be employed to perform this survey. These services can be outsourced. Thermographic finds are invaluable from a safety perspective and typically result in a cost recovery within 1 year.

Passive airborne ultrasonic: It is a low-cost tool for detecting pressure and vacuum leaks in piping, steam traps, pressure vessels, and valves; mechanical systems bearings, lubrication, and mechanical rubbing; and electrical systems arching and corona. Ultrasonic devices are becoming increasingly popular by technicians performing lubrication tasks to determine appropriate lubrication levels. Operators require little training or prior experience and scanners cost as little as $1000.

Lubrication oil analysis: It is often performed on large or critical machines to determine its mechanical wear, the condition of lubricant, if the lubricant has become contaminated, and the condition and appropriateness of the lubricant additives. Lube oil packages include checking for visual condition and odor, viscosity, water content, acidity, alkalinity, and metallic and nonmetallic contamination. Precise procedures must be followed in obtaining clean, representative samples; however, analysis is performed in a laboratory at reasonable costs ($10–$100 per test). A single failure detected could pay for the program for several years.

Electrical condition monitoring techniques: It should be applied to electrical distribution cabling, panels, and connections; switchgear and controllers; transformers; electric motors; and generators. It is estimated that 95% of all electrical problems are due to connections (loose, corroded, undersized, and over tightened), unbalanced load, inductive heating, spiral heating in multistrand wires, slip rings, commutators, and brush riggings. Condition monitoring detects abnormal temperature, voltage, current, resistance, complex impedance, insulation integrity, phase imbalance, mechanical binding, and the presence of arching. The most common predictive tests are

- Infrared thermography—To detect temperature differences and the overheating of circuits (see Chapter 8 for more detail)
- Insulation power factor (PF)—Measures power loss through insulation to ground (see Chapter 3 for more detail)
- Insulation oil analysis—Detects transformer, switch, breaker insulation oil condition, and contamination (see Chapter 4 for more detail)
- Dissolved gas analysis—Trends the amount of nine gases in transformer oil formed by transformer age and stress (carbon monoxide [CO] and carbon dioxide [CO_2] to detect overheating of windings; CO, CO_2, and methane [CH_4] to detect hot spots in insulation; hydrogen, ethane, ethylene, and methane (H_2, C_2H_6, C_2H_4, and CH_4) to detect overheating of oil and/or corona discharge; and acetylene (C_2H_2) to detect internal arching) (see Chapter 4 for more detail)

- Megohmmeter testing—Measures insulation resistance phase to phase or phase to ground (see Chapters 2 and 3 for more detail)
- High-potential (hi-pot) testing—Go/no-go test of the insulation
- Airborne ultrasonic noise—Detects electrical arching and corona discharges
- Battery impedance—Checks impedance between terminals and compares the same battery against previous readings (should be within 5%), compares the battery with others in the bank (within 10%), internal short (impedance > 0), open circuit (impedance > infinity), and premature aging due to heat/discharges (fast rise in capacity loss) (see Chapter 8 for more detail)
- Surge testing—Go/no-go test of winding insulation
- Motor circuit analysis (MCA)—Measures motor circuit resistance, capacitance, imbalance, and rotor influence (see Chapter 10 for details)
- Motor current signature analysis (MCSA)—Provides signatures of motor current variations (see Chapter 10 for details)

Electric motor phase voltage unbalances affect the phase current unbalances, cause motors to run hotter, and reduce the motor's ability to produce torque. For every 10°F increase in operating temperature, it is estimated that the life of the equipment is reduced by half (H.W. Penrose, White Paper, Test methods for determining the impact of motor condition on motor efficiency and reliability).

Some of these electrical tests require the circuits to be energized, and others not. Some tests require specific initial conditions, such as normal operating temperature. Whereas some high loads amplify problems, low load allows for their nondetection.

Electricians, technicians, and electrical engineers trained in electrical predictive techniques can perform the testing. A comprehensive testing program toolbox would include an infrared camera, ultrasonic detector, multimeter/voltohmmeter, clamp-on current transformer, an insulation and PF test set, battery impedance test set, MCSA test set, and MCA tester.

Proactive maintenance: It improves equipment condition and rate of degradation through better design, installation procedures, failure analysis, workmanship, and scheduling. Its procedures and technologies are used during forensic evaluations to determine the cause of failure. Proactive maintenance uses feedback to ensure that changes from lessons learned and best practices are incorporated in future designs and procedures. It employs a life-cycle view of maintenance, ensures that nothing affecting maintenance is done in isolation, and integrates maintenance support functions into maintenance planning. It uses RCFA and predictive technologies to maximize maintenance effectiveness. Common proactive techniques are:

RCM specifications: Specifications that incorporate RCM philosophy and techniques are prepared for new and rebuilt equipment. These specifications include vibration, alignment, and balance standards; electrical testing criteria;

lube oil testing requirements; and commissioning and acceptance testing requirements. Operator and maintenance feedback and RCM analysis documentation provide designers with justification for equipment upgrades and modernization. New and replacement units' design should reflect lessons learned and best practices for improvements on operability, maintainability, and reliability.

Failed part analysis: Involves visually inspecting failed parts to identify the root cause of the failure. It looks at forensic scoring, color, and pitting, particularly of bearings, which are generally the equipment's weakest components and achieve only 10%–20% of their design life.

RCFA: Maintenance technicians usually repair symptoms, although recurring problems are symptomatic of more severe problems. The end result is high cost, questionable mission reliability, strained user goodwill, and safety hazards. RCFA seeks to find the cause, not just the effect, quickly, efficiently, and economically. Predictive maintenance techniques detect and correct problems before failure, but do not act on the root cause. RCFA provide the information to eliminate the recurrence and instill the mentality of "fix forever."

FMEA: Similar to RCFA, but performed prior to failure. Its goal is to identify potential failures and failure modes to take action to prevent the failure, detect the failure earlier, and reduce the consequences of failure. For each affected equipment, it describes the function, identifies failure modes and the effects of failure, the probability and criticality of failure, and suggests a maintenance approach.

Reliability engineering: It involves the redesign, modification, and replacement of components with superior components, such as sealed bearings, upgraded metal, and lubricant additives.

Age exploration: Determines the optimal maintenance frequency. Starts with the manufacturer's recommendations, then adjusts the frequency based on equipment histories and observations and condition assessments during PMs and "open and inspects."

Recurrence control: A repetitive failure is the recurring inability of a system, subsystem, structure, or component to perform the required function. The process analyzes the repeated failure of the same component, repeated failure of various components of the same system, and the repeated failure of the same component of various systems. Historical maintenance and trend data would be monitored to determine if recurring component problems might be symptomatic of possible genetic problems and/or procedures of system aging, corrosion, wear, design, operations, the work environment, or maintenance application (or misapplication).

***Program implementation**:* The planning of a maintenance program should include considerations for proper test equipment, tools, trained personnel to carry out the maintenance tasks, and time required to perform inspections, tests, and maintenance routines. Also, consideration should be given to record-keeping systems that range from computerized maintenance management systems (CMMSs) to manual file systems. There are number of companies that offer computerized maintenance management programs as stand alone programs or they can be incorporated into the facility operational programs. The reader is encouraged to look into this programs since they are not fully covered in this book.

The following are the steps in implementing an effective maintenance program:

1. Determine the objectives and long-range goals of the maintenance program.
2. Survey and consolidate data on equipment breakdowns.
3. Determine equipment criticalities.
4. Determine the risk and the amount of risk that you are willing to tolerate.
5. Establish metrics and key performance indicators (KPIs) to track and trend performance.
6. Establish the best maintenance techniques within your resources to mitigate the risk. Determine the maintenance procedures and frequencies.
7. Schedule and implement the program, starting with the most critical systems and those with the fastest, most beneficial paybacks first.
8. Publicize successes; provide trends, metrics, and KPIs to top management to gain management support.
9. Repeat the cycle.

Maintenance analyst*:* The quality of the maintenance program is reflective of the skill of the maintenance technicians, their workmanship, quality of the supporting documentation, procedures, and the technologies used.

A position for maintenance analyst should be included in an RCM program. This person should be able to detect the equipment condition, must have the skill to analyze the condition, must be able to diagnose the machine or system operation and develop a course of action, and must take the action needed to prevent failure (or allow RTF). The analyst would be responsible for monitoring and analyzing data for the mechanical systems. He or she would receive all work orders, trouble calls, KPIs, and test results and would provide continuous oversight and analysis.

Plant databases*:* CMMSs, building management systems (BMSs), and energy management systems (EMSs) provide invaluable historical data to the maintenance analyst. Historical data from these provide information on age–reliability relationships, data to trend and forecast impending failure, test results, performance data, and feedback to improve performance and to document condition.

RCM involves specifying and scheduling EPM activities in accordance with the statistical failure rate and/or life expectancy of the equipment being maintained and its criticality and productivity, and continually updating EPM procedures and schedules to reflect actual maintenance experience in the plant. RCM is the most cost-effective of the alternative approaches because it improves plant safety, reliability, and availability while reducing maintenance costs by concentrating limited maintenance resources on items which are the most important and/or troublesome, and reducing or eliminating unnecessary maintenance on items which are of little significance and/or highly reliable. A comprehensive RCM program also incorporates structured provisions for failure root cause investigation and correction and for performance monitoring to predict failures. RCM is used extensively in the military and is gaining acceptance among both nuclear utilities and manufacturing plant operators as its advantages are increasingly recognized.

1.3.1 Key Factors in EPM Optimization Decisions

The optimum EPM approach for any specific plant, system, and/or piece of equipment depends on a variety of factors, including the following:

- Safety impact of equipment failure
- Productivity and profitability impact of equipment failure (including costs of lost production as well as failed equipment repair or replacement)
- Cost of PM
- Failure rate and/or anticipated life of equipment
- Predictability of failure (either from accumulated operating time or cycles or from discernible clues to impending failure)
- Likelihood of inducing equipment damage or system problems during maintenance and testing
- Technical sophistication of the plant maintenance staff
- Availability of equipment reliability data to support RCM

1.3.2 General Criteria for an Effective EPM and Testing Program

Effective electrical equipment and subsystem PM and testing programs should satisfy the criteria listed below.

First and most fundamental, a structured EPM program should actually exist. That is, EPM should be performed as follows:

- Under formal management control
- In accordance with defined practices and schedules
- By clearly designated persons

Specifically:

Management should assign a high priority to EPM. As a corollary, adequate resources—personnel, facilities, tools, test equipment, training, engineering, and administrative support—should be devoted to EPM. Adequate support from design engineering and operations are especially important.

EPM activities should be prioritized according to the criticality of the systems and equipment involved, with the highest resource intensity and scheduling priority assigned to equipment, subsystems, and systems important to safety.

EPM should be performed according to unambiguous written procedures based on specific consideration of equipment, application, and environmental characteristics.

EPM procedures and schedules should be maintained and reviewed in order to ensure engineering review of procedural changes and the incorporation of plant modifications.

The EPM program should have provisions to take effective advantage of actual experience accumulated both in the plant and elsewhere (e.g., as professional society and industry association publications, and informal communications with other interested organizations).

The EPM program should incorporate effective provisions for failure root cause analysis, correction, and recurrence control.

Information systems should be in place to record and update the plant maintenance, testing, and operating history, and to facilitate trending of test data, in support of the previous two criteria.

EPM should be performed only by appropriately qualified personnel. (See Section 1.3.3.)

Management should continually monitor and reevaluate the effectiveness of the EPM program, and make appropriate changes in response to identified programmatic problems and advances in maintenance technology.

By clear implication, the "RTF" and "inspect and service as necessary" philosophies described earlier fail to provide enough structure, direction, and monitoring to satisfy the criteria for a sound EPM approach. These philosophies are not acceptable for important equipment and systems. At a minimum, a scheduled EPM program is clearly necessary.

1.3.3 Qualifications of EPM Personnel

The minimum acceptable qualifications for personnel assigned to perform EPM depend on the type of maintenance and the type of the equipment to be maintained. It is normally acceptable for nonspecialists personnel to perform superficial inspections and other undemanding EPM tasks when guided by defined procedures and acceptance criteria. However, effective administrative controls should be in place to ensure that critical PM tasks on important equipment and systems are performed only by—or at least under the immediate and active supervision of—appropriately trained and experienced maintenance technicians. Such tasks typically include internal inspection, testing, calibration, and refurbishment.

Training for critical EPM work on important equipment and systems should include at least the following:

- The fundamentals of electrical power technology
- General electrical maintenance techniques
- Electrical safety methods and practices
- The design and operation of the equipment and system to be maintained
- The applicable maintenance and testing procedures required for the maintenance and testing of the equipment

For critical tasks, technicians' experience should include similar work on the same or closely comparable equipment, preferably in an operational environment, although experience acquired in a training environment under direct supervision of experienced instructors is acceptable.

With regard to electrical safety methods and practices, the National Fire Protection Association (NFPA) and the Occupational Safety and Health Administration (OSHA) have promulgated new guidelines and requirements to protect workers from shock and flash hazards. The NFPA 70E, Article 110.8 (B) (1) requires safety-related work practices to be used to protect employees who might be exposed to the electrical hazards involved when working on live parts operating at 50 V or more. Appropriate safety-related work practices shall be determined before any person approaches exposed live parts within the limited approach boundary by using both shock hazard and flash hazard analyses. Similarly, OSHA 1910.335(a)(1)(i) requires employees working in areas where there are potential electrical hazards to be provided with, and to use, electrical protective equipment that is appropriate for the specific parts of the body to be protected and for the work to be performed. Also in accordance with OSHA 1910.132(d), the employer is required to assess the workplace hazard to determine the use of personal protective equipment (PPE) required to protect the worker from shock and flash hazards. The NFPA 70E and OSHA requirements for shock and arc-flash hazards and guidelines for performing such an analysis are covered in more detail in Chapter 13, Sections 13.2 and 13.3. The maintenance of protective devices and its impact on arc-flash hazard are covered in Section 1.7 of Chapter 1.

1.3.4 Optimization of PM Intervals

Experience in a variety of industries demonstrates that performing PM on an absolutely fixed schedule rarely results in the optimum balance among the costs of preventive and corrective maintenance and the safety and productivity benefits of equipment reliability and availability. Given an adequate historical failure and maintenance database, reasonably straightforward methods can be used to optimize the PM cycle.

Also, several industry standards such as National Electrical Code (NEC) Standard 70B, National Electrical Testing Association (NETA) maintenance specifications, and others including manufacturer's recommendations provide guidelines on the frequency of maintenance of electrical equipment which could be used to establish EPM cycle.

1.3.5 Trending of Test Results

Systematic trending of EPM test results is a key element of a high-quality electrical maintenance program. This is true because the magnitudes (pass or fail value) of many of the parameters measured during EPM tests on equipment are poor predictors of future failures, unless they are so far out of the normal range that they indicate imminent and probably irretrievable failure. Examples include insulation resistance, leakage current, capacitance, PF, and dissipation factor (DF); bearing temperature and vibration; and winding temperature. However, a degrading trend in these parameters strongly indicates impending trouble, especially if the trend is accelerating. A sound trending program can often alert the maintenance and operations staff of the plant in time to arrest the degradation and avert the failure, or at least to minimize the effect of the failure on safety and productivity.

To provide meaningful information, the trending program must be structured to screen the effects of external factors which affect the measured results but which are irrelevant to the actual condition of the equipment health and reliability. Test procedures should mandate precautions to ensure that the external conditions which can affect the test results remain the same from test to test, or to correct the results when this is impractical. (For example, insulation resistances readings taken at varying temperatures are corrected to a common base temperature.) Typical irrelevant external conditions that affect electrical test results include temperature, humidity, and load.

1.3.6 Systematic Failure Analysis Approach

Failure analysis and root cause investigation should be an integral part of any EPM program. The steps to be taken after a failure is observed are

1. Use a failure cause analysis to determine the proximate cause of the failure. The proximate cause is expressed in terms of the piece-part-level failure, e.g., relay XX failed to transfer due to corroded contacts.
2. Compare the proximate cause to past failures or conditions on the same and similar equipment to determine if the problem has a

systematic root cause, e.g., a chemically active environment in the example cited above.

3. If there appears to be no systematic root cause, correct the failure, resume operation, and continue performance monitoring. If there is a discernible root cause, initiate a structured root cause investigation.
4. If the problem is generic, contact other affected plants and manufacturers of the equipment to determine if they have taken any effective corrective actions. If so, adapt these actions to the specific circumstances of the affected equipment; if not, proceed to the next step.
5. If the problem is plant-specific, or if it is generic but no effective solution has been developed elsewhere, determine if it is attributable to a unique system design, to application or environmental factors, or to operational factors such as maintenance, testing, and operations practices.
6. If the problem is determined to be related to system design, equipment application, or environment, determine the specific deficiency (through special tests performance monitoring, environmental monitoring, etc.), and make appropriate corrections.
7. If the problem is related to faulty operations, identify and correct the specific procedures involved.
8. Determine whether the root cause of the problem is a programmatic deficiency, e.g., in procedures writing, training, supervision, or adequacy of resources, and make appropriate corrections.
9. Perform the necessary postcorrection testing and monitoring to close out the problem and ensure that it is corrected.

1.3.6.1 Postmaintenance Testing

Postmaintenance testing provides the best assurance that maintenance actions were accomplished correctly and that the system or component was returned to functional condition. Postmaintenance testing is heavily emphasized in the better-performing plants. In these organizations, postmaintenance tests are performed following any action that potentially affects the operability of a component/subsystem/system and the scope of the testing is broad enough to confirm all of the potentially affected functions. Associated systems, subsystems, or components are tested along with the systems, subsystems, or components which initiated the process if an engineering analysis indicates that the maintenance action could have a significant impact on these associated items.

1.3.6.2 Engineering Support

Engineering support is intended to ensure that the PM program properly addresses the engineering and logistical aspects of maintenance. In view of this broad objective, engineering support of maintenance encompasses much of the engineering and management activity that takes place in a plant. This includes at least the following functions:

- Maintenance engineering
- System engineering
- Design engineering
- Training
- Spare parts and materials management
- Quality assurance
- Quality control

There are, of course, many other areas of maintenance involvement with engineering support groups. The intent here is to show areas which stand out in the better-performing plants and which tend to be missing or underdeveloped in other organizations.

Maintenance engineering is the engineering support activity most directly involved with PM. This function is present in all of the better-performing plants, although its name and where it fits into the organization vary widely from plant to plant. Its purpose is to optimize the maintenance program through planning, feedback, continual evaluation, and periodic updating of policies and procedures. The functions of a maintenance engineering group typically include

- Maintenance procedure development and control
- Periodic review and updating of maintenance practices and procedures
- Maintenance recordkeeping
- In-service inspection and testing (ISI/IST) program development
- Providing guidance to the training staff on maintenance training
- Collecting and trending equipment failure, reliability, availability, and maintainability data
- Tracking and trending the corrective- to preventive-maintenance ratio
- Failure root cause analysis
- Tracking, trending, and analysis of nonconformances
- Identifying and monitoring maintenance-related equipment performance parameters, especially failure precursors
- Identifying and monitoring maintenance performance indicators

1.3.6.3 Summary

The foregoing has been a brief look at the features of the EPM program. There are many ways to effect improvements in an organization, but probably the dominant cause of failing to improve is resistance to change. In the plants that have outstanding maintenance organizations, upper management has overcome this resistance by direct, long-term involvement in establishing and implementing policies leading to improved maintenance. Perceptible improvements in reliability, availability, and thermal efficiency have generally resulted; the indirect results have been both greater safety and higher profits. The changes in these organizations were not easy and required both time and dedication to implement. Effective management appears to be the key to an effective overall maintenance organization, not the number of programs management has in place.

1.4 Planning an EPM Program

There are management, economic, and technical considerations as discussed in Section 1.3 along with other requirements that need to be understood in order to develop an effective maintenance program. Let us review these items from the viewpoint of developing an effective and comprehensive maintenance program. The main parts of the maintenance program can be classified into maintenance management considerations, technical requirements, and those items that should be included in the EPM program.

1.4.1 Maintenance Management Considerations

The design of any maintenance program must meet the ultimate goals of plant management. Maintenance is like an insurance policy: it has no direct payback, yet it is a cost that adds to the cost of the final product. However, one must hasten to say that it has inherent paybacks such as those listed in Section 1.2. It is generally observed that management resists the investment in a maintenance program even though they realize the need for good maintenance. In view of this, it is up to electrical personnel to show management how a properly planned electrical maintenance and testing program is justifiable.

The planning of EPM programs should then include the advantages of a well-planned maintenance along with cost data for lost production due to equipment failure versus cost of budgeted PM. Any maintenance program should prove that it is cost effective and minimizes equipment failure. The planning of the program should include considerations for proper test equipment, tools, trained personnel to carry out maintenance tasks, and time required to perform inspections, tests, and maintenance routines. Also, consideration should be given to record keeping systems, which can range from fully computerized to manual file systems. To set up an EPM and test program, the following steps may be undertaken:

- Determine the factors that will form the basis of the maintenance program, such as the necessity for continuous production, management policy on budgeting for planned maintenance versus replacement of equipment, and the like.

- Survey and consolidate data on equipment breakdowns and cost of lost production. Make an analysis of the cost data to convince management of the benefits of planned maintenance.
- Establish electrical maintenance priorities. These consist of on-line production sequence, most important to least important equipment, weighing the reliability of the equipment, and other factors.
- Establish the best maintenance techniques. This involves selecting the best maintenance method and personnel for the various types of equipment and systems.
- Schedule and implement the program. Monitor its benefits and costs. Analyze program functions periodically for improvement of the program.

After the program has been set up, it is essential that it consist of elements that will prove it to be a success such as responsibilities, inspection, scheduling, work orders, and record keeping.

1.4.1.1 Responsibilities

The responsibilities of the maintenance organization should be clearly defined by organization charts with functional work statements for each unit. The functional work statements must be established by management as a matter of policy. Every other department must be informed of the responsibilities assigned to maintenance organizations. The effectiveness of the maintenance departments will depend upon how well they are organized and how well personnel are utilized.

1.4.1.2 Inspection

Inspection is the key to the success of any maintenance program. Sufficient time should be allocated for inspection to verify the condition of new and installed equipment. The purpose of inspection is to provide advance warning as to the condition of the equipment under investigation. When inspection is performed on definite cycles by qualified people, impending deterioration can be detected in advance so that repair or replacement can be made before failure of the equipment occurs.

1.4.1.3 Scheduling

To perform maintenance, a definite schedule of work to be performed must be established. Maintenance schedules must be based upon minimum downtime for the various operating segments. The schedule for inspection, routine maintenance, and other work may vary for different equipment and will depend upon many factors. These factors can be age of equipment, frequency of service, hours of operation, environmental conditions, damage due to abuse, and safety requirements. Frequency of scheduling of all tasks should be adjusted as data on various equipment are recorded and analyzed to provide a balance between cost of maintenance and replacement cost of the equipment.

1.4.1.4 Work Orders

Work orders are job requests that need action for completion. Work orders can be established for all inspection service and other work on equipment in terms of routines. Any of these routines should include information on when such work is to be performed, where it is to be performed, and exactly what has to be done. These routines can be generated by a computer-based maintenance system. The routines should include all the pertinent information concerning the equipment.

1.4.1.5 Record Keeping

The success of a planned maintenance program depends upon the impetus given by top management and the interest of the maintenance personnel in the program. To have an effective program, it is imperative that maintenance and test inventory data on all equipment should be complete and readily available throughout the service life of the equipment. To that end, record keeping is very important. All forms and reports should be organized to provide ready accessibility to data when needed and to flag down problem areas. Such data may also be used over the years to analyze trends for equipment deterioration. If data are not recorded and maintained properly, the whole purpose of planned maintenance is lost.

1.4.2 Technical Requirements

Technical requirements can be stated as follows:

- Survey of plant equipment
- Listing of plant equipment in the order of critical importance
- Plan to perform EPM on a regular frequency
- Development of instructions and procedures for the EPM program

1.4.2.1 Survey of Plant Equipment

To perform an effective EPM program, it is necessary to have accurate data about the electrical power system. This may include one-line diagrams, short-circuit coordination study, wiring and control diagrams, and other data that can be used as a reference point for future maintenance and testing. The purpose of these diagrams is to document and serve as an official record of equipment and circuit installation. The National Electrical Manufacturer's Association (NEMA) has established standards for diagram symbols, device designations, and electrical symbols. The types of diagrams and drawings in common use are the following:

Process or flow diagram: A conceptual diagram of the functional interrelationship of subsystems in pictorial form.

Block diagram: A group of interconnected blocks, each of which represents a device or subsystem.

One-line (single-line) diagram: It shows, by means of single lines and graphic symbols, the flow of electrical power or the course of electrical circuits and how they are connected. In this diagram, physical relationships are usually disregarded. A typical one-line diagram is shown in Figure 1.4.

Schematic (elementary) diagram: It shows all circuits and device elements of the equipment. This diagram emphasizes the device elements and their

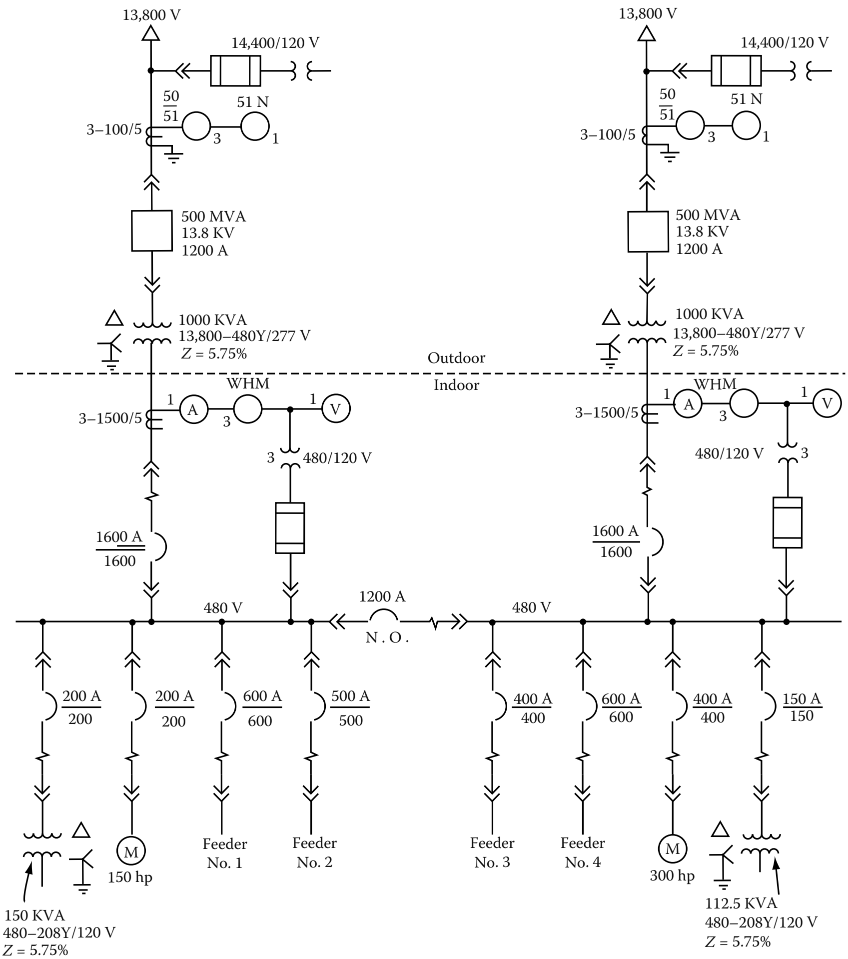


FIGURE 1.4
Typical one-line diagram of a power distribution system.

functions, and it is always drawn with all devices shown in de-energized mode. A typical elementary diagram is shown in Figure 1.5a.

Control sequence (truth-table) diagram: A description of the contact positions, or connections, that are made for each position of control action or device.

Wiring diagram (connection diagram): It locates and identifies electrical devices, terminals, and interconnecting wires in an assembly. This diagram may show interconnecting wiring by lines or terminal designations. A typical wiring diagram is shown in Figure 1.5b.

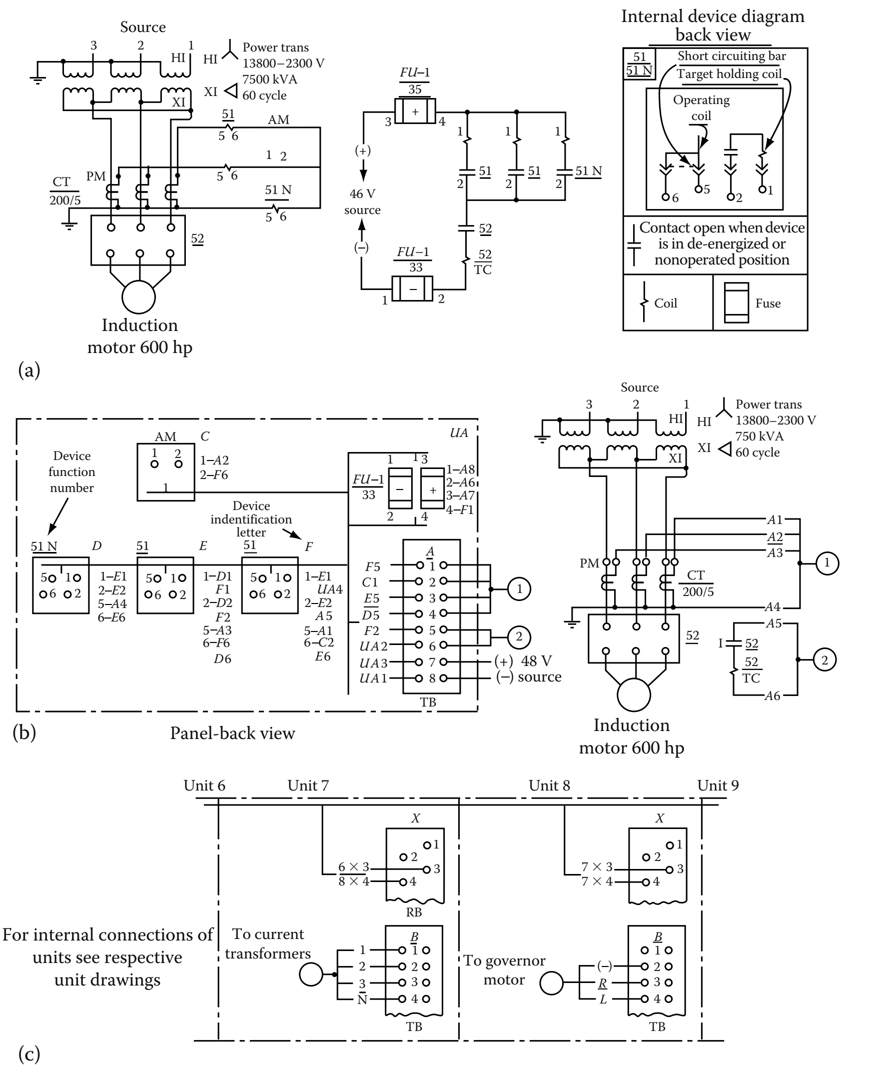


FIGURE 1.5
Typical electrical (a) elementary control, (b) connection, and (c) interconnection diagrams.

Interconnection diagram: It shows only the external connections between controllers and associated equipment or between various housing units of an assembly of switchgear apparatus as shown in Figure 1.5c.

Circuit layout and routing diagram: They show the physical layout of the facility and equipment and how the circuit to the various equipment is run.

Short-circuit coordination study: An electrical power system data, diagrams, and drawings are needed during maintenance and testing of electrical equipment. This may involve information and data relating to protective devices and relays. Such data are usually found in a short-circuit coordination study and usually encompass all the short-circuit values available in the power system, relays, and trip device settings. Normally, this study is performed during the construction and commissioning phase of the facility. It would be much more desirable to perform this engineering study as part of the initial facility design, and then validate it during the construction phase to assure that equipment and values specified have been met. When accepting the facility, this study data should be used as a benchmark, and any changes that may have been made during construction in the system should be incorporated to update the study for future references.

System diagrams: In addition to other data assembled, system diagrams will generally be needed for large systems. Such diagrams may consist of the following:

Control and monitoring system

Lighting system

Ventilation system

Heating and air conditioning system

Emergency system

Other systems

All the system diagrams may interface with one another, such as electrical diagrams, fire and security diagrams, emergency power, hydraulic, pneumatic, and/or mechanical systems. Therefore, it is important to know how these interfaces work and how they can be coordinated in the maintenance program.

1.4.2.2 Listing of Plant Equipment in the Order of Critical Importance

Electrical power system equipment, like any other plant equipment, is vital to the operation of the plant or facility. Failure of the power system may be considered a serious threat to people and property. The listing may be difficult to accomplish because the criticalness of any piece of equipment will vary for each plant or facility. Therefore, a team to mutually identify and list the critical equipment (electrical and other) vital to the operation of a facility may be necessary. The team should consist of representatives from each area of expertise involved in the operation of the plant. All the critical equipment and/or systems should be identified on the drawings. The maintenance department should understand each of these systems, equipment, and/or their functions and how they may affect or interface with other systems. The more knowledgeable the maintenance members are about their system, the better job they will perform in their duties.

1.4.2.3 Plan to Perform EPM on Regular Frequency

Several factors should be considered in establishing the frequency with which equipment is to be maintained:

- Environmental conditions
- Load conditions
- Duty requirements
- Critical nature of the equipment

The purpose of the maintenance schedule is to establish the condition of the equipment and determine what work will be required before its next scheduled maintenance. Usually, manufacturers' service manuals specify recommended frequency of maintenance and/or inspection. These time intervals are based upon standard operating conditions and environments. If these standard conditions change for the equipment, then the frequency should be modified accordingly. However, once the frequency of scheduled maintenance is established, this schedule should be adhered to for at least several maintenance cycles. The schedule should be adjusted if the equipment begins to experience unexpected failures. The frequency in this case can be reduced by as much as 50%. On the other hand, if the equipment does not require maintenance for more than two inspections, the period of frequency for that equipment can be increased by as much as 50%. Adjustment should be continued until the optimum interval is found. Generally, the test frequency can vary from 6 months to 3 years.

1.4.2.4 Development of Instruction and Procedures for the EPM Program

The final technical function in developing an EPM program involves establishment of instructions, procedures, and methods to ensure that the equipment and system components operate without failure. The maintenance department should have fully developed procedures and instructions for thoroughly servicing all equipment and components. In addition, the maintenance department should also develop shutdown procedures, safeguards, interlocking of equipment, alarms, and methods of recording data (forms) and reporting unusual conditions to the proper authority. The maintenance records should be further utilized to evaluate results and as an indicator of possible modifications or changes in the maintenance program. In other words, the recorded information should be used as historical data and for feedback to modify the maintenance program.

1.4.3 What Should Be Included in the EPM Program

The EPM and testing program should encompass the following activities:

- EPM and testing
- Electrical repairs
- Analysis of failures
- Trending of maintenance and testing data

To have an effective and efficient operation, it is essential to carry out these four activities.

1.4.3.1 EPM and Testing

This activity involves inspection, cleaning and adjustment, and testing of equipment to ensure trouble-free operation until its next scheduled maintenance. PM and testing also allow the prediction of impending failure of a particular piece of equipment so that plans can be made to replace it without catastrophic results. The information on testing can be obtained from several different sources such as manufacturer's manuals, published literature on specific equipment, and industry standards. The relevant industry standards are: the Insulated Cable Engineering Association (ICEA), NFPA, Institute of Electrical and Electronic Engineers (IEEE), American National Standard Institute (ANSI), NEMA, NETA, Insurance Company Manuals (ICMs), and others, depending on the equipment to be tested.

1.4.3.2 Electrical Repairs

The repair of electrical equipment and related machinery associated with plant production is the fundamental requirement of good maintenance programs. The maintenance should be performed economically and expeditiously. The basic objective of the maintenance program should be to avoid unexpected breakdowns of equipment. Furthermore, when breakdowns occur, spare parts should be on hand to make the necessary repairs. The maintenance personnel should be properly trained to perform the repairs promptly and correctly in order to minimize the downtime of the equipment.

1.4.3.3 Analysis of Failures

The failure of electrical equipment should be analyzed to assess reasons for its breakdown. Unless the cause is obvious, the equipment quality may be questioned. Reliability can be built into the equipment, but it requires upkeep to retain it. The tendency to ignore regular maintenance and testing generally prevails over regularly scheduled maintenance because regular maintenance may be considered unnecessary and too expensive. Therefore, the best designed and built equipment may break down through lack of attention. Every failure should be analyzed for its cause so that corrective measures can be implemented to prevent similar breakdowns.

1.4.3.4 Trending of Maintenance and Testing Data

Systematic trending of maintenance and testing data (see Section 1.3.5) can alert the maintenance staff of degrading equipment. This allows the maintenance staff to monitor such equipment more closely or take corrective actions to avert a catastrophic failure.

1.4.3.5 Computerized Maintenance Management System

It is essential to have a CMMS for implementing an effective maintenance program. In the past, the maintenance data were manually recorded and managed. It was time consuming and difficult to record data and perform trend analysis of the maintenance test results. Today, most maintenance tasks can be automated with the use of commercially available CMMS programs and a desktop or a laptop computer. The job of maintaining and managing maintenance and test data has become much easier compared to the past. A CMMS is essential for improving performance, analyzing data for key trends and anomalies, forecasting reliability issues, and in making forward-looking decisions that deliver improved bottom-line results. A comprehensive CMMS program can incorporate all of the elements discussed in Sections 1.4.1.2 through 1.4.3.4 and make the electrical maintenance department an effective organization. Typical key functions of CMMS include the following:

Work orders—scheduling jobs, assigning personnel, reserving materials, and recording costs.

PM—keeping track of PM inspections, tests, and jobs, including step-by-step instructions or checklists, lists of materials required, and other pertinent details.

Asset management—recording data on equipment including specifications, nameplate information, purchase date, maintenance history, inspection and test data, and so on.

Inventory control—management of spare parts, tools, and other materials.

Critical equipment listing and inventory—list of critical equipment vital to the operation of the facility.

Root cause analysis of failures—analysis of failures and their causes so that corrective measures can be implemented to prevent similar failures.

Advanced reporting and analytics—creating customized reports and analyses that can be used to forecast likely problems in time to prevent them.

There are number of vendors that offer CMMS for the management of electrical maintenance and testing data and reporting such as Megger "PowerDB," Service Automation Technologies "EPower Forms," and Optima-SMS. For example, PowerDB* is a powerful software package for entry and management of acceptance (start-up) and maintenance test data, storage and reporting. The system allows the user to define data forms for different equipment types. When testing equipment, these forms are used to facilitate data entry, on-screen data presentation, and report printing. Equipment is organized in an organization scheme of up to five levels. This software is designed to work as the Equipment Tree. The Equipment Tree levels are labeled as customer, user, plant, substation, and position. Data entry and reporting for one or more pieces of equipment are organized into jobs. PowerDB stores information in a database. Subsets of the database may be made for field-testing. Results, changes, and additions to the subset may be merged with the master database. All types of test results can be entered and stored into the software for generating formal reports and a permanent historical record. The PowerDB CMMS program is designed to record and manage the maintenance and test data for the many of the electrical equipment including the following: batteries, cables, circuit breakers, coordination data, disconnects, generators and motors, power transformers, insulation fluids, loadbreak switches, motor control centers (MCCs), relays, PF tests, switchboards, transfer switches, watt-hour meters transducers, ground fault tests; ground mat/grid tests; instrument transformers, and so on.

The user interface for viewing or recalling information is also the actual test or inspection entry form. Various forms for each type of apparatus allow input of inspection and electrical test data. Over 200 standard tests forms currently exist in PowerDB, and customized forms can be generated using a built-in forms editor. Archived test results can be trended and compared with newly entered information for quick analysis of equipment condition. Forms include embedded equation calculations as well as functional scripts for operating electrical and electronic field test sets. This capability allows for automated testing and capturing of test results into the database. Customer and contract information is quickly sorted and searched. Opening a specific record shows detailed information about the job, such as type of service, order date, sales contact, and invoice information. Job information and related test results can be transferred between field-use databases and a master database. Job and device productivity reports track the time spent on testing and evaluation of equipment. Test data entry screens and printed

* This CMMS program is cited here as an example of one of several such programs. This listing is not intended as an endorsement of this program by the author or publisher.

forms are identical allowing intuitive operation. Entire test documentation packages consisting of test reports, comment and deficiency summaries, table of contents, and field service reports are created easily.

1.5 Overview of Testing and Test Methods

Testing of electrical equipment is usually performed in the field on new equipment after installation and on existing equipment to assess its condition. The manufacturer conducts electrical tests on equipment before it leaves the factory; these tests, known as factory tests, are outside the scope of this text and therefore will not be discussed. Field tests are conducted to see whether newly installed equipment has been damaged, to indicate whether any corrective maintenance or replacement is necessary on existing equipment, to indicate if the equipment can continue to perform its design functions safely and adequately, to chart the gradual deterioration of the equipment over its service life, and to check new equipment before energization. In view of these objectives, the electrical testing of equipment can be divided into the following:

- Types of tests
- Types of testing methods

1.5.1 Types of Tests

The types of field tests are acceptance tests, routine maintenance tests, and special maintenance tests that are conducted for specific purposes.

1.5.1.1 Acceptance Tests

These tests are known as start-up or commissioning tests and are performed on new equipment, usually after installation and prior to energization. When these tests are repeated within a year, that is before the warranty period expires, then these tests are referred to as proof tests. Tests of this type are made at 80% of the final factory test voltage value. They are run to determine the following:

Whether the equipment is in compliance with the specification

To establish a benchmark for future tests

To determine that the equipment has been installed without damage

To verify whether the equipment meets its design intent and limit

1.5.1.2 Routine Maintenance Tests

These tests are performed at regular intervals over the service life of the equipment. They are made concurrently with PM and at 60% of the final factory test voltage value. In the course of routine maintenance tests, it is very helpful to record the information as it is found on the equipment and to also record the condition in which the equipment is left. Therefore, these tests can be further subdivided into the following:

As-found tests: These tests are performed on equipment on receipt or after it has been taken out of service for maintenance, but before any maintenance work is done.

As-left tests: These tests are performed after maintenance has been performed and just before reenergization. They can indicate the degree of improvement in the equipment and service as a benchmark for comparison for future tests.

1.5.1.3 Special Maintenance Tests

These tests are performed on equipment that is known to be defective or has been subjected to adverse conditions that may affect its operating characteristics. An example might be the fault interruption by a circuit breaker, which requires inspection, maintenance, and tests before it can be put back into service.

1.5.2 Types of Testing Methods

The testing of electrical power system equipment involves checking the insulation system, electrical properties, and other factors as they relate to the overall operation of the power system. Therefore, testing of electrical equipment can be divided into the following types:

- Solid insulation testing
- Insulating liquid testing
- Relay and protective device testing
- Circuit breaker time–travel analysis
- Grounding electrode resistance testing
- Fault gas analysis testing
- Infrared inspection testing

1.5.2.1 Solid Insulation Testing

Insulation can be either solid, liquid, or gaseous dielectric materials that prevent the flow of electricity between points of different potential. Insulation testing is done to determine the integrity of the insulating medium. This usually consists of applying a high potential (hi-pot) voltage to the sample under test and determining the leakage current that may flow under test conditions. Excessive leakage current flows may indicate a deteriorated condition or impending failure of the insulation. Insulation testing can be performed by applying either direct current (DC) voltage or alternating current (AC) voltage. The testing of solid insulation with these voltages can be categorized as nondestructive testing and destructive testing, respectively. The destructive test may cause equipment under test to fail or render it unsuitable for further service. Nondestructive tests are performed at low-voltage stress, and the equipment under test is rarely damaged.

The AC hi-pot test is primarily a "go" or "no-go" test. The voltage is raised to a specified level. If the equipment fails or shows excessive leakage current, the equipment under test is unusable. If the equipment does not fail, it has passed the test. This test can only indicate whether the equipment is good or bad. It cannot indicate with what safety margin the test was passed. However, there are nondestructive tests that can be performed with AC voltage, such as power factor (PF), dissipation factor (DF), capacitance, etc., which are discussed in greater detail in Chapter 3.

The DC hi-pot test can indicate more than a "go" or "no-go" condition. It can indicate that equipment is all right at the present time but may fail in the future. DC testing is done to obtain information for comparative analysis on a periodic basis. With dc testing, the leakage current is measured during the progress of the test and compared to leakage current values of previous tests. However, the DC hi-pot test is considered to be a destructive test if the test voltage is not applied in a predetermined control-voltage steps. The DC voltage tests can be performed at lower voltages, which are nondestructive tests, such as insulation resistance, dielectric absorption ratio, and polarization index. These tests are discussed in more detail in Chapter 2.

1.5.2.2 Insulating Liquid Testing

Insulating liquids used in transformers or other electrical apparatus are subject to deterioration and contamination over a period of time. These contaminants have a detrimental effect on the insulating properties of the fluid, as well as on the solid insulation system of the transformer winding. Basically, the elements that cause the deterioration of the insulating fluids are moisture, heat, oxygen, and other catalysts that result in a chemical reaction that produces acid and sludge, which in turn attack the insulating fluids. The main insulating fluids that are in use today for transformers are oil, silicone, and RTemp and Wecosol. Askarel was used in the past, but its use was banned by federal regulations owing to its high toxicity; however, there may be installations that still may have this fluid at their plant sites. Regular tests are recommended to monitor the condition of the insulating liquid. Samples should be taken from the transformers on periodic basis to perform various tests in accordance with American Society of Testing Materials (ASTM) methods, which are discussed in detail in Chapter 4.

1.5.2.3 Protective Device Testing

Protective device testing involves the testing and maintenance of protective relays, low-voltage draw out power circuit breakers, low-voltage molded-case breakers, and associated equipment such as instrument transformers and wiring. The function of protective relays and devices maintenance and testing is to assure that a particular breaker or protective relay is able to perform its basic protective function under actual operating conditions. The tests on relays, protective trip devices, and circuit breakers can be classified as commissioning tests, routine maintenance testing, and verification testing. These tests are discussed in more detail in Chapters 7 through 9.

1.5.2.4 Circuit Breaker Time–Travel Analysis

The circuit breaker time–travel analysis test is performed to determine if the operating mechanism of the circuit breaker is operating properly. This test is usually performed on medium- and high-voltage circuit breakers and depicts the position of breaker contacts with relation to time. This relationship can then be used to determine the operating speed of the circuit breaker for opening and closing and contact bounce, and the interval time for closing and tripping. The breaker operating time data can be used to evaluate the condition of mechanical parts of breakers, such as closing mechanism, springs, and shock absorbers. Circuit breaker time–travel analysis test is described in greater detail in Chapter 7.

1.5.2.5 Grounding Electrode Resistance Testing

The integrity of the grounding system is very important in an electrical power system for the following reasons:

- To maintain a reference point of potential (ground) for equipment and personnel safety
- To provide a discharge point for traveling waves due to lightning
- To prevent excessive high voltage due to induced voltages on the power system

Therefore, to maintain ground potential effectiveness, periodic testing of grounding electrodes and the grounding system is required. Electrical power system grounding and ground resistance measurements are discussed in greater detail in Chapter 11.

1.5.2.6 Fault Gas Analysis Testing

Fault gas analysis testing comprises of dissolved gas analysis and total combustible gas tests. The dissolved-gas analysis provides information on the individual combustible gases dissolved in the insulating oil. The total combustible fault gas analysis test provides information on incipient faults in oil-filled transformers by measuring the total combustible gases present in the nitrogen cap of the transformer. Because of excessive heat due to loading of the transformer, or arcing and sparking inside the transformer insulating oil, some of the oil in the transformer decomposes and generates combustible gases, which then are dissolved in the oil, and eventually become liberated where they mix with the nitrogen above the top oil. The dissolved oil gas and total combustible gas test methods are discussed in more detail in Chapter 4.

1.5.2.7 Infrared Inspection Testing

There are many different devices available using infrared technology to check hot spots in switchgear and other energized parts of the power system. They are very useful in routine maintenance and inspection for finding bad connections and joints and overloaded terminals or lines. The infrared inspection testing is discussed in greater detail in Chapter 8.

1.6 Review of Dielectric Theory and Practice

All electrical circuits use insulation which is suppose to be nonconductive and confines and guides the electric current to the inside of the circuit. Therefore, the electrical insulation materials should exhibit (1) high resistance to the flow of electrical current, (2) high strength to withstand electrical stress, and (3) excellent heat-conducting properties. There are three fundamental electrical circuits and they are (1) the electric circuit, (2) the dielectric circuit, and (3) the magnetic circuit. These three circuits are analogous in many respects and are all governed by Ohm's law. For example, each of the three circuits can be written as follows:

$$\text{The electric circuit is } I = \frac{E}{R}$$

$$\text{The dielectric circuit is } \psi = \frac{E}{S}$$

$$\text{The magnetic circuit is } \Phi = \frac{F}{\check{R}}$$

where
- E is the electromotive force
- F is the magnetic motive force
- R is the electrical resistance
- S is the dielectric resistance
- $\check{R}$ is the magnetic resistance (reluctance)
- I is the current in the electrical circuit
- ψ is the electrical flux in the dielectric circuit
- Φ is the magnetic flux in the magnetic circuit

Correspondingly, the formulas for electrical, dielectric, and magnetic resistance are also similar; that is

$$S = (1/e_r)(L/A)$$

$$\check{R} = (1/u_r)(L/A)$$

$$R = \rho(L/A)$$

where
- ρ is the resistivity
- e_r is the relative capacitivity (dielectric constant)
- u_r is the relative permeability

Although these circuits are analogous to one another, they differ in actual practice. In the electrical circuit, the circuit is confined to the inside of the conductor and its path is along the conductor, where as in the dielectric and magnetic circuits the length of the path is short, irregular, and there is a large proportion of leakage flux usually into the air. In practice, it is much more difficult to make precise calculations for the dielectric and magnetic circuits than it is for the electric circuits. Furthermore, the current in the electric circuit can be measured very readily where as it is much more difficult to make similar measurements in the dielectric and magnetic circuits. In particular, the dielectric circuit differs further from an electric and magnetic circuit is in its design, predictability, and reliability. The dielectric circuit involves several terms and parameters that need to be understood in order to assess the characteristics and performance of the dielectric circuit. These terms are discussed as follows:

Dielectric: Dielectric is a term used to identify a medium, such as insulation in which an electric field charge can be produced and maintained. The energy required to charge the dielectric is recoverable, in whole or in part, when the charge is removed.

Dielectric constant: Dielectric constant is known as specific inductive capacitance, capacitivity, or permittivity. The dielectric constant of any medium or material is defined as the ratio of the capacitance of a given configuration of electrodes with the medium as a dielectric, to the capacitance of the same configuration with a vacuum (or air) as the dielectric between the electrodes.

Dielectric absorption: Dielectric absorption is a phenomenon which occurs in dielectrics whereby positive and negative charges are separated to respective polarity when a DC voltage is applied to the dielectric. This phenomenon is time-dependent and usually manifests itself as a gradually decreasing current with time after application of DC voltage.

Dielectric loss: Dielectric loss is the time rate at which electric energy is transformed into heat in a dielectric when it is subjected to an electric field. Dielectric loss is associated with real component (watts) losses in a dielectric.

Dielectric PF: The dielectric PF of a material is the ratio of the power dissipated in the material in watts (watt loss) to the effective volt-amperes (effective voltage × current) when tested with sinusoidal (AC) voltage. Numerically, it is expressed as a cosine of the dielectric phase angle (θ) or cos θ.

Dielectric DF: The dielectric DF is the tangent of the loss angle ($90 - \theta$). It is commonly referred to as tan δ (tan delta).

Dielectric loss factor or dielectric loss index: The dielectric loss factor of any material is the product of its dielectric constant and its DF.

Dielectric strength: The dielectric strength of a material is the potential gradient (voltage) at which breakdown (electrical failure) occurs and is a function of the material thickness and its electrical properties.

Voltage gradient: A voltage gradient is defined as the electrical intensity at a point in an electric field, that is, force exerted on unit charge at a point. Numerically, it is equal to the density of the electric flux divided by the dielectric constant.

1.6.1 Characteristics of Dielectrics (Insulation)

Dielectrics (insulation) for electrical equipment and apparatus is used for many different applications. It is expressed for a wide range of environmental conditions such as temperature, moisture, chemicals, other contaminants, and exposure to weather. One major factor affecting insulation life is thermal degradation, although moisture, contamination, voltage stress, and other factors may also contribute to its degradation. In addition, the life of an insulating material depends on the degree of loading, the type of service to which the equipment is subjected, the care it receives during installation and operation, and mechanical vibration and forces to which it is subjected.

The properties of insulating materials that are necessary and desirable are surface leakage, resistance to moisture, chemicals, oils and other contaminants, and mechanical properties. The important electrical characteristics of insulation are volume resistivity, PF, DF, capacitivity, dielectric constant, and dielectric strength. These characteristics, except for dielectric strength, can be assessed by nondestructive testing. These tests are

1. AC dielectric loss
2. PF or DF (tan δ)
3. Capacitance
4. AC resistance
5. Radio interference voltage (RIV)

6. DC insulation resistance
7. DC dielectric absorption

1.6.1.1 Dielectric Loss

All solid and liquid insulations have some measurable loss since there is no perfect insulator. These losses are usually very small in the insulations typically used in electrical equipment and apparatus, and these losses vary as the square of the applied voltage. Gaseous insulations, such as air, do not have a measurable loss until they become overstressed or ionized. Dielectric loss is measured in watts (resistive components) and is a measure of energy dissipation through and over the surface of the insulation. The dielectric losses of most insulations increases with increase in temperature, moisture, and corona. Insulations may fail due to the cumulative effect of temperature, that is, rise in temperature causes an increase in dielectric loss which in turn results in a further rise in temperature. This phenomenon is self-perpetuating and continues until the insulation fails.

1.6.1.2 PF and DF

The PF of insulation is defined as the ratio of watt loss to total charging volt-amperes, or the cosine of the angle θ between total current vector (I_T) and the impressed voltage vector. It is a measure of the energy component (resistive component) of the charging current. The DF is defined as the ratio of the watt loss to charging amperes, or the tangent of the angle δ between the total current vector and the capacitive current vector. The angle δ is the complementary angle of the PF angle θ. Although, the charging volt-amperes and watt loss increase as the volume of insulation being tested increases at a given test voltage, the ratio of watt loss to the volt-amperes (PF or DF) remains the same regardless of the volume of insulation tested. Therefore, the basic relationship of PF or DF eliminates the effect of the volume of insulation—that is, the size of the electrical equipment or apparatus tested. This simplifies the problem of establishing normal insulation values for most types of electrical equipment. PF and DF testing is discussed in greater detail in Chapter 3.

1.6.1.3 Capacitance

In a capacitor, the charge Q (amount of electricity) is proportional to the voltage E. The expression for this relationship can be written as

$$Q = CE$$

where C is a constant called capacitance. The capacitance of any electrical equipment, including capacitors, may be calculated from their geometry.

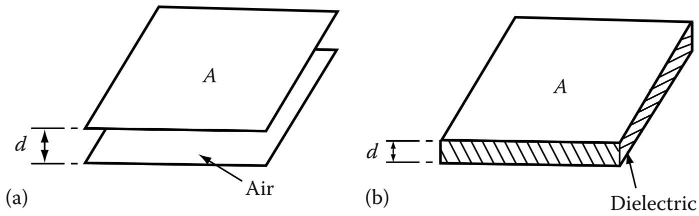


FIGURE 1.6
(a) Parallel-plate air capacitor and (b) parallel-plate capacitor with dielectric material.

A capacitor in its most simple form is the parallel-electrode air capacitor as shown in Figure 1.6a. The capacitance of such a capacitor can be calculated by the following formula:

$$C = \frac{KA}{d}$$

where
- A is the area between the electrodes
- d is the thickness of the insulation (spacing between the electrodes)
- K is the dielectric constant of the insulation (air)

The dielectric constant (K) of air is practically unity and the dielectric constant of the other insulation materials is defined in terms of air or vacuum. Table 1.1 gives the dielectric constant values for most common types of insulating materials.

In cases where the geometry of the electrical equipment is simple and known, capacitance can be calculated mathematically. In the majority of cases, however, most insulation's geometry is usually too complex and not well-enough understood to derive a reliable calculation of capacitance mathematically.

1.6.2 Insulation as a Capacitor

A perfect insulator can be represented by an ideal capacitor as shown in Figure 1.7a. However, all electrical equipment insulation have losses and therefore an insulator is not a pure capacitor. Thus, the electrical circuit of a

TABLE 1.1

Dielectric Constant of Insulating Materials

Vacuum	1.0	Fiber	2.5–5.0
Air	1.0	Glass	5.4–9.9
Paper	2–2.6	Mica	2.5–7.7
Rubber	2–3.5	Wood	2.5–7.7
Oil	2.2	Porcelain	5.7–6.8
Bakelite	4.5–5.5	Polyethylene	2.3

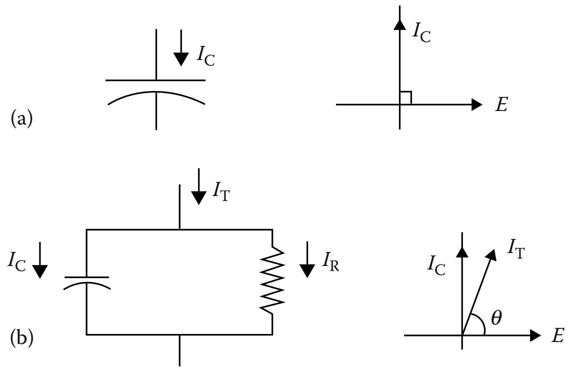


FIGURE 1.7
Electrical representation of insulation: (a) perfect and (b) practical.

practical insulator can be represented by a capacitor with a small resistance in parallel with it, as shown in Figure 1.7b.

The nature of insulation materials is such that 60 Hz current does not easily flow through them and therefore their purpose is to guide the current to the inside of the conductor. When voltage is applied to the conductor, two fields are established; one due to the current flow (magnetic field) and the other due to the voltage (dielectric or electrostatic field). The lines of magnetic flux around the conductor are concentric circles, whereas the lines of the dielectric flux around the conductor are radial. The resulting voltage stress due to the dielectric field varies inversely with the distance between equipotential lines.

The dielectric constant of an insulator is an indication of how much dielectric flux the insulation will allow through it. Under identical conditions insulation with a higher dielectric constant will pass more dielectric flux through it than another insulation having a lower dielectric constant. The dielectric constant for most commercial insulations varies from 2.0 to 7.0 as indicated in Table 1.1. It should be noted that the dielectric constant of water is 81 and generally when insulation becomes wet, its dielectric constant increases along with its capacitance, thus resulting in greater dielectric loss. An ideal insulation can be represented as a capacitor because its behavior is similar to that of a capacitor. Two of the most common configurations considered for insulators are parallel-plate and cylindrical capacitors. For example, the parallel-plate capacitor represents an insulation system of a transformer or a machine winding, whereas the cylindrical capacitor represents an insulation system of a cable or a bushing.

1.6.3 DC Voltage versus AC Voltage Tests

When voltage is applied to the insulation, a current is established consisting of a charging current (I_C) and an in-phase component current (I_R). As shown in Figure 1.7b, the charging current leads the in-phase component current by 90°. The vector sum of the charging current and the in-phase component current is the total current (I_T) drawn by the insulation specimen. The in-phase component current is also referred to as the resistive current, loss current, or conduction current. The ideal insulation (ideal capacitor) behaves somewhat differently under the application of DC versus AC voltages which are discussed below.

1.6.3.1 DC Voltage Tests

When a DC voltage is applied to the insulation, a large current is drawn at the beginning to provide the charging energy, however, this current decreases to a minimum level over time. The minimum current is due to continuous leakage or watt loss through the insulation. The energy required to charge an insulation is known as the dielectric absorption phenomenon.

In actual practice, the losses from dielectric absorption (i.e., the absorption current) are much higher than the continuous leakage losses. In the case of DC voltage testing, the effect of dielectric absorption becomes minimum over time and therefore measurements of continuous leakage current can be made. Dielectric absorption losses are very sensitive to changes in moisture content of an insulation, as well as the presence of other contaminants. Small increases in moisture content of an insulation cause a large increase in dielectric absorption. The fact that dielectric losses are due to dielectric absorption makes the dielectric loss, PF, or DF test a very sensitive test for detecting moisture in the insulation. When a DC voltage is applied to an insulation, the total current drawn by the insulation is comprised of capacitance charging current, dielectric absorption current, and continuous leakage currents. These currents and their behavior are discussed in greater detail in Chapter 2.

1.6.3.2 AC Voltage Tests

In the case of AC voltage application to an insulation, a large current is drawn which remains constant as the AC current alternately charges and discharges the insulation. The effect of dielectric absorption currents remains high because the dielectric field never becomes fully established due to the polarity of the current reversing each half cycle. When an AC voltage is applied to an insulation, the currents drawn by the insulation are due to capacitance charging, dielectric absorption, continuous leakage current, and corona which are discussed below:

Capacitance charging current: In the case of AC voltage, this current is constant and is a function of voltage, the dielectric constant of the insulating material, and the geometry of the insulation.

Dielectric absorption current: When an electric field is set up across an insulation, the dipole molecules try to align with the field. Since the molecules in an AC field are continually reversing and never fully align, the energy required is a function of material, contamination, (such as water), and electrical frequency. It is not a function of time.

Leakage current (conductivity): All insulation materials will conduct some current. If voltage is increased beyond a certain level, electrons will be knocked off of molecules causing current to pass through the insulation. This is a function of the material, contamination (especially water), and temperature. Excessive conductivity will generate heat causing the insulation to cascade into failure.

Corona (ionization current): Corona is the process by which neutral molecules of air disassociate to form positively and negatively charged ions. This occurs due to overstressing of an air void in the insulation. Air voids in oil or solid insulations may be due to deterioration from heat or physical stress, poor manufacture, faulty installation, or improper operation. Corona breaks down the air into ozone which, in combination with water, forms nitrous acid. The ionized air bombards the surrounding insulation and causes heat. The combination of these conditions will result in deterioration of the insulation and carbon tracking. Corona losses increase exponentially as voltage increases.

1.6.4 Insulation Breakdown Modes

Insulation breakdown can be classified as (1) failure due to excessive dielectric loss and (2) failure due to overpotential stress. These failure modes are discussed below:

Excessive dielectric loss is the result of deteriorated insulation or the contamination of the insulation with a poor dielectric such as water. As the dielectric losses increase, the temperature of the insulation increases resulting in even greater dielectric loss. Over time, the phenomenon eventually results in complete failure of the insulation. Overpotential stress occurs when a voltage is applied across an insulation greater than its dielectric strength. The molecular forces are overwhelmed and the insulation becomes a conductor. Some of the causes of insulation failure due to overpotential stress are (1) external increase in applied voltage, (2) decrease of insulation thickness, and (3) air bubbles or pockets in the insulation.

Example of insulation failure

Let us take an example of an oil-filled transformer that has oil and solid paper as an insulation system. For the purposes of this example, let us assume that this insulation system has 2 in. of oil and 2 in. of paper insulation. Since the dielectric constant for both paper and oil is 2.0, we can assume that each insulation system can withstand 2500 V/in., giving a total voltage withstand capacity of 10 kV as shown in Figure 1.8.

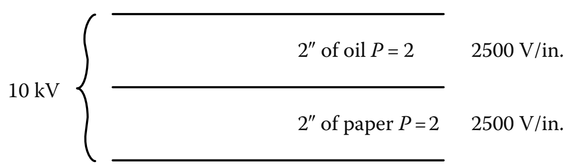


FIGURE 1.8
Insulation system rated for 10 kV.

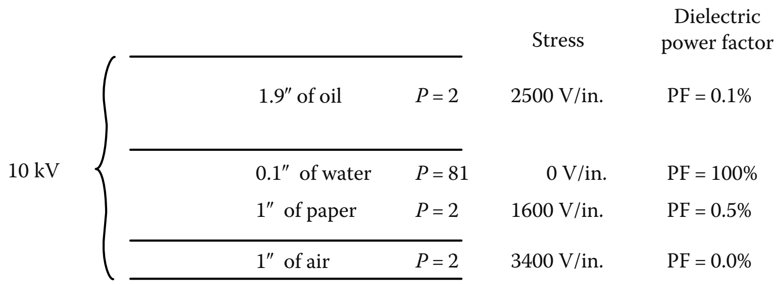


FIGURE 1.9
Insulation system with water and air contamination.

In order to put contamination in this insulation, let us replace one-tenth (1/10) inch of the oil with water and 1 in. of paper insulation with air (i.e., by putting voids in the paper as shown in Figure 1.9). Therefore, with the added contamination, the 10 kV rated insulation system is now rated at 9.750 kV assuming that the air voids do not break down. Since air has a lower dielectric constant, it will take more high-voltage stress than paper as shown in Figure 1.9. In this example, the two failure modes may be described in the following manner:

Failure due to excessive dielectric loss: The contamination of the oil insulation with water increases the dielectric losses in the oil and simultaneously reduces the dielectric strength of the insulation. Because of increased losses in the oil insulation over time, it will become degraded and eventually fail.

Failure due to overpotential stress: This failure mode occurs when air is introduced into the insulation. Air, although a good dielectric at low voltages becomes overstressed at higher voltages. It is assumed, in this example, that the air voids become overstressed at 2500 V and begin ionizing, thus resulting in corona which will eventually deteriorate the paper insulation. In this mode, the reduced thickness of the insulation and the resulting voltage overstress causes the insulation to fail.

1.7 Insulating Materials for Electrical Power Equipment

There are number of materials which are used either separately or as a combination of composite products to form an insulation system for electrical power equipment. The basic materials selected for insulation systems are selected based on their ability to withstand varied electrical, mechanical, and thermal stresses during the life of the equipment. Listed below is a partial summary of the materials and products used for insulating electrical power equipment.

1.7.1 Rigid Laminates Sheet, Rod, and Tube

- Canvas-based phenolic laminate
- Paper-based phenolic laminate
- Glass melamine laminate
- Glass silicone laminate
- Glass epoxy laminate
- Cogetherm mica-based laminate
- Mica epoxy laminate
- Transite HT and NAD-11 high-temperature cement boards

1.7.2 Glass Polyester Products

- Glass polyester sheet
- Glass polyester channels and angles
- Glass polyester stand-off insulators
- Glass polyester rods
- Specialty glass polyester

1.7.3 Flexible Laminates and Films

- Diamond-coated kraft paper
- Vulcanized fiber sheets, rods, and tubes
- Kraft pressboard products
- COPACO rag paper
- Quin-T family of flexible laminates
- Melinex polyester film
- Mylar polyester film
- Dacron–Mylar–Dacron
- Kapton polyimide film
- Nomex aramid paper
- Nomex–Polyester–Nomex
- Rag Mylar and Rag–Mylar–Rag

Over the years organic insulating materials have been replaced with inorganic materials and this progression is still continuing. There are number of organic and inorganic insulating materials that are used in electric power equipment. Although this listing discussed in this section is somewhat long, it is not all encompassing because the choices of available insulating materials are many. The use of the trade names in the listing given here does not represent a particular brand preference but are included for clarity. The characteristics of various insulating materials are discussed as follows.

Cotton: Cotton has been used extensively in electrical insulation because of its low cost, strength, elasticity, flexibility, and adaptability to size requirements and manufacturing process. However, cotton has a tendency to absorb moisture and limited thermal capability. Cotton is always used with varnish or resin impregnation to obtain good dielectric strength and moisture resistance. The use of cotton is restricted to 105°C (Class A insulation system) because temperatures higher than class A cause decomposition of the cotton fibers with resulting embrittlement and loss of mechanical strength.

Cotton fabrics: There are many varieties of treated fabrics that are fundamental Class A insulating materials. Untreated cotton fabrics that have been thoroughly dried are used for oil transformer insulation. These fabrics are quickly impregnated when the transformer is filled with oil, thereby providing excellent physical and dielectric properties. Two most commonly used fabrics are tan-varnish treated cloths and black-varnish treated cloths.

Paper: Many types of paper are used in insulating electrical equipment. These varieties include Japanese tissues, cotton rags, manila (hemp), the kraft (wood pulp), jute, fishpaper (gray cotton rag), fuller board, and the like. Rag and kraft paper often called transformer paper is used to separate windings in a transformer or in applications where there are no sharp edges that might poke through the relatively weak paper. Fishpaper is usually vulcanized and often laminated with Mylar giving it excellent resistance to tear and puncture. The paper–Mylar laminates resist soldering heat better since paper does not melt and the Mylar resist moisture best. Papers made with temperature resistance nylon and/or glass weaves have excellent electrical properties and good temperature resistance. Paper posses similar properties as cotton cloth, but because of its structure it has higher dielectric strength than cotton. The thermal stability and moisture absorption properties of paper are similar to cotton; however, paper does not possess the high mechanical strength of cloth. Untreated paper has little insulating value because of its extreme tendency to absorb moisture.

Asbestos: Recent restriction placed by Environmental Protection Agency (EPA) and OSHA has limited the use of the asbestos as an insulating material. It is used in the form of asbestos paper or asbestos tape, asbestos mill board or asbestos lumber for electrical insulating purposes. In such forms, it may contain 10%–20% wood pulp and glue to give it strength. Asbestos is generally heat resistance, but if heated excessively asbestos loses its hygroscopic moisture and therefore becomes brittle. Asbestos absorbs moisture from the surrounding atmosphere which makes it a less effective insulator.

Glass: Glass insulation comes in a wide variety of forms including solid glass, fiber tapes, fiberglass sheets and mats, woven tubing and cloth, and various composites. The most common form of glass used in electrical equipment is fiberglass. Fiberglass is available as fiberglass yarns for insulating materials. Today, fiberglass cloths and tapes are widely used in high-temperature applications. Two types of fiberglass yarns commonly used for electrical insulation are continuous filament and staple fiber yarns. The continuous filament yarns have the appearance of natural silk or linen whereas the staple fiber yarns exhibit a considerable degree of fuzziness similar to wool yarns. Fiberglass has advantages of high thermal endurance, high chemical resistance, high moisture resistance, good tensile strength, and good thermal conductivity when impregnated or coated with varnish or resin. Glass fibers exhibit poor abrasion resistance therefore fibers must be lubricated before they are woven into cloth. Varnish treatment of glass cloths greatly increases the abrasion resistance. Untreated glass cloth is used primarily as a spacing insulation and when the cloth is impregnated and coated with an insulating resin or varnish it becomes an effective dielectric barrier. Among the many uses of fiberglass are covering of wire, binder tapes for coils, and backing for mica tapes. It is also used as ground insulation and insulation for stator coil connections, leads, ring supports, etc. when treated with oleoresinous and other varnishes. Fiberglass, varnish-treated fiberglass, and nonwoven forms are thermally stable, resistance to solvent depending on the type of varnish used. It is more secure spacer insulation than cotton or paper.

Synthetic textiles and films: Numerous synthetic fiber textiles are in use as electrical insulation. These are either continuous monofilaments of resins, or short fibers made of resins that are spun into threads and woven into fabrics. They have to be coated or impregnated with varnish to become effective dielectric barriers. The thermal ability of these materials lies between cellulose fabrics and glass fabrics and depends on the type of resin coating or impregnating material used more than their own characteristics. Examples of synthetic fiber cloth and mats are Dacron, other polyesters, aromatic nylons, such as Nomex, Kelvar, and others. They have thermal stability, solvent resistance, and lack of fusibility. Several polyester films exhibit excellent electrical and physical properties, such as Mylar which enjoys widespread use in a variety of insulation systems.

Polyester films: They are used at temperatures above 105°C–125°C and have fair solvent resistance. Some specially formulated polyester varieties are used for service up to 180°C. The common uses of polyester films such as Mylar and others are slot liners, layer insulation in transformers, capacitors, and as laminated backing of paper insulation.

Aromatic polyimide (Kapton, Nomex, and others): It is used at temperatures of 180°C–220°C. It has excellent resistance to solvents and has good heat resistance and superb mechanical and electrical properties. Nomex is a Dupont aromatic polyamide with a temperature rating above 220°C and has high voltage breakdown strength.

Polyolefins: Polypropylene and polyethylene are two known polyolefins that are available with ultrahigh molecular grade matching the strength of steel. Polypropylene is used for insulation not to exceed temperatures above 105°C whereas polyethylene film has limited use such as class O insulation system since it softens at temperatures higher than 70°C.

Polycarbonate: Common trade names for it are Lexan and Merlon and are used for insulation system rated at temperatures 105°C and below. It has excellent electrical insulating properties and has good oil resistance but poor solvent resistance.

Polysulfone: This is another thermoplastic that include polyetherimide, polyamide, and polyphenylene with trade names like Noryl, Udel, Vespel, and Torlon. These materials are used at temperatures from 105°C to 130°C and have good oil resistance but not chlorinated solvent resistance.

Polytetrafluoroethylene (Teflon): It is an excellent high-temperature insulation with excellent electrical insulating properties and is used at temperatures of 220°C and higher. Teflon tubing and wire insulation is available in a variety of colors and typically feels slippery. It has good resistance to moisture.

Nylon: Nylon has good resistance to abrasion, chemicals, and high voltages and is often used to fashion electromechanical components. Nylon is extruded and cast and is filled with a variety of other materials to improve weathering, impact resistance, coefficient of friction, and stiffness.

Phenolics: Phenolic laminated sheets are usually brown or black and have excellent mechanical properties. Phenolics are commonly used in the manufacture of switches and similar components because it is easily machined and provides excellent insulation. Phenolic laminates are widely used for terminal boards, connectors, boxes, and components.

Polyvinylcloride (PVC): PVC is perhaps the most common insulating material. Most wiring is insulated with PVC including house wiring. Irradiated PVC has superior strength and resistance to heat. PVC tapes and tubing are also quite common. Electrical and electronic housings are commonly molded from PVC.

Acrylic: Lucite and Plexiglas are trade names for acrylic which has widespread use where toughness and transparency are required.

Beryllium oxide: A hard white ceramic-like material used as an electrical insulator where high thermal conductivity is required. Beryllium oxide is highly toxic in powder form and should never be filed or sanded and consequently has fallen out of common use. Power semiconductor heat sinks can still be found with beryllium oxide spacers for electrical insulation.

Ceramic: Ceramics are used to fabricate insulators, components, and circuit boards. The good electrical insulating properties are complemented by the high thermal conductivity.

Melamine: Melamine laminated with woven glass makes a very hard laminate with good dimensional stability and arc resistance. It is used in combination with mica to form rigid fiber laminates.

Mica: Mica sheets or stove mica is used for electrical insulation where high temperatures are encountered. Two kinds of mica, Muscovite (white or India mica) and phlogopite (amber mica) are generally used for insulating purposes. Mica and reconstituted mica paper are inorganic and infusible. Mica has high dielectric strength, high insulation resistance, low dielectric loss, good mechanical strength, good dielectric constant (specific inductive capacity), and good heat conductivity. Puncture resistance is good but the edges of the mica should be flush against a flat surface to prevent flaking. Mica finds uses in composite tapes and sheets which are useful up to 600°C with excellent corona resistance. Sheets and rods of mica bonded with glass can tolerate extreme temperatures, radiation, high voltage, and moisture. It is also available as mica paper where tiny mica flakes are made into paper like structure and reinforced with fiber, glass, or polyester.

Rigid fiber laminates: They are made of layers of cloth (glass, cotton, polyester, etc.) or paper with resin (phenolic, melamine, polyester, and epoxy) impregnation. They are supplied as thermosetting, thermoforming, and postforming materials used as insulators.

Micarta: It is rigid fiber laminate made of cloth, paper, or wood saturated with either a synthetic or organic resin, and then compressed under heat. This process makes the resin permanently hard and therefore Micarta becomes impermeable to heat, pressure, and solvents. Originally, Micarta was developed as an insulator but today it has many applications. Micarta is mechanically strong, rigid, and nonmagnetic. It is less susceptible to moisture and most acids. Micarta is used for insulating washers, controller panels and cams, slot wedges, brush rigging, bus bar supports, insulating barriers, and transformer insulation.

Synthetic resins: Synthetic resins are used extensively in varnish manufacture. The polyester and epoxy types are representative of heat hardening resins. Varnishes containing such resins are thermosetting and will cure by heat alone and do not require oxygen. Other synthetic resins are phenolic resins suitable for molding and bonding; alkyd type resins are being substituted for the old black varnishes and compounds; melamine resins are used for making laminates and molded compounds; and vinyl resins are used in the compounding of plastics and rubber substitutes.

Varnish: Insulating varnishes are of great importance in the maintenance of electrical equipment and apparatus. An insulating varnish is a chemical compound of synthetic resins or varnish gums and drying oils, having high dielectric strength and other properties that protect electrical equipment. Varnishes provide important insulating and protective functions, which are

- Protect the insulation and equipment against moisture
- Electrically and thermally enhance other insulating materials
- Add mechanical strength to other components of the insulation
- Minimize the accumulation of dust and contaminants, and improve heat dissipation by filling voids
- Enhance and increase the life of insulating materials

Adhesive-coated tapes: Many of the insulating films and fabrics described above can be obtained and used with adhesive backing that are usually thermoset or heat curable.

Rubber: Natural or Buna S rubber is not normally used for insulation these days because it is affected by ozone and has poor thermal stability. On the other hand, butyl and ethylene propylene rubbers are ozone resistance and more thermally stable. These are used for molded parts, cable insulation, and lead insulation in motors.

Silicone rubber: A variety of silicone foam rubbers are available as an insulating material. Silicone rubbers exhibit characteristics of superb chemical resistance, high-temperature performance, good thermal and electrical resistance, long-term resiliency, and easy fabrication. Liquid silicone rubbers are available in electrical grades for conformal coating, potting, and gluing. Silicone rubbers have excellent thermal stability and ozone resistance, but only fair mechanical strength and abrasion resistance.

Silicone/fiberglass: Glass cloth impregnated with a silicone resin binder makes an excellent laminate with good dielectric loss when dry.

1.7.4 Insulation Temperature Ratings

An insulation system is an assembly of insulating materials in association with the conductors and supporting structural parts of an electrical equipment and apparatus. Insulation systems for electrical equipment may be classified as solid, liquid, air and vacuum, and gases. The liquid insulation system comprise of mineral oil, silicone, and other less-flammable fluids. The gas that is primarily used for electrical insulation is SF_6 gas known as sulfur hexafluoride gas. The liquids and gases used as insulating medium in electrical system and equipment are covered in Chapter 4. The air and vacuum insulation system has been used from the very beginning and its characteristics are well documented and understood. The ability of insulating materials or an insulation system to perform its intended function is impacted by other aging factors. The major aging factors are electrical stresses, mechanical stresses, environmental stresses, and thermal stresses. Mechanical stresses imposed upon the system and its supporting structure by vibration and differential thermal expansion may become of increasing importance as the size of the apparatus increases. Electrical stresses will be more significant with high-voltage

TABLE 1.2
Thermal Classification of Electrical Insulating Systems

Thermal Classification	Class Temperature (°C)
A	105
E	120
B	130
F	155
H	180
N	200
R	220
S	250
C	>250

Source: From IEEE Standard 1-2000.

apparatus or with equipment exposed to voltage transients. Environmental stresses will have an impact depending on the presence of moisture, dirt, chemicals, radiation, or other contaminants. Thermal stresses depend upon environmental conditions (high ambient), loading, and ability to dissipate heat. All such factors should be taken into account when selecting insulating materials and/or insulation systems. To help the user, IEEE Standard 1-2001, "IEEE recommended practice—General principles for temperature limits in the rating of electrical equipment and for the evaluation of electrical insulation," has established the temperature rating for solid insulation systems of electrical equipment and apparatus. The IEEE Standard 1-2001 takes into account these factors in establishing the standards of temperature limits for particular classes of apparatus. Thus, for temperature rating purposes insulation systems are divided into classes according to the thermal endurance of the system.

According to IEEE Standard 1-2000, insulation system classes may be designated by letters and may be defined as assemblies of electrical insulating materials in association with equipment parts. These systems may be assigned temperature rating based on service experience or on an accepted test procedure that can demonstrate an equivalent life expectancy. The thermal classification of electrical insulating systems established by IEEE Standard 1-2000 is given in Table 1.2.

1.8 Causes of Insulation Degradation and Failure Modes of Electrical Equipment

The electrical insulation of equipment is usually made up of many different components selected to withstand the widely different electrical, mechanical, thermal, and environmental stresses occurring in different parts of the structure. The level of maintenance required for electrical equipment will depend on the effectiveness of the physical support for the insulation, the severity of the forces acting on it and the insulating materials themselves, and the service environment. Therefore, the length of useful life of the insulation depends on the arrangement of individual components, their interactions upon one another, contribution of each component to the electrical and mechanical integrity of the system, and the process used in manufacturing the equipment. Historically, functional evaluation of insulation was based primarily on thermal stresses. However, with many types of equipment, other aging stresses or factors, such as mechanical, electrical, and environmental may be dominant and significantly influence service life. The following are the major causes of insulation degradation and eventual failure.

Mechanical stress: Mechanical stress can be caused by power frequency transient currents such as when switching on power equipment, such as a motor or a transformer, that give rise to transient power frequency currents. In the case of a motor, this transient current may be as high as six times the normal frequency current. In the case of a transformer, the power frequency current may be as high as 10–12 times the normal current. The magnetically induced mechanical forces in the equipment are the square of the transient current, therefore a motor experiences mechanical forces 36 or more times and a transformer experiences 100 or more times stronger than normal service. If these transient occur frequently, such as frequent starting of motors or energizing of transformers and these forces cannot be withstood it would eventually lead to mechanical damage. Also, insulation can be damaged by mechanical vibration and expansion and contraction at power frequency operation. For example, when current is applied, the end turns of motor windings are twisted. If the twisting force is strong enough to break the bond of insulating varnish, the turns of magnetic wire will wear against each other and cause a turn-to-turn short. Once the turns are shorted, localized heating is caused by the current induced onto the closed loop. This heat rapidly degrades the surrounding insulation and over time destroys the groundwall insulation. A similar example may be applied to a transformer inrush current or through fault currents that can begin as mechanical damage in the turns and eventually manifest as winding faults.

Temperature hot spots: The value of temperature coefficient of resistance of an insulating material is negative and relatively large. Therefore, even a small increase in temperature will cause a large decrease in the insulation resistance. The current distribution over a given insulation is not uniform, therefore the weak part of the insulation carries more current and heated more than other parts, as long as the insulation or adjacent structures can conduct the heat away as fast as it is generated, the temperature will remain stable. However, if the heat is not dissipated as fast as it is generated the weaker spots in the insulation will become increasingly hotter until thermal breakdown occurs.

Environmental (moisture, chemicals, dirt, and oils): The environmental factors that degrade insulation over time are moisture, dirt, dust, oils, acids, and alkalies. Moisture is conductive because it contains impurities. When insulation absorbs or is laden with moisture it decreases the insulation resistance. The moisture penetrates the cracks and pores of the insulation, especially older insulation, and provides low resistance paths for creepage currents and potential sources of dielectric failure. Chemical fumes such as acids and alkalies often found in the industrial environment directly attack insulation and permanently lower its insulation resistance. Similarly, oil films will cover the internal surfaces of insulation of a machine. The oil may come from the environment or a leaking bearing seal. It will tend to lower the insulation resistance, reduce the ability to dissipate heat, and promote thermal aging and eventual failure. Dirt and dust in combination with moisture can become conductive and therefore cause creepage currents and insulation degradation as well as reduce the ability of the insulation to dissipate heat. The life of equipment is dependent to a considerable extent upon the degree of exclusion of oxygen, moisture, dirt, and chemicals from the interior of the insulating structure. At a given temperature, therefore, the life of equipment may be longer if the insulation is suitably protected than if it were freely exposed to industrial atmospheres.

Electrical stresses (*corona, surges, and partial discharges*)*:* Electrical equipment is always subjected to internally generated or external voltage and current surges. A physical rupture of insulation with the destruction of molecular bonds might occur during a voltage surge due to switching of a large inductive load or lightning. This transitory overpotential stresses the molecular structure of the insulating material causing ionization and failure of the insulating material itself. Corona is defined as the form of electrical discharge that occurs when the critical (corona inception) voltage is reached, thus causing air to breakdown. Corona by itself is not harmful to insulation however corona produces ozone which accelerates the oxidation of the organic materials of insulation. Further, the nitrogen oxides produced by the ionization of air form acids when combined with moisture also degrade the insulation. The voids in the cable-extruded insulation once electrified begin to conduct and grow larger. This phenomenon is known as partial discharge in the cable insulation and over time makes the void to grow larger and eventually cause cable to fail. Electrical stresses will be more significant with high-voltage apparatus or with equipment exposed to voltage transients.

Thermal aging: The temperature at which an insulation operates determines its useful life. Thermal stress is the single most recognized cause of insulation degradation. Insulation does not always fail when reaching some critical temperature, but by gradual mechanical deterioration with time at an elevated temperature. The time–temperature relationship determines the rate at which the mechanical strength of organic material decreases. Thereafter, electrical failure may occur because of physical disintegration of the insulating materials. Typical thermal aging mechanisms include

(a) loss of volatile constituents, (b) oxidation that can lead to molecular cross-linking and embrittlement, (c) hydrolytic degradation in which moisture reacts with the insulation under the influence of heat, pressure, and other factors to cause molecular deterioration, and (d) chemical breakdown of constituents with formation of products that act to degrade the material further, such as hydrochloric acid. The electrical and mechanical properties of insulating materials and insulation systems may be influenced in different ways and to different degrees as a function of temperature and with thermal aging. Thermal aging progressively decreases elongation to rupture so that embrittlement finally leads to cracking and that may contribute to electrical failure. Thus, how long insulation is going to last depends not only upon the materials used, but also upon the effectiveness of the physical support for the insulation and the severity of the forces tending to disrupt it. Even though portions of insulation structures may have become embrittled under the influence of high temperature, successful operation of the equipment may continue for years if the insulation is not disturbed. Because of the effect of mechanical stress, the forces of thermal expansion and contraction may impose temperature limitations on large equipment even though higher temperature limits proved satisfactory in small equipment when similar insulating materials were used. The rate of physical deterioration of insulation under thermal aging increases rapidly with an increase in temperature. The oxidation of the insulating materials is a chemical reaction in which the rate of reaction is given by Arrhenius law. In his paper, "Electrical insulation deterioration treated as a chemical rate phenomenon," *AIEE Transaction*, 67 (Part 1) (1948) 113–122, T.W. Dakin realized the relationship between the thermal aging phenomenon and the Arrhenius law of chemical reaction rates. The life of insulation is related to temperature and can be expressed by

$$L_{\mathrm{H}} = A\mathrm{e}^{-E/RT}$$

where

L_{H} is life in hours (or the specific reaction rate)
A is the frequency of molecular encounters
E is the activation energy (constant for a given reaction)
R is the universal gas constant
T is the absolute temperature (K)

The above equation can be simplified as

$$L_{\mathrm{H}} = A\mathrm{e}^{B/T}$$

where A and B are constants.

An approximation of the above equation states that life of insulation will be reduced by half for every 10°C rise in temperature. From the above equation, it is apparent that higher the temperature, the shorter the expected life of the insulation.

1.8.1 Failure Modes—Electrical Power Equipment

Failures can occur in any electrical equipment at any time. The major power equipment considered for discussion are transformers, switchgear breakers, switchgear buses, electromechanical relays, cables, and rotating machines. The insulation systems makeup of the above referenced equipment contains dielectric materials which are the key components for gauging its reliability. A failure in insulation, or an insulation system, is failure of the power equipment. Therefore, we will briefly review the insulation systems of major electrical equipment and apparatus for an understanding why and how power equipment fails. A better understanding of the failure modes and effects will help broaden the understanding in the care and servicing of electrical power equipment.

1.8.1.1 Transformers

Major components that make up a transformer are primary winding, secondary winding, magnetic iron core, coolant (air, gas, oil, or synthetic fluid), bushings, and tank. The insulating materials used in the makeup of transformer insulation system are enameled conductors (wire), kraft paper, glass, thermoplastic insulating tape, presswood, glass fabric, wood, resins, porcelain, cements, polymer coatings, gasket materials, internal paints, and mineral oil or synthetic fluid. The iron core with its clamping structure, the primary and secondary windings with their clamping arrangement, and leads and tapping from windings together with their supporting structure complete the construction components of a transformer. Insulating materials used in the manufacturing of bushing are porcelain, glass, thermosetting cast resins, paper tape, and oil. The paper used in bushing is usually oil-impregnated paper, resin-impregnated paper, or resin-bonded paper. The feed-through lead conductor with its insulation system is enclosed in porcelain or glass housing. Bushings are constructed as condenser bushing or noncondenser bushing (see Section 3.6.2 for more detail). The condenser bushings are used in transformers with primary voltage rating above 50 kV whereas the noncondenser type bushings are used below 50 kV applications.

Transformer failures, while infrequent, are usually the culmination of a series of events: unusual loading, impressed surges (from protective circuitry failure or local switching), or improper maintenance. Nearly always, incipient failures can be determined by testing, and PM performed to correct the condition. If, however, the transformer does fault, other connected or adjacent equipment is protected by the sensing elements and circuit breakers. Any fluid spill or fire activates the fire extinguishing system if installed. There is very little probability that even a major transformer fault will mechanically damage any equipment other than itself. The mechanical damage will largely be confined to nearby piping, support structures, or electrical connections. The possible spill of flaming transformer oil into a trench carrying either oil-filled cables, hydrogen supply lines, or the transformer oil-filtering piping could easily involve areas and elements of

TABLE 1.3

Causes of Transformer Failures

Cause of Failure	% Failures (1998 study)
Insulation failure	13.0
Design/materials/ workmanship	2.9
All others	24.2
Overloading	2.4
Line surge/thru faults	21.5
Improper maintenance/ operation	11.3
Loose connection	6.0
Lightning	12.4
Moisture	6.3

Source: From Hartford Steam Boiler Insurance Company's article-Analysis of transformer failures, Part 2-causes, prevention and maximum service life, William H. Bartley.

equipment not electrical in nature. There is, of course, a small chance that projectiles from the bushings could impact on ceramic supports or feed through of other nearby equipment and contribute to their failure. If the transformer fault involves arcing between the high- and low-voltage windings, the physical damage resulting from the fault may well extend into the low-voltage bus work and connections.

Table 1.3 displays results of Harford Steam Boiler Insurance Company (HSB) 1998 study on the causes of transformer failures. Table 1.4 displays the results of HSB 2003 study on distribution of transformer failures. For the causes of failures reported line surge/through faults are the number one cause for all types of failures. Insulation failure was the second leading cause of transformer failures and these failures were attributed to defective installation,

TABLE 1.4

Distribution of Failures by Age of Transformers rated at 25 MVA and above

Age at Failure	Number of Failure
0–5 years	9
6–10 years	6
11–15 years	9
16–20 years	9
21–25 years	10
Over 25 years	16
Age unknown	35

Source: From Hartford Steam Boiler Insurance Company's transformer data for the period 1997 through 2001.

insulation deterioration, and short circuits. For failures due to aging, the winding insulation looses mechanical and dielectric withstand strength over time and therefore is weakened to the point where it can no longer sustain the high radial and compressive forces induced by a line surge, or an internal or through fault. Also, as the load increases due to system expansion, the operating stresses increase in a transformer.

Large power transformers used in the medium-voltage electrical distribution system are typically of liquid-immersed type. The primary and secondary coils are immersed in oil, which acts to insulate as well as cool the coils. The coils are wrapped on an iron core, which is enclosed in a tank and filled with oil. A dedicated cooling system consisting of finned radiators with temperature-controlled cooling fans will be provided to remove heat from the internals. In addition, some cooling systems include one or more circulating pumps to increase the flow of oil through the heat exchanger and provide more efficient core cooling. The insulating oil is circulated through the transformer tank and heat is rejected via the heat exchanger. The power for the circulating pumps and cooling fans is typically 480 V AC. Smaller power transformers, such as those found in load center switchgear, may be either oil-filled or dry-type units. Dry-type transformers may be air-cooled with natural circulation alone, or more typically, forced-air-cooled with temperature-controlled cooling fans. Power connections to electrical buses and cables are routed through insulated bushings to the interior transformer windings.

Age-related degradation of transformers is primarily associated with the coils and the electrical connections. Degradation of the coils can occur due to continual exposure to elevated temperature, or degradation of the insulating oil. When the oil starts to degrade, gas is generated, which will accumulate inside the transformer tank. Checking for gas content in the oil is one method of transformer condition monitoring. Moisture intrusion is also a concern since entrained moisture can cause the formation of bubbles in the insulating oil during transformer operation. Formation of bubbles can degrade the performance of the transformer. Some examples of failure causes of power transformers are the following:

- Short circuit to ground
- Turn-to-turn short
- Primary to secondary short
- External oil leakage
- Degraded or inoperable cooling system (reduces transformer million volt amperes (MVA) rating)

To develop and implement a rigorous PM program, an understanding of transformer failure modes is necessary. The transformers can fail from any combination of electrical, mechanical, and thermal factors. Actual transformer failures as listed above involve breakdown of the insulation system which may result from any of the factors (failure modes) just mentioned above. Table 1.5 summarizes the stressors, failure modes and effects of power transformers.

5

Transformers

5.1 Introduction

This chapter covers information on the maintenance and testing of power transformers. To ensure trouble-free service over the life of the transformer, it has to be maintained regularly, but equally important it must be operated properly. Therefore this chapter provides information on the basic design, construction, application, and operation of power distribution transformers with the expectation that this information will help toward better care and maintenance of transformers.

A transformer is an energy transformation device that transforms alternating current (AC) or voltage at one level to AC and voltage at another level. A transformer can economically convert voltage or current from low to high levels, or from high to low levels. The transformer usually consists of two or more insulated windings on a common iron core. In industrial and commercial applications, transformers are used to step down voltages from utility service voltage to lower distribution voltage levels or lower utilization voltages that may be required for a facility or a plant. Transformers are very reliable devices and can provide service for a long time if maintained and serviced regularly. Transformer failures, when they occur, are usually of a very serious nature, which may require costly repairs and long downtime. The best insurance against transformer failure is to ensure that they are properly installed and maintained.

5.2 Transformer Categories and Type

For consideration of maintenance requirements, transformers can be divided into the following categories:

Insulating medium
Construction
Application and use

5.2.1 Insulating Medium

The transformer's insulating medium can be subdivided into two types: dry and liquid filled.

10.4.5 Horsepower, Torque, and Speed Considerations

The horsepower of a motor can be defined as the capability of the motor to do a given amount of work. Motors are rated as fractional or integral horsepower. The torque of a motor can be defined as the turning force developed by the motor, or it can be referred to as the resistance offered to the turning force by the driven load. Usually, torque for motors is expressed in terms of percentage of rated full-load torque. The speed of the motor is expressed as rpm, that is, a rate of measure of motion. The several definitive speed terms (as outlined in the section on the classification of motors according to variability of speed) that are common to all motors are standardized in order to relate the delivery of torque at a given speed for purposes of application. For AC motors the synchronous speed can be calculated as

$$\text{Synchronous speed (Ns)} = 120 \times \left\{\text{frequency/(no. of poles)}\right\}$$

Induction motors, however, operate at actual speeds that are less than the synchronous speed because of losses in the motor. The difference between synchronous and actual speed is knows as slip. Slip is usually expressed as a percentage of synchronous speed and can be calculated as

$$\begin{aligned}\text{Slip (\%)} = &\{\text{Synchronous rpm} - \text{actual rpm} \times 100\}\\ &/\{\text{Synchronous rpm}\}\end{aligned}$$

The horsepower of the motor can be stated in mechanical or electrical terms. One horsepower (1 hp) is equal to 33,000 ft. lb/min. The torque produced by an electric motor can be calculated as

$$\text{Torque} = \{5252 \times \text{hp}\}/\{\text{actual speed}\}$$

Also

$$\begin{aligned}\text{Horsepower (hp)} &= \text{Watts}/746 = \text{kW}/0.746\\ &= \{\text{torque} \times \text{actual speed}\}/\{5252\}\end{aligned}$$

A typical torque–speed curve for a motor is shown in Figure 10.5. The various NEMA design motor torque–speed curves are shown in Figure 10.6.

In order to apply motors, the first thing to determine is the desired full-load speed and the desired horsepower at that speed. Other factors required when applying motors are type of torque required by the load and the starting current limitations. Motor torque characteristics must match those of the load from starting to the time when the motor reaches its rated speed. The motor must develop net accelerating torque for every point on the load curve in order to reach its actual speed.

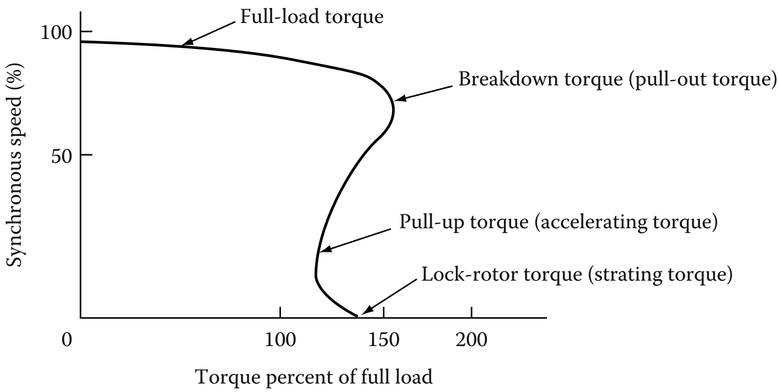


FIGURE 10.5
Typical torque–speed curve.

To understand the torques developed by the various motors, the following definitions are given; they are shown in Figure 10.5 for each design type of motor.

- *Lock-rotor torque (starting torque):* The minimum torque developed by the motor for all angular positions of the rotor when the primary winding (stator winding) is energized with AC power supply.
- *Accelerating torque:* The torque developed with rated power input during the period from standstill to full speed. This is the net positive torque available to the motor beyond the torque required by the load.

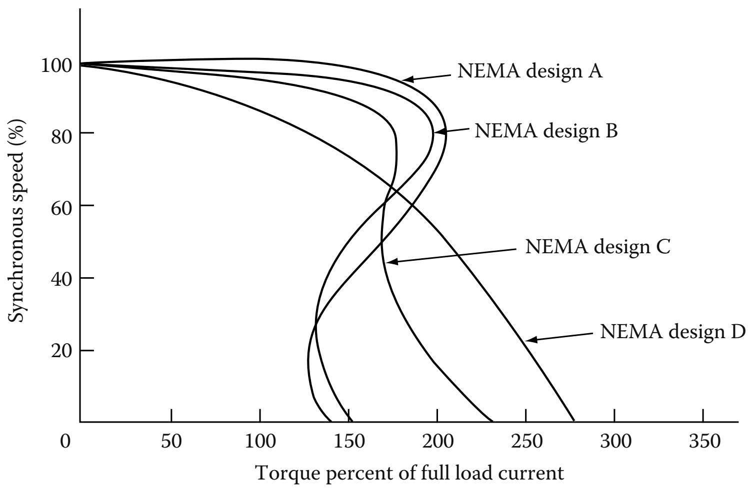


FIGURE 10.6
NEMA design motors torque–speed curves.

- *Breakdown torque (maximum torque):* The maximum torque developed by the motor at rated power input without an abrupt change in speed.
- *Pull-out torque:* The maximum torque developed by a motor for 1 min without stalling. It is frequently referred to as the breakdown torque.
- *Pull-in torque:* The torque developed during the transition from rated speed (slip speed) to synchronous speed.
- *Pull-up torque:* The minimum torque developed with rated power input during the period of acceleration from standstill to rated speed.
- *Full-load torque:* The torque developed at rated speed with rated power input.

Torque characteristics of various motors can best be described by comparing one motor type with another. Torques are classified as very high, high, medium, low, and very low. The torque–speed curves for the various NEMA motor designs as listed under classification according to application shown in Figure 10.6.

10.4.6 Power Factor

The connected motor load in a facility is usually a major factor in determining the system PF. Low system PF results in increased losses in the distribution system. Induction motors inherently cause a lagging system PF and, under certain circumstances, they can cause a very low system PF.

The PF of an induction motor decreases as the load decreases. When the load on the motor is increased, the rated load PF increases; that is, a fully loaded motor has a higher PF. Several induction motors, all operating at light load, can cause the electrical system to have a low PF. The PF of induction motors at rated load is less for low-speed than for high-speed motors.

A small increase in voltage (10%) above rated voltage will decrease the PF, and a small decrease in voltage (10%) below rated voltage will improve the PF of an induction motor. However, other performance characteristics may be adversely affected by such a change in voltage. Therefore, operation as close as possible to the nameplate voltage and horsepower ratings is recommended.

The PF of synchronous motors can range from 1.0 to approximately 0 PF leading, depending on the rated PF and the load for which they are built. Standard designs are usually rated for unity, 0.8 lagging, or 0.8 leading PF. As previously stated, synchronous motors have the capability of improving the PF of the electrical system.

10.4.7 Motor Selection

Induction motor: The selection of the induction motor depends on the performance characteristics of the driven machine, and these, in turn, determine the operating characteristics of the motor. Some machines, such as most fans, blowers, centrifugal pumps, and unloaded compressors, require a relatively low starting torque. After starting, the required driving torque increases with increasing speed up to the full-load speed and torque. A design B motor is frequently selected to drive this type of application.

Other machines, such as reciprocating air compressors and loaded conveyors, require high starting torque. The torque needed to start the machine is sometimes greater than the torque required at full-load speed. A design C motor is frequently selected to drive this type of application. For driven machines that impose pulsating loads or require frequent starting of the motor, such as punch press and well pumping, and hoist applications, a design D is often used.

Synchronous motors: In general, large synchronous motors can be applied to any load that induction motors with design B or C characteristics can handle. They have a higher efficiency than an induction motor of the equivalent rating and are capable of improving the system PF. When efficiency is a primary consideration in choosing a relatively large motor, a 1.0 PF synchronous motor may provide the solution. Where system PF improvement is a primary consideration, the use of a 0.8 leading PF synchronous motor may provide the solution.

Multispeed motors: Multispeed motors can be designed to have speed–torque characteristics similar to those of design A, B, C, or D motors of the equivalent rating. They can be designed for variable torque, constant torque, or constant horsepower. For the highest efficiency, it is important to select the correct multispeed motor characteristic for the load at all operating speeds. Typical examples of variable-torque loads are fans and centrifugal pumps. Constant-torque motors are used to drive apparatus such as conveyors, positive displacement pumps, and compressors. Machine tools and winches are examples of drives requiring the use of constant-horsepower motors.

10.5 AC Generators

Application criteria for AC generators are discussed next.

10.5.1 Service Conditions

Ac generators, like AC motors, should be correctly selected with respect to their service conditions. The usual and unusual conditions are the same for generator applications as those listed for AC motors. Some generators may operate in accordance with their ratings under one or more unusual service conditions. However, where some unusual service condition exists, a special-purpose generator may be required. Even though in such cases past experience may be the best guide in selecting the machine, it is recommended that the manufacturer be consulted concerning the mechanical and thermal duty of the machine.

10.5.2 Ratings

The continuous basis of rating synchronous generators is in kilowatts (kW) or kilovolt-amperes (kVA) at 80% PF. The ratings of kVA, speed, voltage, frequency, and so on, are expressed in NEMA MG1 standards for three-phase and single-phase machines. The excitation voltages for the field windings are also stated in the same NEMA standards; they are 62.5, 125, 375, and 500 V DC. These excitation voltages apply to machines with brushes only. Synchronous generators are capable of carrying a 1 min overload of 50% of normal rated current with the field set at normal rated load excitation. A synchronous generator is designed to withstand three-phase short-circuit current at its terminal for 30 s operating at rated kVA and PF, at 5% overvoltage with fixed excitation. The phase current due to faults other than three-phase faults must be limited by external means to a value that does not exceed the maximum phase currents obtained from three-phase fault.

The kW output of the machine depends upon the voltage, armature current, and PF. Also, the synchronous generator kVA ratings may be stated at definite voltage and frequency. The permissible load output of the synchronous generator depends upon the balance of the load. It is maximum for balanced loads and minimum for single-phase loads.

10.5.3 Temperature Rise

The temperature rise under rated load conditions for synchronous generators is based on the insulation system used for the machines. The temperature rise is determined in accordance with the latest IEEE std 115-1995, IEEE guide: *Test Procedures for Synchronous Machines*. The method of temperature determination may be resistance or embedded resistance temperature detector (RTD). Table 10.4 lists the various temperature rises for the various generator sizes and insulation systems.

TABLE 10.4

Temperature Rise for Synchronous Generators

Machine Component	Method of Temperature Measurement	Temperature Rise (°C)			
		A	B	F	H
Armature windings					
All kVA ratings	Resistance	60	80	105	125
1563 kVA and less	RTD	70	90	115	140
Over 1563 kVA					
7000 V and less	RTD	65	85	110	135
Over 7000 V	RTD	60	80	105	125
Field windings	Resistance	60	80	105	125

Note: NEMA standard MG1.

The standard ambient temperature is taken as 40°C, and where the ambient temperature is higher than the standard, it is recommended that the temperature rise of generators be reduced as follows:

- For increases in ambient temperature above 40°C up to and including 50°C, decrease the temperature rise by 10°C
- For increases in ambient temperature above 50°C up to and including 60°C, decrease the temperature rise by 20°C

10.5.4 Variation in Voltage

Synchronous generators can operate at rated kVA, frequency, and PF at voltages above and below the rated voltage not to exceed 5%. The maximum voltage any synchronous generator can produce at a definite frequency depends upon the permissible pole flux and field heating. To maintain a rated voltage output, specific field excitation is necessary at some specified load and PF.

10.5.5 Regulation

Regulation of a synchronous generator at any given PF is defined as a percentage rise in voltage, a constant frequency at excitation, when rated kVA load is removed. The regulation depends upon armature reactance, armature effective resistance, change in leakage flux with change in load, and armature reaction.

10.6 DC Motors

Application criteria for DC motors are discussed next.

10.6.1 Service Conditions

Similar to AC motors, the DC motors should be selected with regard to their environmental conditions. The service conditions may be usual or unusual and may involve environmental as well as operating conditions. The service conditions listed for AC motors also apply to the application of DC motors.

10.6.2 Operation of DC Motor on Rectified AC

The performance of a DC motor operating on rectified AC is different than if it were operating on a DC source having the same effective value of voltage. The reason for this is due to the continuous ripple or pulsation of the output voltage from the rectified AC voltage source. The ripple effect appears in the motor armature current and thus affects its performance. The effect of the rectified voltage on the motor armature current becomes significant when the rectifier pulse number is less than 6 or the amount of phase control is more than 15%. Also, when a DC motor is operated from an unfiltered rectifier power supply, bearing currents may result. Ripple currents may flow to ground by means of capacitive coupling between rotor winding and core. Even though these currents are small in magnitude, they may cause damage to antifriction and sleeve bearings under certain circumstances. Measures should be taken to minimize these currents to avoid damage to the motor.

10.6.3 Operation of the DC Motor below Base Speed

When a DC motor is operated below base speed by means of reduced armature voltage, the motor will heat up if rated full-load torque is maintained. To avoid overheating of the motor, reduce the load to compensate for the overheating of the motor. The speed of the DC motor is directly proportional to the armature voltage, and the torque is directly proportional to the armature current. Overheating can result due to the insufficient heat dissipating ability of the motor at these speeds.

10.6.4 Operation of the DC Motor above Base Speed

DC motors are built so that in case of an emergency they can withstand an overspeed of 25% above rated full-load speed without mechanical injury.

10.6.5 Overload Capability

The general industrial motors of open, forced ventilation, and totally enclosed water–air-cooled types are capable of carrying, with successful commutation, 115% of rated horsepower load continuously at rated voltage throughout their speed range. Refer to NEMA standard MG1, Sections 23.10, 23.11, and 23.28 for overload capability, momentary load capability, and rate of change of load current, respectively, on these types of motors.

10.7 DC Generators

Application criteria for DC generators are discussed next.

10.7.1 Service Conditions

The DC generators should be correctly selected with respect to their service conditions. These conditions may be usual or unusual, involving environmental and operating conditions. The typical service conditions that have been listed under Section 10.4 also apply to DC generators.

10.7.2 Ratings

The DC generators are classified into industrial DC and other DC integral-horsepower generators and large-apparatus DC generators (larger than 0.6 kW/rpm) of open type. The industrial generator ratings range from 0.75 to 720 kW, speeds range from 720 to 3450 rpm, and voltages range from 125 to 500 V. The large-apparatus DC generator ratings range from 125 to 6400 kW, speeds range from 200 to 900 rpm, and voltages range from 250 to 700 V. Refer to NEMA standards MG1, Section II, Part 15 and MG1, Section III, Part 24 for specific information on generator size, speed, and voltage ratings.

10.7.3 Temperature Rise

The temperature rise of DC generators under rated load conditions is dependent on the type of insulation system and enclosure used for the various parts of the machine. Either the thermometer or the resistance method is used for the measurement of temperature rise. Refer to NEMA standards MG1, Section II, Part 15 and MG1, Section III, Part 24 for specific information on temperature rise for the two types of generators.

10.7.4 Overload Capability

Industrial-type generators are capable of carrying overload for 1 min, with successful commutation loads of 150% of the continuous rated load amperes at rated load excitation. Large-apparatus DC generators of open type are capable of carrying 115% of rated current for 2 h and 200% of rated current for 1 min at rated speed and rated or less than rated voltage.

10.7.5 Voltage Excitation

Large-apparatus DC generators, when operated at less than rated voltage, shall carry currents equal to those corresponding to their kilowatt and voltage ratings. The load voltage at rated load of a self-excited, flat, compound-wound, drip-proof industrial generator, rated at 50 kW and smaller and employing class B insulation, shall not exceed 112% of the rated voltage at rated load.

10.7.6 Overspeed

DC generators are constructed so that, in an emergency, they will withstand overspeed of 25% without mechanical injury.

10.8 Motor and Generator Insulation Systems

10.8.1 Machine Insulation System

Insulation is obviously a limiting factor in the design of an electrical machine. If the thickness of the insulation is increased, the space available for the current carrying conductor is reduced and the conduction of heat from the conductor to the iron is restricted. Requirements of an insulation system for machine stator windings are

1. High dielectric strength
2. High resistance to partial discharges (PD)
3. High thermal conductivity
4. Good resistance to abrasions
5. Good resistance to tape separation caused by thermal heating
6. Good resistance to moisture and oil vapor

Machine insulation system is made up of five major insulation subsystems as discussed below.

Turn-to-turn insulation system: Turn-to-turn insulation is located between separate wires in each coil. This is usually in the form of an enamel coating on the wire. Glass over enamel is used on severe applications both for formed and random-wound coils.

Phase-to-phase insulation system: Phase-to-phase insulation is located between adjacent coils in different phase groups.

Phase-to-ground insulation system: Phase-to-ground insulation is located between windings, as well as between windings and the ground or structural parts of the motor. A sheet material such as the liner used in stator slots provides both dielectric and mechanical protection.

Slot wedge insulation system: Slot wedge which holds conductors firmly in the slots is referred to as slot wedge insulation.

Impregnation insulation system: Impregnation is used to bind all of the other components together and to fill in the air spaces. A total impregnation applied in a fluid form and hardened, provides protection against contaminants.

The various insulation systems that make up the machine insulation system are shown in Figure 10.7. Refer to Section 1.7 in Chapter 1 for additional information on insulating materials used for electrical equipment. The insulation systems used for machine windings are classified by NEMA and are listed below:

Class O: This insulation is rated for a total temperature of 100°C. It is made of materials or combinations of materials such as cotton, silk, and paper without impregnation.

Class A: This insulation is rated for a total temperature of 105°C. It is made of materials or combinations of materials such as cotton, silk, and paper when suitably impregnated or coated or when immersed in a dielectric liquid such as oil.

Class B: This insulation is rated for a total temperature of 130°C. It is made of materials or combinations of materials such as mica,

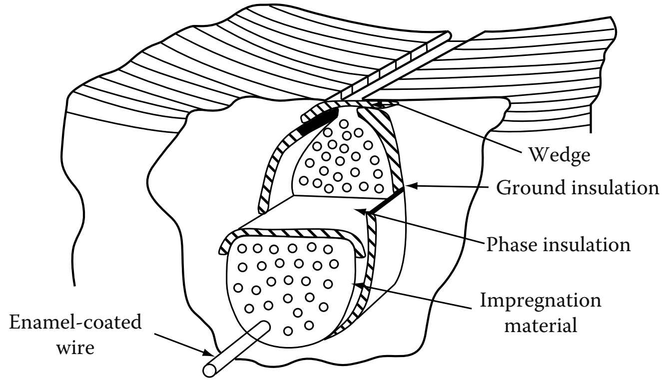


FIGURE 10.7
Cross section of the machine winding coils and insulation system.

glass fiber, asbestos, etc., with suitable bonding substances capable of operation at 130°C.

Class F: This insulation is rated for a total temperature of 155°C. It is made of materials or combinations of materials such as mica, glass fiber, asbestos, etc., with suitable bonding substances capable of operation at 155°C.

Class H: This insulation is rated for a total temperature of 180°C. It is made of materials or combinations of materials such as silicone elastomer, mica, glass fiber, asbestos, etc., with suitable bonding substances such as appropriate silicone resins and other materials capable of operation at 180°C.

Class C: This insulation is rated for a total temperature of 220°C. It is made of materials or combinations of materials such as Teflon and other natural or synthetic materials capable of operation at 220°C.

The industry standards, such as IEEE standards 112 and NEMA MG1 describe methods of temperature-rise measurements in rotating machinery. They are (1) measurements by thermometer and (2) resistance methods. Briefly, the resistance method is based upon the ambient and the total temperature rise, which is shown in Figure 10.8b. The thermometer method is based on four factors: (1) the standard ambient temperature of 40°C, (2) a service factor, (3) the measured temperature rise, and (4) the allowable hot spot. This is shown in Figure 10.8a. The various insulation systems normally used for machines are shown in Table 10.5.

The temperature determined by the resistance method gives an indication of the average total temperature of the motor windings. The life of the insulation system is dependent on both the temperature rise and the total temperature of the motor windings. The total temperature for the various insulation classes is shown in Table 10.5. The motor temperature measurement by resistance

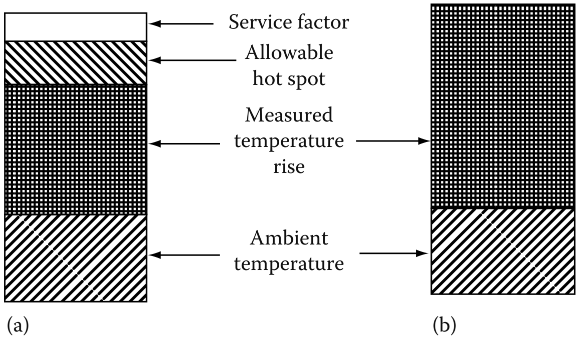


FIGURE 10.8
Total temperature measurements by (a) thermometer and (b) resistance methods.

method takes into consideration only two factors: the ambient temperature and the temperature rise measured by resistance at service-factor load. The sum of these two temperatures makes up the basis of total temperature of the insulation system. The resistance method eliminates the consideration of hot spot allowance, the 10°C allowance for service factor, and temperature rise measured by thermometer at nameplate load. Under the resistance method, the insulation system needed for the motor can simply be specified in terms of the operating ambient temperature and the service factor of the motor.

The use of the resistance method for the measurement of insulation temperature does not change the limitation imposed on the various classes of insulation systems. The resistance method has simplified the specification

TABLE 10.5
Insulation System Temperatures (°C) for Motors with 1.15 Service Factor

		Thermometer Method				
		Temperature Rise				
Insulation Class	Ambient Temperature (Standard)[a]	Measure Rise	Service Factor	Hot Spot Allowance[b] (Average)	Resistance Method	Total Temperature
O	40	50	—	—	—	90
A	40	40	10	15	65	105
B	40	65	10	15	90	130
F	40	90	10	15	115	155
H	40	115	10	15	140	180
C	40	155	10	15	180	220

[a] The standard ambient is 40°C, whereas for higher temperature applications, 65°C, 90°C, and 115°C ambient temperatures are standard.

[b] The hot spot allowance is a temperature allowance for the difference between the measured temperature rise of the winding and the estimated hottest location in the winding. This number varies from 5°C to 25°C with measured rise, enclosure, and temperature measurement method.

of the insulation temperature rating system for machine windings. As a result of this change in the temperature measurement method, the class B insulation system has been adopted as a standard for motor windings.

10.9 Motor and Generator Maintenance

This section deals with the inspection and maintenance of motors and generators of all sizes except steam and gas turbines. To obtain maximum efficiency and reliability of motors and generators, they have to be operated and maintained correctly. When motors and generators are maintained, many precautions must be followed to avoid damage. Usually this damage results from maintenance personnel lacking thorough knowledge of motor design, construction, application, and correct maintenance. The purpose of this section is to provide general maintenance and failure mechanism information common to most types of motors and generators. The information is divided into several subsections; the first two sections provide information on the failure mechanism and overall general inspection for all types of machines. Also, the reader should refer to Section 1.8 in Chapter 1 for additional information on causes of insulation degradation and failure modes of motors. The remaining sections deal with particular types of machines and components.

10.9.1 Failure Mechanisms

The failure mechanisms of the machine are divided into stator winding, rotor winding, and exciter. These are discussed in Sections 10.9.1.1, 10.9.1.2, and 10.9.1.3.

10.9.1.1 Stator-Winding Insulation

The failure mechanisms of stator winding are (1) age deterioration, (2) electrical cause, (3) mechanical causes, (4) thermal causes, and (5) environmental contamination.

The age-related deterioration causes brittleness, shrinkage, and cracks in insulation. The electrical causes are corona, slot discharge, lightning, switching surges, single-phasing, unbalance voltages, overheating effects, and test failures. The single phasing and voltage unbalance can be caused by either problems in the utility distribution system or the in-plant distribution system. Voltage unbalance causes negative sequence currents, which cause overheating of the remaining phase windings and the stator. The negative sequence currents also cause rotor overheating, which in turn causes stator induced currents that can lead to stator-winding failure. Rotor heating may result in rotor vibration and shaft/bearing overheating, which can result in machine-bearing failure. Similarly, the overloading problems can be caused by low voltage on the incoming utility line supplying the plant or facility, or problems in the in-plant distribution system. The effects of overloading are stator-winding overheating, mechanical stresses on winding end turns and individual coils. This in turn results in deterioration of the turn-to-turn, coil-to-coil, phase-to-phase, and coil-to-ground insulation. The mechanical causes are vibration, loose ties and wedges, broken amortisseur bars, fan blades, loose iron, loose connections, close-in, or out-of-step synchronizing, and foreign objects. The thermal causes are overloading, overheating from short-circuited laminations, thermal cycling, loss of cooling, overheating from failure of strand insulation, and tape separation. The environmental and contamination causes are conducting dust or particles, moisture, oil, and magnetic particles.

10.9.1.2 Rotor-Winding Insulation

The failure mechanisms of rotor insulation are (1) age deterioration, (2) electrical causes, (3) mechanical causes, (4) thermal causes, and (5) environmental contamination.

The age deterioration causes are the same as discussed for the stator. The electrical causes are starting transients, switching surges, and high voltage induced from the stator faults. The mechanical causes are vibrations, high resistance connections, cracked or broken lead support insulators, collar deterioration, broken amortisseur bars, close-in unbalanced faults, broken banding wire, and loose mechanical parts. The thermal causes are excessive field current, loss of cooling and unbalanced faults. The environmental factors are moisture, bridging of magnetic pole gaps, or groups of energized parts by foreign objects or conductive dust.

10.9.1.3 Exciter Insulation

The failure mechanisms of exciter insulation are age deterioration, electrical causes, mechanical causes, thermal causes, and environmental contamination as discussed under stator and rotor insulation.

10.9.2 General Inspection

The fundamental justification for the inspection and maintenance of motors and generators is to prevent service interruptions resulting from equipment failure. A definite program of inspection and maintenance should be organized so that all apparatus is assured of attention at stated periods; these periods should be adjusted to meet the actual need that experience over a number of years as indicated is necessary. To assure adequate inspection, it is essential that an inspection record be kept for each piece of apparatus.

Maintenance should be supplemented by visual inspection of all areas that experience has shown to be vulnerable to damage or degradation. Obviously, this necessitates scheduling disassembly of the apparatus at the time the electrical tests are made. Following is a general maintenance guide that is applicable to all motors and generators.

10.9.2.1 Visual Inspection

The most significant parts on which inspection should be made are the (1) armature (or stator) windings, (2) field winding (or rotor), (3) brush rigging and collector rings or commutator surfaces.

Armature windings
Check for the following signs of deterioration:

- Deterioration or degradation of insulation resulting from thermal aging. Examination of coils might reveal general puffiness, swelling into ventilation ducts, or a lack of firmness of the insulation, suggesting a loss of bond with consequent separation of the insulation layers from themselves or from the winding conductors or turns.
- Girth cracking or separation of the ground wall from wound coils. This is most likely to occur on long stator coil having asphaltic-type bonds. Particular attention should be paid to the areas immediately adjacent to the ends of the slots. Where considerable cracking is observed, it is recommended that the wedges at the ends of the slots be removed, as dangerous cracks may also have occurred just within the slots.
- Contamination of coil and connection surfaces by substances that adversely affect insulation strength, the most common being carbon dust, oil, and moisture contamination.
- Abrasion or contamination of coil and connection surfaces from other sources, such as chemicals and abrasive or conducting substances. Such effects are aggravated in the case of motors used in adverse atmospheric industrial applications, such as chemical plants, rubber mills, and paper manufacturing facilities, and wastewater treatment installations.
- Cracking or abrasion of insulation resulting from prolonged or abnormal mechanical stresses. In stator windings, looseness of the bracing structure is a certain guide to such phenomena and can itself cause further mechanical damage if allowed to go unchecked.
- Eroding effects of foreign substances embedded or lodged against coil insulation surfaces. Particularly damaging are magnetic particles that vibrate with the effects of the magnetic field in the machine.
- Insulation deterioration due to corona discharges in the body of the medium voltage machine or end windings. These are evidenced by white, gray, or red deposits and are particularly noticeable in areas where the insulation is subject to high electrical stresses. Some experience is required to distinguish these effects from powdering, which can occur as a result of relative vibratory movement between hard surfaces and which can be caused by loose end-winding structures.

- Loose slot wedges or slot fillers that, if allowed to go uncorrected, may themselves cause mechanical damage or reduce the effectiveness of stator coil retention against short-circuit and other abnormal mechanical forces.
- Effects of overspeeding may be observed on DC armatures by distortion of the windings or commutator rises, looseness or cracking of the banding, or movement of slot wedges.
- Commutators should be checked for uneven discoloration, which can result from short-circuiting of bars, or for pinholes and burrs resulting from flashover.
- Risers (connections between commutator bars and coils in slots) may collect carbon deposits and cause electrical leakage and subsequent failure.

Field windings

In addition to insulation degradation from causes similar to those listed under armature windings, close attention should be paid to the following in field windings:

- Distortion of coils due to the effects of abnormal mechanical, electrical, or thermal forces. Such distortions might cause failure between turns or to ground.
- Shrinkage or looseness of field-coil washers. This permits coil movement during periods of acceleration and deceleration, with the probability of abrading turn insulation, and breaking or loosening of connections between coils.
- Breakage or distortion of damper bars due to overspeed or abnormal thermal gradients between bars and the connecting end ring. Such breaks are often difficult to observe in machines that have operated in contaminated conditions and usually occur near the end ring or at the end of the pole piece. Low-resistance measurements between bar and end ring by means of a micro-ohmmeter, or digital low resistance ohmmeter, or similar instrument provides a means of detection.
- Loose damper bars with related burning of the tips of the pole-piece laminations. Among other cases, this could occur as a result of incorrect swaging or other means of retention of the bar during manufacture.
- In cylindrical-pole (or round motor) windings, evidence of heating of wedges at their contact with the retaining-ring body and half-mooning or cracks on the retaining rings can be caused by high circulating currents due to unbalanced operation or sustained single-phase faults close to the generator, such as in the leads or generator bus.
- Condition and tightness of end-winding blocking, signs of movement of the retaining-ring insulating liner, and any other looseness should be noted.

- Powered insulation in air ducts is evidence of coil movement. Red oxide at metallic joints is evidence of metal parts.
- Check tightness of field lead connections and condition of collector lead insulation.

Brush rigging

- Brush rigging should be checked for evidence of flashover.
- Before disassembly, the brush boxes should be checked to ensure that the clearance from the collector or commutator surface is in line with the manufacturer's recommendations. They should be checked to see whether the brushes are free riding and that excessive carbon buildup is not present.
- Brushes themselves should be checked to see whether any excessive edge chipping, grooving, or double facing is evident.
- Brush connections should also be checked.

Voltage checks

- Unbalanced voltage or single-phase operation of polyphase machines may cause excessive heating and ultimate failure. It requires only a slight unbalance of voltage applied to a polyphase machine to cause large unbalanced currents and resultant overheating. In such cases, the power supply should be checked and rectified if even the slightest unbalance is found.
- Single-phase power applied to a three-phase motor will also cause excessive heating from failure to start or from unbalanced currents.
- Unbalanced currents may also be caused by attempts to operate machines having one or more coils disconnected or cut out of one or more phases. If the unbalance is appreciable, the machine should be rewound.

10.9.3 DC Motors and Generators and Repulsion-Induction Motors

The following recommendations are given for DC motors; they also apply to repulsion-induction motors used on AC circuits.

10.9.3.1 Cleanliness

One of the principal causes of malfunction and eventual failure in DC and repulsion-induction rotating equipment is dirt, either from an accumulation of day-to-day dust or from contamination by particles from nearby machinery, such as metallic dust, lint, oil vapors, and chemicals. This is particularly true of this type of electrical apparatus because of its commutators, brushes, and brush rigging, which can become fouled with dirt, resulting in unsatisfactory performance, arcing, and subsequent burning.

The electrical conductors in all electrical equipment are separated from the mechanical components by insulation. Insulation is used on coils to isolate individual turns and to separate the coils from the core. Insulation is used in commutators to separate the bars from each other and, on the brush rigging, to isolate it from the frame or end bracket. Here again, the importance of cleanliness must be stressed since electrical insulation materials are nonconducting only when clean and dry. Accumulations of dust and dirt not only contribute to insulation breakdown but they operate to increase temperature through the restriction of ventilation and by blocking the dissipation of heat from the winding and frame surfaces.

10.9.3.2 Armature

The armature is the heart of the DC motor. The line current flows through the armature and, if the machine is overloaded, it is the first component to show evidence of damage. If given reasonable attention by scheduled periodic inspection and cleaning, it should give little or no trouble if the unit is operated within its normal rating. Repairs should be entrusted only to a competent entity.

When the armature is removed from the frame for either maintenance or repair, the following precautions should be observed to ensure that the armature is not damaged:

- Steps should be taken at all times to protect the commutator and shaft-bearing surfaces.
- Armature should not be rolled about the floor since injury to the coils or banding may result.
- Armature should be supported or lifted only by its shaft if possible. Otherwise, a lifting belt should be used under the core.
- Weight of the armature should never be allowed to rest on the commutator or coil heads.

Periodic inspection, varnish treatment, and curing will prolong the life of the winding. Loose slot wedges and banding should be replaced before varnish treatment and curing. Cleaning, varnish treatment, and curing should include the operations listed under Section 10.9.6. Treatment of this type is definitely recommended for equipment that is subjected to excessive temperatures or contaminants and is desirable even though the equipment is not subject to adverse conditions. Windings dry out and loosen in operation, and loose windings fail rapidly when subjected to centrifugal stresses and vibrations. Varnish treatments fill the pores and crevices. They help to preserve flexibility in the insulation and hold the coils solidly in the slots, thereby keeping failures to a minimum.

If the armature is to be rebanded with steel wire, it is necessary to duplicate very closely the banding originally furnished by the manufacturer with respect to material, diameter of the banding wire, width, and position of each band. Any change in banding width, position, or material could cause heavy current in the bands sufficient to overheat and melt the solder.

Recent developments and tests of the use of resin-filled glass for the banding of armatures have eliminated many of the risks inherent in the use of the metal bands. When correctly applied, the strength factor of resin-filled glass is equal to that of steel bands; therefore, replacement of the original banding by resin-filled glass bands can be accomplished in the space provided for steel bands if the magnetic field is not disturbed. Since resin-filled glass is a good insulator, additional heavy insulation under the band is not required and eddy currents are nonexistent. It is imperative that resin-filled glass banding be applied under tension by an expert utilizing the correct equipment as the forces the banding must withstand under full-speed and full-load conditions are significant.

Commutation

Commutation is the process of collecting current from a commutator, which, at the same time, short-circuits those coils in which the current is reversed (Figure 10.9). Since there is voltage (even though small) generated in each of these short-circuited coils, a circulating current is present in the face of the carbon brush in addition to the load current. The voltage causing this circulating current is proportional to the load current and the speed, and, as the speeds and ratings of modern machines are increased this becomes a more serious factor. Since this voltage, under some conditions, becomes so high as to cause excessive sparking, it is the designer's problem to control this reactive voltage by designing the machine to minimize the effect of the flux generated in the

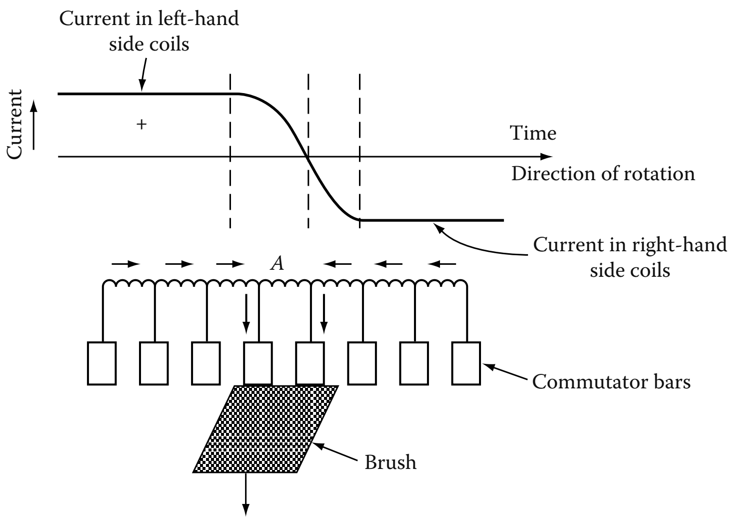


FIGURE 10.9
Coil A undergoing commutation.

armature circuit and by the judicious use of commutating poles, sometimes called interpoles. Successful commutation also requires a good continuous contact between the brush and the commutator surface.

It is obvious that successful commutation is not a function of the brush alone or of the commutator or electrical circuit alone but results from optimum electrical and mechanical brush-to-commutator conditions, and the correct electromechanical position of the brush rigging.

Commutation is such a complex problem that it is necessary to keep the many adverse variables at a minimum. Commutation may be adversely affected by dust, dirt, gases, oil vapor, and the like, and varying atmospheric conditions such as high temperature or low humidity. Where a commutation problem exists owing to one or more of these ambient conditions, it is sometimes possible to arrive at a solution by altering the unit to offset the condition. If the commutation of a unit is not satisfactory and a change in brush grade is indicated, the manufacturer should be consulted. However, in general, this is not a true solution.

The mechanical condition of the unit can also greatly affect commutation. Commutators should be periodically checked for high bars, which will cause flashing and generally poor commutation. Both commutators and slip rings should be smooth, round, and concentric with the axis of rotation. If there is any appreciable vibration, the cause should be determined and corrected.

Some of the most common service problems with commutator are shown in the commutator check chart (Figure 10.10). Frequent visual inspection of the commutator can indicate when any of the conditions shown in the Figure 10.10 are developing so that corrective actions can be taken. The causes of poor commutator condition are shown in Table 10.6.

Frequent visual inspection of commutator surfaces can warn you when any of the above conditions are developing so that you can take early corrective action. Table 10.6 may indicate some possible causes of these conditions, suggesting the correct maintenance. There are several causes of commutator problems. High commutator bars generally produce sparking, noisy operation, and chipped or broken brushes. The causes are usually a loose commutator, incorrect undercutting, open or high resistance connections, or electrical shorts. Streaking or threading of the commutator surface causes rough surfaces with associated sparking. Primary faults can be

- Low average current density in brushes due to light machine loading
- Contaminated atmosphere
- Oil on commutator or oil mist in air
- Low humidity
- Lack of film-forming properties in brush
- Brushes too abrasive

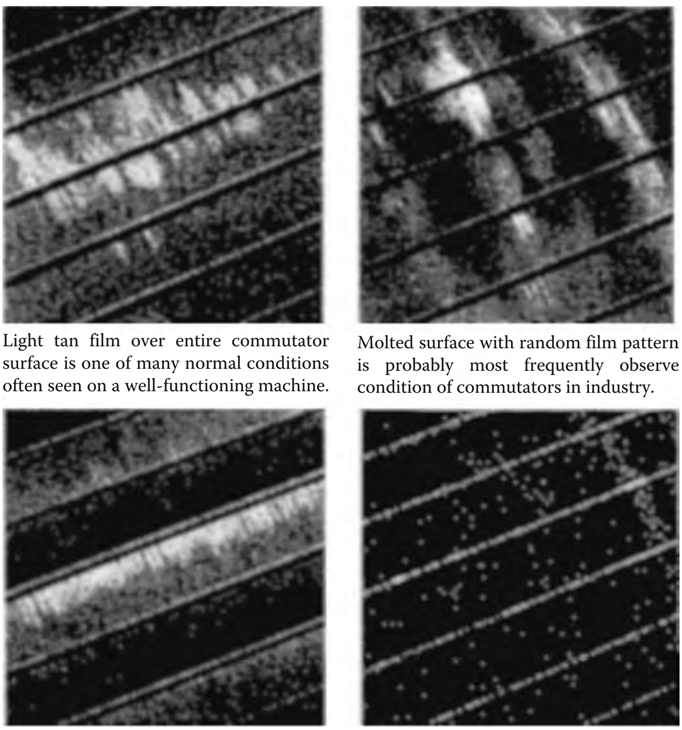
Bar etching or burning produces a rough commutator with associated sparking and eventual flashover. Such burning often results from

- High mica
- Operation of machine with brushes off neutral
- Dirty commutator
- Incorrect spring tension
- Machine operating overloaded or under rapid load change such as plugging

Bar marking at pole pitch spacing produces a rough commutator with associated sparking and eventual flashover. This burning is generally caused by electrically shorted commutator bars or coils, open armature of field circuits, severe load conditions, misalignment of the coupling, and vibration. The burning in the early stages is generally evident at one-half the number of poles.

Bar marking at slot spacing produces rough bars at regular intervals around a commutator. Since several coils are embedded in each armature slot, all the coils may not be equally compensated. The energy unbalance is

Satisfactory commutator surfaces



Light tan film over entire commutator surface is one of many normal conditions often seen on a well-functioning machine.

Molted surface with random film pattern is probably most frequently observe condition of commutators in industry.

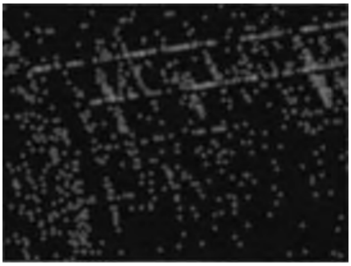
Slot bar-marking, a slightly darker film, appears on bars in a definite pattern related to number of conductors per slot.

Heavy film can appear over entire area of efficient and normal commutator and, if uniform is quite acceptable.

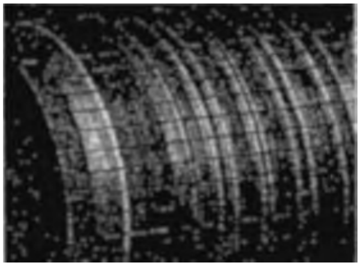
(a)

FIGURE 10.10
Commutator check chart.

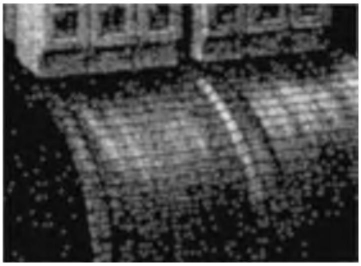
Watch for these danger signs



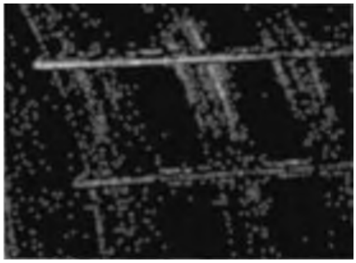
Streaking on the commutator surface signals the begining of serious metal transfer to the carbon brush. Check the chart below for possible causes.



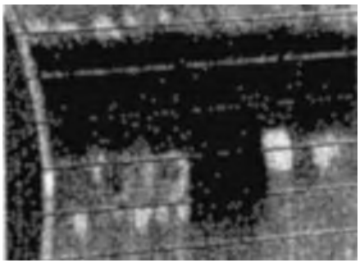
Threading of commutator with fine lines results when excessive metal transger occurs. It usually leads to resurfacing of commutator and rapid brush wear.



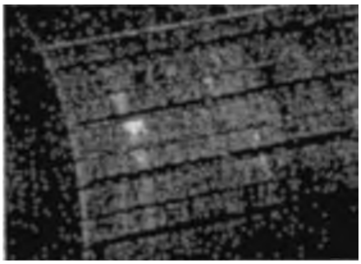
Grooving is a mechanical condition caused by abrasive material in the brush or atmos phere.It grooves form, start corrective action.



Copper drag, an abnormal build-up of commutator material, forms most often at trailing edge of bar. Condition is rare but can cause flashover if not checked.



Pitch bar-marking produces low or burned spots on the commutator surface. The number of these markings equals half or all the number of poles on the motor.



Heavy slot bar-marking can involve etching of trailing edge of commutator bar. Pattern is related to number of consuctors per slot.

(b)

FIGURE 10.10 (continued)
Commutator check chart.

reflected into the last coil in the slot to undergo commutation and will result in a spark at the brush. Such a spark will cause burned spots on the bars equally spaced according to the bars per slot ratio.

Selective commutation can occur on machines with more than one brush per brush stud if the resistance path of one brush is lower with respect to the other brushes on the same stud. Due to higher spring pressure, incorrect staggering of brushes, or a breakdown of the commutator film in one path, the brush with the low contact drop will have a tendency to carry more than its share of the current.

TABLE 10.6

Causes of Poor Commutator Condition

								Type of Brush in Use		Contamination	
	Electrical Equipment	Electrical Overload	Light Electrical Overload	Armature Connection	Unbalanced Shunt Field	Brush Pressure (Light)	Vibration	Abrasive Brush	Perous Brush	Gas	Perous Dust
Streaking			X			X		X	X	X	X
Threading			X			X			X	X	
Grooving								X			X
Cooper drag						X	X	X		X	
Pitch bar-marking				X	X	X	X	X			
Slot bar-marking	X	X								X	

The exposed portion of the front vee-ring insulation is normally the target for moisture, oil, and dirt, which may cause flashovers and breakdowns to ground. It is, therefore, essential that the exposed surface of the mica be kept clean and protected by means of other insulation. There are various ways to apply extra insulation at this point, depending upon the individual ideas of the machine designer. In general, however, this consists of a cord or tape of cotton or glass wound in tight layers over the surface of the exposed section of the mica cone or veering. The exposed surface is then treated with several coats of varnish suitable for the operating temperature of the machine. These multiple coats of varnish are applied to obtain a smooth, easily cleanable surface. The purpose is to obtain extra insulation that will protect the vee-ring insulation and, so far as possible, seal the joint between the commutator bars and the vee ring.

10.9.3.4 Field Windings

If the field winding of any type of DC motor is open circuited, the motor will fail to start or it will operate at excessive speed at light loads and serious sparking will occur at the commutator. It should not be concluded that a field is defective until rheostats, switches, and other devices in the motor circuit have been carefully inspected.

To check for grounded fields, a conventional high-potential transformer may be used. If the field circuit is free of grounds and shorted shunt field is suspected, comparative resistance measurements should be made of the individual coils and compared with the resistance of a similar coil that is known to be in good condition. Such a comparative check should preferably be made when the field windings are hot or near their normal operating temperature. A shunt field coil may show the correct resistance when it is cold but may show a lower value when it is hot or near its normal operating temperature. This is due to defective insulation between turns of adjacent conductors, and short circuits may not occur until expansion has taken place because of the increased temperature. If the correct resistance value of good coils is not known, comparative checks made with either a Wheatstone bridge or by the voltmeter method will usually provide a reliable indication of shunt field resistance. If neither a bridge nor an ammeter is available, a check as to the condition of the coils may be obtained by connecting all shunt coils in series to a source of constant potential and measuring the voltage drop across individual coils. For short circuits in series and commutating field coils, where the resistance is necessarily low, the use of more sensitive instruments may be necessary to detect defects.

A common cause of field coil failure is overheating, which may result from the following:

- Operation of the machine at low speed, preventing correct ventilation
- Full field current left on the machine continuously while it is shutdown

- Excitation voltage too high
- Overloading machine
- High ambient temperature

Faulty performance, indicated by poor commutation, incorrect speed, and overheating, is frequently traceable to defective field coils or to incorrectly connected field windings.

In removing a shunt or series field coil, the coil should be disconnected from the adjacent coils, and the bolts that secure the pole pieces to the frame should be removed. This will make it possible to remove the pole piece and coil, after which the pole piece, with a new or reinsulated coil, can be installed. Particular care should be taken in replacing the pole with its coil to be sure that the same steel or nonmagnetic shims between the frame and the back of the pole are in the same position to ensure the same air gap that was present in the machine when it was new.

When reconnecting the coil, the correct polarity must be maintained. A simple means of testing the polarity is by the use of a compass, a magnetized needle, or a piece of magnetized steel wire suspended from the middle by a string. The polarity should be alternatively north and south around the frame. When the compass needle is brought within the magnetic field of any pole, one end of the needle will point toward this pole and this end should be repelled by the next pole, and so on around the frame. If this reversal of the needle does not occur, there is a faulty connection of one or more of the field coils.

Since there is a possibility of reversing the poles of a compass with a strong field, similar results can be obtained by putting the compass on a work bench, placing a steel scale against the pole of the machine, and then setting the scale against the compass. The readings will, of course, be reversed as compared to the direct reading with a compass.

10.9.4 Induction Motor

There are two types of AC induction motor construction: squirrel cage and wound rotor. Stator design is the same for both; they differ mainly in rotor design. There are no external rotating or secondary connections on a squirrel-cage motor; most wound rotors have three-phase winding connected through collector rings to an adjustable secondary resistance.

Today's induction motor, especially the squirrel-cage type, is a highly efficient machine whose periods of trouble-free service can be considerably prolonged by systematic care. Correct application and installation will minimize maintenance requirements.

Essentially, maintenance of squirrel-cage induction motors centers on the stator windings and bearings. Rotors require little or no special care in normal service, except to make certain that bolts or other fasteners remain tightly secured. For wound-rotor types, rotor construction with the associated brush rigging requires additional maintenance.

Stator windings differ in induction motors, depending on the size of the stator frame. Smaller motors, generally, are known as mush wound and are sometimes called random or wire wound. Mush-wound coils are made by looping wire in an elliptical form without exact dimensions. Coils are inserted, a few wires at a time, in semiclosed stator slots.

Larger motors utilize form-wound coils, constructed by winding magnet wire in a loop, which is then formed to an exact shape to meet specific dimensions of width, height, and pitch. Coils are fitted in open slots in the stator iron.

Since the life of a motor is limited largely by that of its insulation, proper care can greatly extend its service reliability. Maintenance of winding insulation is mostly a matter of keeping the machine clean and dry, providing it with an adequate supply of cool, dry, ventilating air, and operating the machine within its rating.

10.9.4.1 Stator Windings

A regular schedule of inspection can prevent costly shutdowns and repairs by revealing small defects, which can be corrected before they develop into serious faults. The operating temperature of the machine should be checked a regular intervals. Open-type machines must be inspected more frequently than closed types, with the machines shutdown if possible.

The interior of larger machines is often inaccessible because of the end covers, air baffles, and fans. These obstructions should be removed at regular intervals to permit a closer inspection.

The best way to evaluate the condition of insulation is to measure the insulation resistance at regular intervals when the machine is hot. A sudden decrease in the insulation resistance may indicate an approaching break down, which may be avoided if the cause is located and corrected in time.

10.9.4.2 Air Gap

A small air gap is characteristic of induction motors and has an important bearing on the machine's PF. Anything that may affect the air gap, such as grinding the rotor laminations or filing the stator teeth, may result in increased magnetizing current and lower PF.

The air gap should be periodically checked with a feeler gauge to ensure against a worn bearing that might permit the rotor to rub against the stator core. Even slight rubbing of the rotor against the stator will generate enough heat to destroy the coil insulation.

Measurements should be made on the drive end of the motor. Openings are provided in the end shields and inner air baffles of some machines for the insertion of feeler gauges for this purpose. This check is needed particularly for sleeve-bearing motors. A change in air gap seldom occurs in antifriction-bearing motors unless the bearing fails. For small sleeve-bearing motors without feeler gauge openings, a check of bearing wear using a dial indicator on the shaft extension should be considered.

A record of air gap checks should be kept, especially on larger machines. Four measurements should be taken approximately 90° apart. One point of the measurements should be made in the direction of load. A comparison of periodic measurements will permit early detection of bearing wear.

10.9.4.3 Wound-Rotor Windings

Rotor windings of wound-rotor motors have many features in common with stator windings, and the same comments apply to their care and maintenance. However, the rotor requires additional consideration because it is a rotating element.

Most wound rotors have a three-phase winding and are susceptible to trouble from single-phase operation and open circuits. The first symptoms of these faults are lack of torque, slowing down in speed, growling noise, or perhaps failure to start the load.

The first place to look for an open secondary circuit is in the resistance or the control circuit external to the rotor. Short-circuiting the rotor circuit at the slip rings and then operating the motor will usually determine that the trouble is in the control circuit or in the rotor itself.

Some rotors are wave wound, with windings made up of copper strap coils with clips connecting the top and bottom halves of the coil. These end connections should be inspected for possible signs of heating, which could be an indication of a partial open circuit. Faulty end connections are a common source of open circuits in rotor windings. The open circuit may be at one of the stud connections to the collector rings.

A ground in a rotor circuit will not affect motor performance except that in combination with another ground, it might cause the equivalent of a short circuit. This would have the effect of unbalancing the rotor electrically. Reduced torque is a symptom; others might be excessive vibration of the motor, sparking, or uneven wear of the collector rings. A test for this condition can be made with a megohmmeter.

Another fairly successful method of checking for short circuits in the rotor windings is to raise the brushes off the collector rings and energize the stator. A rotor winding that is free from short circuits should have little or no tendency to rotate, even when disconnected from the load. If there is evidence of considerable torque or a tendency to come up to speed, the rotor should be removed and the winding opened and examined for the fault. In making this test, it should be noted that some rotors having a wide tooth design may show a tendency to rotate even though the windings are in good condition.

With the rotor in place, the stator energized, and the brushes raised, the voltages across the collector rings should be check to see if they are balanced. These voltages bear no particular relation to the line voltage and may be considerably higher. For example, they may be as high as 500 for a 200 V stator. To make sure that any inequality in voltage measurements is not due to the relative positions of the rotor and stator phases, the rotor should be moved to several positions in taking these voltage measurements.

10.9.4.4 Brushes and Rings

Brushes and collector rings on wound rotors need special care. Although a certain amount of wear is inevitable, conditions that lead to grooving of rings (concentration of wear in narrow rings or ruts) should be prevented, and abrasive dust should be wiped off the rings at regular intervals.

Rough or uneven ring surfaces should be remedied as soon as possible, before sparing, pitting, and accelerated brush wear result. Allowing the rotor to oscillate axially will distribute wear more evenly. Unevenly worn brushes should be replaced to assure best operation.

10.9.4.5 Centrifugal Switches

Basically, all single-phase motors are designed with a special arrangement of winding for starting. To accomplish this, some method is used to automatically change the electrical connections of a motor. This may be one of the following:

- Starting and running windings, with centrifugally operated switches to disconnect the starting winding.
- Central switch to disconnect or change capacitor circuits.
- Potential relay (occasionally used instead of centrifugal switches).
- Repulsion-induction-type motor with wound rotor and commutator, which utilizes a centrifugally operated switch to short-circuit the commutator at a predetermined speed.
- Repulsion-inductor-type motor with wound rotor and commutator and a squirrel-cage rotor winding that automatically come into use near full speed needs no transfer device.

It is usually more practical to replace defective centrifugal switches than to repair them.

10.9.4.6 Squirrel-Cage Rotors

Squirrel-cage rotors are more rugged and, in general, require less maintenance than wound rotors. Open circuits or high-resistance joints between the end rings and the rotor bars may give trouble. The symptoms of such conditions are generally the same as with wound-rotor motors, that is, slowing down under load and reduced starting torque. Look for evidence of heating at the end ring connections, particularly when shifting down after operating under load.

Fractures in the rotor bars usually occur between the point of connection to the end and the point where the bar leaves the laminations. Discolored rotor bars are evidence of excessive heating.

Brazing or replacing broken bars requires considerable skill. Unless a capable serviceman is available, the manufacturer or an experienced service shop should be consulted before attempting such repairs at the plant.

10.9.5 Synchronous Motors and Generators

The stator of a synchronous machine requires approximately the same care as the stator of an induction motor. In large-sized synchronous machines, the windings are generally more accessible and this facilitates cleaning.

The rotor field coils of a synchronous machine should be cleaned in the same manner as the field coils on a DC machine. Slow-speed synchronous machines have rotor poles held by the spider with studs and nuts, while in high-speed synchronous machines a dovetail construction is utilized with tapered wedges securing the poles.

Some synchronous machines have the poles bolted to the shaft using bolts through the poles. Some 400-cycle synchronous generators utilize a laminated field structure with coils placed in slots, each tooth representing a pole. Following is a general maintenance guide for synchronous motors:

- During any general overhaul, the nuts on the studs or the wedges for the dovetail poles should be check for looseness. The amortisseur winding should be checked for loose or cracked connections.
- In dusty installations where collector ring enclosures are not used, the collector rings and brush holders should be blown off weekly with clean dry air. When oil deposits form on the collector ring or brush holder insulation, it should be cleaned by wiping with a suitable solvent and coated with a high-gloss insulating varnish. When cleaning the brush holders, the brushes should be removed to prevent their absorbing the solvent.
- Coat all insulated surfaces of the brush holders and slip rings with a high-gloss insulating varnish. Caution should be exercised. Do not coat brush contact surfaces of the slip rings.
- If the collector rings become eccentric, grooved, pitted, or deeply scratched, this condition can best be corrected by grinding the rings with a rotating-type grinder, with the machine running at rated speed in its own bearing. Fine emery cloth or sandpaper should be used for light scratches on iron or steel rings but not on bronze rings.
- Regardless of the method used, rings, should be polished to a high gloss with crocus cloth and oil. After polishing, the rings should be thoroughly cleaned with a solvent to remove all abrasives and foreign materials.

- In as much as the wear due to electrochemical action is not the same on both the positive and negative collector rings, it is suggested that the polarity be reversed about every 3 months of operation to compensate for this condition.
- Field current specified on the nameplate should not be exceeded for continuous operation.

10.9.6 Cleaning and Varnishing of Machine Windings

The life of a winding depends upon keeping it in its original condition as long as possible. In a new machine, the winding is snug in the slots, and the insulation is fresh and flexible and has been treated to be resistant to the deteriorating effects of moisture and other foreign matter.

Moisture is one of the most subtle enemies of the machine insulation. Insulation should be kept clean and dry. Certain modern types of the insulation are inherently moisture proof and require infrequent varnish treatment, but the great majority, if exposed to a damp atmospheric place, should be given special moisture-resisting treatment.

One condition that frequently hastens winding failure is movement of the coils caused by vibration during operation. After insulation dries out, it loses its flexibility. Mechanical stresses caused by starting and plugging, as well as natural stresses in operation under load, sometimes precipitate short circuits in the coils and possibly failures from coil to ground, usually at the point where the coil leaves the slot.

Periodic varnish treatment and curing, correctly done so as to fill all spaces caused by drying and shrinkage of the insulation, will provide an effective seal against moisture and should be a matter of routine electrical maintenance. Varnish treatment and curing of rotating electrical equipment follow a logical procedure.

10.9.6.1 Cleaning

Some machines are exposed to accumulations of materials, such as talc, lint, or cement dust, which although harmless by themselves may obstruct the ventilation. The machine will then operate at higher temperatures than normal, and the life of the insulation will be decreased. Such materials can sometimes be blown out with clean dry compressed air.

The most harmful types of foreign materials include carbon black, metallic dust and chips, and similar substances that not only impair the ventilation but also form a conductive film over the insulation and increase the possibility of insulation failure. Metallic chips may also work themselves into the insulation because of the ventilation and magnetic fields. When windings are cleaned, inspection should be made for any signs of deterioration.

Epoxy-encapsulated windings, a construction finding increasing favor, are sealed against contaminants. They need little attention other than removing dirt accumulations. The common practice when such windings are damaged is replacement with a new winding.

It is extremely important that all wound stators and rotors be perfectly clean before varnish treatment and curing. Unless all conducting dirt and grease are removed, the varnish treatment will not be fully effective. Also, after varnish treatment, the leakage path caused by conducting materials will be difficult to uncover and remove. Correct cleaning involves the following steps:

- Dirt should be removed from all coil surfaces and mechanical parts. Air vent ducts should be clear. As an alternative, clean, dry air at a pressure of not more than 50 psi may be used. Higher air pressure may damage windings. Do not use air if dust from the machine can damage critical equipment nearby.
- As much oil, grease, and dirt as possible should be removed by wiping the windings with clean, dry cloths and then with clean cloths that have been moistened with a solvent recommended by the coil manufacturer. If the original varnish on the windings is cracked, a brush should be dipped in solvent and used to clean all conducting particles from the cracks.
- For cleaning, armatures or wound rotors should be placed in a vertical position with the commutator or collector ring end up, and a pressure spray gun with solvent should be used to clean under the collecting device and through vent holes. The same procedure should be repeated with the opposite end up, and then repeated again with the commutator or collector ring end up. Most large DC armatures are ventilated through open commutator risers at the front end. The solvent spray should be directed through these risers to reach the inner surface of the armature coils and inner commutator vee-ring extensions.
- Silicone-insulated equipment can be cleaned by the same methods used with other insulation systems. If a liquid cleaner is found to be necessary, the recommendations of the coil manufacturer should be followed.
- For windings other than silicone, there are a number of good commercial cleaners on the market. The manufacturer can recommend the one most suitable for the conditions. Plant safety rules concerning the use of flammable and toxic solvent should be observed and followed.
- Caution should be exercised to remove all liquid cleaners.

10.9.6.2 Drying

The wound apparatus should be dried in an oven held at a temperature of 115°C–125°C (239°F–257°F) for 6–12 h or until the insulation resistance becomes practically constant. If a vacuum is used, the drying time may be reduced.

The apparatus should be brought up to temperature slowly because excessive moisture may be present in the windings. If heated rapidly, this moisture may vaporize quickly enough to rupture the insulation.

Before treatment, the apparatus should be cooled to within 10°C (50°F) above room temperature, but never to a temperature lower than 25°C (77°F). If the apparatus is cooled to room temperature and allowed to stand, it will take up moisture quickly. If placed in the varnish at a temperature higher than that specified, the varnish will tend to harden.

10.9.6.3 Varnish

The selection of varnish is dependent upon the operating conditions to which the motor is subjected; also, the type of environmental conditions (i.e., moisture, corrosion, chemical, abrasion) should be taken into consideration.

Varnish must be compatible with the insulation system with which it is to be used. If it is incompatible, it may not adhere and may not give the desired protection. For most applications, the selection of a general-purpose high bonding, yet resilient, synthetic resin varnish is recommended. The varnish can be either class A, B, or F, depending upon the insulation system rating. On large AC stators using class A insulation, the use of a flexible asphalt or oleoresinous varnish is suggested; then, if it becomes necessary to lift a coil, the coil will not be destroyed.

Many types of varnishes are available, and when applying the insulating varnish, the recommendation of the manufacturer should be followed with respect to specific gravity, viscosity, and curing cycle for the particular varnish in question. After the varnish has been adjusted to give the desired film build and drainage characteristics, the specific gravity and viscosity readings should be recorded; then at periodic intervals the varnish should be examined for either specific gravity or viscosity, or both, and adjustments should be made to bring it within the original limits.

The units should be cured in a correctly ventilated forced-air circulating oven to remove the solvent vapors. The oven can be either gas fired or electrically heated. Infrared heat can be used if desired.

For the most part, the time and temperature of the cure should follow the varnish manufacturer's recommendations. The time of cure will vary from short bakes of several hours up through 16–24 h, based on the physical dimensions and makeup of the units, and taking into consideration the particular characteristics of the type of varnish that has been applied to the equipment.

Curing temperatures will vary from 75°C to 125°C (167°F to 257°F) for oleoresinous-type varnishes to 135°C to 155°C (275°F to 311°F) for classes B and F varnishes. Silicone varnishes usually require a cure temperature range of 185°C–200°C (365°F–392°F) or higher.

Complete rewinding jobs should receive at least two coats of varnish. Baking time can usually be reduced on the first or impregnated coat, with an extended period of time used on the final coat. The use of additional coats is based on what is expected of the unit after it is in operation. If severe conditions are to be encountered, multiple-coat systems are recommended. Also, apparatus such as high-speed armatures should receive multiple coats for the maximum bonding of the conductors. One coat is all that is necessary on older units that have been cleaned up on which no rewind work has been done.

In the case of large stators or rotors where the size is such that dipping is not possible, the varnish must be sprayed on the windings. Old winding surfaces must be completely coated.

For most applications, conventional dip methods are recommended. Other accepted methods are brushing and flooding. However, if the length or depth of the slots is great and the windings tightly packed, it may be necessary to use a vacuum impregnation system.

10.9.7 Lubrication, Bearings, and Oil Seals

10.9.7.1 Lubrication

Of all the important items of maintenance, lubrication ranks as one of the highest. Incorrect oiling or greasing will produce as disastrous results as any other type of motor mistreatment.

Excess oil may get into the windings where it will collect dust and other foreign matter. Too much grease in antifriction bearings causes heat and sometimes failure of bearings and may also coat the windings. Most manufacturers furnish data on correct oiling and greasing, and numerous articles have been written on the subject. The important point is to set up a definite lubrication schedule and follow it. Years of experience have demonstrated that it is as bad to use too much as too little oil and grease.

Of equal importance is the type of oil or grease used. In general, the recommendations of the manufacturer or experienced oil companies should be followed. In some cases, for design reasons, manufacturers insist on the use of particular lubricants that have been adopted after exhaustive test by the manufacturer. It will pay to follow these recommendations.

10.9.7.2 Sleeve Bearings

Some oil-lubricated machines are shipped without oil and, in the case of large machines, the journals are often packed and treated for protection during shipment. The rotating elements may also be blocked to prevent damage to the bearings and journals during shipment. Where lubrication is required, the bearing must be opened, the packing removed, and the journal cleaned and flushed before filling the housing with oil. All motor and generator bearings should be checked for oil before starting up.

The bearings of all electrical equipment should be carefully inspected at scheduled periodic intervals in order to obtain maximum life. The frequency of inspection, including the addition of oil, changing the oil, and checking the bearing wear, is best determined by a study of the particular operating conditions. If makeup oil is required in excessive amounts, an investigation for oil leaks should be started immediately.

The more modern types of sleeve-bearing housings are relatively dust and oil tight and require very little attention, since the oil does not become contaminated and oil leakage is negligible. Maintenance of the correct oil level is frequently the only upkeep required for years of service with this type of bearing.

Older types of sleeve bearings require more frequent inspection and checking for wear, and oil changes should be made more often. Never add oil to bearings when the machine is running.

In most cases, the safe temperature rise for a bearing is considered to be within 40°C above the room ambient.

Small sleeve-bearing motors use either wool packing or fluid wick for transferring the lubricant to sleeve bearings instead of oil-ring lubrication. Some of these small motors have provision for relubrication.

When electrical equipment must operate under extreme differences in air temperatures, the use of a lighter oil may be found desirable during cold weather.

Care should always be exercised in the use of reclaimed lubricating oils. The filtering operation should be positive and should remove all foreign and injurious matter.

A hot bearing is usually due to one of the following causes:

- No oil.
- Poor grade of oil or dirty oil.
- Failure of the oil rings to revolve with the shaft.
- Excessive belt tension.
- Rough bearing surface.
- Incorrect fitting of the bearing.
- Bent shaft.
- Misalignment of shaft and bearing.
- Loose bolts in the bearing cap.
- Excessive end thrust due to incorrect leveling. A bearing may become warm because of excessive pressure exerted by the shroud of the shaft against the end of the bearing.
- Excessive end thrust due to magnetic pull, with the rotating part being sucked into the stator or field because it extends farther beyond the magnetic structure or field poles at one end than at the other end.
- Excessive side pull because the rotating part is out of balance.

If bearing becomes hot, the load should be reduced if possible and lubricants fed freely, loosening the nuts on the bearing cap. If the machine is belt connected, the belt should be slackened. In case relief is not afforded, the load should be removed and the machine kept running slowly, where possible, until the shaft is cool in order that the bearing will not freeze. The oil supply should be renewed before starting the machine again.

A new machine should always be run unloaded or at slow speed for an hour or so to make sure that it operates correctly. The bearings should be carefully watched to observe that the oil rings revolve and carry a plentiful supply of oil to the shaft.

10.9.7.3 Antifriction Bearings

Ball or roller bearings carry the load by direct contact, as opposed to sleeve bearings, which carry the load on lubricating film. Lubrication is necessary to minimize the friction and generation of heat caused by the balls rubbing on the outer race as they roll over the top or on the retainer of the cage.

Antifriction bearings require considerable care to prevent loss of end clearance, distortion of balls, and marking of races. If too much force is used in pressing the bearing on the shaft, the clearance may be destroyed. It is recommended that antifriction bearings be heated in a hot bath of clean oil rather than by the use of dry heat. When the bearing is pulled off, with all the stress on the outer race, both races may be damaged, with resultant failure when put back in service. The bearing manufacturer's recommendations should be followed when removing and reapplying this type of bearing.

Bearing manufacturers produce a bearing known as the prelubricated shielded bearing. Several years use of this bearing has demonstrated that, for many applications, no further lubrication is needed. Such bearing construction is usually indicated on the nameplate.

In general, to obtain maximum service, ball-bearing motors should be relubricated at intervals determined by the type, size, and service of the bearing. Many motor manufacturers offer as a guide a table suggesting the intervals between lubrication. These tables show time intervals between greasing that range from 3 months or so for motors operating in very severe service, as in conditions involving dirt or vibrating applications, those where the end of the shaft is hot, or subject to high ambient temperatures, to intervals of up to 3 years for easy service, where motors operate for short periods or infrequently.

The bearing housing is usually arranged to introduce new grease and purge the bearing of old grease, allowing it to discharge through a partially restricted escape port or relief hole. This will, in general, allow filling to the desired degree, which is one-third to one-half full, leaving some space in the housing to allow for expansion of the grease.

It is again stressed that overgreasing can be just as harmful as undergreasing. Overgreasing causes churning and internal friction that can result in heating, separation of the oil and soap, oxidation of the grease, and possible leakage through the retaining seals.

10.9.7.4 Installation of Oil Seals

The importance of correctly installing an oil seal cannot be overemphasized. Failure to observe correct installation procedures probably accounts for more cases of the incorrect functioning of oil seals than any other single cause. To secure the ultimate in satisfactory service, it is recommended that the following precautions be observed.

Correct seal
It is essential that the seal be the correct size for the installation. Oil seals are made for a specified shaft size. When they are installed on a shaft of a larger diameter, there will be drag, frictional heat, and excessive wear on the sealing element and shaft. When installed on a shaft having a smaller diameter, immediate leakage can occur.

Fluid contact
The seal should be assembled with the toe or wiping edge of the sealing element pointing toward the fluid to be retained. Exceptions for unusual applications must be by specification in manuals or instructions furnished with the assembly.

Bore
The bore should be checked for adequate chamfer (30° angle to a minimum depth of 1/16 in.). The bore should be inspected for scratches and all sharp edges removed. The seal outside diameter should be correct for the bore in the assembly. When a leak at the outer edge of either metal or rubber-covered seals is caused by abrasion of the oil seal, it may be directly related to incorrect chamfer on the bore of the use of incorrect installation tools.

Shaft
The surface of the shaft should be uniform and free from burrs, nicks, scratches, and grooves. The surface finish should be between 10 and 20 μin. and, on a repair job, should be buffed to this thickness with crocus cloth.

Lubrication
In all cases, a lubricant should be applied to the shaft or to the sealing element of the oil seal. This aids installation and reduces heat buildup during the first few minutes of run. The application of a lubricant to the outer periphery of a synthetic rubber-covered seal will reduce the possibility of shearing or bruising.

Pressing tools
In pressing the seal into the bore, it is imperative that the correct-sized pressing tool be used to localize the pressure on the face of the seal and in direct line with the side walls of the seal case to prevent damage and distortion to the seal cases during the installation. When a seal must penetrate the bore below the surface, the correct pressing tool should be 1/32 in. smaller than the bore diameter. On installations where the seal is flush with the housing, the correct pressing tool should be at least 1/8 in. larger in diameter, and more if room permits. Care should be taken to avoid hammer blows, uneven pressure on seal surfaces, and cocking of the seal during this operation.

When an oil seal of open channel construction is pressed-fit heel first into the bore, an installation tool will be helpful. The tool is designed to have contact with the inside diameter of the seal case.

Shaft end

If the seal is to be installed toe first, the end of the shaft should have a 30° by 3/16 in. taper, or an installation tool must be used. If the seal is to be installed heel first, no special precautions are necessary other than to remove burrs or sharp edges from the end of the shaft.

Shaft with keyways and the like

When an oil seal is installed over the keyway, splines, and the like, an installation thimble should be used with the outside diameter not more than 1/32 in. over the shaft.

Pressure-lubricated bearings

Because of speed and bearing loading, it is necessary to pressure lubricate the bearings on some larger motors and generators. Pressure gauge readings may not show the amount of oil flowing, but machines have a sight oil-flow detector where oil flow may be checked. Orifices in the feed lines may clog, and oil-flow detection devices will protect the bearings.

Bearing insulation

If the bearing is insulated, care must be taken so that the insulated bearing is not grounded by bearing temperature detectors or relays.

10.9.8 Brushes

Correct care of brushes, brush rigging, and current-collecting parts is a fundamental necessity if satisfactory performance is to be obtained. Adequate inspection is essential to the maintenance of this equipment and the following points should be observed:

- Brush holder box should be adjusted between 1/16 and 1/8 in. from the surface of the commutator.
- Care should be taken to see that dirt and particles broken from the edges of brushes or the commutator have not lodged in the face of the brush.
- Brushes must be correctly aligned, and the commutator brushes must be correctly staggered, pairs of arms (+ or −) being set alternately.
- Brush is affected by such adverse conditions as sparking, glowing, rough commutator, severe chattering, no-load running, overload running, incorrect spring pressure, and selective action.
- Brush on a machine that sparks or glows owing to load conditions, off-neutral operation, or an electrical fault in the machine will be burned and pitted near the sparking edge.

- Severe chattering of the brush is caused by a high-friction film on the surface of the commutator or by incorrect spring pressure.
- Brush chattering due to a high-friction film occurs on machines where there is considerable no-load or light-load running. The characteristic curve of friction versus load current is of such a shape that minimum friction can be obtained at approximately 55 A/in.^{2} and as load current is either reduced or increased, the brush friction is increased. Accordingly, it is sometimes good practice, when a machine is running at very light loads for a considerable period of time, to lift one or more brushes per arm to bring the brush friction into the desirable range. Cases where the load current is above the normal values are more serious, because the higher currents produce sparking, overheating of the machine and brush chatter simultaneously.
- Spring pressure has a direct effect on the riding characteristics of a brush. A common error is to reduce spring pressure for cases where brush wear or marking of the commutator has been observed. This permits the brush to bounce on the commutator, which, in turn, causes sparking and selective action and produces a rough commutator. On the other hand, excessive spring pressure causes brush wear and commutator wear, and usually lowers the electrical contact voltage drop to the point where satisfactory commutation is not obtained. Correct spring pressure should be 2½–5½ lb/in.^{2} for industrial service and 5–10 lb/in.^{2} for traction service. The lower range on traction work will be found where spring-supported motors are used; axle-hung motors use the higher range.
- When checking spring pressure, the action of the brush in the box should be free. Dirt or gummy oil on the brush or in the brush box sometimes causes the brush to stick and in some cases, to completely break the contact between the brush and the commutator.
- Commutator wear in various forms is frequently attributed to a brush that is too hard. Actually, the abrasiveness of a brush does not result from its hardness. Some of the most abrasive brushes are soft to the touch or low when measured for scleroscopic hardness. The property in a brush of five grade that causes abrasiveness is controlled by the brush manufacturer, who should be consulted for information as to the relative cleaning properties of the various grades.

10.9.8.1 Brush Adjustment

The brushes of a new machine are generally adjusted at the factory to the electrically neutral position, and it should not be necessary to change the adjustment. An exception to this rule may occur on large machines where an off-neutral setting is sometimes used to improve commutation. In any case, the method for identifying the correct brush position is given in the manufacturer's instruction book. Various methods may be used for determining the neutral position. The kick method is commonly used as is outlined here.

With all brushes raised from the commutator and the machine standing still, voltages will be induced in the armature by transformer action if the shunt field is excited to about one-half of its normal strength and the field current suddenly broken. It will be found that the induced voltages in conductors located at equal distances to the right and left of the main pole centers will be equal in magnitude and opposite in direction.

Hence, if the terminals of a low-reading voltmeter (5 V) are connected to two commutator bars on the opposite side of a main pole and exactly halfway between the centerlines of two main poles, the voltmeter will show no deflection when the field current is broken. The spacing of these commutator bars is, therefore, the correct distance between brushes on adjacent brush arms.

The most practical method of making this check is to make two pilot brushes of wood or fiber to fit the regular brush holder, each brush carrying in its center a piece of copper fitted for line contact with the commutator bar. With a lead for the connection of adjacent brush arms, the brush rigging may then be shifted slightly forward or backward, as necessary, until breaking the field current produces no deflection on the voltmeter. By noting the position at which no deflection is obtained for each pair of brush arms, the average of the positions of neutral thus obtained will give the correct running location for the brushes.

A quick and convenient method of locating the neutral position on a DC motor and shunt fields is to check the speed of the motor in either direction with the same impressed line voltage. The position of the brushes that produces the same speed in either direction under the same voltage conditions is the correct neutral position.

Another shortcut is to take a piece of lamp cord and bend it in the middle, bringing the two ends together. The insulation should be removed for 1/2 in. on each end and the bare wires twisted together, fanning out to form a brush. When this brush is held so that it spans two bars at the outer end of the commutator and moved with and against the direction of rotation, the point of least sparking at the ends of the wires is the correct location for the centerline of the brushes.

10.9.9 Balancing

Electrical failures are often ascribed to deteriorated insulation, open circuit, short circuit, and so on, but in many cases, failure of insulation results from mechanical disturbances. Unusual noises in electrical apparatus may be the result of grounds, short-circuited coils, changes in voltage or frequency, rubbing or looseness of parts, vibration, defective bearings, and many other causes.

Any unusual amount of vibration or an increase in machine vibration should be investigated immediately. Common causes of undue vibration, other than imbalance, or bearing wear, dirt accumulation, misalignment, an incorrect or a settled foundation, uneven air gap, parts rubbing the rotating element, sprung shafting, a short-circuited field coil, or imbalanced stator currents in the case of AC machines. These should be investigated before balance weights are added or shifted. If at any time it should be necessary to remove the balance weights, they should be replaced in the same position.

Before disassembling a pole on high-speed machines, the axial position of that pole should be accurately marked so that it can be replaced in the same position. Should it become necessary to replace a field coil, or a complete pole, the balance must be checked.

10.9.9.1 Need for Balancing

Vibrations produced by unbalanced rotating parts may result in the following:

- Excessive bearing wear
- Noisy operation of the equipment
- Failure of structural parts
- Reduced overall mechanical efficiency
- Vibration of machine parts or the supporting structure

10.9.9.2 Imbalance Measurement

Imbalance is generally measured in ounce-inches (oz-in.). An imbalance of 1 oz-in. in a rotating body will produce a centrifugal force equivalent to that produced by 1 oz of weight 1 in. from the rotational axis. A rotor weighing 62.5 lb (1000 oz) whose mass center is displaced 0.001 from the rotational axis is 1 oz-in. out of balance.

Only force imbalance is measured by static balancing, which is a single-plane correction. The part being balanced is not rotated. Dynamic balancing of a part by rotation is required when there is appreciable axle length because, by this method, force imbalance, moment imbalance, or a combination of both may be measured. This is a two-plane correction.

The balancing process is not complete until corrections have been applied relative to the size and that the exact location indicated by the balancing machine. Corrections for balance may be made by the addition or removal of metal.

10.9.10 Belts, Gears, and Pinions

10.9.10.1 Belts

In most industrial organizations, installation, adjustment, inspection, and care of belts is the responsibility of a specially trained individual or group. The application of belts involves alignment and belt tension, which affect bearing operation. Maintenance personnel must report belt alignments that seem inaccurate, tensions that appear excessive, and splices that look doubtful. Drives having upward belt tension may be questioned. Bearing loads on sleeve-bearing motors should not be against that portion of the bearing where the oil is fed into the bearing. Action should be taken to protect the electrical apparatus when there is evidence of belt-produced static.

10.9.10.2 Gears and Pinions

Gears and gear trains are among the principal sources of noise and vibration. In designing such mechanisms, the manufacturer strives for the best tooth term to give the least amount of whip and backlash, with the gear center so located that the teeth mesh at the correct pressure points.

It is essential, therefore, that the bearings be so maintained that these gear center distances do not change. Correct lubrication of gears is essential to keep down the wear of teeth. A gear with worn teeth, even though it appears to have considerable life left in it, should be replaced to keep vibration and noise to a minimum.

10.10 Predictive Maintenance Guide on Motors and Variable Frequency Drives

Electrical maintenance personnel have for years been limited to troubleshooting motors with no more than a multimeter and an insulation resistance tester (megohmeter). The insulation resistance tester unfortunately does not provide enough information to allow most technicians to feel totally confident in determining whether or not an electrical problem exists or not. The troubleshooting of motors has become more difficult in recent years since many motors today are coupled to variable frequency drives (VFDs). The VFD itself in many cases can cause problems in the motor since it produces harmonics that pollute the power supply to the motor. At the end of this section, a discussion is offered on VFD and its interaction with the motor to help the reader understand its impact on a motor.

There has always been an on-going struggle to utilize technology to identify problems in motors. Recently technologies, such as vibration analysis has been developed to aid in the identification of problems in motors. When vibration analysis shows a two times line frequency ($2F_L$) spike, it is assumed that it must mean an electrical problem. However, it must be kept in perspective that there are many other variables that may be responsible for producing a $2F_L$ spike; therefore, removing a motor from service for an electrical repair due only to a high $2F_L$ could be a mistake, possibly an expensive one.

Also, just measuring the insulation resistance of motor windings may not be enough to say that the motor is fine for continued service or it can be put back in service after it has tripped off-line. The fact is numerous reasons can exist which causes a motor to trip that will not be seen by an insulation test,

FIGURE 10.11
Six electric areas of a motor. (Courtesy of PdMA Corporation, Tampa, FL.)

such as a turn-to-turn short. Breakdown in the insulation between individual turns of a winding can occur inside a stator slot or at the end turn and be completely isolated from ground. Phase-to-phase shorts can occur the same way. If these faults are left unattended, they can result in rapid deterioration of the winding, potentially ending in a complete motor replacement. Restarting of a motor that has tripped should be considered only after these faults have been ruled out. Troubleshooting an electric motor that is suspected to have an electrical problem requires checking the insulation system as well other components in the motor. To confidently assess the electrical condition of a motor and ensure that it will run reliably, there are six electrical areas in a motor analysis that must be looked at during the troubleshooting effort. Missing any of these areas could result in missing the problem and not having enough information to make a correct decision. The six areas are illustrated in the Figure 10.11.

Predictive technologies and tools are available today to troubleshoot and test these areas of interest. PdMA Corporation is just one of the several entities that have developed technologies and tools for diagnosing motor problems. PdMA offers two instruments that go beyond the conventional insulation resistance (megohmmeter) tester and multimeter for predictive maintenance and troubleshooting. These instruments are EMAX and MCE. How they can be used to help diagnose motor problems in the six electrical areas of a motor and how to evaluate these areas are discussed next.

10.10.1 Power Quality

Power quality has recently been thrust in the forefront due to the application of AC and DC drives, as well as other nonlinear loads. The variable frequency drives (VFDs) and other nonlinear loads can significantly increase the distortion levels of voltage and current. How can this distortion be minimized? What equipment is required, and is the concern purely financial or is equipment at risk? Power quality problems as it pertains to motor health involve voltage and current harmonic distortion, voltage spikes, voltage unbalance or imbalance and PF. The basic principle that ties them all together including thermal heating are discussed in this guide from the perspective of motor reliability and troubleshooting.

FIGURE 10.12
PdMA's EMAX instrument. (Courtesy of PdMA Corporation, Tampa, FL.)

By developing a methodical step-by-step process, power analysis (PA) tests using a power quality analyzer, such as PdMA's EMAX shown in Figure 10.12, can be used to get information on quality of the power supply being delivered to the motor. These test results can quickly be used to assess three of the six areas listed above. These areas are derived from the most common electrically related motor failures in an industrial environment. This discussion focuses primarily on the quality of the power supply to the motor, followed by a recommended process on how to evaluate the data recorded during a PA capture.

The EMAX is a dynamic tester that collects data while the motor is operating. This information can be used to evaluate incoming power quality, motor efficiency, rotor, stator, air gap, and power circuit conditions. It simultaneously collects all three phases of current and voltage to provide spectral and digital data in the areas of power, motor current, signature analysis, efficiency, crest factor (CF), total harmonic distortion (THD), sequence data, PF, impedance, current, and voltage.

Power quality refers to the condition of the voltage and current signals. Single- and three-phase nonlinear loads, VFDs, switch-mode power supplies, starting and stopping of large inductive loads, voltage spikes, and the like that can cause poor power quality. These influences can cause excessive harmonics on the electrical distribution system, which can result in overheating of the insulation system and other undesirable effects on the electrical distribution equipment. The term "power quality" is used for defining the quality of power supplied to the motor to do its job. But what is being actually

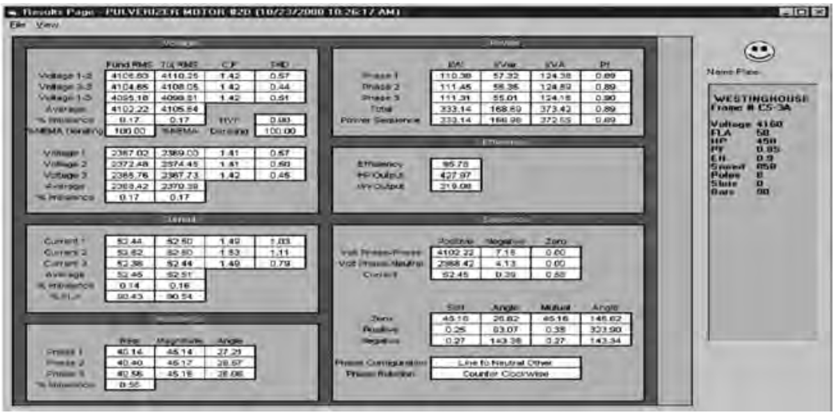


FIGURE 10.13
Phase-to-phase voltage imbalance of a motor—sample result page from PdMA EMAX. (Courtesy of PdMA Corporation, Tampa, FL.)

evaluated is the quality of the voltage that is being supplied to the motor circuit. The power supply system can only control the quality of the voltage; it has no control over the currents that a particular load might draw.

PA test allows a technician to take a power quality snapshot in order to see the condition of the voltage signal and evaluate the effect it will have on the motor. The actual sample time for the simultaneous measurement of the three voltage and current phases takes 0.17 s or less. From this snapshot, the technician focuses primarily on the three phase-to-phase voltages of the power delivered to the motor and determines what effect they are having on motor performance.

Data used to evaluate power quality is located in the phase-to-phase voltage section of the results page as is shown in Figure 10.13. In Figure 10.13, the result page shows among other data the input power to the motor, fundamental root mean square (rms), total rms, CF, and THD for each of the phase-to-phase voltages. The average voltage and percent imbalance are also listed. Additionally, recommended NEMA derating factors are provided for both phase-to-phase voltage imbalance and harmonic voltage factor (HVF).

The motor, or for that matter any three-phase machine, is a symmetrical device and is designed to operate on three-phase balanced sinusoidal voltages. When line voltages applied to a motor are not equal, negative sequence currents are introduced into the motor windings. The negative sequence currents flow in the windings of the motor in the opposite direction to the normal (positive sequence) currents. Therefore, these negative sequence currents produce an air gap flux that rotates in opposite direction to the rotation of the motor. This reduces the net motor torque, affecting its operation and increasing the temperature rise of the motor.

NEMA standard MG1-2006 provides a recommended derating factor based on percent voltage imbalance (Figure 10.14). The usual recommendation is to

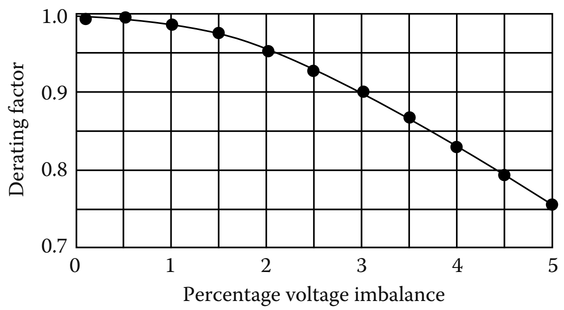


FIGURE 10.14
Derating factor chart for voltage unbalance (NEMA MG1-2006). (Courtesy of PdMA Corporation, Tampa, FL.)

not run a motor when the voltage imbalance is greater than 5% (per NEMA MG-1). For a given phase-to-phase voltage imbalance, rated horsepower of an induction motor should be multiplied by the derating factor in accordance with the NEMA MG1-2006 recommendation. If the load on the motor exceeds this derated value, take steps to correct the imbalance, or reduce the load on the motor. Running the motor with the imbalanced voltage will cause excessive temperature rise in the windings and damage the insulation.

Terminal Voltage

Terminal voltage has a major effect on motor performance. The effect of low voltage on electric motors is well known and understood; however, the effect of high voltage on motors is often misunderstood. The effects of low and high terminal voltages are discussed next.

Effects of low voltage

When a motor is operated below nameplate rated voltage, some of the motor's characteristics will change slightly and other characteristics more dramatically. To drive a fixed mechanical load, a motor must draw a fixed amount of power from the circuit to produce the necessary torque to drive the load. The amount of power is roughly related to the voltage times current. So with a lower voltage, there will be a rise in current to maintain the required power. In terms of torque, the torque produce by the motor is proportional to the square of the voltage. For example, if the voltage to the motor is reduced by 10%, the torque will be reduced by 19%. This in itself is not alarming, unless the torque delivered by the motor is less than the torque required by the fixed load. In order to produce the necessary torque the motor will draw more current, therefore rise in current may exceed the nameplate current rating of the motor. When this happens the buildup of heat within the motor will damage the insulation system.

Aside from the possibility of overtemperature and shortened insulation life, other important effects on the motor's performance need to be understood. Starting, pull-up, and pull-out torque of induction motors all change based on the applied voltage squared. Thus, a 10% reduction from nameplate voltage (100%–90%) would reduce the starting, pull-up, and pull-out torque to 81%. At 80% terminal voltage, the motor would produce 64% torque of the nameplate values. Clearly, it would be difficult to start those hard-to-start loads under such conditions. Similarly, the motor's pull-out torque will be much lower than during normal voltage conditions.

Effects of high voltage

A common misconception is that high voltage tends to reduce current draw on a motor, since low voltage increases the current. This is not always the case. High voltage on a motor tends to push the magnetic portion of the motor into saturation. This causes the motor to draw excessive current in an effort to magnetize the iron beyond the point to which it can easily be magnetized. Generally, motors will tolerate a certain change above nameplate voltage; however, extremes above this value will cause the amperage to go up with a corresponding increase in heating and a shortening of motor life. For example, motors are generally designed to operate satisfactorily with a band of ±10% in accordance with NEMA standards. Even though this is the so-called tolerance band, the best performance would be at rated terminal voltage. Operation at the ends of this band would put unnecessary stress on the motor.

These tolerance bands are in existence not to set a standard that can be used all the time, but rather to set a range that can be used to accommodate the normal hour-to-hour swings in-plant voltage. Continuous operation at either the low or high end of the band will shorten the life of the motor.

The graph shown in Figure 10.15 is widely used to illustrate the general effects of high and low voltage on the performance of T-frame motors. It is acceptable to show general effects, but remember these effects will change slightly from one motor design to another. High voltages will always tend to

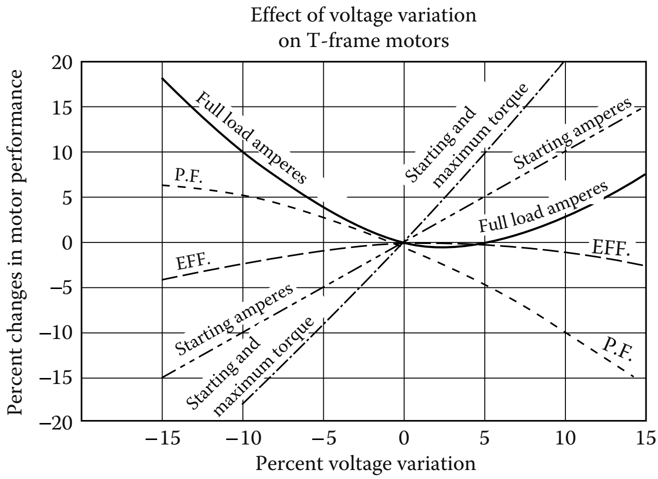


FIGURE 10.15
Effects of voltage variation on T-frame motors (NEMA MG1-2006). (Courtesy of PdMA Corporation, Tampa, FL.)

reduce PF and increase losses in the system, which results in higher operating cost for the equipment and the system. The following guidelines are provided for assistance in evaluating the voltage of a motor circuit:

- Small motors tend to be more sensitive to overvoltage and saturation than large motors
- U-frame motors are less sensitive to overvoltage than T frames
- Premium/high efficiency motors are less sensitive to overvoltage than standard efficiency motors
- Overvoltage can drive up amperage and temperature even on lightly loaded motors; thus, motor life can be shortened by high voltage
- Full-load efficiency drops with either high or low voltage
- PF improves with lower voltage and drops sharply with high voltage
- Inrush current goes up with higher voltage

Simply put, the best life and efficient operation of electric motors occurs when motors are operated at voltage as close to nameplate ratings as possible.

Harmonics

The presence of harmonic distortion in the applied voltage to a motor will both increase electrical losses and decrease efficiency. These losses will increase motor temperature, resulting in even further losses. High harmonics can result in a temperature rise in motor temperature. NEMA MG1-2006 provides a chart for recommended harmonic derating factor known as HVF to aid in evaluating the harmonic voltage effects on the motor's performance. Figure 10.16a shows sinusoidal current and voltage waveforms of a linear load such as a motor. Figure 10.16b shows the nonsinusodial current and voltage waveforms of nonlinear load, such as drawn by a VFD.

When performing PA testing of motor circuits, the power analyzer, such as EMAX, samples the applied voltage signal. It analyzes the voltage waveform, identifies the fundamental frequency and all harmonics present and their percent of the waveform. With this information the HVF is calculated and, if required, recommended derating per NEMA guidelines is provided. The HVF derating curve is shown in Figure 10.17.

There is usually no need to derate motors if the voltage distortion remains within Institute of Electrical and Electronic Engineers (IEEE) Standard 519-1992 limits of 5% THD and 3% for any individual harmonic. Excessive heating problems begin when the voltage distortion reaches 8%–10% and higher. Such distortion should be corrected for long motor life.

The PA test, i.e., snap shot of power quality, provides a wealth of detailed information for identifying the power quality being delivered to the motor in a distribution system. In addition, this simple to perform test also provides the data required for detailed evaluation of motor circuits that utilize VFDs. Phase-to-phase voltage, harmonic distortion, bus voltage, and THD have an effect on the performance and condition of a motor.

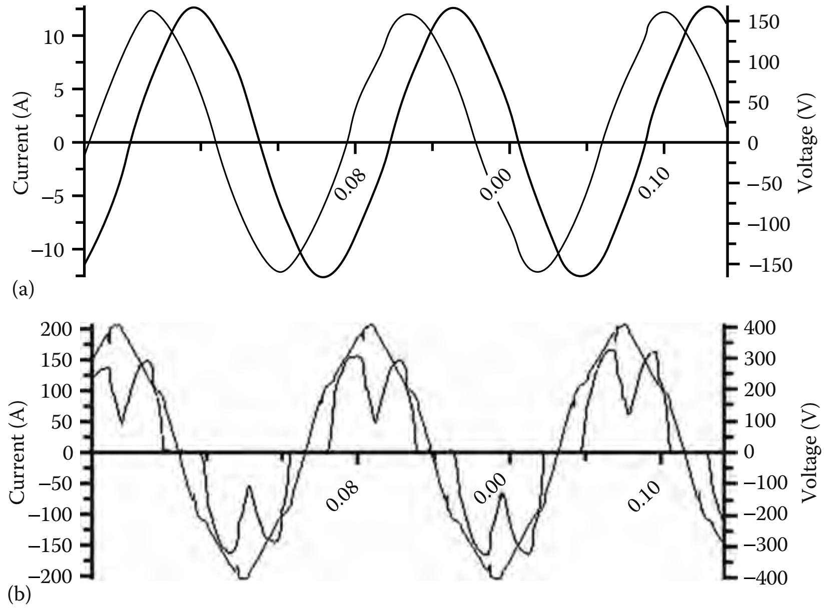


FIGURE 10.16
(a) Current and voltage waveforms of linear load. Linear loads are electrical load devices, which, in steady-state operation, present essentially constant impedance to the power source throughout the cycle of applied voltage. An example of a linear load is an induction motor. Note how the current is proportional to the voltage throughout the sine wave as shown. (b) Current and voltage waveform of nonlinear load. Nonlinear loads are electrical loads, which draw current discontinuously or whose impedance varies throughout the cycle of the input AC voltage sine wave. Examples of nonlinear loads in an industrial distribution system are arc lighting, converter power supplies for VFDs (6 and 12 pulse), and DC power supplies. An example of a discontinuous current draw is shown in Figure 10.16b, illustrating a phase of voltage and current supplying a VFD. (Courtesy of PdMA Corporation, Tampa, FL.)

10.10.2 Power Circuit

The power circuit refers to all the conductors and connections that exist from the point at which the testing starts through to the connections at the motor. This can include circuit breakers, fuses, contactors, overloads, disconnects, and lug connections. A 1994 demonstration project on industrial power distribution systems found that connectors and conductors were the source of 46% of the faults reducing motor efficiency. When evaluating the condition of a motor, it is a good practice to use as many technologies as possible. The anomalies in a power circuit and how to identify them are discussed next.

Power circuit refers to all the conductors and connections that exist from the power supply bus to the connections at the motor. This can include circuit breakers, fuses, contactors, overloads, disconnects, and lug connections. Many times a motor, although initially in perfect health, is installed into a faulty power circuit. This causes problems like voltage imbalances, current imbalances, etc. As these problems become more severe, providing the

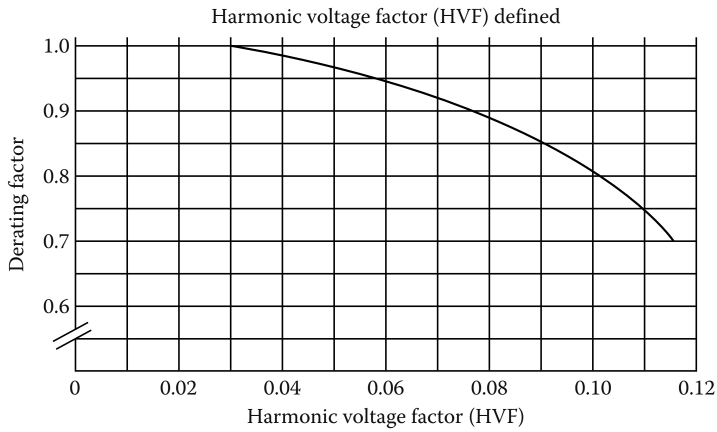


FIGURE 10.17
HVF curve (NEMA MG1-2006). *Note*: The curve does not apply when the motor is operated at other than rated frequency or when operated from a variable voltage or frequency source (VFD). (Courtesy of PdMA Corporation, Tampa, FL.)

same horsepower output from the motor requires more current, causing temperatures to increase and insulation damage to occur. The PA test as discussed under power quality is performed on energized AC induction, AC synchronous, AC wound-rotor motors, and motors being powered by VFDs. The PA test indicates anomalies in the power circuit, power quality, and the stator fault zones.

High resistance connections in the power circuit result in unbalanced terminal voltages at the motor. The consequences of the unbalanced terminal voltage are overheating of the components adjacent to the high resistance connection, loss of torque, other phases drawing additional current to compensate, overheating of the insulation system, and a decrease in motor efficiency. Voltage imbalances will cause the motor to draw more current in order to perform the required work. Therefore, this could lead to premature single-phasing or motor burn out resulting in shutdown of a process due to the failed motor.

The values from the PA test that are used to evaluate the health of the power circuit are: phase-to-phase voltage, phase-to-phase current, and their respective imbalances. These measured values are recorded and compared against industry standards. An unbalanced power delivery not only causes a voltage imbalance but also causes a much higher percent current imbalance. Some rules of thumb to apply when troubleshooting the power circuit are listed next.

- A 1% voltage imbalance can result in a 6%–7% current imbalance, according to the Electrical Apparatus Service Association.
- A 3.5% voltage imbalance can raise winding temperatures by 25%, according to the Electrical Power Research Institute.
- A 10°C increase in winding temperature (above design) can result in a 50% reduction of motor life.

Phase voltage unbalance causes three-phase motors to run at temperatures greater than their published ratings. This excessive heating is due mainly to negative sequence currents attempting to cause the motor to turn in a direction opposite to its normal rotation. These higher temperatures soon result in degradation of the motor insulation and shortened motor life. The percent increase in temperature of the highest current winding is approximately two times the square of the voltage unbalance. For example, a 3% voltage unbalance will cause a temperature rise of about 18%. The greater the unbalance, the higher the motor winding temperature and the sooner the insulation will fail. NEMA standards recommend a maximum voltage unbalance of 1% without derating the motor. The motor can be derated down to 75% for a maximum of a 5% voltage unbalance. If the voltage unbalance exceeds 5%, it is recommended that the motor not be operated.

The easiest way to test a power circuit is using the PA test while the motor is under normal operating condition. A current imbalance is a possible indication of a high resistance connection. However, a voltage as well as a current imbalance is a better indicator. What determines whether both imbalances are present in the event of a high resistance connection is the test location.

Both voltage and current imbalances are not a requirement in the event of a fault in the power circuit. There can be many different reasons to look for a high resistance connection, a power circuit component failure, or an imbalance that points to another fault zone. Trending power circuit anomalies is most effective at similar loads. Higher loads may result in the fault being more obvious due to the stresses being greater at higher loads. The easiest way to verify the current draw of a motor is by looking at the percent full-load amperes (% FLA) in the current section on the results page of the power analyzer as shown in Figure 10.18.

As mentioned earlier, a current imbalance is a possible indicator of a power circuit anomaly. This is because the location of the anomaly in reference to

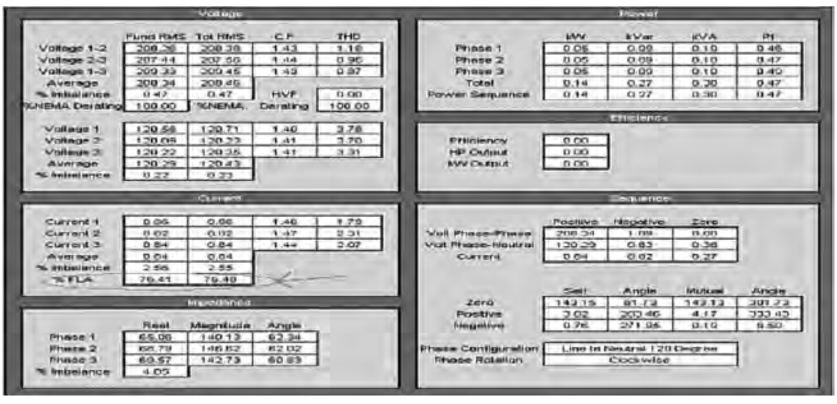


FIGURE 10.18
Motor current in %FLA—sample result page from PdMA EMAX. (Courtesy of PdMA Corporation, Tampa, FL.)

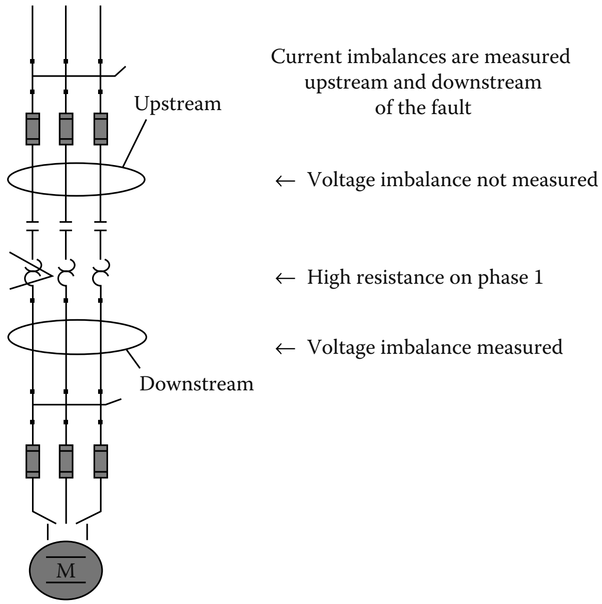


FIGURE 10.19
Location of testing for motor troubleshooting. (Courtesy of PdMA Corporation, Tampa, FL.)

the voltage test leads will show different imbalances. However, measured current values are consistent regardless of test location. Figure 10.19 shows how voltage readings can change based on test location. If the test is being performed upstream of the anomaly, then there will only be a current imbalance, and if the test is downstream, there will be both a current and voltage imbalance.

Loads using three-phase power sources are subject to loss of one of the three phases from the power distribution system. This condition is known as single-phasing of the primary power supply system. The loss of one phase, or leg, of a three-phase line causes voltages to become unbalanced on the secondary distribution power system, thereby causing serious problems for motors. The motor windings will overheat due primarily to the flow of negative sequence currents, a condition that exists anytime there is a phase voltage imbalance. The loss of a phase also inhibits the motor's ability to operate at its rated horsepower.

In conclusion, a high resistance connection results in voltage and current imbalances, which reduces the horsepower rating significantly. When a good motor is installed into a faulty power circuit, it causes problems with power imbalances, as well as, negative sequence currents. As the problems become more severe, the horsepower rating of the motor drops causing temperatures to increase resulting in overheating of adjacent components, damage to the rotor, stator, insulation, shortened motor life, reduced motor efficiency, motor failure, or fire. While damage to the rotor, stator, or insulation might be symptoms of a problem; the root cause still lies with the power circuit.

Replacing the motor without fixing the high resistance connection causes the failure cycle to begin again.

10.10.3 Insulation Condition

This refers to the insulation between the windings and ground. High temperatures, age, moisture, and dirt contamination all lead to shortened insulation life. It has been said that if the industry would just use the space heaters available to keep the insulation dry, then doubling the life of our motors would not be out of the question.

The importance of having good electrical insulation systems is obvious. The designs and applications of electrical equipment are almost infinite in their variety, but all units have one common characteristic. For electrical equipment to operate correctly, one of the most important characteristics is that the flow of electricity takes place along well-defined paths or circuits. These paths are normally limited to conductors, either internal or external to the electrical component. It is important that the flow of current be confined to defined conducting paths and not leak from one path to another through materials not intended to become conducting paths. Deterioration of insulation systems can result in an unsafe situation for personnel exposed to the leakage current.

Despite great strides in electrical equipment design in recent years, the weak link in the chain is still the insulation system. When electrical equipment fails, more often than not the fault can be traced to defective insulation. Even though an electric motor is correctly designed and tested prior to installation, there can be no guarantee that a fault in the insulation will not occur at some time in the future.

Many outside influences affect the life of electrical insulation systems. Outside influences include contamination of the insulation surfaces with chemicals from the surrounding atmosphere that attack and destroy the molecular structure, physical damage due to incorrect handling or accidental shock, vibration, and excessive heat from nearby industrial processes. Voltage transients in the conductors inside the insulation, such as surges or spikes caused by VFDs, can lower the dielectric strength to the point of failure. The deterioration occurs in many ways and in many places at the same time. For example, as chemicals and heat change the molecular structure of the insulating materials, they become semi-conductive, allowing more current to be forced through them by voltage resulting in leakage current.

Correctly conducted insulation system testing, analysis of the data collected, and followed by appropriate corrective actions can minimize the possibility of failures. Therefore, the significance of understanding insulation system testing has never been more important. The reader should refer to Chapters 1 and 2 for detail discussion of insulation (dielectric) theory and practice and conducting tests using DC voltage. A brief overview of the subject matter is offered here from the perspective of motor-winding insulation.

Insulation resistance measurements

The insulation system of motor windings is often checked using DC voltage tests. One of the most common test conducted is to measure the insulation resistance of the motor windings using an insulation resistance tester. When testing insulation with DC voltage, the total current drawn is the sum of four different currents: surface leakage, geometric capacitance, conductance, and absorption.

The surface leakage current is constant over time. Moisture or some other type of partially conductive contamination present in the machine causes a high surface leakage current, i.e., low insulation resistance.

The geometric capacitance current is a reversible component of the measured current on charge or discharge that is due to the geometric capacitance. That is the capacitance as measured with AC of power or higher frequencies. With direct voltage, this current has a very short time constant and does not affect the usual measurement.

The conduction current in well-bonded polyester and epoxy-mica insulation systems is essentially zero unless the insulation has become saturated with moisture. Older insulation systems, such as asphaltic-mica or shellac mica-folium may have a natural and higher conduction due to the conductivity of the adhesive tapes used as backing of the mica.

The absorption current is made of two components: the polarization of the insulation material and the gradual drift of electrons and ions through the insulating material. The polarization current is caused by the reorientation of the insulating material. This material, usually epoxy, polyester, or asphalt tends to change the orientation of their molecules when in the presence of a DC electric field. It normally takes a few minutes of applied voltage for the molecules to be reoriented, and thus for the current-supplied polarizing energy to be reduced to almost zero. The absorption current, which is the second component, is the gradual drift of electrons and ions through the insulating material. These electrons and ions drift until they become trapped at the mica surfaces usually found in motor insulation systems. The positively and negatively charged molecules of an insulation system are shown in Figure 10.19.

Figure 10.20a shows the random orientation of the insulation's molecules. As DC voltage is applied to the insulation, the molecules start to polarize and align, as shown in Figure 10.20b. The energy required to align the molecules, and subsequently reduce the amount of escaping molecules, is known as absorption current. Since absorption current is a property of the insulation material and the winding temperature, a specific absorption current is neither good nor bad. The absorption currents will vary from different insulating material. Prior to 1970, older thermoplastic materials used for motor winding insulation were typically asphalt or shellac, which has a higher absorption current.

After 1970, the shift was made to thermosetting polyester or epoxy-bonded insulating material, which significantly decreased the absorption current. Nonetheless, this does not mean that the more modern insulating materials are better because they have less absorption current. The amount of applied voltage must be appropriate to the nameplate voltage and the basic insulation condition. This is particularly important in small, low-voltage machines

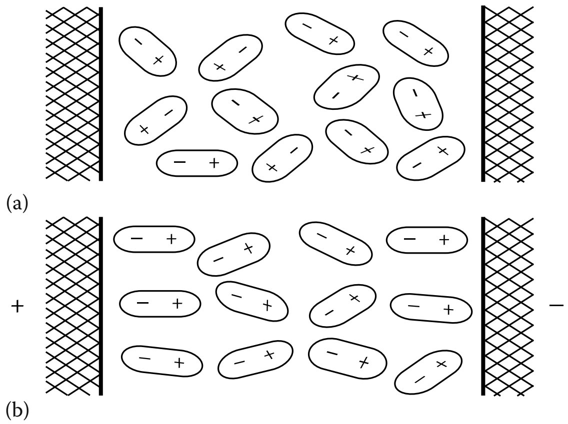


FIGURE 10.20
Positively and negatively charged molecules of an insulation system. (Courtesy of PdMA Corporation, Tampa, FL.)

where there is only a single layer of insulation. If test voltages are too high, the applied voltage may over stress the insulation. See Table 10.7 for recommended voltage application.

Also, the capacitance value of insulation may be measured to reflect on the cleanliness of the windings. A buildup of contamination on the surface of the windings results in higher capacitance readings. With a buildup of contamination on the insulation surface, dirty windings produce higher capacitance values than clean ones do. Over time, capacitance values steadily increased indicating an accumulation of dirt and that cleaning is necessary.

TABLE 10.7
Guidelines for DC Voltages for Insulation Resistance Tests

Winding Rated Voltage (V)[a]	Insulation Resistance Test Direct Voltage[b]
<300	500
>300–1,000	500–1,000
1,000–2,500	500–1,000
2,501–5,000	1,000–2,500
5,001–12,000	2,500–5,000
>12,000	5,000–10,000

[a] Rated line-to-line voltage for three-phase AC machines, line-to-ground voltage for single-phase machines, and rated direct voltage for DC machines or field windings.
[b] Refer to IEEE 43-2000 for a guide on DC test voltages.

Effects of contamination

There are many factors that can affect insulation resistance. The surface leakage current is dependant upon foreign matters, such as oil and carbon dust on the winding surfaces outside the stator slot. The surface leakage current may be significantly higher on large turbine generator rotors and DC machines, which have relatively large-exposed creepage surfaces. Dust and salts on insulation surfaces, which are ordinarily nonconductive when dry, may become partially conductive when exposed to moisture or oil, and this will cause increased surface leakage current and lower insulation resistance. The reason a motor's capacitance increases with contamination is because of how a capacitor works. Any two conducting materials, called plates, separated from each other by a dielectric material, form a capacitor. A dielectric material is anything that is unable to conduct direct electric current. A cable or motor winding surrounded by insulation provides one conductor and the dielectric material. The second plate is formed by the stator core and motor casing iron. It is this second plate that is increased in plate size as contamination builds up.

Effects of temperature

A higher temperature affects the resistance of both the insulation and conductor. There is a term called temperature coefficient (K_T). A material has either a positive or negative K_T. If the material has a positive K_T, then with added heat the resistance readings will increase. Inversely, if a material has a negative K_T, then the resistance readings will decrease with higher temperature. In metals, i.e., the magnetic wire of the stator, higher temperature introduces greater thermal agitation and reduces the movements of free electrons. Because of this reduction in free movement, the resistance readings will increase with added heat and therefore the conductor has a positive K_T. However, in insulation, the added heat supplies thermal energy, which frees additional charge carriers and reduces the resistance reading. Therefore, an increase in temperature on insulation reduces the resistance and it is said to have a negative K_T. This higher temperature affects every current except the geometric capacitive current.

The recommended method of obtaining data for an insulation resistance versus winding temperature curve is by making measurements at several winding temperatures, all above the dew point, and plotting the results on a semilogarithmic scale. Since this type of temperature coefficient plotting is usually not feasible, it is recommended to avoid the effects of temperature in trend analysis, subsequent tests should be conducted when the winding is near the same temperature as the previous tests. Otherwise the insulation test values should be corrected to a common base temperature of 40°C for trend analysis.

Therefore, resistance-to-ground readings must be temperature corrected for trending and comparison purposes. Temperature correction of the reading is required because the temperature of the insulation system under test may vary depending on operating conditions prior to testing, atmospheric conditions, or ambient temperature. Insulation material has a negative temperature coefficient, which means that the resistance characteristics vary inversely with temperature. In the test setup screen of a standard test, the temperature of the windings will have an effect on the measurement. The measured megohm value is then adjusted to a temperature correction to 40°C. The result is the

TABLE 10.8

Recommended Minimum Insulation Resistance Values at 40°C (All Values in Megohm)

$IR_{1\,min} = kV + 1$	For most windings made before about 1970, all field windings, and others not described below
$IR_{1\,min} = 100$	For most DC armatures and AC windings built after 1970 (form-wound coils)
$IR_{1\,min} = 5$	For most machines with random-wound stator coils and form-wound coils rated below 1 kV

Source: From IEEE Std 43-2000, IEEE Recommended Practice for Testing Insulation Resistance of Rotating Machinery.

corrected megohm readings. To accurately trend resistance reading for a motor over time, keep the test voltage and duration of applied voltage constant.

The temperature-corrected megohm readings should be recorded and graphed for comparison over time. If a downward trend is observed, look for dirt or moisture. A single reading will not have much meaning in regards to the overall health of the insulation system; a reading as low as 5 MΩ may be acceptable if related to a low-voltage application. See Table 10.8 for recommended minimum insulation resistance. Also, refer to Section 2.10.1 in Chapter 2 for additional discussion on recommended minimum insulation resistance values.

This is important because dirt and contamination reduce the motor's ability to dissipate heat generated by its own operation, resulting in premature aging of the insulation system. A general rule of thumb is that a motor's life decreases by 50% for every 10°C increase in operating temperature above the design temperature of the insulation system. Heat raises the resistance of conductor materials and reduces the insulation resistance of the winding insulation, and therefore breaks down the insulation. These factors accelerate the development of cracks in the insulation, providing paths for unwanted current to flow to ground. The effects from temperature to insulation resistance are shown in Figure 10.21.

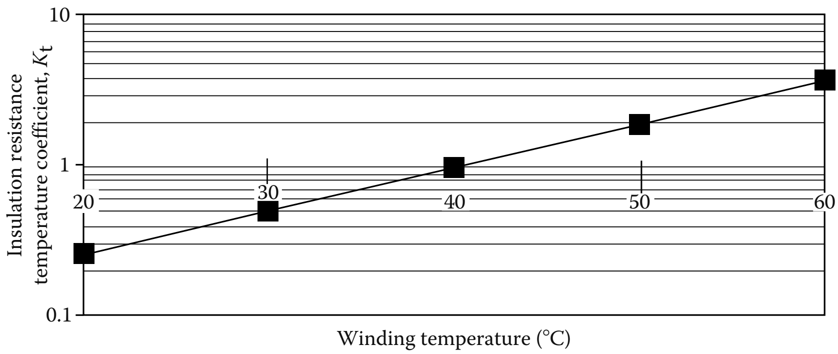


FIGURE 10.21
Temperature versus insulation resistance curve. (Courtesy of PdMA Corporation, Tampa, FL.)

Polarization index and dielectric absorption

The polarization index (PI) and dielectric absorption (DA) tests are performed with a megohmmeter on a deenergized motor. It is not necessary to perform a DA test if a PI test is performed. Refer to Sections 2.3.1.2 and 2.3.1.3 for description of DA and PI tests. The purpose of the PI test is to determine whether or not a motor's insulation system is suitable for continued service. The PI test is not limited to AC induction motors only. It also applies to wound-rotor motors, salient pole machines, and certain DC fields. The DC field would have to have conductors that are fully encapsulated in insulation. Therefore, the PI test can be a worthwhile test for multiple type machines. When performing a PI test, it is not necessary to correct for temperature. Since the machine temperature does not change appreciably between the 1 min and the 10 min readings, the effect of temperature on the PI is usually small. However, if the motor recently shut down and a PI test is performed, the results may be a substantial increase in insulation resistance. This would result in an unusually high PI, at which point additional testing should be performed once the windings have cooled to 40°C or lower. Refer to Table 2.14 in Chapter 2 for Interpretation of PI and DA data. Excellent results should indicate a PI ratio of 2–4, achieve higher than minimal insulation resistance values, and should be a nonsporadic rise in the megohm readings as shown in Figure 10.22.

Erratic insulation resistance values occurring at anytime during the test are indicative of short-term current transients. These may be due to contamination or moisture. It is important to know how low the insulation resistance values fall to in order to grade the insulation. For example, the IEEE standards

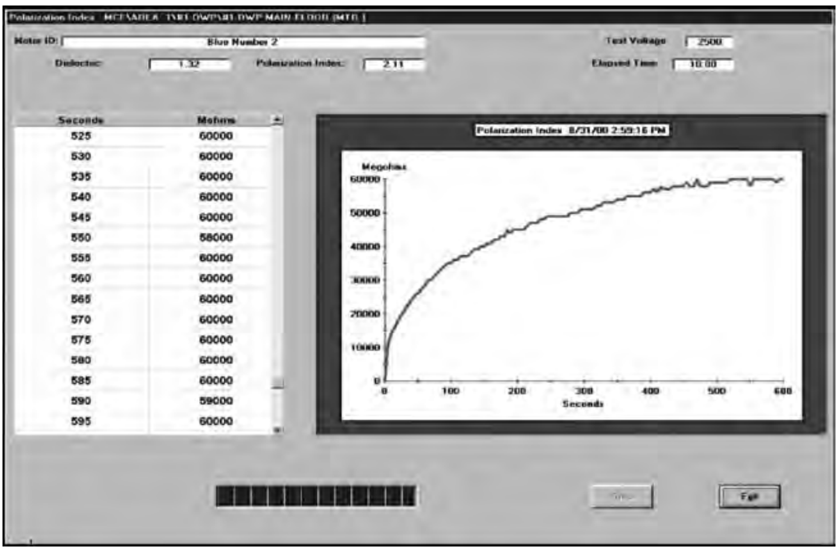


FIGURE 10.22
Graph showing megohm values versus time for calculating PI and DA sample result page from PdMA MCE. (Courtesy of PdMA Corporation, Tampa, FL.)

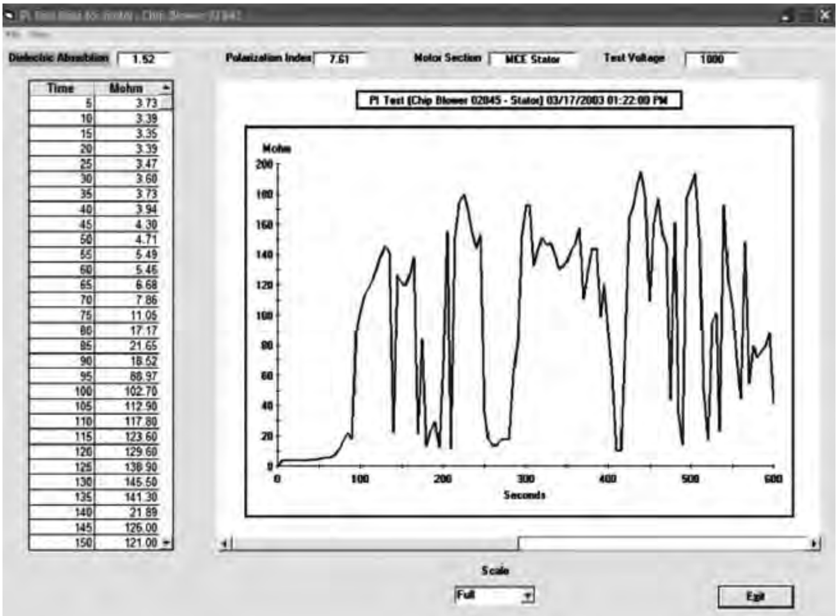


FIGURE 10.23
Graph showing megohm values falling below the minimum value. Sample result page from PdMA MCE. (Courtesy of PdMA Corporation, Tampa, FL.)

recommend minimum insulation resistance value of 100 MΩ for form-wound coils. Figure 10.23 shows insulation resistance values dipping below the suggested minimum value of 100 MΩ for a form-wound coil. The PI and DA tests can be both used as go–no-go, based on the minimum insulation resistance readings.

The PI value of greater than 4 does not necessarily mean that the health of the insulation system is good. The higher PI value may indicate other problems with the insulation system, such as being too dry and brittle indicating that it has lost some or all of its mechanical properties. According to the EASA's principles of large AC motors, it states that PI ratios of greater than 5 should be considered the result of dry or brittle insulation. This may be because of age of the insulation or operating the motor at higher than designed temperatures as shown in Figure 10.24. A very dry or brittle insulation may indicate good insulation resistance but it may not have the necessary dielectric strength and mechanical pliability.

10.10.4 Stator Condition

When discussing the stator, we are referencing the DC or three-phase AC windings, insulation between the turns of the winding, solder joints between the coils, and the stator core or laminations. This fault zone creates a lot of debate as to the cause and rate of failure. The stator fault zone is

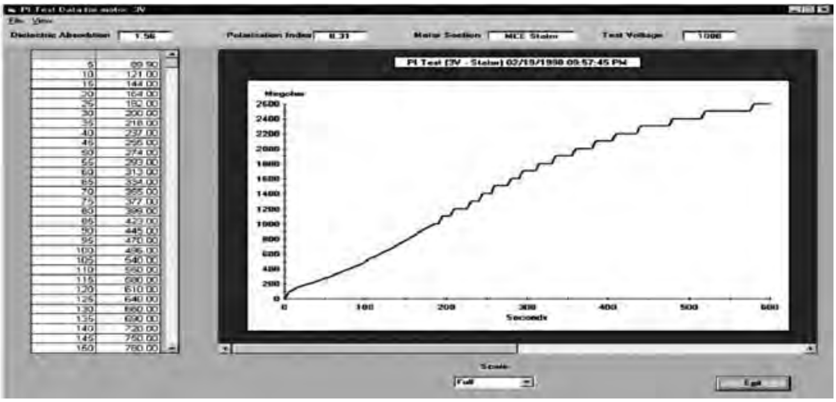


FIGURE 10.24
Graph showing insulation resistance readings of very dry or brittle insulation. Sample result page from PdMA MCE. (Courtesy of PdMA Corporation, Tampa, FL.)

often considered one of the most controversial areas due to the significant challenge in early fault detection and the prevention of motor failure surrounding the stator windings. This challenge is further intensified in higher voltage machines, where the fault-to-failure time frame becomes much shorter. The stator fault zone is identified as the health and quality of the insulation between the turns and phases of the individual turns and coils inside the motor.

Failure Mechanisms

The likely mechanisms of a stator-winding fault are either a turn-to-turn, phase-to-phase, or turn-to-ground short. A turn-to-turn short is identified as a short of one or more windings in a coil. This can develop into a very low impedance loop of wire, which acts as a shorted secondary of a current transformer. This results in excessive current flow through the shorted loop, creating intense heat and insulation damage. Due to the nature of a random wound design, a shorted turn could occur with much higher impedance, allowing the motor to run for extended periods of time before eventually destroying the coil with the high currents. As a result, it is not unusual to find random wound motors still running with bad stator windings. Form-wound coils however, do not exhibit high turn impedances and will therefore heat up quickly following the presence of a turn-to-turn short. A phase-to-phase short is identified as a short of one or more phases to another phase. This fault can be quite damaging due to the possibility of very large voltage potential existing between phases at the location of the short.

Analysis

The big controversy, which surrounds the stator fault zone, is whether technology can give ample warning of an impending stator-winding failure. A motor will develop a turn-to-turn, phase-to-phase, or ground short over

FIGURE 10.25
PdMA's MCE tester. MCE may be used to test all major types of motors: induction, synchronous, wound rotor, DC, servo, and spindle. (Courtesy of pdMA Corporation, Tampa, FL.)

its life. The goal of any test, when faced with this type of long-term certainty, is to identify the impending conditions, which may be conducive to these faults, so the condition can be corrected. If the conditions conducive to faults are removed, then a longer life for the motor can be expected. If a turn-to-turn short has occurred, then preventing a restart of the motor may be the best thing at that point in the troubleshooting effort. Again, if you wait until the turn-to-turn short has occurred before you test the motor, you have waited too long.

A surge comparison test set, or PdMA's MCE test instrument, shown in Figure 10.25, applies a high-frequency AC signal and a low-voltage DC signal to the stator windings to perform stator analysis. From these signals, inductance and resistance measurements are taken for comparison between like coils and historical data. When testing a three-phase AC induction motor, comparison between the three phases is the most powerful tool. When testing a DC motor, only a single phase exists and comparison to historical test data or identical motors would be effective. Inductance is a highly sensitive parameter and is influenced by many variables within the motor. Rotor condition, air gap flux, frame construction (iron or aluminum), and winding condition are a few of the variables. The most influential variable on the inductance reading is the winding condition. Specifically the number of turns is a squared value in the overall inductance equation as seen below:

$$L = \frac{0.4\pi N^2 \mu A \times 10^{-8}}{l}$$

where

L is the inductance (Henerys)
N is the number of turns of coil
μ is the permeability of core in electromagnetic units
A is the cross-sectional area of core (cm^2)
l is the mean length of core (cm)

Although it is our goal to prevent a turn-to-turn short from occurring, you can see that a loss of a single turn in a stator winding will have a dramatic effect on the overall inductance of one or more phases based on the coil configuration. In our effort to identify the conditions that are conducive to a turn-to-turn short, we can use other variables in the equation to identify anomalies, which could create stator problems.

Stator faults often end up as a turn-to-turn short, but begin as something else. An example is a motor with excessive vibration, which results in winding movement, friction, and eventually worn insulation between the winding turns. Another example is rotor defects, which create intense heat on the winding surface and eventually create weakened turn insulation or even a ground fault. Core iron defects, such as shorted laminations, will also create additional heat, airflow disturbance, and elevated vibration due to imbalanced magnetic fields and air gap flux. What influence do these situations have on stator inductance? Other than vibration, rotor defects and air gap flux anomalies have a direct impact on the permeability (μ) of the stator windings. Changes in μ due to a stator core defect will create changes in inductance related to a specific group of coils located near the defect. Changes in μ due to rotor defects will have a varying influence on the stator inductance as the rotor position changes. A quick comparison of the inductance and inductive imbalance values between the three phases or to historical data will indicate changes in these variables and prompt further action or testing to be performed in an effort to prevent the turn-to-turn short.

Stator analysis may be performed by evaluating the phase relationship of voltage and current for each of the three phases of an AC induction motor. These values are used to determine the impedance of each phase and display them as an impedance imbalance. Any change in the real or reactive component of one phase that is not duplicated on another phase will indicate a change that needs to be investigated. One of the hurdles involved in this type of testing is acquiring this dynamic data at a load substantial enough to allow these values to be affected by the condition of the windings and not the design. An unloaded motor may run with a current imbalance. This creates variations in the phase impedance, which duplicates indications of a stator fault. Therefore, it is important to have approximately 70% load or more to remove the design impact on these values. Testing should not stop at <70% load, but you must use the test data as comparison values only.

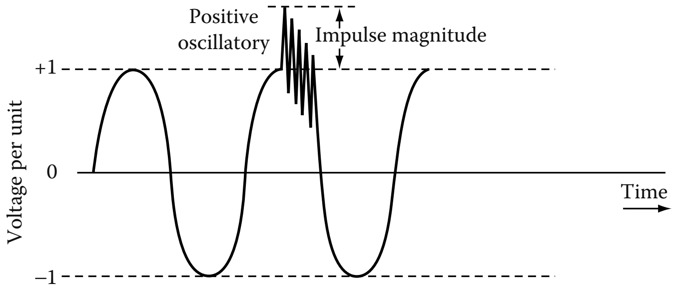


FIGURE 12.5
Oscillatory transient.

Switching transient: Switching of power equipment can cause a transient voltage to be generated due to the stored energy contained in the circuit inductances (L) and capacitances (C). The size and duration of the transient depends on the value of inductance and capacitance and the waveform applied. Examples of switching surges are fault clearing, capacitor switching, and switching of inductive loads on and off. Damage from transient overvoltages can be immediate or latent. The latent damage occurs when equipment or components are severely stressed by repeated transient overvoltages or by a single transient overvoltage condition, but not to the point of immediate failure. Each exposure reduces the ability of the equipment or component's ability to withstand additional stress. At some later time, the equipment or component fails unexpectedly without apparent cause due to its weakened nature from previous transients. This latent effect may not become apparent for some time.

Interruptions: Power interruptions are a complete loss of power lasting for cycles, seconds, minutes, hours, or days (Figure 12.6). A variety of factors can cause power interruptions, such as tripping of the main circuit breaker due to a fault, malfunction or failure of equipment, or operation of protective devices in response to faults that occur due to acts of nature or accidents, or other anomalies in the power supply. These interruptions may cause loss of computer memory, equipment shutdown/failure, hardware damage, and productivity loss.

Frequency variations: A frequency variation is a deviation from a prescribed input frequency range such as 60 Hz (Figure 12.7). This deviation can be either higher or lower than normal. Sudden changes in load, switching of power

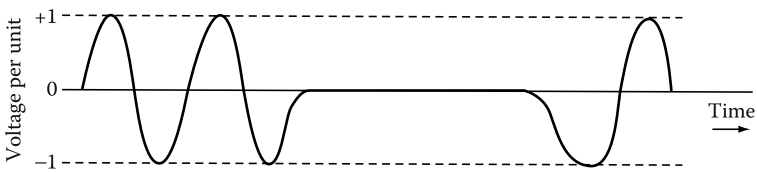


FIGURE 12.6
Power interruption.

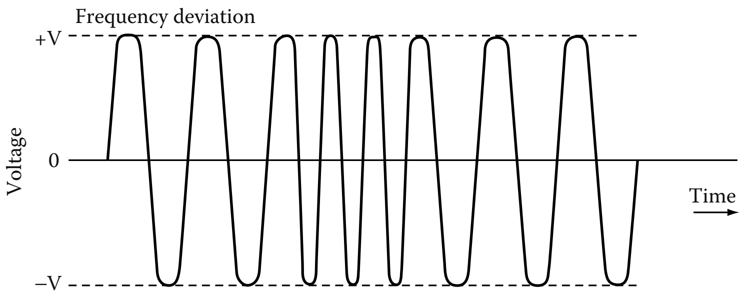


FIGURE 12.7
Frequency variations.

between utility and on-site generator, utility generator malfunctions, or mismatch between generation and load can cause such variations.

Harmonics: Harmonics are voltages or currents at frequencies that are integer multiples of 60 Hz frequency (120, 180, 240, 300 Hz, etc.). They are designated by their harmonic number or multiple of the fundamental frequency. For example, a harmonic with a frequency of 180 Hz—(three times the 60 Hz fundamental frequency) is called the third harmonic. As shown in Figure 12.8, harmonics superimpose themselves on the fundamental waveform, distort it, and change its waveform. In industrial power systems, for example, 15%, 20%, or 25% total harmonic current distortion (THD) may be experienced. THD can be determined by calculating the square root of the sum of the squares of all harmonics, divided by the nominal 60 Hz value. This yields

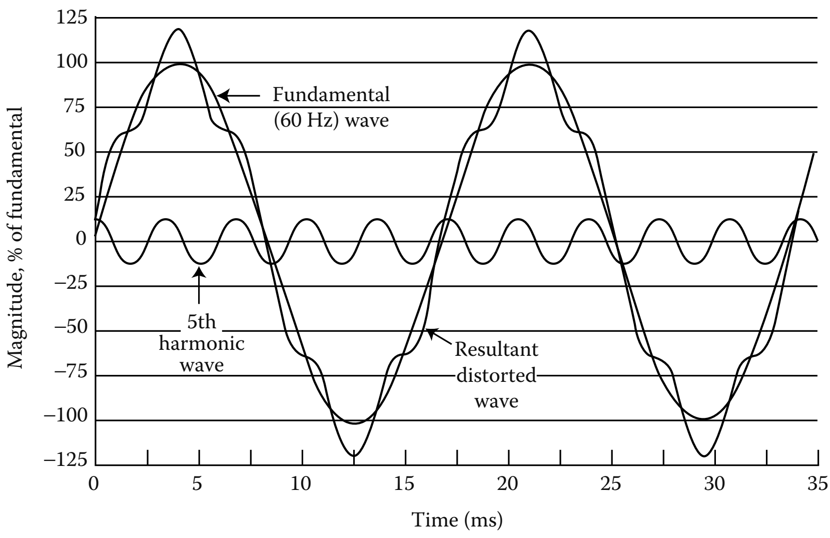


FIGURE 12.8
HD caused by fifth harmonic current superimposed on 60 Hz waveform. (Courtesy of Plant Engineering Magazine, 2000 Clearwater Dr., Oak Brook, IL.)

a root-mean-square (rms) value of distortion as a percentage of the 60 Hz waveform. Note, odd-order harmonic currents are additive in the common neutral of a three-phase system, whereas the even-order harmonics cancel out to zero. The odd-order harmonic currents such as the third and all odd multiples of the third harmonic (9th, 15th, etc.) are equal and in phase for a three-phase, four-wire system. Therefore, they add in the neutral. Other odd harmonics (5th, 7th, 11th, etc.) are also additive, although not fully since they are equal but not exactly in phase. Mathematically, the total is a vector sum of the three-phase harmonic currents. The phase angles between the three-phase harmonic currents results in partial addition and partial cancellation. Therefore, the total neutral current for these harmonics is more than any one harmonic phase current, but less than three times any harmonic phase current. Whereas for the second harmonic and all even harmonics (fourth, sixth, eighth, etc.), currents are not in phase and the sum of the positive and negative neutral currents equals to zero for a three-phase, four-wire system. Harmonics are caused by nonlinear loads, that is loads in which the current waveform does not conform to the waveform of applied voltage. All equipment operating on the principle of ferromagnetic induction (lighting ballasts, lifting magnets, solenoids, motors, etc.) produces some degree of harmonics. A prime example of a device that produces harmonics is a power converter such as a rectifier that draws current in only a portion of each cycle. Other devices, such as those which change impedance with applied voltage, also produce harmonics. These include saturated transformers and gaseous discharge lighting, such as fluorescent, mercury arc, and high pressure sodium lights.

Harmonics can cause overloading of conductors and transformers and overheating of utilization equipment, such as motors. Odd-numbered triplen harmonics (3rd, 9th, 15th, etc.) can especially cause overheating of neutral conductors on three-phase, four-wire systems. While the fundamental frequency line currents and other even harmonic currents cancel each other in the neutral, the triplen harmonic and other odd harmonic currents are additive in the neutral. Harmonics also can cause nuisance tripping of molded-case circuit breakers and power switchgear equipped with solid-state trip-sensing units designed to sense peak (as opposed to rms) current. As increased amounts of sensitive electronic equipment are being added to today's workplaces, concern for harmonics has escalated as well. Electronic equipment miss operation can result from harmonics because much of electronic circuitry—notably that in which action is instigated by an electronic pulsing clock—is triggered by zero crossing on the waveform.

Harmonic currents may contribute to capacitor failure and blown fuses on PF improvement capacitors under resonance conditions on the power system. Resonance occurs when the power system inductance and capacitance come in tune (i.e., equal) with each other at a particular frequency; capacitive and inductive reactance are both functions of frequency. Every circuit containing inductive and capacitive devices has one or more resonant frequencies. Resonance can cause very high voltages to appear across elements of the power system. At series resonance, minimum circuit impedance occurs at the resonant frequency and is equal to the resistance of the circuit since the

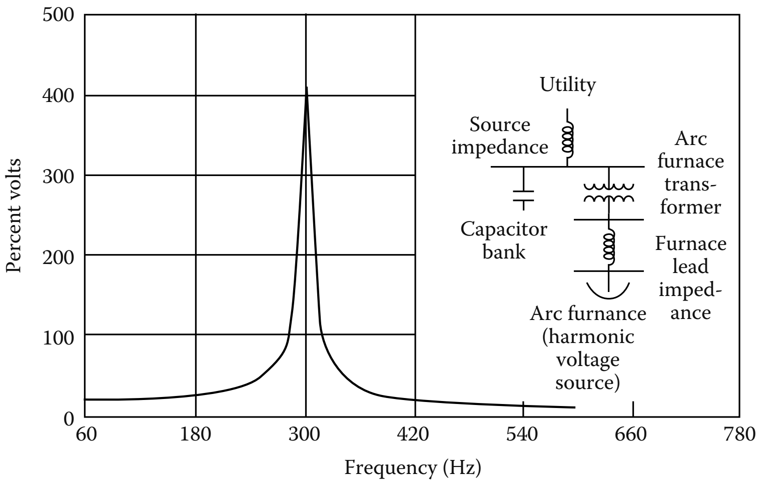


FIGURE 12.9
Parallel resonance condition indicating very high peak voltages at about 300 Hz.

inductive and capacitive impedances are equal. Series resonance provides a low impedance path for the harmonic currents present in the system.

Figure 12.9 illustrates a typical resonant condition on an arc furnace circuit containing PF improvement capacitors. The plot of voltage response versus frequency models the arc furnace as a harmonic current source of varying frequency. A resonance peak occurs at very close to 300 Hz, or the fifth harmonic. This harmonic source develops excessive voltage at the capacitor terminals, resulting in extremely high current flow through the capacitor.

Voltage imbalance: A voltage imbalance is a long term, steady state problem. It is expressed as a percent, i.e., the maximum deviation of voltage from the average of three-phase voltages, multiplied by 100, divided by the average of the voltages. Voltage imbalances are caused by unbalanced phase loading conditions, defective transformers, and ground faults in ungrounded or resistive grounded systems. These imbalances usually are caused by large single-phase loads. They cause premature failures of motors and transformers due to overheating. Voltage imbalances only affect three-phase applications.

Electrical noise: Electrical noise is a low-voltage, low-current, high-frequency signal that rides a 60 Hz sine wave, distorting it. Noise may be caused by any of the following: RFI, EMI, harmonics from nonlinear loads, and the like. Even though microprocessor-based equipment is grounded in accordance with National Electric Code (NEC) requirements, some continue to have failures, execution and reading errors, and unpredictable and intermittent operations because of electrical noise. Some manufacturers of microprocessor-based equipment recommend electrical separation to minimize the effects of electrical noise, i.e., to locate the microprocessor-based equipment and/or data lines not too close to large power apparatus such as transformers, motors, etc.

Two types of electrical noise can occur in a power distribution system. They are normal mode (line-to-neutral, L–N or line-to-line) noise and CM (neutral-to-ground, N–G) noise.

Normal mode noise is measured between the phase (hot) and neutral lines or phase-to-phase. CM noise is a potential difference that occurs between any or all current-carrying conductors and the grounding conductor or earth. In the three-phase, grounded-wye power supplies typical of large computer systems, these disturbances also can be potential differences between neutral and ground. Some computer-based loads are sensitive to excessive levels of voltage potential between the neutral and grounding conductors. A ground is used to reference the electronic logic in equipment and should be stable. Equipment manufacturers sometimes specify acceptable limits for neutral to ground voltage, for example, one volt peak to peak. CM disturbances can be generated by a ground potential difference between elements of the computer or remote peripherals connected to the computer. This type of disturbance is influenced by several factors, including the system configuration and the impedance of the grounding system. Both of these factors generally are beyond the direct control of the user, except in the construction of a new facility. However, CM noise can be suppressed by the use of an isolation transformer. Equalizing ground potentials is often difficult due to the broad frequency band involved in wiring resonances. However, proper computer system grounding, including a signal reference grid (SRG), has been found to be effective against most CM disturbances. CM noise on the primary of the transformer that appears as normal mode noise on the secondary is commonly referred to as transverse mode or sometimes as intercoupling or differential mode (DM) noise. CM transient voltages that appear on the transformer primary winding will be coupled through the transformer interwinding capacitance, appearing across the secondary winding as normal mode voltages. Electrical noise typically occurs in the RF MHz range. It also may occur at frequencies below MHz range. The 60 Hz (power) grounding system often is not effective for conducting RF signals to the common reference point grounding electrode. In some cases, computers and peripherals are themselves responsible for generating noise disturbances. A properly designed power grounding system has sufficiently low impedance at 60 Hz to maintain enclosures, raceways, and all grounded metals at the same voltage potential (ground reference). But the 60 Hz ground system is unable to provide this equalization at higher frequencies because of the increased impedance caused by inductive reactance and the skin effect. (Skin effect is known as the tendency of current to flow more at the surface of the conductor than its center, thereby increasing the AC resistance of the conductor). The inductive reactance at a frequency of 30 MHz is 500,000 times as great as that of the same conductor when the applied voltage is at 60 Hz. At microprocessor switching speeds (over 1 to 30 MHz), current penetration in the copper conductor is less than at 60 Hz, with the result that the effective impedance between one point and another is pronounced. Also, as frequency rises, the wavelength proportionally decreases. Circulating (noise) currents see an apparent open circuit at intervals of one-quarter wavelength, so that the current path is interrupted or becomes unreliable. Some frequencies pass and some do not, causing distortion. Consequently, the long grounding conductors used in the grounding systems designed to meet NEC requirements become ineffective for grounding of high-frequency systems. Short returns are always recommended for fast-rise circuits to provide effective signal returns at system signal frequencies.

Table 12.1 is a summary of the electromagnetic phenomena categories and their characteristics of the power system.

TABLE 12.1

Electromagnetic Phenomena and Characteristics

Categories	Typical Characteristics
Overvoltage	
Impulse	Nanosecond: 5 ns rise time for <50 ns impulse
	Microsecond: 1 μs rise time for of 50 ns–1 ms impulse
	Millisecond: 0.1 ms rise time for >1 ms impulse
Oscillatory	Low frequency: <5 kHz for 0.3–50 ms at 0–4 PU
	Medium frequency: 5–500 kHz for 20 μs at 0–8 PU
	High frequency: 0.5–5 MHz for 5 μs at 0–4 PU
Short duration voltage variations	
Interruption	Momentary: <0.1 PU for 1/2 cycles—3 s
	Temporary: <0.1 PU for 3 s–1 min
Voltage dip (sag)	Instantaneous: 0.1–0.9 PU for 0.5–30 cycles
	Momentary: 0.1–0.9 PU for 30 cycles—3 s
Swell	Instantaneous: 1.1–1.8 PU for 0.5–30 cycles
	Momentary: 1.1–1.4 PU for 30 cycles—3 s
	Temporary: 1.1–1.2 PU for 3 s–1 min
Long duration voltage variations	
Interruption	Sustained: 0.0 PU for >1 min
Undervoltage	0.8–0.9 PU for >1 min
Overvoltage	−1.2 PU for >1 min
Voltage waveform distortions	
DC offset	0.0%–0.1%
Harmonics	0.0–100th harmonic order with 0%–20% magnitude
Interharmonics notchings	0.0–6 kHz with 0.0%–2% magnitude
Voltage fluctuations	
Intermittent	<25 Hz with 0.1%–7% magnitude

12.3 Origins of PQ Problems and Harmonics

Power disturbances can originate from many sources external and internal to a facility's electrical power distribution system. External sources are

- Power system faults
- Lightning
- Switching
- Surges
- Accidents involving electric power lines and feeders

Examples of internal sources are

- Line and capacitor switching
- Motor starting or switching of large inductive loads
- Harmonic producing loads (linear and nonlinear (solid-state and electronic) loads)

The mechanisms involved in generating electrical disturbances often determine whether occurrence of disturbances is random or repeatable, unpredictable, or easy to find. Untrained users often attribute power disturbances to the utility source. However, recent Electrical Power Research Institute (EPRI) studies indicated that most (up to 80%) electronic system malfunctions attributable to power disturbances are the result of electrical wiring and grounding errors, or interactions of loads within the facility's distribution system.

A brief description of some of the major sources of power disturbances follows:

Power system faults: Power system faults can cause a momentary voltage reduction to a complete loss of power lasting for a few cycles, seconds, minutes, hours, or days. Power system faults may be classified as temporary or permanent. Usually the temporary faults are confined to overhead distribution lines where a line may suffer a momentary fault which will open the circuit breaker. However, the circuit breaker will reclose immediately to restore the circuit. Permanent faults are confined usually to underground feeders. Due to their location, the detection and repair of these types of faults require a considerable amount of time. Also, the power system faults may result from power apparatus failure such as transformers, circuit breakers, etc. which require a longer time to repair or replace.

Lightning surges: Direct lightning strikes to the power system conductors cause overvoltages near their points of impact. Direct hits inject the total lightning surge into the system. As a result, current amplitudes can range from a few thousand amperes to a few hundred thousand amperes. The rapid change of current through the impedance of the conductors produces a high voltage drop, which causes secondary flashover to ground. This diverts current even in the absence of an intentional diverter. Lightning strikes also can activate lightning arrestors and/or surge arrestors. A flashover of line insulators can trip a breaker, with reclosing delayed by several cycles, causing a power interruption. The power system also can be affected indirectly by lightning. These effects include overvoltages in conductors and ground potential rises in grounding grids or the earth.

Load switching and surges: Load switching forms a transient disturbance whenever a circuit containing capacitance and inductance, such as capacitors, starting motors, or switching feeders, is switched on or off. In these circuits, the currents and voltages do not reach their final value instantaneously. The severity of such disturbances depends on the power level of the load being switched and on the available short-circuit current of the power system. Switching large loads on or off can produce long-duration voltage changes beyond the immediate transient response of the circuit. More complex switching can produce surge voltages reaching 10 times the normal circuit voltages, involving energy levels determined by the power rating of the elements being switched. Also, energizing loads, such as large motors, may cause voltage dip that can affect operation of microprocessor-based equipment.

Linear and nonlinear loads: The power system harmonic problem is an old problem and, in many instances in the past, we have been able to go around it and reduce its effects. The harmonic producing linear loads are devices such as transformers, generators, motors, electromagnetic ballasts, and saturated magnetic devices that have been around a long time. These are discussed in more detail in Section 12.4. The nonlinear loads are generally classified as those devices that are electronic and solid-state devices used in power conversion and control. It is clear that nonlinear loads draw nonsinusoidal currents from the power system, even if the power system has a perfect sinusoidal waveshape. These currents produce nonsinusoidal voltage drops in the system's source impedance which distorts the sine wave produced by the power source. A typical nonlinear load is a direct current (DC) power supply with capacitor-input filter. They are used in most computers and draw current only at the peaks of the voltage sine wave. Nonlinear loads typically result in harmonic distortions (HDs) in the power system. These loads can be broadly classified into four categories as follows.

1. *Power electronic devices:* Power electronic devices are being employed in small appliances to huge converters on the transmission system. Typical applications of power electronics include switch-mode power supplies (SMPS), adjustable speed drives (ASDs), electronic ballasts, and the like.
2. *Saturatable devices:* Most saturatable devices are transformers which generate harmonics due to the nonlinearity of the transformer excitation. These harmonics are small unless the transformer is overexcited due to high voltage magnitudes.

3. *Arcing devices:* Arcing devices are used most commonly in fluorescent, high and low pressure sodium and mercury-vapor lamps. Other types of these devices include arc furnaces or arc welders.
4. *Electrostatic discharges (ESDs):* An ESD buildup results from a rubbing action between two materials (solid or liquid) of different surface energy characteristics. This is due to an absence of a conductive path between the two materials. The ESD is quickly released when a conductive path (discharge arc) is established. Such discharges can be harmful to semiconductor devices in sensitive electronic equipment. Discharge voltages often range from 5 to 40 kV.

Grounding design and installation: Improperly grounded systems which have multiple ground points are common causes of PQ disturbances. Grounding systems which do not have sufficiently low ground impedance do not allow the proper amount of current flow necessary for the operation of the circuit protection devices, thereby compromising the safety of personnel and equipment. Such systems also cause failures in electronic equipment due to leakage currents. Leakage currents created by power line noise, coupled with high-ground impedances, cause voltage to develop on the ground conductor that can trigger a failure in electronic equipment. A ground system with multiground points can create multiground loops and impose stray currents on the logic chips of microprocessors. Therefore, it is essential that the design and installation of earth grounds and equipment grounds should be done carefully. Since the ground system also serves as an equal potential reference between peripherals, an improperly designed ground can affect microprocessor logic and inject unwanted signals. The logic circuitry of a microprocessor uses the ground system as a zero conductor. See Section 12.7 for a more detailed discussion on grounding design and installation.

Wiring design and installation:
Wiring design and installation problems can be classified as follows:

1. Problems involving the hot, neutral, and ground wires
2. Missing connections, improper connections, loose connections, open grounds, N–G shorts, two hot wires in an outlet, reversed polarity
3. Lack of an isolated ground (IG) receptacle when called for

Because microprocessors use the ground wire as the zero-voltage reference, stray currents imposed upon it can change information and damage microprocessor components. Additional power distribution problems can occur because many pieces of equipment typically are connected together through the building's grounding system, including conduit or data cables. If the ground paths of individual pieces of equipment are not isolated from one another, currents carried on one can affect another's operation. When a piece of equipment is plugged into a standard wall receptacle without an IG designation, its ground wire is immediately connected to every other piece of equipment in the building by means of building conduit. This is similar to the manner in which a large radio antenna picks up radio signals it was never meant to receive. Data cables are extremely sensitive to such cross talk.

12.4 Characteristics of Typical Linear and Nonlinear Loads

The harmonic loads may be classified as linear and nonlinear loads. The linear loads that produce harmonics are iron core devices which operate in the nonlinear (saturated) region of the iron core. Also, depending on the winding pitch, motors and generators may produce harmonics. These sources (loads) have been around since the early days of power systems, but the harmonics produced by these devices have been manageable. The traditional (established) sources of harmonics include the following:

- Tooth ripple or ripples in the waveform arising from the rapid pulsations and oscillations of the field flux caused by movement of the poles in front of the projecting armature teeth cause harmonic output. This tooth ripple causes flux distortion in synchronous machines.
- Variations in air gap reluctance over the synchronous machine pole pitch set up a continuous variation in flux, which permeates to the waveshape, and leaves harmonics as a result.
- Flux distortion in the synchronous machine may be due to load effects. Sharp variations in the load result in sudden changes in machine speed without changes in flux, thus setting up a distorted waveshape.
- Generation of nonsinusoidal emf's are due to nonsinusoidal distribution of the flux in the air gap of synchronous machines.
- Limited transformer current harmonics, primarily third harmonic, occur at no load.
- Imposition of small and limited amount of nonsinusoidal currents, although input voltages are pure sine wave, occur in networks containing nonlinearity. Typical of these nonlinearities are welders, arc furnaces, voltage controllers, frequency converters, etc.

To a lesser extent, but of importance is the fact that a drastic change in the design philosophy of all power equipment and load equipment has taken place. In the past, manufacturers tended towards underrating or overdesigning most equipment. Now, in order to be competitive, power devices and equipment must be critically designed. In the case of iron core devices, this means that the operating points are more into the nonlinear characteristics, resulting in a sharp rise in harmonics from the established power equipment and load equipment.

Today, however the application of electronic equipment continues to change the electrical environment in the power distribution system of most commercial and industrial facility. In the past, the most common loads found in electrical distribution systems were linear loads such as motors, incandescent lighting, and electric heating. Although these loads still exist in modern facilities, other loads—primarily electronic—that have nonlinear load characteristics represent a large percentage of the total load. Because of the proliferation of nonlinear loads, harmonic currents have increased significantly in electrical distribution systems. Since the electrical distribution systems in most facilities were designed to match the characteristics of linear loads (i.e., nearly sinusoidal waveforms), the application of nonlinear loads have caused serious problems such as overheating of conductors, transformers, inadvertent circuit breaker tripping, capacitor failures, and malfunction of electronic equipment. The nonlinear loads consume substantial amounts of energy and thus have a greater impact compared to the linear loads on a facility's electric power distribution system. Linear loads have an impedance characteristic which is basically constant over time with applied voltage. If a sinusoidal voltage is applied to these loads, the current drawn also is sinusoidal.

In contrast, nonlinear electronic loads do not draw sinusoidal current. The applied power to these loads is either rectified by a diode bridge or the device is turned on and off with switching components such as SCRs, triacs, or transistors. Figure 12.10 shows the current waveforms of linear load (sinusoidal) and rectifier (SMPS) load. In Figure 12.10, the sine waveform is representative of heaters, incandescent and motor type loads, the pulse waveform is representative of electronic loads that draw current in pulses (i.e., nonsinusoidal waveform), or draw current for the portion of each cycle by turning on and off. The nonsinusoidal loads do not draw current for the entire cycle but rather draw current in

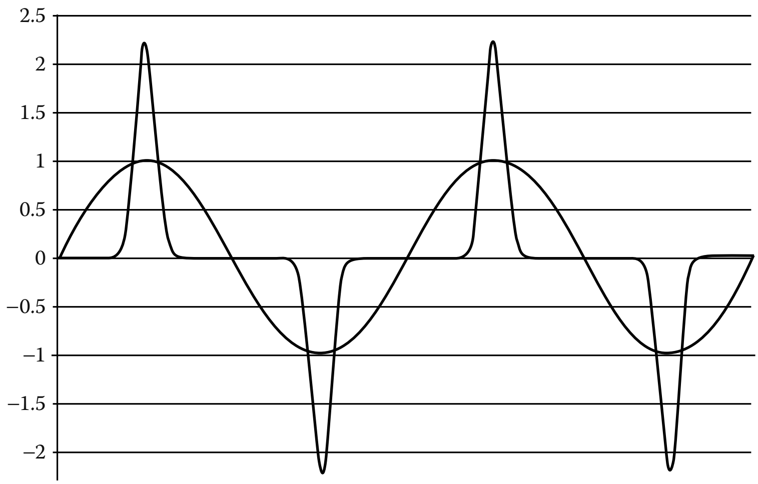


FIGURE 12.10
Load current waveforms: sinusoidal load and rectified (nonsinusoidal) load.

small period per cycle or turn on at a specific point in the cycle. The current drawn by the electronic loads is in abrupt transitions which interact with system impedance causing voltage loss and transients (impulses).

Some electronic loads are constant power loads, such as SMPS, and for these loads a decrease in voltage within the operating range will cause an increase in current to maintain constant power. Also, the harmonic currents of the load interact with the impedance of the distribution system thereby causing harmonic voltage drops. When the distribution system impedance is high, the harmonic voltage drops are high and the harmonic currents for the nonsinusoidal loads are lower. When the distribution system impedance is low, the harmonic voltage drops are low and harmonic current for the nonlinear loads are high. The nonlinear loads when combined with high current inrush and high distribution system impedance tend to cause severe voltage dips and voltage waveform distortion. Under these conditions, the constant power electronic loads attempt to compensate by increasing current draw. The increased current draw interacts with the impedance of the distribution system and adds to the voltage dip, and if the voltage dip is severe enough loads throughout the distribution system will crash. In addition to producing line voltage drops, the third harmonic currents (odd-order triplen harmonics) do not cancel out and flow in the neutral circuit of a three-phase, four-wire system. As a result, these currents return back to the power source over the neutral conductor. These currents can be higher than the phase currents and, therefore, create new concerns over the adequacy of the neutral of the three-phase power supply system.

To cope with harmonics problems caused by nonlinear loads, load characteristics of system harmonics must be studied and understood. The load characteristics can, for the most part, be determined from an examination of the load response to a distorted voltage waveform at load terminals.

12.4.1 Voltage and Current Characteristics of Nonlinear Loads

12.4.1.1 HD Terminology

The nonsinusoidal periodic waveform of nonlinear loads can be represented through Fourier analysis as the sum of a DC component and sine waves of various amplitudes and phase displacement from some relative angle. The sine waves all have frequencies which are multiple of the fundamental frequency of 60 Hz. The voltage and current waveforms can then be represented as the sum of a DC component and sine waves with a fundamental frequency ω_1 as follows:

$$V(t) = V_0 + \sum_{h-1}^{N} V_h \sin(h\omega_1 t + \delta_h)$$

and

$$I(t) = I_0 + \sum_{h-1}^{N} I_h \sin(h\omega_1 t + \theta_h)$$

The voltage and current equations represent sine waves that are multiples of a fundamental frequency, and are called harmonics. The effective value (rms) of current waveform where the amplitude of each harmonics is known can be obtained by the equation as follows:

$$I_{\text{rms}} = \sqrt{\sum_{h=1}^{\infty} (I_h)^2}$$

The nonlinearity (i.e., distortion) of the waveform can be determined in terms of THD, crest factor (CF), and form factor. The THD is defined as the ratio of the rms value of the total harmonic currents and the rms value of the fundamental current. The THD is expressed as a percentage of the fundamental current is given by the equation:

$$\text{THD} = \frac{\sqrt{\sum_{h=2}^{\infty} (I_h)^2}}{I_1}$$

The CF is defined as the ratio of the peak of a waveform to its rms value and can be written as

$$\text{Crest factor} = \frac{I_{\text{peak}}}{I_{\text{rms}}}$$

In a purely (i.e., linear) sinusoidal waveform the CF is equal to square root of 2 (i.e., 1/(0.707)), or 1.414. The form factor is defined as the ratio of the rms value of a waveform to rms value of the waveform's fundamental, and can be written as

$$\text{Form factor} = \frac{I_{\text{rms}}}{I_1}$$

12.4.1.2 Types of Nonlinear Loads

Four types of nonlinear power electronic devices are increasingly being used in commercial facilities. These are fluorescent lighting, ASDs, SMPS, and uninterruptible power supplies (UPS). A brief description of voltage and current characteristics of each is detailed below.

Fluorescent lighting: Fluorescent lighting has overtaken incandescent lighting as the most popular and widely used lighting system. Light in fluorescent lamps is generated by gas discharge. The lamps require a ballast to provide proper starting and operating voltages and to limit current during lamp operation. Two types of ballasts are used with fluorescent lamps: magnetic core–coil and electronic. Both types generate harmonics. Magnetic ballasts generate third HD typically in the range of 13%–20%. In contrast, recent tests conducted by Lawrence Berkeley Laboratory show that HD generated by currently available electronic ballasts can vary from 5% to well over 33% of the fundamental current, depending on their design. In fact, some types of electronic ballasts generate less harmonic currents than magnetic ballasts. Most manufacturers are holding HD to levels well below those recommended by ANSI (THD less than 32%). In summary, the THD of electronic ballast is comparable to magnetic ballasts, electronic ballast have wide range of individual harmonic currents, and use much less power than magnetic ballasts.

Variable frequency drives (VFDs): Most VFDs contain a front-end rectifier, DC link, and an inverter, operating together with a control system. The rectifier converts the three-phase AC input to DC voltage. Depending on the type of system, a reactor, a capacitor, or a combination of these are used to smooth the DC signal. The inverter circuit uses the DC voltage to create a variable frequency AC voltage to control the speed of the AC motor. The VFDs are also referred to as ASDs or variable speed drives (VSDs). The characteristic harmonics for a VFD or ASD are based on the number of rectifiers (pulse number) in a circuit and can be determined by the following:

$$h = (n \times p) \pm 1$$

where
h is the harmonic order
n is an integer (1, 2, 3, 4, 5, 6, …)
p is the number of pulses of rectifier

For example, using the above equation, the six-pulse rectifier shown in Figure 12.11a will create characteristic harmonics of 5th, 7th, 11th, 13th, 17th, 19th, and so on. The degree and magnitude of the harmonics is function of the drive design and the interrelationship of the nonlinear load with the connected distribution system impedance. The power source line impedance ahead of the controller will determine the magnitude and amplitude of harmonic currents and voltages reflected back into the distribution system as is shown in Figure 12.11b. The distorted current reflected through the distribution impedance causes a voltage drop or harmonic voltage distortion. This relationship is proportional to the distribution system available fault current and to the distribution system impedance.

The two most commonly used AC drives are: voltage source inverter (VSI) drives and current source inverter (CSI) drives. Each is briefly described below.

VSI drives: VSI drives employ a large capacitor in the DC link to provide a relatively constant voltage to the inverter. The inverter then breaks up this DC voltage to provide the variable frequency AC voltage for the motor. Most inverter drives use pulse width modulation (PWM) techniques to improve the quality of the output voltage waveform. Typical applications of these drives are motors up to 100 hp.

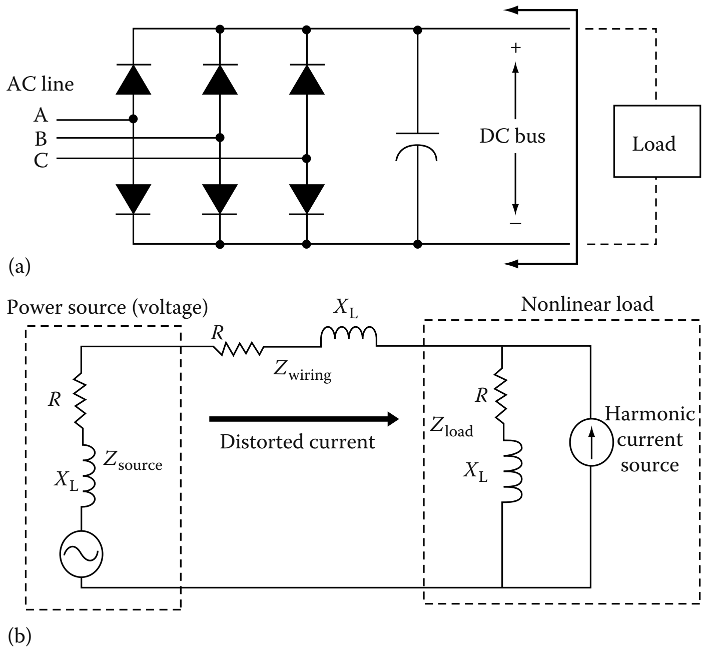


FIGURE 12.11
(a) Six-pulse front-end converter for AC drive, and (b) its equivalent circuit.

CSI drives: CSI drives are typically used for larger motor applications where custom design can be justified. The DC link consists of a large choke to keep the DC current relatively constant. The inverter then breaks up this current waveform to provide the variable frequency AC signal for the motor.

PF characteristics of VFDs also can be very important because the application of capacitors for PF correction can create special problems, including harmonic resonance and transient voltage magnification. The displacement component of the PF is associated with the angle between the voltage and the current. Without any distortion, the PF is equal to the displacement PF (DPF). Both drives have distorted current waveforms, that adds a distortion component to the PF (true PF is real power divided by total apparent power).

The distortion, and therefore the PF, can be considerably worse for VSI-type drives than for most CSI-type drives. Phase-controlled CSI drives have a very poor PF if operated with large rectifier firing delay angles. Transient voltage withstand capability is another important characteristic of VFDs. Power semiconductor switches that have a peak inverse voltage (PIV) rating of only 1200 V are used in many VFDs. On a 480 V distribution system, this PIV rating equates to 177% of normal system voltage. In most power semiconductor switch assemblies, onboard metal-oxide varistors (MOVs) are utilized for protection purposes. While the MOVs are effective for many low energy transients, they can be destroyed by magnified capacitor switching transients if not sized correctly. Drive topology and the control system characteristics also

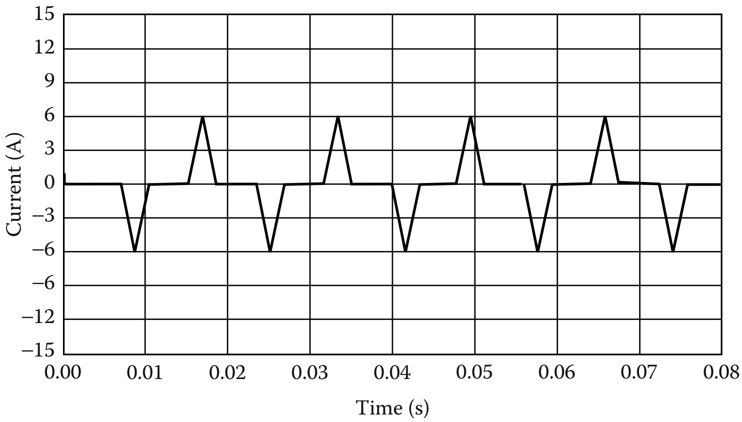


FIGURE 12.12
Current waveform of SMPS. (Courtesy of Electrotek Concepts, Inc., 9040 Excutive Park Dr., Knoxville, TN.)

affect the sensitivity of VFDs to transient disturbances. VSI-type drives require smoothing of the DC line voltage with a large capacitor for proper operation. For protection of inverter components, the DC bus voltage is monitored and the drive is tripped when it exceeds a preset level. Momentary interruptions or voltage dip on the input voltage can affect drive controls as well. This characteristic is very dependent on the specific controls involved, but it is not uncommon for voltage dips lasting only a few cycles to cause drives to trip.

SMPS: SMPS generate harmonics due to the switching action of the rectifier bridge which supplies the switching regulator. A DC capacitor provides an essentially constant DC voltage for the switching regulator. In order to maintain this DC voltage, the capacitor only needs to draw a pulse of current near the peak on each sine wave. The resulting current waveform is shown in Figure 12.12. The power relationship based on sinusoidal voltage and currents will not be valid with these waveforms. For one thing, the peak current is no longer 1.414 times the rms current. The CF (ratio of peak to rms) for this current is much higher and any meter, controls or relay which is sensitive to the peak current must take this into account. The current drawn by the SMPS contains significant harmonic components. Figure 12.13 shows that the highest harmonic component is the third.

Harmonic components in this current also have a dramatic effect on the PF of the load. Although the 60 Hz component of the current (fundamental) is in phase with the voltage (DPF close to unity), the harmonic components reduce the true PF and indirectly reduce the real power available.

12.4.1.3 PF Characteristics of Loads

PF is defined as the ratio of real power divided by the apparent (total) power, i.e., watts divided by volt-amps (VA). Resistive loads produce unity PF, however,

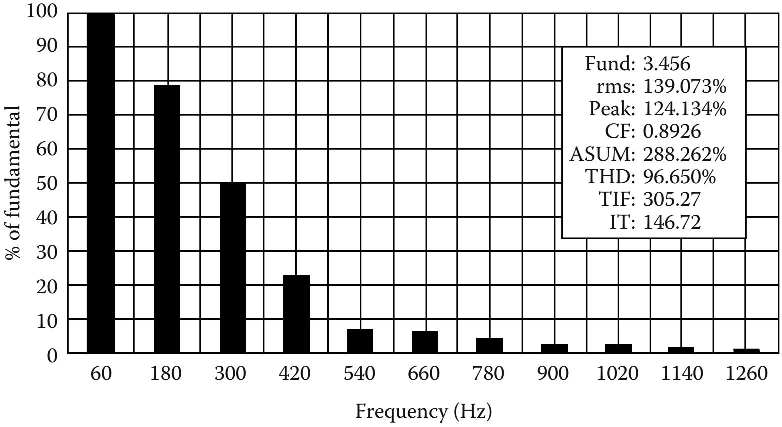


FIGURE 12.13
Harmonic current of SMPS. (Courtesy of Electrotek Concepts, Inc., 9040 Excutive Park Dr., Knoxville, TN.)

all reactive (inductive and capacitive) loads produce nonunity (i.e., less than 1.0) PF. The PF for the linear and nonlinear loads is given by the following expressions:

1. *Linear loads*

$$\mathrm{PF}_{\text{Displacement}} = \frac{\mathrm{kW}_{60\,\mathrm{Hz}}}{\mathrm{kVA}_{60\,\mathrm{Hz}}} = \cos\theta$$

where

$$\mathrm{kVA}_{60\,\mathrm{Hz}} = \left[\mathrm{kW}_{60}^2 + \mathrm{kVAR}_{60}^2\right]^{1/2}$$

2. *Nonlinear loads*

$$\mathrm{PF}_{\text{True}} = \frac{\mathrm{kW}_{60\,\mathrm{Hz}}}{\mathrm{kVA}_{\mathrm{rms}}} \neq \cos\theta \quad \text{(i.e., the true power factor is not equal to } \cos\theta)$$

where

$$\mathrm{kVA}_{\mathrm{rms}} = \left[\left(\mathrm{kW}_{60}^2 + \mathrm{kW}_{\mathrm{har}}^2\right) + \left(\mathrm{kVAR}_{60}^2 + \mathrm{kVAR}_{\mathrm{har}}^2\right)\right]^{1/2}$$

Uncorrected electronic power supplies exhibit very poor true PF and high harmonics which generate heat in the phase and neutral wires of the electrical power distribution system, especially where single-phase 120 V power is supplied from a 208/120 V three-phase wiring system. The PF defines how efficiently a load utilizes the current that it draws from an AC power system. The PF can also be expressed in terms distortion factor to give an assessment of the efficiency of the load utilization in the presence of harmonics. Therefore for a sinusoidal circuit (i.e., no harmonics), we can write voltage and current equations at the load as the following;

$$V(t) = V_1 \sin(\omega_1 t + \delta_1)$$

and

$$I(t) = I_1 \sin(\omega_1 t + \theta_1)$$

where
 V_1 and I_1 are peak values of the 60 Hz voltage and current
 δ_1 and θ_1 are the relative phase angles

The true PF at the load is defined as the ratio of the average power to apparent power, or

$$\mathrm{PF}_{\mathrm{True}} = \frac{P_{\mathrm{avg}}}{S} = \frac{P_{\mathrm{avg}}}{V_{\mathrm{rms}} I_{\mathrm{rms}}}$$

For a purely sinusoidal case, the above equation can be written as;

$$\mathrm{PF}_{\mathrm{True}} = \mathrm{P^F}_{\mathrm{Disp}} = \frac{P_{\mathrm{avg}}}{\sqrt{P^2 + Q^2}} = \frac{\left(V_1/\sqrt{2}\right)\left(I_1/\sqrt{2}\right)}{\left(V_1/\sqrt{2}\right)\left(I_1/\sqrt{2}\right)} \cos(\delta_1 - \theta_1) = \cos(\delta_1 - \theta_1)$$

where $\mathrm{PF}_{\mathrm{Disp}}$ is commonly known as the DPF, and $(\delta_1 - \theta_1)$ is known as the PF angle. Therefore in a purely sinusoidal situation, there is only one PF because true PF and DPF are equal. However, this is not true in the case of nonsinusoidal situations because voltages and currents contain harmonics. The average power for a nonsinusoidal situation can be represented by including the significant harmonics such as the third, fifth, seventh, and so on. We can then write the equation as:

$$P_{\mathrm{avg}} \sum_{h=1}^{\infty} V_{\mathrm{hrms}} I_{\mathrm{hrms}} \cos(\delta_{\mathrm{h}} - \theta_{\mathrm{h}}) = P_{\mathrm{lavg}} + P_{\mathrm{2avg}} + P_{\mathrm{3avg}}$$

where, each harmonic makes a contribution to the average power. Also, the rms value of the voltage and current can be expressed as following:

$$V_{\mathrm{rms}} = \sqrt{\sum_{h=1}^{\infty} \frac{V_h^2}{2}} = \sqrt{\sum_{h=1}^{\infty} V_{h\mathrm{rms}}^2}$$

$$I_{\mathrm{rms}} = \sqrt{\sum_{h=1}^{\infty} \frac{I_h^2}{2}} = \sqrt{\sum_{h=1}^{\infty} I_{h\mathrm{rms}}^2}$$

The above equations can be written in terms of the distortion factor (i.e., THD) as

$$V_{\text{rms}} = V_{1\text{rms}}\sqrt{1+(THD_V/100)^2}$$
$$I_{\text{rms}} = I_{1\text{rms}}\sqrt{1+(\text{THD}_I/100)^2}$$

We can now substitute the above equations in the original equation for true PF at the load.

$$\text{PF}_{\text{True}} = \frac{P_{\text{avg}}}{S} = \frac{P_{\text{avg}}}{V_{\text{rms}}I_{\text{rms}}}$$

$$\text{PF}_{\text{True}} = \frac{P_{\text{avg}}}{V_{1\text{rms}}I_{1\text{rms}}\sqrt{1+(\text{THD}_V/100)^2}\sqrt{1+(\text{THD}_I/100)^2}}$$

The above equation can be expressed as a product of two components as the following:

$$\text{PF}_{\text{True}} = \frac{P_{\text{avg}}}{V_{1\text{rms}}I_{1\text{rms}}} \times \frac{1}{\sqrt{1+(\text{THD}_V/100)^2}\sqrt{1+(\text{THD}_I/100)^2}}$$

Also, by assuming that P_{avg} is approximately equal to $P_{1\text{avg}}$ and since usually THD_V is less than 10%, $V_{\text{rms}} = V_{1\text{rms}}$. By incorporating these two assumptions in the above equation, it then can be written as

$$\text{PF}_{\text{True}} \approx \frac{P_{\text{avg}I}}{V_{1\text{rms}}I_{1\text{rms}}} \times \frac{1}{\sqrt{1+(\text{THD}_I/100)^2}} = \text{PF}_{\text{Disp}} \cdot \text{PF}_{\text{Dist}}$$

where PF_{Dist} is the distortion PF.

Because DPF (PF_{Disp}) can never be greater than unity, the above equation shows that the true PF in a nonsinusoidal situations has the upper bound given by the following equation:

$$\text{PF}_{\text{True}} \le \text{PF}_{\text{Dist}} = \frac{1}{\sqrt{1+(\text{THD}_I/100)^2}}$$

The above equation provides insights into the nature of the true PF of electronic (nonlinear) loads, especially single-phase loads. It appears from the above equation that higher the HD, lower is the true PF even though the DPF can be very high. The displacement and true PF relationships are shown in Figure 12.14.

The true PF is calculated for a nonlinear load with distortion (THD_I %) as shown below:

THD_I (%)	Maximum True PF
10	0.99
15	0.989
20	0.98
30	0.96
50	0.89
70	0.82
100	0.71

The true PFs calculated above represent maximum true PFs for nonlinear loads. Actual true PF is the product of maximum true PF and DPF, and the product can be significantly lower than DPF. The PF comparison shown above gives an optimistic picture because harmonic currents actually cause more losses per ampere than do fundamental currents.

12.4.1.4 Phase Sequence of Harmonics

In a balanced three-phase power system, the voltages and currents in phases a–b–c are shifted in time by ±120° of fundamental. Taking a-phase as a reference, we can write an equation for a-phase current as

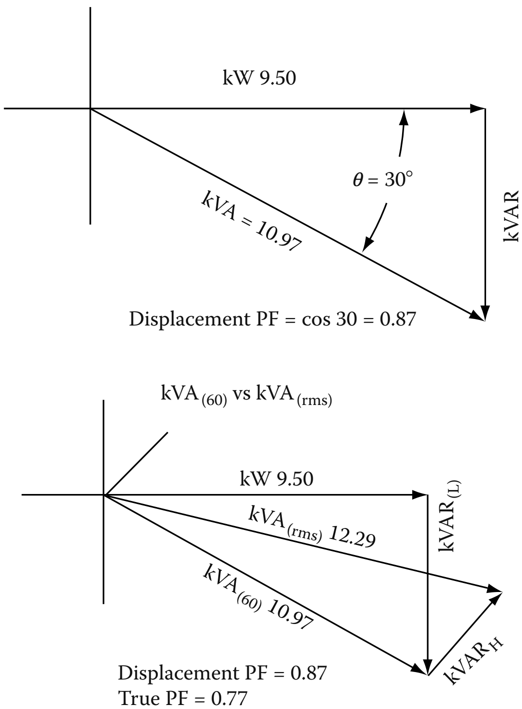


FIGURE 12.14
DPF versus true PF.

$$i_a(t) = \sum_{h=1}^{\infty} I_h \sin(h\omega_1 t + \theta_h)$$

then the currents in phases b and c lag and lead by ($2\pi/3$) rad (120°), respectively. Thus the current in the b and c is as follows:

$$i_b(t) = \sum_{h=1}^{\infty} I_h \sin\left(h\omega_1 t + \theta_h - h\frac{2\pi}{3}\right)$$

$$i_c(t) = \sum_{h=1}^{\infty} I_h \sin\left(h\omega_1 t + \theta_h + h\frac{2\pi}{3}\right)$$

Also, similar equations can be written for phase voltages which are shown in Figure 12.15 with b-phase voltage lagging a-phase voltage by 120° and c-phase voltage leading a-phase voltage by 120° (or lagging by 240°).

When the above equations are expanded to include the first three harmonics, we see an important pattern. Thus the above equations for a–b–c phases are

$$i_a(t) = I_1 \sin(1\omega_1 t + \theta_1) + I_2 \sin(2\omega_1 t + \theta_2) + I_3 \sin(3\omega_1 t + \theta_3)$$

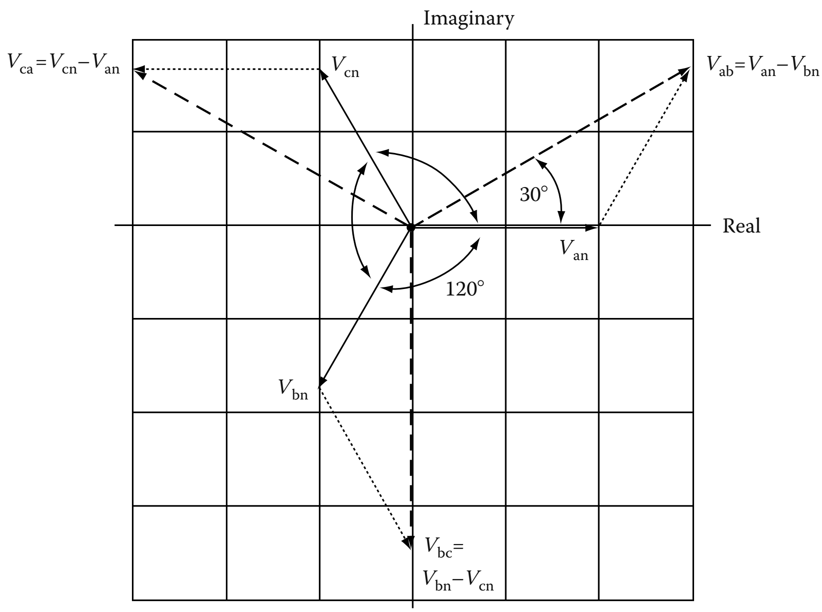


FIGURE 12.15
Voltage phasors in a balanced three-phase system (phase sequence abc).

$$
\begin{aligned}
i_b(t) &= I_1 \sin\left(1\omega_1 t + \theta_1 - \frac{2\pi}{3}\right) + I_2 \sin\left(2\omega_1 t + \theta_2 - \frac{4\pi}{3}\right) \\
&\quad + I_3 \sin\left(3\omega_1 t + \theta_3 - \frac{6\pi}{3}\right) \quad \text{or} \\
&= I_1 \sin\left(1\omega_1 t + \theta_1 - \frac{2\pi}{3}\right) + I_2 \sin\left(2\omega_1 t + \theta_2 + \frac{2\pi}{3}\right) \\
&\quad + I_3 \sin(3\omega_1 t + \theta_3 + 0)
\end{aligned}
$$

$$
\begin{aligned}
I_c(t) &= I_1 \sin\left(1\omega_1 t + \theta_1 + \frac{2\pi}{3}\right) + I_2 \sin\left(2\omega_1 t + \theta_2 + \frac{4\pi}{3}\right) \\
&\quad + I_3 \sin\left(3\omega_1 t + \theta_3 + \frac{6\pi}{3}\right) \quad \text{or} \\
&= I_1 \sin\left(1\omega_1 t + \theta_1 + \frac{2\pi}{3}\right) + I_2 \sin\left(2\omega_1 t + \theta_2 - \frac{2\pi}{3}\right) \\
&\quad + I_3 \sin(3\omega_1 t + \theta_3 - 0)
\end{aligned}
$$

By examining the above current equations, we see that

- The first harmonic (i.e., the fundamental) is positive sequence (a–b–c) because phase b lags phase a by 120°, and phase c leads phase a by 120° (or lags phase a by 240°)
- The second harmonic is negative sequence (a–c–b) because phase b leads phase a by 120°, and phase c lags phase a by 120°
- The third harmonic is zero sequence because all three phases have the same phase angle

The pattern for a balanced system repeats and is shown below as "Phase sequence of harmonics in three-phase balanced system."

Harmonic	Phase sequence
1	+
2	–
3	0
4	+
5	–
6	0
...	...

If a system is not balanced, then each harmonic can have positive, negative, and zero sequence components. However, in most cases, the pattern shown above can be assumed to be valid.

Because of Kirchhoff's current law, zero sequence currents cannot flow into a three-wire connection such as a delta transformer winding or a delta-connected load. In most cases, systems are fairly well balanced, so that it is common to make the same assumption for third harmonics and other triplens. Thus, a delta-grounded wye transformer at the service point of an industrial facility usually blocks the flow of triplen harmonic load currents into the power system. Unfortunately, the transformer does nothing to block the flow of any other harmonics, such as fifth, seventh, and so on. Zero sequence currents flow through neutral or grounding paths. Positive and negative sequence currents sum to zero at neutral and grounding points. Another interesting observation can be made about zero sequence harmonics. Line-to-line voltages never have zero sequence components because, according to Kirchhoff's voltage law, they always sum to zero. For that reason, line-to-line voltages in commercial buildings are missing the third harmonic that dominates L–N voltage waveforms. Thus, the V THD of line-to-line voltages is often considerably less than for L–N voltages.

12.4.1.5 Harmonic Generating Characteristics

In the past, harmonic currents originated primarily from a few major sources, such as arc welders, fluorescent ballasts and lights, arc furnaces, etc. As explained previously, significant harmonics are being generated by today's load equipment such as switching power supplies, solid-state controls, and other sensitive electronic equipment. The harmonics in these nonlinear loads cause voltage distortion, poor PF, and stress on supply power system equipment. Harmonics from nonsinusoidal loads interact with electrical distribution system impedance, creating heat in electrical distribution equipment. Harmonic voltage distortion limits peak applied voltage and may increase susceptibility to momentary voltage dropouts.

12.4.1.6 Sensitivity to Harmonics

Most electronic equipment is affected by harmonics because high levels of harmonic currents cause problems in the power system that is not designed for nonlinear loads. The problems are:

- Overloading of the phase and neutral conductors of the power distribution system
- Overheating of the distribution transformers, where high-frequency currents can cause higher losses from eddy currents, magnetic hysteresis, and skin effect
- Overloading of power sources such as UPS systems and emergency generators including generator controls
- Poor utilization of available power from the branch circuits because of low PF

- Premature failure of PF correction capacitors because of overheating by harmonic currents
- Flat-topping of the voltage waveform caused by high-peak currents which reduce the ride-through capability of the electronic equipment

12.4.1.7 Sensitivity to Voltage Variation

All electronic equipment is generally sensitive to supply voltage variations. For example, computer systems can experience performance problems if the following voltage thresholds are exceeded: sags greater than −20% rms, spikes greater than 100% peak, and swells greater than +10% rms. When assessing the impact of voltage variation on electronic equipment, it is helpful to know the related voltage waveforms, that is whether they are swell, sag, impulse, or electrical noise. The effects of power line voltage variation, resulting from a utility's power system disturbances or interaction of the load and its power source, may appear in many forms. Sensitive electronic equipment may cease to operate, errors may occur in processing and data transfer, or hardware damage may occur.

12.4.1.8 Sensitivity to Voltage Flicker

Voltage changes which are cyclical in nature (occur in the range of 0.5–30 Hz) are commonly referred to as voltage flicker. Voltage flicker can be caused by: repetitive motor starting, punch presses, large reciprocating compressors, resistance welders, and arc furnaces. Voltage flicker can affect the sensitive electronic load equipment, especially if it happens near peak voltage when the DC power supply usually draws AC line current.

12.4.1.9 Sensitivity to Noise

All power lines, motors, generators, and other current handling devices radiate magnetic fields of varying strengths (electric noise). In addition to the above sources of electrical noise, fault produced transients, surges, and ground potential rises also produce unwanted magnetic fields. The generated and radiated magnetic fields couple across to other cables (both power and communications) and affect sensitive electronic equipment. The level of electrical noise that is considered acceptable depends on the signal level and accuracy requirements of the load equipment. Separation of the electrical noise sources and load signal cables, proper grounding, and proper cable configuration are some of the techniques for reducing noise.

12.5 Effects of Harmonic on Power System Equipment and Loads

The HD of concern here is the nonfundamental periodic voltage resulting from the steady state operation of nonlinear elements connected to the power distribution system. This periodic voltage often, but not always, consists of harmonics of the power system fundamental frequency. The effect of voltage distortion may be divided into three general categories: (1) insulation stress due to voltage effects, (2) thermal stress due to current flow, and (3) load disruption. Load disruption is defined as objectionable abnormal operation or failure caused by voltage distortion. While this definition is general enough to include such items as torques generated in electromechanical devices, load disruptions appear to b e limited to the various types of solid-state loads. In this section we offer a discussion on general concepts involved in evaluating the effects of harmonics on power apparatus, to provide quantitative analysis of the effects and to identify potential problems.

12.5.1 Basic Concepts on Effects of Harmonics

A distorted periodic voltage or current waveform can be expanded into a Fourier series to give the harmonic terms by the following equations:

$$V(t) = V_1 \cos(\omega t + \delta_1) + V_2 \cos(2\omega t + \delta_2) + V_3 \cos(3\omega t + \delta_3) + \cdots$$

$$I(t) = I_1 \cos(\omega t + \theta_1) + I_2 \cos(2\omega t + \theta_2) + I_3 \cos(3\omega t + \theta_3) + \cdots$$

where

- V_1 and I_1 are voltage and current peak values of the fundamental
- V_h and I_h, $h = 2, 3, 4, \ldots$ are voltage and current peak values of the hth harmonic
- δ_h and θ_h are the relative phase angles of the hth harmonic

The current distortion factor (CDF) or the THD_I was discussed in Section 12.4 and is repeated here again as follows:

$$\mathrm{CDF} = \mathrm{THD}_I = \frac{\sqrt{\sum_{h=2}^{\infty} (I_h)^2}}{I_1}$$

similarly the voltage distortion factor can be written as

$$\mathrm{VDF} = \mathrm{THD}_V = \frac{\sqrt{\sum_{h=2}^{\infty} (V_h)^2}}{V_1}$$

Harmonics also generate telephone interference through inductive coupling. The telephone interference is defined as telephone influence factor (TIF) which is expressed as follows:

$$\mathrm{TIF} = \frac{\sqrt{\sum_{h=2}^{\infty}(w_h I_h)^2}}{I_1}$$

where w_h is a weight factor for audio and inductive coupling effects at the hth harmonic.

The rms value of the voltage distortion does not provide peak voltage levels which are needed to assess the effects HD on insulation. A more meaningful measure for assessing HD on insulation is magnitude factor (MF), which is given by the following equation:

$$\mathrm{MF} = \frac{\sum_{h=2}^{\infty} V_h}{V_1}$$

The distortion factors, current, voltage (rms and peak), and telephone influence are utilized to describe the quantitative effect of the harmonics on electric loads and other apparatus. For example, the CFD is useful in quantifying the copper losses in a constant resistance load, the TIF to quantify telephone interference, MF in assessing dielectric stress, etc. In general, the diversity of the effects of harmonics makes it extremely unlikely that any one measure of voltage distortion will adequately describe all effects. A better approach is to identify the sensitivities of apparatus performance to distortion factors, and thereby, identify the relative usefulness of these parameters. The effects of harmonics on thermal stress, insulation stress, and load disruption are discussed as follows.

12.5.1.1 Thermal Stress

In general, the presence of harmonic current increases the losses and thus the thermal stress of the equipment. The losses are copper losses, iron losses, and dielectric losses. In a given power equipment, one or more of above losses may determine the thermal stress of the device. These losses can be computed as follows:

Copper losses: The copper losses (P_C) can be computed with the following general formula

$$P_C = \frac{1}{2}\left[\sum_{h}^{\infty} R_h I_h^2\right]$$

where I_h is the peak value of the hth harmonic current, R_h is the resistance of the apparatus at the hth harmonic.

In cases where resistance of the apparatus is constant (independent of frequency), the copper losses can be written in terms of the CDF as follows;

$$P_C = \frac{1}{2}R\left[\sum_{h}^{\infty} I_h^2\right] = \frac{1}{2}RI_1^2\left(1 + (\mathrm{CDF})^2\right)$$

As shown in the equation above, the CFD determines the increase of copper losses due to the presence of harmonics. In general, however, the resistance of power apparatus increases with frequency because of the skin effect. The impact of skin effect on harmonic losses becomes more important in large diameter conductors and deep bar induction motors.

Iron losses: Iron losses are made up of (1) hysteresis loss and (2) eddy current loss. These losses are given by the following formulas:

Hysteresis loss (P_h) is a function of magnetic material used and frequency of the current. For a given magnetic core, the hysteresis loss is equal to

$$P_\mathrm{h} = a_\mathrm{h} f B_\mathrm{m}^{v}$$

where
  a_h is a constant dependent on core dimensions
  f is the frequency of electric current
  B_m is the maximum value of the magnetic flux density
  v is an exponent dependent on the core material (for commonly used materials, v = 1.5–2.5)

Eddy current loss (P_e) depends on core material (resistivity of core), thickness of lamination, frequency of electric currents, and magnetic flux density. For a given magnetic circuit the eddy current losses are given by

$$P_\mathrm{e} = a_\mathrm{e} f^2 B_\mathrm{m}^2$$

where
  a_e is a constant dependent on material and thickness of lamination
  f is the frequency of electric current
  B_m is the maximum value of the magnetic flux density

The total losses are given by the sum of hysteresis and eddy current losses, therefore

$$P_{\mathrm{iron\,loss}} = a_{(\mathrm{h})} f B_\mathrm{m}^{v} + a_\mathrm{e} f^2 B_\mathrm{m}^2$$

The total iron loss is a nonlinear function of frequency and maximum magnetic flux density. For a given voltage harmonic, the frequency is known and the maximum magnetic flux density is proportional to the harmonic current. The constant of proportionality depends on coil and magnetic core design. The equation for iron loss is valid for a sinusoidal excitation of the power apparatus of frequency *f*. In case the excitation source is polluted with harmonics, one can cautiously use the equation for iron loss to compute the iron loss for each harmonic and add the contributions. This procedure (superposition) is correct only for linear apparatus. Because of magnetic saturation and magnetic hysteresis, magnetic circuits are not exactly linear systems. However, for normally encountered operating conditions and level of harmonics, superposition can be used as a reasonable approximation.

Dielectric losses: The dielectric losses are applicable to cables and capacitors and at a given harmonic, *h*, are given by the following equation

$$P_e = (1/2)(\tan\delta)_h V_h^2 h\omega C$$

where
ω is the fundamental angular frequency
V_h is the peak value of the *h*th harmonic voltage
C is the capacitance of the apparatus
$(\tan \delta)_h$ is the dielectric loss factor at the *h*th harmonic

12.5.1.2 Insulation Stress

Insulation stress primarily depends on instantaneous voltage magnitude and voltage rate of increase secondarily. The presence of voltage harmonics can result in an increase of the crest value of the voltage and thus increased insulation stress. This increase is not of concern for most power system apparatus because they are insulated for much higher voltage levels than those usually encountered from harmonics. Capacitor banks, however, are very sensitive to overvoltages and must be protected against overvoltages resulting from harmonics. A special discussion is provided later in this section. The voltage rate of increase is important in switchgear and it is discussed in this section also. An area of possible concern is the effect of voltage distortion on surge protective devices, including the sparkover and recovery of gapped surge arresters.

12.5.1.3 Load Disruption

Load disruption is defined as objectionable abnormal operation or failure caused by voltage distortion. Many electronic equipment are susceptible to load disruption because their normal operation depends on the existence of a sinusoidal voltage source. The effects of the harmonics on electronic equipment are discussed later in this section. Load disruption also includes decreases of useful magnetic electromagnetic torque in electric machinery because of the presence of harmonics. Specifically, current harmonics circulating in the armature of electric machinery may generate pulsating or constant electromagnetic torques. Pulsating torques result in equipment wear and shortening of equipment life. Constant torques, in most cases, reduce the useful electromagnetic torque and, result in reduced efficiency.

12.5.2 Harmonic Effects on Power System Equipment

12.5.2.1 Transformers

The effects of harmonics on transformers are

- Increased copper losses
- Increased iron losses
- Possibly resonance between transformers
- windings and line capacitance
- Insulation stress
- Neutral overheating due to triplen harmonics

The copper losses and iron losses in the presence of harmonics can be computed with the general equations presented in Section 12.5.1.1. The application of general equations given in Section 12.5.1.1 assumes that the transformer is a linear device which it is not. However, for normal, operating conditions and normal levels of harmonics, this is a reasonable approximation. Similarly, an approximate expression for total hysteresis losses can be determined by using the equations given in Section 12.5.1.1. However, the increase of hysteresis losses due to harmonics is only a fraction of the eddy current losses.

Voltage harmonics result in higher transformer voltage, therefore higher insulation stress. This is not a problem since most transformers are insulated for much higher voltage levels than the overvoltages due to usual levels of harmonics. There is a certain degree of interaction between voltage and current harmonics for transformers designed to operate near the saturation point (knee of the saturation curve). It is possible a small level of voltage harmonic to generate a high level of current harmonics. This phenomenon depends on specific harmonic and phase relationship to the fundamental. To address the overheating of transformers due to harmonics, the ANSI/IEEE published a standard C57.110-1998, "Recommended practice for establishing transformer capability when supplying nonsinusoidal load currents," which was reaffirmed in 2004. This standard establishes methods for determining derating factors for transformer capability to carry nonsinusoidal load currents.

In 1990, Underwriters Laboratory (UL) established the method for testing transformers that serve nonlinear loads. The UL test addresses coil heating due to nonlinear loads and overheating of the neutral conductor by assigning a "K" factor to the transformer. The *K*-factor is meant to apply to transformers serving general nonlinear loads. UL has devised the *K*-factor method for labeling and rating the ability of dry-type transformers to withstand the effects of harmonics. The *K*-factor rating indicates the transformer′s ability to tolerate the additional heating caused by harmonics. The *K*-factor is based on the methodology similar to that discussed in the ANSI/IEEE C57.110 standard. The *K*-factor can be calculated as the sum of the product of each harmonic current squared and that harmonic number squared for all harmonics from the fundamental to the highest harmonic of consequence. When *K*-factor is multiplied by the stray losses of the transformer, the result represents the total stray losses in the transformer caused by harmonic currents. To obtain the total load losses, the total stray losses are then added to the load losses. It should be obvious that the *K*-factor for linear loads (absence of harmonics) is 1. Also, the *K*-factor does not mean that the transformer can eliminate harmonics. Harmonics increase heating losses in all transformers, and some of these losses are deep within the core and windings and some are closer to the surface. Oil-filled transformers react differently to the increased heat and are better able to cool whereas dry-type transformers are more susceptible to the harmonic current effects and are so labeled. The UL test addresses coil heating due to nonlinear loads and overheating of the neutral conductor.

There are two methods for calculating *K*-factor. They are UL method and normalized method. The UL method, based on the transformer's rated rms current, is generally used when rms current is measured. The UL method is defined as follows:

$$K = \sum_{h=1}^{\infty} I_{h(\mathrm{PU})}^{2} h^{2}$$

where

h is the harmonic order

$I_{h(\mathrm{PU})}$ is the rms current of the harmonic expressed as a per unit of the rated rms transformer current

The normalized method is based on the load's fundamental current. Harmonic measurements are often taken with a harmonic analyzer. A majority of harmonic analyzers output data is in per unit values related to the fundamental current. Therefore, the normalized method is applicable. The normalized method is defined as follows:

$$K = \sum_{h=1}^{\infty} f_h^2 h^2$$

where f_h is the fundamental current in per unit (the first harmonic = 100%) An example of the two methods for the same harmonic spectrum of data is given in Tables 12.2 and 12.3.

The *K*-factor rating of dry-type transformers is available from 1 through 50. However, for majority of application rating of 20 or less should suffice. Table 12.4 lists the available *K*-factor rated transformers.

TABLE 12.2

Calculation of *K*-Factor per UL Method

Harmonic	I_h (PU) (Measured)	I_h (PU)^2	h^2	I_h (PU)^2 h^2
1	0.72	0.52	1	0.52
3	0.52	0.27	9	2.43
5	0.31	0.10	25	2.40
7	0.25	0.06	49	3.06
9	0.15	0.02	81	1.82
11	0.07	0.00	121	0.59
13	0.05	0.00	169	0.42
			K-factor =	11.24

TABLE 12.3

Calculation of *K*-Factor per Normalized Method

Harmonic	f_h (PU)	f_h (PU)^2	h^2	f_h (PU)^2 h^2
1	1.00	1.00	1	1.00
3	0.72	0.52	9	4.69
5	0.43	0.19	25	4.63
7	0.35	0.12	49	5.91
9	0.21	0.04	81	3.52
11	0.10	0.01	121	1.14
13	0.07	0.00	169	0.82
		1.88		21.71
		K-factor =	21.71/1.88 =	11.54

TABLE 12.4

K-Factor Rating of Dry-Type Transformers

K-Factor	Comments and Typical Applications
1	Normal transformer for sinusoidal load applications with a harmonic factor less than 0.05
4	Welders and induction heaters, high intensity discharge (HID) and fluorescent lighting, solid-state controls
9	Not readily available or usually specified
13	Telecommunications equipment, classrooms and health care facilities
20	Data processing equipment, ASD
30	Extended range
40	Extended range
50	Extended range

The basic sources of data for computing *K*-factor are from measurements or estimates. Exercise care in measuring loads so the data is accurate and simulates the transformer at full load. When estimating loads, the computed *K*-factor is usually overly conservative (large) as it does not take into account potential harmonic phase cancellations. To address this, UL has specified that the rms current of any single harmonic greater than the 10th be considered as no greater than $1/h$ of the fundamental rms current. This attempts to compensate for otherwise conservative computed impacts of higher frequencies. Equipment manufacturers can be a source of data for nonlinear loads. As *K*-factor increases, the transformer becomes larger and its impedance decreases markedly. Lower source impedance can result in higher distortion, which can aggravate a problem instead of solving it.

Another problem that occurs with transformers is the overheating of the neutral in a three-phase four-wire power distribution system. When single-phase nonlinear loads are connected to the secondary of a wye–delta transformer, such as is found in many industrial and commercial applications, the triplen harmonics (third, ninth, and so on) algebraically add up in the neutral of the secondary of the transformer. These currents are often in excess of the phase currents and therefore cause overheating of the neutral conductor, components, bus bars, etc. Also these currents are reflected back into the delta primary windings where they circulate and cause the transformer to overheat or fail.

12.5.2.2 Rotating Machines

The effects of harmonics in rotating machinery are increased heating due to copper and iron losses, changes in electromagnetic torque which affect, machine efficiency and machine torsional oscillations. The level and importance of these effects depend on electric machine design and harmonic source type. Electric machines can be classified as synchronous machines (three-phase), three-phase induction machines and single-phase induction motors. On the other hand, the source of harmonics for three-phase systems may be a balanced three-phase source or may be a single-phase source injecting harmonics in one phase only. The latter case can be analyzed with the use of symmetrical components which is applicable to each one harmonic. Thus for three-phase electric machinery only the effects of balanced three-phase harmonic excitation need to be examined. The effects of single-phase harmonic excitation can be deduced from the former. A good understanding of the effects of harmonics on rotating machinery requires a good understanding of the electromagnetic fields inside the machines due to harmonic currents. Because of the complex construction of rotating machinery, the frequency of the magnetic flux may not coincide with the frequency of the armature currents. In addition, at a given harmonic, the frequency of the magnetic flux in the rotor is different of the frequency in the stator. The below listed observations can be used for analyzing the effects of harmonics on rotating machines.

1. The zero sequence harmonics ($h = 3, 6, 9, 12, \ldots$) do not produce a net magnetic flux density. Thus the only effect they produce is ohmic losses.
2. The positive sequence harmonics ($h = 1, 4, 7, 10, 13, \ldots$) produce a rotating magnetic flux which rotates with speed $h\omega$ in the positive direction and magnitude proportional to the harmonic current. The relative speed of the rotating magnetic field with respect to the rotor is $(h - 1)\omega$ [or $(h - 1 + S)\omega$ for induction machines, S = slip]. Because of induction motor action, an electromagnetic torque will be developed in the direction of rotation. The frequency of the alternating magnetic flux is $60h$ in the stator and $60(h - 1)$ in the rotor. These frequencies determine the iron losses which occur partly in the stator and partly in the rotor.
3. The negative sequence harmonics ($h = 2, 5, 8, 11, \ldots$) produce a rotating magnetic flux which rotates with speed $-h\omega$ (opposite to the direction of rotation) and magnitude proportional to the harmonic current. The relative speed of the rotating magnetic field with respect to the rotor is $-(h + 1)\omega$ [(or $-(h + 1 - S)\omega$ for an induction machine, S = slip)]. Because of induction motor action, an electromagnetic torque will be developed in a direction opposite to that of rotation. The frequency of the alternating magnetic flux is $60h$ in the stator and $60(h + 1)$ in the rotor.

The performance of an induction motor, operating from a supply voltage rich in harmonics, deteriorates because the presence of negative sequence harmonics generates opposing torque and the presence of any harmonic increases copper and iron losses. These effects result in a net derating of the motor.

Another effect results from the interaction of the magnetic field generated by a harmonic and the fundamental magnetic field. Consider, for example, the seventh harmonic in a synchronous, machine. The seventh harmonic magnetic field rotates, relatively to the rotor field, with a speed $(h - 1)\omega$. The interaction of the two fields will produce a pulsating torque of frequency $60(h - 1) = 360$ Hz. In the same way, the fifth harmonic will generate a pulsating torque of frequency $60(h + 1) = 360$ Hz. Thus pairs of harmonics generate pulsating torques of frequency 180, 360, 540 Hz, etc. In a typical system, the 360 Hz pulsating torque is substantial and results in oscillations of the machine shaft. It is possible that the natural frequency of the machine is in the vicinity of this frequency. In this case, the fifth and seventh harmonics may excite a super synchronous resonance condition which involves torsional oscillations of the rotor elements. Supersynchronous resonance occurs when the frequency of a mode of mechanical vibration exists close to the frequency of electrical stimulus. In this case, high resonant mechanical oscillations may be developed which could result in fatigue of the shafts.

The pulsating torques, due to the presence of harmonics, also result in higher noise emission as compared with pure sinusoidal excitation.

The ANSI standards C50.13-2005, *American National Standard Requirements for Cylindrical-Rotor Synchronous Generators*, defines a limit on the negative sequence current (60 Hz) for generators operating continuously at rated kVA and maximum current not exceeding 105% (of rated) in any phase.

12.5.2.3 Capacitor Banks

Capacitor impedance decreases with frequency. For this reason, capacitor banks act as sinks of harmonics. In a system with distributed harmonic sources, the harmonics will converge to the capacitor bank. As a result most harmonic problems show up first at shunt capacitor banks. Severe harmonic problems at capacitor banks manifest themselves with (1) fuses blowing and (2) capacitor canister (can) failure. The presence of harmonics at capacitor banks can cause:

- Increased dielectric losses and thus heating
- Resonance conditions resulting in magnification of harmonics
- Overvoltages

Distribution line capacitor banks: Distribution capacitor banks can form a resonant circuit with the inductance of distribution lines at a frequency near the harmonics of interest. In this case, the harmonics may be amplified at the capacitor location. Consider, for example, a portion of an overhead distribution circuit represented for simplicity with an R, L circuit, a capacitor bank, and a source of harmonics as in Figure 12.16.

The harmonic voltage, V_c, at the capacitor bank is given by the equation:

$$V_c = V\frac{1}{1-\omega^2 LC + j\omega C}$$

where

V is the applied harmonic voltage

R, L is the equivalent circuit representation of the distribution line

C is the capacitance of the capacitor bank

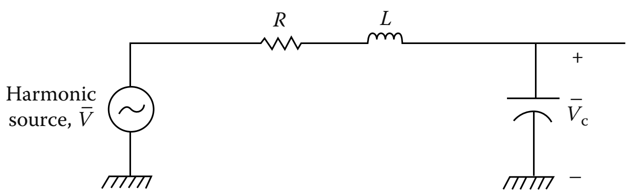


FIGURE 12.16
Equivalent circuit of a distribution line and a capacitor.

The resonance frequency is given by the equation

$$f_0 = \frac{1}{\sqrt{2\pi LC}}$$

and can coincide with a harmonic frequency.

At this frequency, the voltage V_c is given by the equation

$$V_c = V \frac{1}{j\omega RC}$$

Today computer programs are available to predict these resonance conditions and the harmonic frequency can be predicted with which the capacitor will resonate. Therefore, this effect can be mitigated by installing a correct filter to shunt the harmonic currents thereby avoiding the resonance condition.

PF correction capacitor banks: Every power capacitor installation is in parallel with the inductance of the power system, and this combination is in resonance at some frequency. If this frequency is at one of the static power converters characteristic harmonics, the current of that harmonic can excite the resonant circuit and cause an oscillating current to be exchanged between the two energy storage elements. These high harmonic currents can produce high harmonic voltages which in turn can force harmonic currents to flow in adjacent circuits. This diversity of conditions makes it hard to determine if all parameters are going to be present to cause problems. This happens enough times to make system designers nervous when the combination of static power converters and power factor capacitors occurs on the same power system (see Figure 12.17).

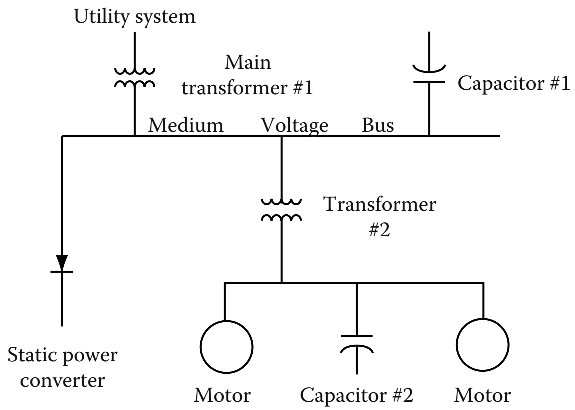


FIGURE 12.17
Power distribution system with static power converters and power factor capacitors.

Criteria for trouble: There are some quick rules of thumb that might be used to determine if there might be a problem. The first is the resonant value of the combination of the system impedance and the capacitor bank size:

$$f_{\mathrm{p}} = \sqrt{\frac{\text{SC MVA}}{\text{CAP MVAR}}} = \sqrt{\frac{X_{\mathrm{c}}}{X_{\mathrm{sc}}}}$$

where
f_{p} is the per unit parallel resonant frequency
X_{c} is the capacitor bank reactance (per unit or ohms)
X_{sc} is the system reactance (per unit or ohms)

A second rule of thumb involves the size of the static power converter with respect to the size of the electrical system feeding the converter. The term short-circuit ratio (SCR) has been used to describe this and is defined as

$$\text{SCR} = \frac{\text{short-circuit MVA}}{\text{converter MVA}}$$

If the converter is small compared to the system capacity, the per-unit harmonic currents will be small and the system impedance will be low, so any harmonic voltage will be insignificant. If the SCR is above 20 and the f_{p} is above 8.5, the probability of problems is low. If the SCR is below 20, and if the parallel resonance f_{p} is near one of the converter characteristic harmonics, there is a high probability of producing excessive harmonic voltage and high harmonic currents. The increased use of static power converters and power factor capacitors can set up system conditions to cause problems. However, with the judicial design of filters using the power factor capacitors to control the harmonic currents from the static power converters, both pieces of equipment can be used to take full advantage of all the economics that both of them offer.

Another effect of the harmonic components on the capacitor bank is to cause additional heating because of increased dielectric losses. The increased losses due to harmonics may be calculated with

$$L = \frac{1}{2}\sum_{h=2}^{\infty}(\tan\delta)_h C h\omega V_h^2$$

where
L is the increase in losses
h is the order of harmonic
C is the capacitance
$(\tan\delta)_h$ is the loss factor at the frequency of the hth harmonic
ω is the fundamental angular frequency
V_h is the peak value of the hth voltage

The overvoltage appearing at a capacitor bank due to the presence of harmonics depends on the phase relationship of harmonic and fundamental voltages. It is possible that the instantaneous overvoltage is greater than the rms overvoltage. As the corona inception and extinguishing voltage levels are a function of peak voltage, and not rms voltage, the life of the capacitor could be affected due to corona discharges. Capacitors, unlike most other power apparatus, have strict limits on current, kVAR, and voltage. The IEEE 18-2002, "Shunt power capacitors," specifies the limit on harmonics that the shunt capacitors can be subjected to under normal operation. The standard states that the capacitor may be continuously operated in the presence of harmonics provided (1) the total reactive power is not greater than 135% of its rated value, (2) the current due to the fundamental and harmonic frequency components does not exceed 180% of rated rms value, and (3) the rms value of the applied voltage is not more than 110% of rated terminal voltage and the crest value (1.2 × (square root of two)) of the applied voltage does not exceed 120% of rated peak voltage.

12.5.2.4 Switchgear

Harmonic components in the current waveform can affect the interruption capability of the switchgear. This takes place with two distinct mechanisms: (1) the presence of harmonics affects the rate of rise of the transient recovery voltage and the maximum value of the transient voltage and (2) harmonics affect the operation of the blowout coil in the stored-energy breakers. These effects will be discussed next.

The presence of current harmonics may result in high di/dt values at current zero. In this case, the rate of rise of the transient recovery voltage across the breaker will be higher than normal creating the possibility of dielectric failure and restrike. Also, the presence of harmonic currents affects the time that current crosses zero. This time affects the crest value of the transient recovery voltage. For example, if this time coincides with the maximum of the source voltage (fundamental), the crest value of the transient recovery voltage can reach $2.82E$ where E is the rms value of the rated voltage. This value may cause breaker restrike. Circuit breakers have failed to interrupt currents due to the inability of the blowout coils to operate adequately in the presence of severe harmonics. As the blowout coil assists in the arc's movement into the arc chute where the interruption takes place, its inefficient operation prolongs arcing and eventually results in breaker failure. Similar problems can exist in other current interrupting devices such as load break switches, circuit switchers, etc. Vacuum breakers are less sensitive to harmonic currents. There are no definite standards set forth by the industry on the level of harmonic currents that switching devices are required to interrupt. All the interrupting tests are performed at the rated supply frequency. The effect of harmonics on transient recovery voltage is by far the most difficult because it depends on specific system configuration.

One of the principal problems due to harmonics is the one that occurs within the switchgear neutral of three-phase four-wire systems when harmonics are present. The problem associated with neutrals is the result of the addition of triplen harmonic currents (i.e., multiple of the third harmonic) to the fundamental current in the neutral. The result often is that the neutral, which would normally carry very little current in a balanced three-phase system, now carries currents in excess of the phase currents for the system. Since neutral conductors, lugs, bus bars, etc, often are sized smaller than phase conductors and current components, the result is that the neutral system components are overloaded and often overheat, fail, or even burn down.

12.5.2.5 Protective Relays

Relays that depend on voltage/current crest or voltage zeroes for their operation are obviously affected by HD. System harmonics affect relay operation in a very complex manner. The induction disk and electromechanical relays are affected in the following way. The presence of harmonic currents results in additional torque components altering the time delay characteristics of the relays. Ground relays cannot distinguish between zero sequence current and third harmonic current. Thus, the presence of excessive third harmonic current can cause ground relays to trip. A recent Canadian study documents the effects of harmonics on relay operation as follows:

1. Relays exhibited a tendency to operate slower and/or with higher pickup values rather than to operate faster and/or with lower pickup values.
2. Static underfrequency relays were susceptible to substantial changes in operating characteristics.
3. In most cases, the changes in operating characteristics were relatively small over the moderate range of distortion expected during normal operation.
4. Depending on the manufacturer, the overvoltage and overcurrent relays exhibited various changes in operating characteristics.
5. Depending on harmonic content, operating torques of relays can be reversed.
6. Operating times can vary widely as a function of frequency mix in the metered quantity.
7. Balanced beam impedance relays can exhibit both overreach and underreach.
8. Harmonics can impair the high speed operation of differential relays. Several tests indicated that the relays could exhibit complete restraint.

In general, the harmonic levels required to cause misoperation of relays are greater than levels which would be considered maximum acceptable limits for other equipment. Harmonic levels of 10%–20% are generally required to cause problems with relay operation, except in unusual circumstances.

12.5.2.6 Metering Devices

Metering and instrumentation are affected by the presence of voltage and current harmonics. Induction disk devices, such as watt-hour meters and overcurrent relays, are designed and calibrated only for the fundamental current and voltage. The presence of harmonic currents and voltages generates additional electromagnetic torque on the disk which can cause erroneous operation. A Canadian study indicates that a 20% fifth harmonic content can produce 10%–15% error in a two element three-phase watt transducer. Other studies have shown that the error due to harmonics may be positive, negative, or smaller with third harmonics. This, of course, is dependent on the type of meter under consideration. Solid-state meters can measure power based on waveshape. In general, the distortion must be severe (>20%) before significant errors are detected.

12.5.2.7 Electronic Equipment

In many cases, electronic equipment are significant sources of harmonics. On the other hand, the operation of electronic equipment is often dependent on accurate determination of voltage zero crossings or other aspects of the voltage waveshape. For example, HD can result in a shifting of the zero crossing of the voltage waveform. This may be critical for many types of electronic circuit controls, and misoperation, such as commutation failures, can result from the shifts of the zero crossing. A large class of loads utilize energy in some form other than at the incoming line frequency, and require rectification or frequency conversion. External distortion may affect the performance of either the power converter or the converter load. The severity of these effects are influenced by the equipment design. Analysis of these effects is complicated by the fact that the converter itself is a complex nonlinear apparatus producing its own harmonics. Inverters used for DC to AC conversion or vice versa, generate a voltage notch during commutation. Voltage notching effects are of sufficient concern that notch limits on distorting apparatus have been included in some standards and guidelines. Voltage and current distortion may lead to disruption of the operation of electronic equipment. These disruptions may be divided into two categories: disruption of the converter operation and disruption of the converter load operation. The diversity of converter designs and the wide range of loads fed by these converters makes any general analysis difficult. It can be noted, however, that these disruptions are very much a function of converter design, and that electrical isolation of the sensitive load from loads producing distortion reduces the likelihood of disruption. Empirical data and operating experience with steady state voltage and current distortion in industrial plants has led to specific design recommendations summarized in the IEEE standard 519-1992, "IEEE guide for harmonic control and reactive compensation of static power converters."

12.5.2.8 Lighting Devices

Incandescent lamps: The incandescent lamp is one of the devices of this load group which is most sensitive to increased heating effects. A relative equation for bulb life is given by the equation:

$$L = \left[\frac{1}{V}\right]^n = \left[\frac{1}{V_1^2\left(1+(V\mathrm{DF})^2\right)}\right]^{n/2}$$

where
L is the PU bulb life (to rated life base)
V_1 is the PU fundamental voltage
V is the PU rms voltage (to rated voltage base)
n is a constant (representative value for n is 13)

It can be noted that large distortion factors will significantly shorten the bulb life, and that changes in the fundamental voltage are relatively more significant than changes in the distortion factor.

Arc lamps: The various types of arc lamps exhibit nonlinear resistance characteristics where the resistance declines as the current increases. The lamps have a safe operating region, and a ballast is required to place the lamp operating point in the safe region for all line voltage conditions throughout the range of various lamp characteristics. During normal lamp operation, the ballast functions as a current-limiting element. With inductive ballasts, the influence of voltage distortion would be roughly described by the distortion factor. It would appear that modest distortion factors would not cause a large shift in the lamp-operating point. Capacitive ballasts must be viewed with some concern, however, as the ballast reactance would drop as the frequency of the harmonic rises. Because the bulb itself is a highly nonlinear device, it is not at all clear what effect voltage distortion would have on lamps with capacitive ballasts.

12.6 Predictive Maintenance and PQ Measurements*

12.6.1 Introduction

In this section a discussion is provided on PQ measurements that can be used as predictive maintenance of power system and plant equipment. Unexpected failures can be avoided in both production equipment and power system apparatus when basic PQ measurements are added to maintenance

* This predictive PQ guide is based on information provided by Fluke Corporation.

procedures. Insurance claims data in the NFPA 70B indicates that roughly half of the cost associated with electrical failures could be prevented by regular maintenance. A study published in IEEE 493-1997 says that a poorly maintained system can attribute 49% of its failures to lack of maintenance. To determine the cost of a failure, it helps to consider the cost of lost income (gross margin) due to downtime, cost of labor to troubleshoot, patch, clean up, repair and restart, and cost of damaged equipment and materials, including repairs, replacements and scrapped materials.

Predictive maintenance of PQ focuses on a small set of measurements that can predict power distribution or critical load failures. By checking the PQ at critical loads, one can see the effect of the electrical system up to the load. The predictive maintenance inspection program should include motors, generators, pumps, A/C units, fans, gearboxes, or chillers on site. The voltage stability, HD, and unbalance voltages are good indicators of load and distribution system health and can be taken and recorded quickly with little incremental labor. Current measurements can identify changes in the way the load parameters are changing. All of these measurements can be taken without halting operations and measurement data can easily be entered into computer maintenance management software (CMMS) and plotted over time (see Section 1.4.3.5 for information on CMMS). For each measurement point or piece of equipment, limits can be set to trigger corrective action. Limits should be set well below the point of failure, and as time goes on limits may be tightened or loosened by analyzing historical data. The appropriate limits depend somewhat on the ability of the loads to deal with power variation. But for most equipment, the maintenance team can devise a set of default, house limits based on industry standards and experience. The cost of three-phase power analyzers and other PQ tools is lower now than before and measurements discussed in this section should be part of the predictive maintenance program.

12.6.2 Safety Standards for Test Instruments

12.6.2.1 Test Instrument Standards

IEC 61010 establishes international safety requirements for low voltage (1000 V or less) electrical equipment for measurement, control, and laboratory use. The low voltage power distribution system is divided into four categories, based on the proximity to the power source. Within each category are voltage listings—1000, 600, 300 V, etc. The key concept to understand is that you should use a meter rated to the highest category, as well as the highest voltage, that you might be working in. For PQ troubleshooting, a meter rated to CAT IV-600 V should always be used. The CAT ratings should be marked near the voltage inputs of the instrument. IEC 61010 requires increased protection against the hazards of transient overvoltages. Transients can cause an arc-over inside an inadequately protected meter. When that arc-over occurs in a high energy environment, such as a three-phase feeder circuit, the result can be a dangerous arc blast. The potential exists for serious harm to personnel as well as damage to the meter. Also, when undertaking PQ measurements,

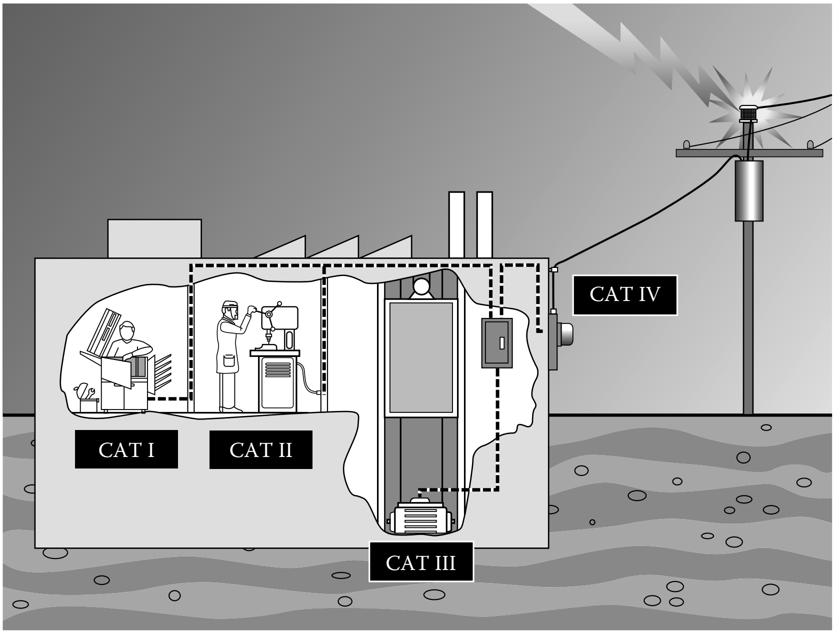


FIGURE 12.18
IEC (61010) safety categories of electrical equipment for measurements use. (Courtesy of Fluke Corporation, Everett, WA.)

the personnel should follow the requirements of safety-related work practices listed in Chapter 13 of the NFPA 70E, and rules promulgated by OSHA (Code of Federal Regulations, Title 29, Subtitle B, Chapter XVII, subpart S, paragraph 1910.331–1910.335) for safety-related work practices. Further, the instrument's manufacturer application notes and information should be consulted when making such measurements. The four categories of electrical equipment for measurements are depicted in Figure 12.18.

Manufacturers can self-certify that they meet IEC 61010 specifications, but there are obvious pitfalls for the end-user in self-certification. Certification by an independent testing laboratory provides assurance that the meter meets IEC requirements. Before using the test instruments, look for a symbol and listing number of an independent testing laboratory such as UL, CSA, TÜV, VDE, or others.

Overvoltage Category	**Summary Description**
CAT IV	Three-phase at utility connection, any outdoors conductors (under 1000 V)
CAT III	Three-phase distribution (under 1000 V), including single-phase commercial lighting and distribution panels
CAT II	Single-phase receptacle connected loads
CAT I	Electronic

12.6.2.2 Instruments for PQ Measurements

PQ monitoring requires a variety of instruments due to the many different measurements that must be performed. A general description of test instruments is given in this to make the reader familiar with the instruments that are normally used for PQ surveys and/or measurements. As an example, Table 12.5 lists the test instruments manufactured by Fluke Corporation which are applicable to the type of measurements discussed in this section. Similar instruments are available from other manufactures. Note that a true-rms multimeter, ammeter,

TABLE 12.5

Test Instruments Applicable to PQ Measurements

Test Tools (Model)[a]	PQ Analyzer (43B-Single-Phase Analyzer)	Harmonic Analyzer (435 Three-Phase Analyzer)	PQ Recorder [(Three-Phase-1750; Single-Phase–VR1710)]	Rms Digital Multimeter (Single-Phase-87 V)	PQ Clamp Meter (1ϕ Power-345)
Power	kVA, kW, kVAR, PF, DPF	kVA, kW, kVAR, PF, DPF			
Recording	TrendPlot, PC logging	PC logging	4000 V events		
Real-time clock	—		—		
Harmonics	To 51st harmonic	To 50th harmonic		True-rms volts and current	True-rms volts and current
Voltage transients	20 ns with waveform		1 μs event recording	250 μs peak MIN/MAX	
Sags and swells (voltage only)	Single cycle MIN/MAX with trend		Single cycle event recording	100 ms MIN/MAX	
Sags and swells (simultaneous voltage and current)	Single cycle MIN/MAX				
Outages	Single cycle MIN/MAX with trend	Event recording with duration		100 ms MIN/MAX	
Documentation, RS232 computer	FlukeView PQ software	FlukeView PQ software	EventView software		
Motor in-rush current	Waveform with cursors			MIN/MAX	MAX hold
Waveform	20 MHz scope	Fundamental			
Noise	—				
Peak	—	—		—	
True-rms	—	—		—	—

Sources: Courtesy of Fluke Corporation, Everett, WA.

[a] Models listed are Fluke Instruments used for PQ measurements. Similar instruments are available from other PQ instrument manufacturers.

ground impedance tester, and power line monitor/analyzer are absolutely essential equipment for minimum effective power disturbance detection and analysis.

True-rms multimeters: A true-rms digital multimeter is used to measure voltage and continuity.

True-rms clamp-on ammeters: A true-rms clamp-on ammeter is used to measure current and analyze current waveforms, particularly when sinusoidal waveforms are involved. It is recommended due to the ease of use and broad bandwidth characteristics of transformer-based meter designs. Several types of ammeters currently are available such as direct reading and indirect reading ammeters.

Ground impedance testers: A ground impedance tester is a multifunctional instrument designed to detect wiring and ground problems in low-voltage power distribution systems. Such problems can include: wiring errors, neutral–ground (N–G) shorts and reversals, IG shorts ground, and neutral impedance shorts. Some testers are designed for use on 120 V AC single-phase systems while others can be used on both single and three-phase systems up to 600 V AC.

Earth ground tester: An earth ground tester is used to measure the ground electrode impedance. Ground resistance tests should be conducted with a fall-of-potential method instrument. Clamp-on instruments that do not require the grounding electrode to be isolated from the building may be used with the understanding that these instrument may not give the most accurate readings of the ground electrode impedance.

Oscilloscope: An oscilloscope can be used to detect harmonics in an electrical system. It also can be used for noise measurements when combined with a line decoupler. In this case, the input is connected to the voltage of interest with the appropriate lead. If a voltage above the range of the oscilloscope is to be examined, probes with resistance-divider networks are available to extend the range of the instrument.

Spectrum analyzers: A spectrum analyzer equipped with appropriate measurement capabilities can be used to measure harmonics, electrical noise, and frequency deviations. Special-purpose harmonic meters or low frequency or broadband spectrum analyzers also can be used to measure these voltage and current disturbances.

Static meters: Static meters typically are used to measure ESD. These are handheld devices.

Psychrometer: A psychrometer is used to measure temperature and humidity in the environment, although such measurements also can be made with power monitoring devices equipped with special probes.

Field strength meter: A field strength meter equipped with a special probe can be used to measure electric or magnetic field strength.

Infrared detectors: Infrared detectors can be used to detect overheating of transformers, circuit breakers, and other electrical apparatus.

12.6.3 PQ Measurement Guidelines

PQ covers a wide range of issues, from voltage disturbances like voltage dips (sags), swells, outages and transients, to current harmonics, to performance wiring and grounding. The symptoms of poor PQ include intermittent lock-ups and resets, corrupted data, premature equipment failure, overheating of components for no apparent cause, etc. The ultimate cost is in downtime, decreased productivity, and frustrated personnel. This application note gives information on how to troubleshoot PQ problems. It also gives you information on how to start fixing those problems. But before grabbing that meter, the following cautionary notes must be adhered to:

1. Suggested measurements should only be made by qualified personnel who are trained to make these measurements in a safe manner, using proper procedures and test tools rated for work on electrical power circuits.
2. To the best of the author's knowledge, recommended solutions are consistent with the NEC, but in any case, NFPA 70 (NEC), NFPA 70E, and OSHA requirements must not be violated.
3. The information provided in this guidance is believed to be accurate and current, but it is not intended to be a substitute for the specialized knowledge and experience of professional PQ practitioners. What this application guide offers is a starter kit, not the final word on PQ predictive maintenance.

12.6.3.1 Preparation for Conducting Measurements

To troubleshoot PQ problems, one approach is to start as close to the problem load as possible. The problem load is the sensitive load, typically electronic, that is somehow malfunctioning. Poor PQ is suspected, but part of your job is to isolate PQ as a cause from other possible causes (hardware, software?). Like any detective, you should start at the scene of the crime. This bottom-up approach can take you a long way. It relies on making use of a sharp eye and on taking some basic measurements. An alternative is to start at the service entrance, using a three-phase monitor, and work back to the problem load. This is most useful if the problems originate with the utility. Yet survey after survey has concluded that the great majority of PQ problems originate in the facility. In fact, as a general rule, PQ is best at the service entrance (connection to utility) and deteriorates as you move downstream through the distribution system. That is because the facility's own loads are causing the problems. Another illuminating fact is that 75% of PQ problems are related to wiring and grounding problems! For this reason, many PQ

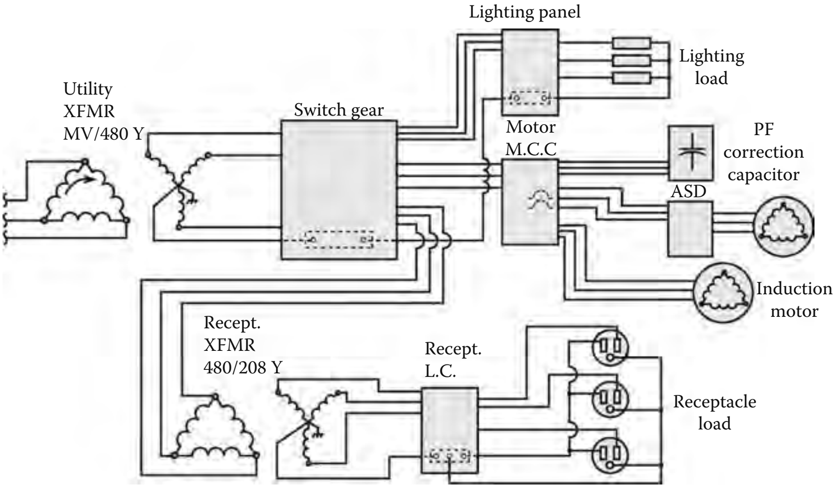


FIGURE 12.19
Simplified electrical distribution system, typical of commercial and industrial facilities. (Courtesy of Fluke Corporation, Everett, WA.)

authorities recommend that a logical trouble shooting flow is to first diagnose the electrical infrastructure of the facility, then monitor if necessary. The bottom-up troubleshooting procedure is designed to help you do this detective work.

1. *Make a map:* Obtain or create a current one-line diagram of the power distribution system. It is tough to diagnose PQ problems without having a working knowledge of the site being investigated. You can start by locating or reconstructing a "as built" one-line (or three-line) diagram of the distribution system (see Figure 12.19). The one-line will identify the AC power sources and the loads they serve. If you work on-site, the map might already exist in your head, but it will be a big help to everyone, including yourself, if it is on paper. If you are coming to a work site for the first time, getting an up-to-date one-line means identifying new loads or other recent changes in the system. Why go to this effort? Systems are dynamic; they change over time, often in unplanned and haphazard ways. Furthermore, while some problems are local in origin and effect, there are many problems that result from interactions between one part of the system and another. Your job is to understand these system interactions. The more complete your documentation, the better off you will be. It is true, however, that the sites that need the most help are the ones least likely to have a good record of what is going on in their system. So the simple rule is, at this point in the investigation, do the best you can to get good documentation, but do not count on it being available.

2. Do a walk around of the site. Sometimes a visual inspection will offer immediate clues:
   - A transformer that is much too hot
   - Wiring or connections discolored from heat
   - Receptacles with extension strips daisy-chained to extension strips
   - Signal wiring running in the same trays as power cables
   - Extra N–G bonds in subpanels
   - Grounding conductors connected to pipes that end in midair. At a minimum, you will get a sense of how the facility is wired and what the typical loads are
3. Interview affected personnel and keep an incident log. Interview the people operating the affected equipment. You will get a description of the problem and often turn up unexpected clues. It is also good practice to keep a record of when problems happen and what the symptoms are. This is most important for problems that are intermittent. The goal is to find some pattern that helps correlate the occurrence of the problem in the problem load to a simultaneous event elsewhere. Logically, this trouble-logging is the responsibility of the operator closest to the affected equipment.
4. The typical electrical distribution system for a commercial building or a light industrial facility is shown in Figure 12.19 that can be divided in to two parts: (1) distribution system and (2) three-phase loads. We will start the predictive maintenance from the bottom-up, i.e., starting at the branch circuit and moving up to the service panel, transformer, and then going into three-phase loads as listed below.

   Distribution system

   Receptacle branch circuit

   Service panels

   Transformers

   Electrical noise and transients

   Lightning protection

   Three-phase loads

   Polyphase induction motors

   AC ASD

   Commercial lighting

12.6.3.2 Basic Power Measurements

The basic power measurements for assessing PQ problems are phase voltages, neutral-to-ground voltage, phase currents, voltage and current distortion, voltage unbalance or imbalance, etc. The basic power measurements for PQ are listed in Table 12.6

TABLE 12.6

Basic Power Measurements for Three-Phase Wye Equipment

Voltage measurements	Phase-to-neutral voltages
	N–G voltages
Voltage sags	Phase to neutral sag count
Voltage harmonics	Phase voltage THD
Current measurements	Phase currents
Voltage unbalance	Negative sequence, zero sequence

Sources: Courtesy of Fluke Corporation, Everett, WA.

Good voltage level and stability are fundamental requirements for reliable equipment operation. The following power conditions are indicative of PQ problems and should be checked.

Voltage: Running loads at overly high or low voltages causes reliability problems and failures. Verify that line voltage is within 10% of the nameplate's rating. As connections in the power system deteriorate, the rising impedance will cause drops in voltage. Added loads, especially those with high inrush, will also cause voltage decline over time. The loads farthest from the service entrance or transformer will show the lowest voltage. Neutral-to-ground voltage shows how heavily the power system is loaded and helps quantify the triplen harmonic currents. Neutral-to-ground voltage higher than 3% should trigger further investigation.

Voltage sag count: Taking a single voltage reading tells only part of the story. How is the voltage changing during an hour and during a day? Sags, swells, and transients are short-term variations in voltage. The voltage sag (or dip) is the most common and troublesome variety. Sags indicate that a system is having trouble responding to load requirements and significant sags can interrupt production. Voltage sags can cause spurious resets on electronic equipment such as computers or controllers, and sag on one phase can cause the other two to overcompensate, potentially tripping the circuit. Sags have several dimensions: depth, duration, and time of day. Utilities use a special index to track the number of sags that occur over a period of time. To gauge the depth of the sags, they count how often voltage drops below various thresholds. The longer and larger the voltage variations more likely the equipment is susceptible to malfunction. For example, the Information Technology Industry Council (ITIC) curve specifies 120 V computer equipment should be able to run as long as voltage does not drop below 96 V for more than 10 s or below 84 V for more than 0.5 s.

Current: Current measurements that trend upward are a key indicator of a problem or degradation in the load. While equipment is running, monitor phase, neutral and ground current over time. Make sure none of the currents are increasing significantly, verify that they are less than the nameplate rating, and keep an eye out for high neutral current, which can indicate harmonics and unbalance.

Voltage unbalance: In a three-phase system, significant differences in phase voltage indicate a problem with the system or a defect in a load. High voltage unbalance causes three-phase loads to draw excessive current and causes motors to deliver lower torque. Also, it causes motor overheating, for example, 3% unbalance in voltage causes a temperature rise of 25°C. The negative sequence voltage (V_{neg}) and zero sequence voltage (V_{zero}) are an indication of voltage asymmetry between phases. It is desirable to keep V_{neg} to be less than 2%. The negative sequence voltage and zero sequence voltage are also referred to as V_2 and V_0, respectively.

Voltage HD: HD is a normal consequence of a power system supplying electronic loads such as computers, business machines, electronic lighting ballasts, and control systems. Adding or removing loads from the system changes the amount of distortion, so it is a good idea to regularly check harmonics. Harmonics cause heating and reduced life in motor windings and transformers, excessive neutral current, increased susceptibility to voltage sags, and reduced transformer efficiency. As current harmonics interact with impedance, they are converted into voltage harmonics. THD is a sum of the contributions of all harmonics. By tracking voltage THD over time one can determine if distortion is changing. The voltage harmonic distortion (voltage THD) in accordance with IEEE 519 should be less than 5%.

12.6.3.3 Measurements at the Receptacle of a Branch Circuit

Many PQ problems show up at the branch circuit level. There is a simple reason for this: that is where most of the sensitive loads are located. It is also the end of the line of the electrical distribution system, and the place where shortcomings cannot be hidden. Let us assume you have been called in to solve the problem. You have already talked to the people involved have a rough idea of the symptoms (equipment lockups, intermittent resets or crashes, etc.) and as much sense of the timing and history of the problems as you can get. So it is time to gather hard evidence: it is time to take measurements. Our primary focus with troubleshooting at the receptacle level is to determine if the L–N voltage available is of sufficient stability and amplitude to supply the needs of the load(s). Make the following measurements.

Waveform: The waveform gives us quick snapshot information. An ideal waveform would be a sine wave. In this case, (Figure 12.20) the voltage waveform is flat-topped, which is typical of a building with many nonlinear loads such as computers and other office equipment. Our other measurements will tell us whether this flat-topping is excessive.

Peak voltage: The peak value is critical to electronic loads because the electronic power supply charges its internal capacitors to the peak value of the line voltage. If the peak is too low, it affects the ability of the caps to charge fully and the ability of the power supply to ride through momentary dips in the line voltage. For an rms voltage of 120 V, the peak value for a sine wave

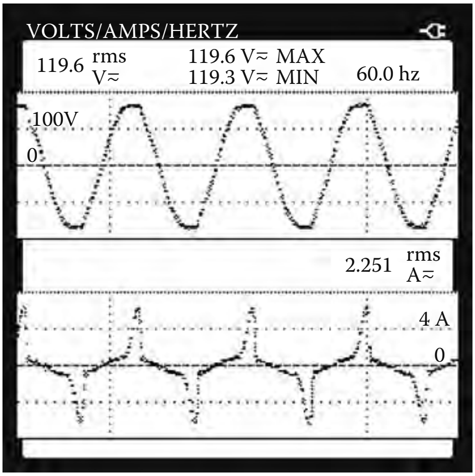


FIGURE 12.20
Flat-topped voltage waveform measured at a receptacle. (Courtesy of Fluke Corporation, Everett, WA.)

should be 169.7 V (1.414 × 120 V). However, as we see from Figure 12.20, the flat-topped waveform will have a lower peak value.

The flat-topped waveform is typical of the voltage in facilities with computer loads. What causes flat-topping? The utility supplies AC power, but electronic equipment runs on DC power. The conversion of AC into DC is done by the power supply (SMPS) of the computer. The SMPS has a diode bridge which turns AC into pulsating DC, which then charges a capacitor. As the load draws the capacitor down, the capacitor recharges. However, the capacitor only takes power from the peak of the wave to replenish itself, since that is the only time the supplied voltage is higher than its own voltage. The capacitor ends up drawing current in pulses at each half-cycle peak of the supplied AC voltage. This is happening with virtually all the electronic loads on the circuit. If the AC power source were perfectly stiff, meaning that it had an infinite capacity to supply all the current that was required, then there would be no such thing as flat-topping (or sags or any voltage distortion). There are practical limits to what the AC power source can supply. This limit is usually described by a concept called source impedance, which is the total impedance from the point where the load is located back to the source. There are two major contributors to this source impedance. One is the wiring; the longer the conductor and the smaller the diameter (higher gauge), the higher the impedance. The other factor is the internal impedance of the power supply transformer (or other source equipment). This internal impedance is simply a way of saying that a transformer of a given size/rating can only supply so much current. The source impedance is naturally greatest at the end of a branch circuit, the farthest point from the source. That is the same place where all those electronic loads are demanding current at the peak of the wave. The result is that the voltage peak tends to get dragged down—in other words, flat-topped. The more loads there are, the greater the flat-topping. Also, the higher the source impedance, the greater the flat-topping of the voltage waveform is going to be incurred.

Rms voltage: Nominal line voltage is measured in rms which corresponds to the effective heating value. Equipment is rated in rms, not peak, because their main limitation has to do with heat dissipation. rms voltage can be too high or too low, but it is usually the low voltage that causes problems. Low rms voltage combined with flat-topping (low peak) is a deadly combination for sensitive loads. Voltage drop is a function of both the loading of the circuit and the source impedance, which in effect means the length and diameter (gauge) of the wire run. The NEC (210-19.a, FPN No. 4) recommends a limit of a 3% voltage drop from the branch circuit breaker to the farthest outlet, and a total voltage drop of less than 5% including the feeder and branch circuit.

Recording (short-term): The limitation of the above measurement is that it is static. Many loads require more current (inrush current) when they are first turned on. This momentary high current may cause a momentary low voltage (sag) because of the additional IR drop through the conductors. Such sags are often caused by loads drawing inrush currents on the same branch circuit, or on the same panelboard. You can measure a worst case sag of 100 ms or more (about six cycles at 60 Hz) by using a rms digital multimeter, while energizing the load. What if you want to know if there are recurring sags? The recurring sags can be recorded by using a PQ analyzer which will continuously capture sags of as little as single cycle duration (17 ms). A 1 h recording time may be enough to indicate if there are recurring sags and swells.

Recording (long-term): For longer term recording an instrument, such as Fluke's VR1710 voltage event recorder, can be used to record sags, swells, outages, transients, and frequency deviations while plugged into the outlet. The device can be left on-site, unattended, for days and weeks, all the time catching intermittent events. The correlation of equipment malfunction with voltage events is hard evidence of a PQ problem.

N–G voltage: Let us say a simple L–N measurement at the outlet has a low reading. The low reading does not tell if the reading is low because the feeder voltage is low (at the subpanel), or if the branch circuit is overloaded. You could try to measure the voltage at the panel, but it is not always easy to tell which panel feeds the outlet you are measuring and it is also sometimes inconvenient to access a panel. N–G voltage is often an easier way of assuring the loading on a circuit. As the current travels through the circuit, there is a certain amount of voltage drop in the hot conductor and in the neutral conductor. The drop on the hot and neutral conductors will be the same if they are the same gauge and length. The total voltage drop on both conductors is subtracted from the source voltage and is that much less voltage available to the load. The bigger the load, the higher the current, and the greater the N–G voltage drop. Think of N–G voltage as the mirror of L–N voltage: if L–N voltage is low, that will show up as a higher N–G voltage. N–G voltage exists because of the voltage drop due to the current traveling through the neutral back to the N–G bond. If the system is correctly wired, there should be no N–G bond except at the source transformer (at what the NEC calls the source of the separately derived system (SDS), which is usually a transformer). Under this situation, the ground conductor should have virtually no current and therefore no voltage drop on it. In effect, the ground wire is available as a long test lead back to the N–G bond.

Shared neutrals: The three-phase circuits are usually wired so that they share a single neutral. The original idea was to duplicate on the branch circuit level the four wire (three phases and a neutral) wiring of panelboards. Theoretically, only unbalanced current should return on the neutral. If the loads supplied from the three-phase circuits are balanced, which is usually the case for linear loads then there should be minimum current returning on the neutral. However, this is not the case with nonlinear (electronic) loads, therefore the single neutral carries a much higher current. This old conventional method of wiring has become a problem with the growth of single-phase nonlinear loads. The problem is that zero sequence current from nonlinear loads, primarily third harmonic, will add up arithmetically and return on the neutral. In addition to being a potential safety problem because of overheating of an undersized neutral, the extra neutral current creates a higher N–G voltage. Remember that this N–G voltage subtracts from the L–N voltage available to the load. The measurement of N–G voltage of a shared neutral is shown in Figure 12.21.

The following guide is offered on the N–G measurements for assessing and resolving PQ problems.

1. A rule-of-thumb used by the industry is that N–G voltage of 2 V or less at the receptacle is okay, while a few volts or more indicates overloading; 5 V is seen as the upper limit. There is obviously some room for judgment in this measurement.
2. A high reading could indicate a shared branch neutral, i.e., a neutral shared between more than one branch circuit. This shared neutral simply increases the opportunities for overloading as well as for one circuit to affect another.
3. A certain amount of N–G voltage is normal in a loaded circuit. If the reading is stable at close to 0 V, suspect an illegal N–G bond in the receptacle (often due to loose strands of the neutral touching some ground point) or at the subpanel. Any N–G bonds other than those at the transformer source (and/or main panel) should be removed to prevent return currents flowing through the ground conductors.
4. If N–G voltage is low at the receptacle, you are in good shape. If it is high, then you still have to determine if the problem is mainly at the branch circuit level, or mainly at the panel level. Remember, assuming there is no illegal N–G bond in intervening panels or receptacles, your ground test lead goes all the way back to the source, so you are reading voltage drops all the way to the source.

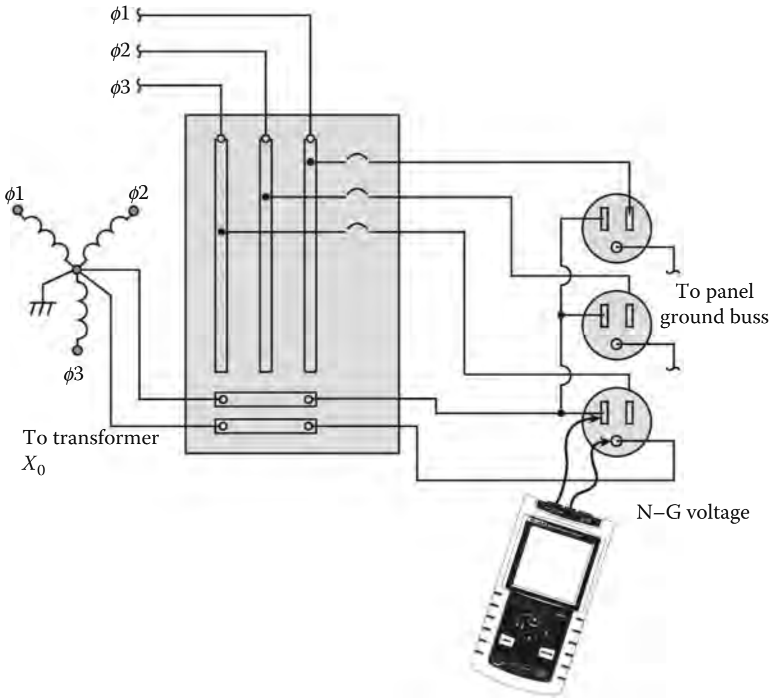


FIGURE 12.21
Measurement of N–G voltage of a shared neutral. (Courtesy of Fluke Corporation, Everett, WA.)

Summary: The PQ measurements on receptacle of branch circuits as discussed above are summarized in the Table 12.7. The quality of power depends on quality wiring which is referred to in the industry as performance wiring. The basic intent of performance wiring is to maintain or restore correct L–N voltage to the load. There is a distinction between performance wiring and code minimum wiring. The NEC sets the absolute minimum requirements for a wiring and is primarily concerned with fire prevention and personnel safety. The NEC should, of course, never be violated, but it is also important to understand that the Code's objective is not to establish standards to achieve PQ. However, many facilities are finding that it pays to take the extra step and install or even retrofit facilities with performance wiring for correct operation of nonlinear loads. The attributes of performance wiring are listed in Table 12.8. There are also situations where receptacle-installed power conditioning devices are a good solution, either as a complement to the wiring changes or as an economically viable alternative to some wiring changes. By monitoring voltage events at the receptacle, any anomalies in the voltage (phase-neutral and N–G) can be detected. Predictive maintenance of PQ will ensure that that the sensitive loads are receiving the correct voltage.

TABLE 12.7

PQ Measurements on Receptacle of Branch Circuits

Voltage Measurement	Look for	Instrument
1. Waveform	Snapshot of severity of voltage distortion	Three-phase or single-phase analyzer
2. Peak voltage	Excessive flat-topping	Three-phase or single-phase analyzer, rms digital multimeter (peak min max)
3. Rms voltage	Low rms (steady state low rms or intermittent/cyclical sags)	Three-phase or single-phase analyzer, rms digital multimeter (peak min max)
4. Recording (short-term)	Sags, swells, interruptions while troubleshooter remains on-site (4 min to 1 h typical recording time)	Three-phase or single-phase analyzer (sags/swells or transients)
5. Recording (long-term)	Up to 4000 sags, swells, outages, transients	Three- or single-phase recorder
6. N–G	N–G voltage too high (or close to zero)	Three-phase or single-phase analyzer, rms digital multimeter (peak min max)

Source: Courtesy of Fluke Corporation, Everett, WA.

TABLE 12.8

Suggestions for Performance Wiring of Branch Circuits

Recommendation	Reason
Check for loose connections	It is easy to overlook the obvious
Eliminate shared neutrals. In new installations, pull individual neutrals for each branch circuit	Minimize load interaction and source impedance
Limit the number of receptacles per branch circuit to three	Minimize loading and load interaction
Limit length of 120 V branch circuits to 50 ft (15 m)	Minimize source impedance
Install dedicated branch circuits for all laser printers and copy machines. Dedicated circuits should be run in their own conduit	Keep victim loads and culprit loads separated. Conduit prevents coupling between circuits
Install a green wire ground (do not just depend on the conduit connection)	Maintain a continuous, low impedance ground
Label all panels, circuit breakers, and receptacles	This would not improve PQ, but it will sure make life easier for the troubleshooter and the installer

Source: Courtesy of Fluke Corporation, Everett, WA.

12.6.3.4 Measurement at the Service Panel

In the bottom-up approach, the next step is to inspect and monitor PQ attributes at the service panel. While inspecting, checkout for the following:

- Visual inspection
- Feeder conductor current test
- Neutral conductor current test (feeder and branch)
- Phase-to-neutral voltage test (feeder and branch)
- N–G voltage test (feeder)
- Circuit breaker voltage drop and current on branch phase conductors

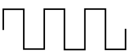
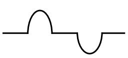
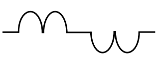
The service panel is where the effects of single-phase harmonic loads are easy to measure. A true-rms meter ensures accurate readings of nonlinear voltages and currents. Refer to Table 12.9 for comparison of average reading and true-rms reading multimeters.

Visual inspection

- Look for an illegal N–G bond in subpanels (see Figure 12.22). This is a violation of the NEC as well as of PQ wiring. It is also extremely common. If an illegal N–G bond is found in one panel at a site, it is likely to be in any number of them. Who knows why they are there: perhaps the installer was thinking that all panels are wired like residential service panels; or that the quickest way to reduce N–G voltage was to install a jumper, or that the more grounds the better. In any case, remove all illegal N–G bonds—no exceptions.
- Look for signs of overheating, such as discolored connecting lugs. Loose connections and excessive loading show up as heat. High

TABLE 12.9

Comparison of Average-Responding and True-rms Multimeters

		Multimeter Reading	
Waveform	**Description**	**Average-Sensing DMM**	**True-rms DMM**
	Sine wave	Correct	Correct
	Square wave (flat-top voltage)	10% high	Correct
	Current to single-phase diode rectifier	40% low	Correct
	Current to three-phase diode rectifier	5%–30% low	Correct

Source: Courtesy of Fluke Corporation, Everett, WA.

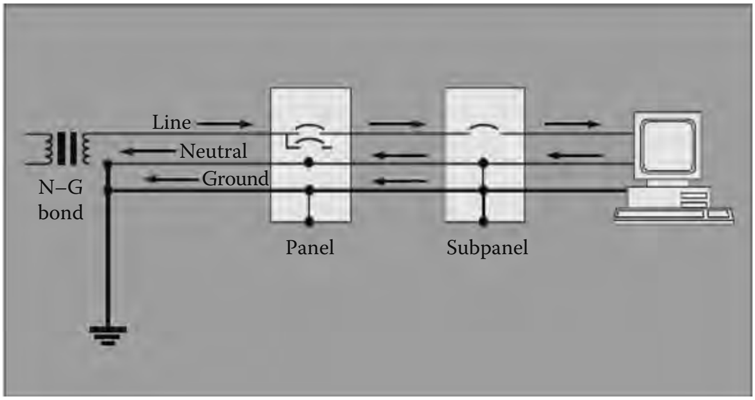


FIGURE 12.22
Subpanel N–G bonds cause load return currents to flow on ground conductors. This causes corrosion of pipes in grounding system as well as noisy grounds. (Courtesy of Fluke Corporation, Everett, WA.)

levels of harmonic current that were not accounted for in the original wire sizing can also cause overheating. Infrared sensors are the preferred method for noncontact temperature measurement.

- Of particular concern is the size of the feeder neutral conductor. It has long been understood that any fundamental current resulting from the unbalance of single-phase loads among the three phases will return on the neutral, but a relatively recent phenomenon is the third harmonic (triplen) currents generated by nonlinear single-phase loads that all return on the neutral. The NEC-1996, the first time stated that "On a four-wire, three-phase wye circuit where the major portion of the load consists of nonlinear loads, there are harmonic currents present in the neutral conductor, and the neutral shall be considered to be a current-carrying conductor." (Article 310, "Notes to ampacity tables of 0 to 2000 Volts," Note 10.c). In effect, this requires that the neutral conductor should be at least equal to the size of the phase conductor. Many experts now recommend that the neutral be double the size of the phase conductor.
- Check for shared branch neutrals. Count neutral conductors for branch circuits: if there are fewer than the phase conductors, there are shared neutrals.
- Check tightness of conduit connections, especially if the conduit is being used exclusively as the grounding conductor (not recommended).

Measurements

The measurements that are to be made at the service panel are summarized in Table 12.10.

TABLE 12.10

Service Panel Measurements

Measurement	Look for	Instruments
1. Feeder phase current	Overloading and balance	Three-phase analyzer; true-rms clamp meter
2. Feeder neutral current	High currents from unbalanced fundamental and third harmonics	Three-phase analyzer; rms DMM to find dominant frequency
3. Feeder N–G voltage	High voltage indicates excessive current, near-zero indicates possible subpanel N–G bond	Same
4. Branch L–N voltage	Low voltage	Same
5. Branch neutral current	Shared neutrals	Same
6. Voltage drop across breaker contacts. Hot breakers	Worn contacts. Breakers in need of replacement	Same

Source: Courtesy of Fluke Corporation, Everett, WA.

Feeder phase current: Check each phase to make sure it is not overloaded. Also check for excessive unbalance.

Feeder neutral current: Measure the feeder neutral conductor for cumulative neutral current. Third harmonic currents from all three phases will add arithmetically in the neutral.

Feeder N–G voltage test: Measure the neutral-to-ground voltage, excessive N–G voltage indicates overloading. A N–G voltage at or very near zero indicates the existence of an illegal N–G bond in a subpanel.

Phase-to-neutral voltage test: Phase-to-neutral voltages are measured and recorded. They can be compared with receptacle L–N voltages to measure voltage drop.

Branch neutral current: Measure each branch neutral for overloading. The neutrals are measured instead of the phase conductors because they might share the return current of several phase conductors, yet they are not protected by breakers.

Circuit breaker voltage drop: The voltage drop across a set of breaker contacts will give you a quick measure of the wear of those contacts. Ideally, the voltage drop should be zero. In practice, there will be some voltage drop in the millivolt range, with the exact value being dependent on the load current. As a general rule, the voltage drop should not exceed 20–100 mV, depending on load. This test can also be performed as contact resistance measurement test. For more details refer to Chapter 8.

Summary: The recommendations for improving PQ at the service panel are summarized in Table 12.11.

TABLE 12.11

Service Panel Recommendations for Improving PQ

Recommendation	Reason
Limit length of 208 V feeder runs to 120 V subpanels to 200 ft (65 m)	Minimize source impedance and chance of voltage sags
Do not cascade (daisy chain) subpanels off of other subpanels if possible, and especially if the upstream panel is heavily loaded or has loads with high inrush currents	Upstream loads can cause voltage sags that will affect all downstream loads
Install a green wire ground conductor (do not rely on conduit connections)	Maintain a continuous, low impedance ground
	Minimize heat, voltage sags
Reduce the load on the panel if necessary	Reduce neutral return current (of the fundamental current)
Redistribute branch circuit loads to improve balance of the three phases	
Upsize the feeder neutral if necessary, to accommodate the third harmonic. This can be done by running another neutral in parallel.	Prevent overloading and heating of feeder neutral. Will reduce N–G voltage
Install third harmonic filter	Reduce neutral current
Nonlinear load panel	Manufacturer designed for nonlinear loads

Source: Courtesy of Fluke Corporation, Everett, WA.

In addition, the following should be considered to reduce the effects of harmonics if PQ problems are encountered at the service panel:

1. Double the neutral, going beyond the NEC requirements.
2. Use nonlinear load panels.
3. Install zero sequence filters. Such a filter effectively sinks the third harmonic, preventing overloading on the feeder neutral and the transformer.
4. Install zigzag transformers.
5. Replace older motor drives with newer, harmonics compensated ones.
6. Coping with harmonics involves larger neutrals and other methods of better being able to handle the harmonics that are present. Curing harmonics involves eliminating or reducing harmonics at their source.
7. In some cases, you can try to reduce the spread of harmonics in the system—for example, by putting certain loads on their own transformer and panel.
8. Many harmonics problems exist because of the way things are wired. Major rewiring is usually expensive in terms of downtime and so it is not normally the first method used to fight a harmonics problem.
9. Look carefully at the system before implementing any curing or coping method, so you do not wind up trying one after another until

you finally have to concede you should have rewired to begin with. The trial and error approach to fixing harmonics-related problems will usually delay an effective remedy, while dramatically raising the total cost of solving the problem.

10. With the right testing on the particular wiring, you can isolate the problem and proceed with reasonable certainty as to whether a wiring change is required or not.
11. To correct phase unbalance:
    - Redistribute loads to different phases to balance current in three phases. Look for single-phase loads being fed from primarily one phase in the panel.
    - This redistribution and balancing has many benefits. It reduces the risk of overheating any particular phase in the transformer, minimizes neutral current, reduces the chances of nuisance breaker tripping, and provides other advantages in terms of maintenance and reliability.
12. To correct loose connections, use an infrared sensor to check for hot spots. Do not use the method of retorquing to prevent loose connections. This nearly always results in overtorquing. A fastener does its job by stretching to near what is called its elastic limit. Once you exceed this, the fastener can never provide the clamping power it was designed to provide. And the clamping power is what allows that connection to be made tight. Once you exceed the elastic limit of a fastener, you have eliminated its ability to give you a reliable connection. Overtorquing can eventually strip threads. But, this does not mean you are okay as long as you do not strip the threads. What matters is how far you stretched the fastener. Once you exceed the torque limit for that fastener, it will no longer fasten properly.
13. Examine connections on wireways. For electrical metallic tubing (EMT), check that the coupling screws are not loose. Do not overtighten these. You cannot economically tighten conduit, as it is threaded together.
14. For critical circuits, consider installing a bonding jumper around every metallic wireway connection. For example, install a bonding jumper around each conduit coupling or around each EMT fitting.
15. As already mentioned, remove any load-side N–G bonds.

12.6.3.5 Measurements at the Transformer

Transformers are subject to overheating from harmonic currents. Transformers supplying nonlinear loads should be checked periodically to verify operation is within acceptable limits. Transformers are also critical to the integrity of the grounding system. Table 12.12 lists the various measurements needed for transformers.

TABLE 12.12

Measurements at the Distribution Transformer

Measurement	Look for	Instrument
1. kVA	Transformer loading. If loading exceeds 50%, check for harmonics and possible need for derating	Three-phase or single-phase analyzer
2. Harmonic spectrum	1. Harmonic orders/amplitudes present: third harmonic (single-phase loads), fifth, seventh (primarily three-phase loads) 2. Resonance of higher order harmonics 3. Effectiveness of harmonic trap filters	Same
3. THD	Harmonic loading within limits: voltage %THD <5%, current %THD <5%–20%	Same
4. *K*-factor	Heating effect on transformer from harmonic loads	Same
5. Ground currents	1. Objectionable ground currents are not quantified but are prohibited by the NEC 2. N–G bond in place 3. Electrical safety ground (ESG) connector to ground electrode (typically building steel) in place	Same and true-rms clamp-on multimeter

Source: Courtesy of Fluke Corporation, Everett, WA.

Measurements

Transformer loading (kVA): If the transformer has a four-wire wye secondary, which is the standard configuration for commercial single-phase loads, actual kVA can be easily determined by measuring phase currents supplied from each winding and then calculating each kVA, or measuring directly the kVA in each phase. The sum of individual phase kVA then gives the three-phase kVA of the transformer. Compare actual load kVA measured or calculated against nameplate kVA rating to determine % loading. If the load is balanced, a single measurement is sufficient. Transformers loaded at less than 50% are generally safe from overheating. However, as loads increase, measurements should be made periodically. At some point the transformer may require derating because of nonlinear loading.

Harmonic spectrum: The harmonic spectrum of the secondary (load) current will give an idea of the harmonic orders and amplitudes present:

In a transformer feeding single-phase loads, the principal harmonic of concern is the third. The third will add arithmetically in the neutral and circulate in the delta primary of a delta–wye transformer. The delta–wye connected transformer tends to isolate the rest of the system from the third harmonic currents from the primary system, however it does isolate the fifth, seventh or other nontriplen harmonics. The third harmonic and triplen harmonic current however will cause additional heating of the transformer.

In a transformer feeding three-phase loads which include drives or UPS systems with six-pulse converters, the fifth and seventh harmonic will tend to predominate. Excessive fifth is of particular concern because it is negative sequence. It will tend to produce counter-torque and overheating in polyphase motors.

Harmonic amplitudes normally decrease as the harmonic frequency goes up. If one frequency is significantly higher in amplitude than lower frequencies, we can suspect a resonant condition at that frequency. If such a condition is detected, be sure to take readings at capacitor banks to see if the caps are experiencing overcurrent/overvoltage conditions.

Before-and-after harmonic spectrum measurement is extremely valuable to determine if harmonic mitigation techniques, like trap filters, which are tuned to specific frequencies, are sized properly and are working as expected. Different harmonic frequencies affect equipment in different ways. See Table 12.13 for harmonic sequences and their effects on equipment.

TABLE 12.13

(a) Harmonic Frequencies, Sequences, and (b) Effects

Name	First	Second	Third	Fourth	Fifth	Sixth	Seventh	Eighth	Ninth
(a) Harmonic frequencies and sequences									
Frequency	60	120	180	240	300	360	420	480	540
Sequence	+	–	0	+	–	0	+	–	0

Sequence	Rotation	Effects (from skin effect, eddy current etc.)
(b) Effects of harmonic sequences		
Positive	Forward	Heating of conductors, circuit breakers, etc.
Negative	Reverse	Heating as above + motor heating and problems
Zero	None	Heating of the neutral conductor, bus and transformer neutral

Rule: If waveforms are symmetrical, even harmonics disappear.
Harmonics are classified as follows:

1. Order or number: Multiple of fundamental, hence, third is three times the fundamental, or 180 Hz.
2. Odd or even order: Odd harmonics are generated during normal operation of nonlinear loads. Even harmonics only appear when there is DC in the system. In power circuits, this only tends to occur when a solid-state component(s), such as a diode or SCR, fails in a converter circuit.
3. Sequence:
   a. Positive sequence. Main effect is overheating.
   b. Negative sequence. Create counter-torque in motors, i.e., will tend to make motors go backwards, thus causing motor overheating. Mainly fifth harmonic.
   c. Zero sequence. Add in neutral of three-phase, four-wire system. Mainly third harmonic.

Source: Courtesy of Fluke Corporation, Everett, WA.

THD: Check for THD of both voltage and current:

For voltage, THD should not exceed 5%. For current, THD should not exceed 5%–20%.

IEEE 519 sets limits for harmonics at the point of common coupling (PCC) between the utility and customer (EN50160 is the European standard that is equivalent to the IEEE 519). IEEE 519 addresses THD measurements that are taken at the PCC which is usually considered to be the main transformer between the utility and the customer. Therefore the THD measurements are often made at the secondary of the customer's main transformer, since that is the point most easily accessible to all parties. Some PQ practitioners have broadened the concept of PCC to include points inside the facility, such as on the feeder system, where harmonic currents being generated from one set of loads could affect another set of loads by causing significant voltage distortion. The emphasis is on improving in-plant PQ, rather than on simply not affecting utility PQ.

Voltage THD: THD has a long history in the industry. The underlying concept is that harmonic currents generated by loads will cause voltage distortion as they travel through the system impedance. This voltage distortion then becomes the carrier of harmonics system wide. If for example, the distorted voltage serves a linear load like a motor, it will then create harmonic currents in that linear load. By setting maximum limits for voltage distortion, we set limits for the system-wide impact of harmonics.

Voltage distortion, however, depends on source impedance, i.e., on system capacity. It is quite possible for the first (or second or third) customer to inject significant harmonic currents into the system and not cause voltage THD to exceed 5%. The entire responsibility for harmonic mitigation could fall on the last customers unlucky enough to push voltage THD over 5%, even if their particular harmonic load was relatively small.

Current THD: To restore some fairness to this situation, standards for maximum current harmonics were added, since current harmonics were under the control of the local facility and equipment manufacturer (remember, harmonic loads act as generators of harmonics). This emphasis on the mitigation of current harmonics at the load, including the not-too-distant requirement that the load generate virtually no harmonics, has become the prevailing regulatory philosophy. It puts the burden of responsibility on the local site and on the equipment manufacturers. For equipment manufacturers, EN50160, IEC/EN 61010, and IEC/EN 61000-4, are the applicable European standards. To meet requirement for the European market, USA manufacturers will have to meet the above listed standards. The limits set in IEEE 519 for harmonic currents depend on the size of the customer relative to the system capacity. The SCR is a measure of the electrical size of the customer in relation to the utility source. The smaller the customer (higher SCR), the less the potential impact on the utility source and the more generous the harmonic

TABLE 12.14

IEEE 519 Limits for Harmonic Currents at the PCC

	Odd Harmonics					
SCR = I_{sc}/I_L	**<11**	**11–17**	**17–23**	**23–35**	**>35**	**TDD**
<20	4.0%	2.0%	1.5%	0.6%	0.3%	5.0%
20–50	7.0%	3.5%	2.5%	1.0%	0.5%	8.0%
50–100	10.0%	4.5%	4.0%	1.5%	0.7%	12.0%
100–1000	12.0%	5.5%	5.0%	2.0%	1.0%	15.0%
>1000	15.0%	7.0%	6.0%	2.5%	1.4%	20.0%

Source: IEEE Std 519-1992, IEEE Recommended Practices and Requirements for Harmonic Control in Electric Power Systems.

Note: IEEE allows these limits to be exceeded for up to one hour per day, while IEC allows them to be exceeded for up to 5% of the time.

limits. The larger the customer's power system (smaller SCR), the more stringent the limits on harmonic currents. Refer to Table 12.14 for current harmonic limits at the PCC.

Total demand distortion (TDD) and THD: TDD is the ratio of the current harmonics to the maximum load (I_L). It differs from THD in that THD is the ratio of harmonics to the instantaneous load. Why TDD instead of THD? Suppose you were running a light load (using a small fraction of system capacity), but those loads were nonlinear. THD would be relatively high, but the harmonic currents actually being generated would be low, and the effect on the supply system would in fact be negligible. Therefore, TDD allows harmonic load to be referenced to the maximum load: if harmonic load is high at maximum load, then we have to watch out for the effect on the supply source. So where does that leave current THD as a useful measurement. The closer the current THD reading(s) is taken to conditions of maximum load, the closer it approximates TDD. The one place not to apply the specs is at the individual harmonic-generating load. This will always be a worst-case distortion and a misleading reading. This is because as harmonics travel upstream, a certain amount of cancellation takes place (due to phase relationships which, for practical purposes, is difficult to predict). THD and TDD should be measured at a PCC, or at the source transformer.

K-factor: *K*-factor is a specific measure of the heating effect of harmonics in general and on transformers in particular. It differs from the THD calculation in that it emphasizes the frequency as well as the amplitude of the harmonic order. This is because heating effects increase as the square of the frequency.

A *K*-4 reading would mean that the stray loss heating effects are four times normal. A standard transformer is, in effect, a *K*-1 transformer. As with THD, it is misleading to make a *K*-factor reading at the load or receptacle because there will be a certain amount of upstream cancellation; transformer *K*-factor is what counts. Once the *K*-factor is determined, choose the next higher trade size. *K*-factor rated transformers are available in standard trade sizes of *K*-4, *K*-13, *K*-20, *K*-30, etc. *K*-13 is a common rating for a transformer supplying office loads. The higher ratings tend to be packaged into power distribution units (PDUs) which are specially designed to supply computer and other PQ sensitive installations. For additional information on *K*-rated transformer, refer to Section 12.5.2.1.

Ground currents: Two prime reasons for excessive ground current are illegal N–G bonds (in subpanels, receptacles, or even in equipment) and so-called IG rods:

Subpanel N–G bonds create a parallel path for normal return current to return via the grounding conductor. If the neutral ever becomes open, the equipment safety ground becomes the only return path; if this return path is high impedance, dangerous voltages could develop.

Separate IG rods almost always create two ground references at different potentials, which in turn cause a ground loop current to circulate in an attempt to equalize those potentials. A safety and equipment hazard is also created: in the case of lightning strikes, surge currents traveling to ground at different earth potentials will create hazardous potential differences.

Transformer grounding: The proper grounding of the transformer is critical. NEC Article 250 in general and 250-26 in particular address the grounding requirements of the seperately derived systems (SDS).

A ground reference is established by a grounding connection, typically to building steel (which, in turn, is required to be bonded to all cold water pipe, as well as to any and all earth grounding electrodes). Bonding should be by exothermic weld, not clamps that can loosen over time. The grounding electrode conductor itself should have as low a high-frequency impedance as possible (not least because fault current has high frequency components). Wide, flat conductors are preferred to round ones because they have less inductive reactance at higher frequencies. For the same reason, the distance between the grounding electrode conductor connection to the system (i.e., N–G bond at the transformer) and the grounding electrode (building steel) should be as short as possible.

The neutral and ground should be connected at a point on the transformer neutral bus. Although permitted, it is not advisable to make the N–G bond at the main panel, in order to maintain the segregation of normal return currents and any ground currents. This point at the transformer is the only point on the system where N–G should be bonded. Refer to Table 12.15 for inspection of the transformer grounding related to PQ problems.

TABLE 12.15

Inspection of the Transformer Grounding for PQ Problems

Inspection of Transformer Ground	Explanation
Check for N–G bond	A high impedance N–G bond will cause voltage fluctuation
Check for grounding conductor and integrity of connection to building steel (exothermic weld)	Fault currents will return to the source via these connections, so they should be as low impedance as possible
Check for tightness of all conduit connections	If the conduit is not itself grounded, it will tend to act as a choke for higher frequencies and limit fault current (remember that fault currents are not just at 60 Hz but have high-f components)
Measure for ground currents on the grounding conductor	Ideally there should be none, but there will always be some ground current due to normal operation or leakage of protective components (MOVs, etc.) connected from phase or neutral to ground. However, anything above an amp should be cause for suspicion (there is no hard and fast rule, but experienced PQ troubleshooters develop a feel for possible problems)

Source: Courtesy of Fluke Corporation, Everett, WA.

Solutions: There are a number of solutions for transformer-related PQ problems. They are

- Install additional distribution transformers
- Derate transformers
- Install *K*-rated transformers
- Used forced air cooling

SDS: The distribution transformer is the supply for a SDS, a term which is defined in the NEC (Article 100). The key idea is that the secondary of this transformer is the new source of power for all its downstream loads: this is a powerful concept in developing a PQ distribution system. The SDS accomplishes several important objectives, all beneficial for PQ:

- It establishes a new voltage reference. Transformers have taps which allow the secondary voltage to be stepped up or down to compensate for any voltage drop on the feeders.
- It lowers source impedance by decreasing, sometimes drastically, the distance between the load and the source. The potential for voltage disturbances, notably sags, is minimized.
- It achieves isolation. Since there is no electrical connection, only magnetic coupling, between the primary and secondary, the SDS isolates its loads from the rest of the electrical system. To extend this

isolation to high frequency disturbances, specially constructed isolation transformers provide a shield between the primary and secondary to shunt RF noise to ground. Otherwise, the capacitive coupling between primary and secondary would tend to pass these high-frequency signals right through.

- A new ground reference is established. Part of the definition of the SDS is that it "has no direct electrical connection, including a solidly connected grounded circuit conductor, to supply conductors originating in another system." (NEC 100) The opportunity exists to segregate the subsystem served by the SDS from ground loops and ground noise upstream from the SDS, and vice versa.

K-rated transformers: Harmonics cause heating in transformers, at a greater rate than the equivalent fundamental currents would. This is because of their higher frequency. There are three heating effects in transformers that increase with frequency

- **Hysteresis:** When steel is magnetized, magnetic dipoles all line up, so that the north poles all point one way, the south poles the other. These poles switch with the polarity of the applied current. The higher the frequency, the more often the switching occurs, and, in a process analogous to the effects of friction, heat losses increase.
- **Eddy currents:** Alternating magnetic fields create localized whirlpools of current that create heat loss. This effect increases as a square of the frequency. For example, a third harmonic current will have nine times the heating effect as the same current at the fundamental.
- **Skin effect**. As frequency increases, electrons migrate to the outer surface of the conductor. More electrons are using less space, so the effective impedance of the conductor has increased; at the higher frequency, the conductor behaves as if it were a lower gauge, lower ampacity, higher impedance wire. The industry has responded with two general solutions to the effects of harmonics on transformers: install a *K*-factor rated transformer or derate a standard transformer. Let us look at pros and cons of the *K*-factor approach first. *K*-factor is a calculation based on the rms value, %HD of the harmonic currents, and the square of the harmonic order (number). It is not necessary to actually perform the calculation because a harmonic analyzer will do that for you. The important thing to understand is that the harmonic order is squared in the equation and that is precisely where the high-frequency heating effects, like eddy current losses, are taken into account. *K*-rated transformers are designed to minimize and accommodate the heating effects of harmonics. *K*-rated transformers do not eliminate harmonics (unless additional elements like filters are added).

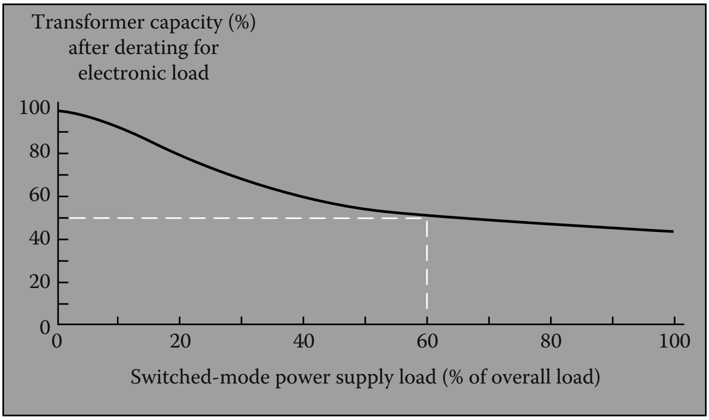


FIGURE 12.23
Transformer derating curve (IEEE Std 1100-1992, IEEE Recommended Practice for Powering and Grounding Sensitive Electronic Equipment.)

> They accommodate harmonics with techniques such as the use of a number of smaller, parallel windings instead of a single large winding: this gives more skin for the electrons to travel on. The primary delta winding is up-sized to tolerate the circulating third harmonic currents without overheating. The neutral on the secondary is also up-sized for third harmonics (typically sized at twice the phase ampacity).

Application issues with K-factor transformers: *K*-rated transformers have been widely applied, but there are certain issues with them. Many consultants do not see the need for using transformers with a rating higher than *K*-13 although *K*-20 and higher might be supplied as part of an integrated PDU. Also, early applications sometimes overlooked the fact that *K*-rated transformers necessarily have a lower internal impedance. Whereas a standard transformer has an impedance typically in the 5%–6% range, *K*-rated transformers can go as low as 2%–3% (lower as the *K*-rating increases). In retrofit situations, where a standard transformer is being replaced by a *K*-rated transformer of equivalent kVA, this may require new short-circuit calculations and resizing of the secondary overcurrent protective devices.

Derating standard transformers: Some facilities managers use a 50% derating as a rule-of thumb for their transformers serving single-phase, predominantly nonlinear loads. This means that a 150 kVA transformer would only supply 75 kVA of load. The derating curve (see Figure 12.23), taken from IEEE 1100-1992 (Emerald Book), shows that a transformer with 60% of its loads consisting of SMPS, which is certainly possible in a commercial office building, should in fact be derated by 50%. The following is an accepted method for calculating transformer derating for single-phase loads only. It is based on the very reasonable assumption that in single-phase circuits, the third harmonic will predominate and cause the distorted current waveform to look predictably peaked. Use a true-rms meter to make these current measurements:

1. Measure rms and peak current of each secondary phase. (Peak refers to the instantaneous peak, not to the inrush or peak load rms current).
2. Find the arithmetic average of the three rms readings and the three peak currents and use this average in step 3 (if the load is essentially balanced, this step is not necessary).
3. Calculate xformer harmonic derating factor:

$$\text{xHDF} = (1.414 * I_{\text{rms}})/I_{\text{peak}}$$

4. Or, since the ratio of peak/rms is defined as CF, this equation can be rewritten as:

$$\text{xHDF} = 1.414/\text{CF}$$

If the test instrument has the capability, measure the CF of each phase directly. If the load is unbalanced, find the average of the three phases and use the average in the above formula. Since a sine wave current waveform has a CF = 1.414, it will have an xHDF = 1; there will be no derating. The more the third harmonic, the higher the peak, the higher the CF. If the CF were 2.0, then the xHDF = 1.414/2 = 0.71. A CF = 3 gives us an xHDF = 0.47. A wave with CF = 3 is about as badly distorted a current waveform as you can expect to see on a single-phase distribution transformer.

Caution: This method does not apply to transformers feeding three-phase loads, where harmonics other than the third tend to predominate and CF is not useful as a simple predictor of the amount of distortion. A calculation for three-phase loads is available in ANSI/IEEE C57.110. However, there is some controversy about this calculation since it may underestimate the mechanical resonant vibrations that harmonics can cause, and that accelerate transformer wear above and beyond the effects of heat alone.

12.6.3.6 Electrical Noise

Electrical noise is the result of more or less random electrical signals getting coupled into circuits where they are unwanted, i.e., where they disrupt information-carrying signals. Noise occurs on both power and signal circuits, but generally speaking, it becomes a problem when it gets on signal circuits. Signal and data circuits are particularly vulnerable to noise because they operate at fast speeds and with low voltage levels. The lower the signal voltage, the less the amplitude of the noise voltage that can be tolerated.

The signal-to-noise ratio describes how much noise a circuit can tolerate before the valid information, the signal, becomes corrupted. Noise is one of the more mysterious subjects in PQ, especially since it must be considered

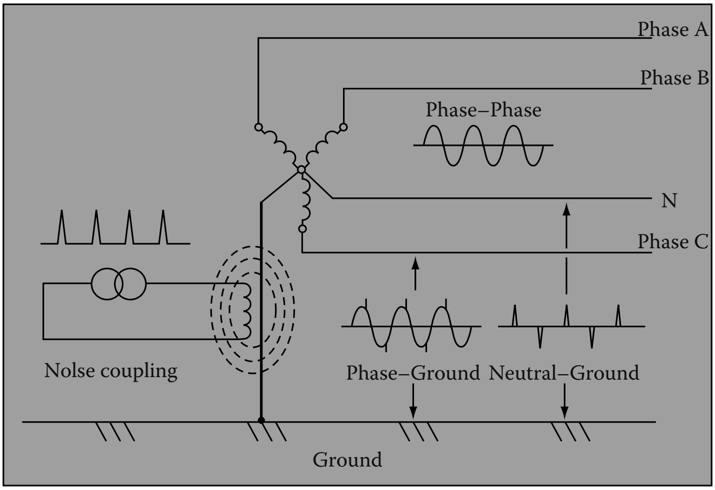


FIGURE 12.24
Noise coupling. Ground noise measured as ø-G or N–G noise. (Courtesy of Fluke Corporation, Everett, WA.)

with its equally mysterious, grounding. To lessen the mystery, there are two key concepts to understand:

- The first is that electrical effects do not require direct connection (such as through copper conductors) to occur. For an electrician who's been trained to size, install and test wiring, this may not be intuitive. Yet think of lightning, or of the primary and secondary of an isolation transformer, or of the radio antenna: there is no direct, hard-wired connection, but somehow complete electrical circuits are still happening. The same electrical rules-of-behavior are in operation for noise coupling, as will be explained later.
- The second concept is that we can no longer stay in the realm of 60 Hz. One of the benefits of 60 Hz is that it is a low enough frequency that power circuits can be treated (almost) like DC circuits; in other words, basic Ohm's law applies. But when it comes to noise, we need to keep in mind that signal circuits occur at high frequencies, that noise is typically a broad spectrum of frequencies, and that we need to consider the frequency-dependent behavior of potential sources of noise.

Coupling mechanisms: There are four basic mechanisms of noise coupling (see Figure 12.24). It pays to understand them and how they differ one from the other because a lot of the troubleshooter's job will be to identify which coupling effect is dominant in a particular situation.

Capacitive coupling: This is often referred to as electrostatic noise and is a voltage-based effect, lightning discharge is just an extreme example. Any conductors separated by an insulating material (including air) constitute a capacitor—in other words, capacitance is an inseparable part of any circuit. The potential for capacitive coupling increases as frequency increases (capacitive reactance, which can be thought of as the resistance to capacitive coupling, decreases with frequency).

Inductive coupling: This is magnetic-coupled noise and is a current-based effect. Every conductor with current flowing through it has an associated magnetic field. A changing current can induce current in another circuit, even if that circuit is a single loop; in other words, the source circuit acts as a transformer primary with the victim circuit being the secondary. The inductive coupling effect increases with the following factors: (1) larger current flow, (2) faster rate of change of current, (3) proximity of the two conductors (primary and secondary), and (4) the more the adjacent conductor resembles a coil (round diameter as opposed to flat, or coiled as opposed to straight). Here are some examples of how inductive coupling can cause noise in power circuits:

Noise in power circuits: A transient surge, especially if it occurs on a high-energy circuit, causes a very fast change in current which can couple into an adjacent conductor. Lightning surges are a worst case, but common switching transients or arcing can do the same thing.

- If feeder cables are positioned such that there is a net magnetic field, then currents can be induced into ground cables that share the raceway.
- It is well-known that signal wires and power conductors should not be laid parallel to each other in the same raceway, which would maximize their inductive coupling, but instead be separated and crossed at right angles when necessary. Input and output cables should also be isolated from each other in the same manner. Magnetic fields are isolated by effective shielding. The material used must be capable of conducting magnetic fields (ferrous material as opposed to copper). The reason that a dedicated circuit (hot, neutral, and ground) should be run in its own metal conduit when possible is that is in effect magnetically shielded to minimize inductive coupling effects. Both inductive and capacitive coupling are referred to as near field effects, since they dominate at short distances and distance decreases their coupling effects. This helps explain one of the mysteries of noise—how slight physical repositioning of wiring can have such major effects on coupled noise.

Conducted noise: While all coupled noise ends up as conducted noise, this term is generally used to refer to noise that is coupled by a direct, galvanic (metallic) connection. Included in this category are circuits that have shared conductors (such as shared neutrals or grounds). Conducted noise could be high frequency, but may also be 60 Hz. These are some common examples of connections that put objectionable noise currents directly onto the ground:

- Subpanels with extra N–G bonds.
- Receptacles miswired with N and G switched.
- Equipment with internal solid-state protective devices that have shorted from line or neutral to ground, or that have not failed but have normal leakage current. This leakage current is limited by UL to 3.5 mA for plug-connected equipment, but there is no limit for permanently wired equipment with potentially much higher leakage currents. (Leakage currents are easy to identify because they will disappear when the device is turned off).
- Another common example is the so-called IG rod. When it is at a different earth potential than the source grounding electrode, a ground loop current occurs. This is still conducted noise, even though the direct connection is through the earth.
- Datacom connections that provide a metallic path from one terminal to another can also conduct noise. In the case of single-ended, unbalanced connections (RS-232), the connection to terminal ground is made at each end of the cable. This offers a path for ground currents if the equipment at each end is referenced to a different power source with a different ground.

RFI: RFI ranges from 10 kHz to the 10s of MHz (and higher). At these frequencies, lengths of wire start acting like transmitting and receiving antennas. The culprit circuit acts as a transmitter and the victim circuit is acting as a receiving antenna. RFI, like the other coupling mechanisms, is a fact of life, but it can be controlled (not without some thought and effort, however).

RFI noise reduction employs a number of strategies:

- Fiber optic cable, of course, is immune to electrical noise.
- Shielded cabling (such as coax cables) attempts to break the coupling between the noise and signal.
- Balanced circuits (such as twisted pair) do not break the coupling, but instead take advantage of the fact that the RFI will be coupled into both conductors (signal and return). This noise (called CM noise) is then subtracted, while the signal is retained. In effect, the balanced circuit creates a high impedance for the coupled noise.
- Another example of the high-impedance-to-noise approach is the use of RF chokes. Whether used with data or power cables, RF chokes can offer effective high-frequency impedance (X_L increases with frequency).
- A low-impedance path can be used to shunt away the noise. This is the principle behind filtering and the use of decoupling caps (low impedance to high frequency, but open at power line frequencies). But a sometimes over looked, yet critical, aspect is that the

ground path and plane must be capable of handling high-frequency currents. High-frequency grounding techniques are used to accomplish this. The SRG, first developed for raised floor computer room installations, is an effective solution. It is essentially an equipotential ground plane at high frequency.

Signal grounding: To understand the importance of clean signal grounds, let us discuss the distinction between DM versus CM signals. Imagine a basic two-wire circuit: supply and return. Any current that circulates or any voltage read across a load between the two wires is called DM (the terms normal mode, transverse mode, and signal mode are also used). The DM signal is typically the desired signal (just like 120 V at a receptacle). Imagine a third conductor, typically a grounding conductor. Any current that flows now through the two original conductors and returns on this third conductor is common to both of the original conductors. The CM current is the noise that the genuine signal has to overcome. CM is all that extra traffic on the highway. It could have gotten there through any of the coupling mechanisms, such as magnetic field coupling at power line frequency or RFI at higher frequencies. The point is to control or minimize these ground or CM currents, to make life easier for the DM currents.

Measurement: CM currents can be measured with current clamps using the zero-sequence technique. The clamp circles the signal pair (or, in a three-phase circuit, all three-phase conductors and the neutral, if any). If signal and return current are equal, their equal and opposite magnetic fields cancel. Any current read must be CM; in other words, any current read is current that is not returning on the signal wires, but via a ground path. This technique applies to signal as well as power conductors. For fundamental currents, a clamp meter or digital multimeter (DMM) + clamp would suffice, but for higher frequencies, a high bandwidth instrument like the Fluke 43 PQ analyzer or scope meter should be used with a clamp accessory.

12.6.3.7 Transients

Transients should be distinguished from surges. Surges are a special case of high-energy transient which result from lightning strikes (see Section 12.6.3.8). Voltage transients are lower energy events, typically caused by equipment switching. They are harmful in a number of ways:

- They deteriorate solid-state components. Sometimes a single high-energy transient will puncture a solid-state junction, sometimes repetitive low-energy transients will accomplish the same thing. For example, transients which exceed the PIV rating of diodes are a common cause of diode failure.
- Their high-frequency component (fast rise times) cause them to be capacitively coupled into adjoining conductors. If those conductors

are carrying digital logic, that logic will get trashed. Transients also couple across transformer windings unless special shielding is provided. Fortunately this same high-frequency component causes transients to be relatively localized, since they are damped (attenuated) by the impedance of the conductors (inductive reactance increases with frequency).

- Utility capacitor switching transients are an example of a commonly occurring high-energy transient (still by no means in the class of lightning) that can affect loads at all levels of the distribution system. They are a well known cause of nuisance tripping of VFDs (ASDs): they have enough energy to drive a transient current into the DC link of the drive and cause an overvoltage trip. Transients can be categorized by waveform. The first category is impulsive transients, commonly called spikes, because a high-frequency spike protrudes from the waveform. The cap switching transient, on the other hand, is an oscillatory transient because a ringing waveform rides on and distorts the normal waveform. It is lower frequency, but higher energy.

Causes: Transients are unavoidable. They are created by the fast switching of relatively high currents. For example, an inductive load like a motor will create a kickback spike when it is turned off. In fact, removing a Wiggy (a solenoid voltage tester) from a high-energy circuit can create a spike of thousands of volts. A capacitor, on the other hand, creates a momentary short circuit when it is turned on. After this sudden collapse of the applied voltage, the voltage rebounds and an oscillating wave occurs. Not all transients are the same, but as a general statement, load switching causes transients. In offices, the laser copier/printer is a well-recognized "bad guy" on the office branch circuit. It requires an internal heater to kick in whenever it is used and every 30 s or so when it is not used. This constant switching has two effects: the current surge or inrush can cause repetitive voltage sags; the rapid changes in current also generate transients that can affect other loads on the same branch.

Measurement and recording: Transients can be captured by digital storage oscilloscopes (DSOs). The Fluke 43 PQ analyzer, which includes DSO functions, has the ability to capture, store and subsequently display up to 40 transient waveforms. Events are tagged with time and date stamps (real-time stamps). Another voltage event recorder, such as Fluke's VR101S will also capture transients at the receptacle.

Peak voltage and real-time stamps are provided.

TVS suppressors (TVSS): Fortunately, transient protection is not expensive. Virtually all electronic equipment has (or should have) some level of protection built in. One commonly used protective component is the MOV which clips the excess voltage. TVSS are applied to provide additional transient protection. TVSS are low voltage (600 V) devices and are tested and certified to UL

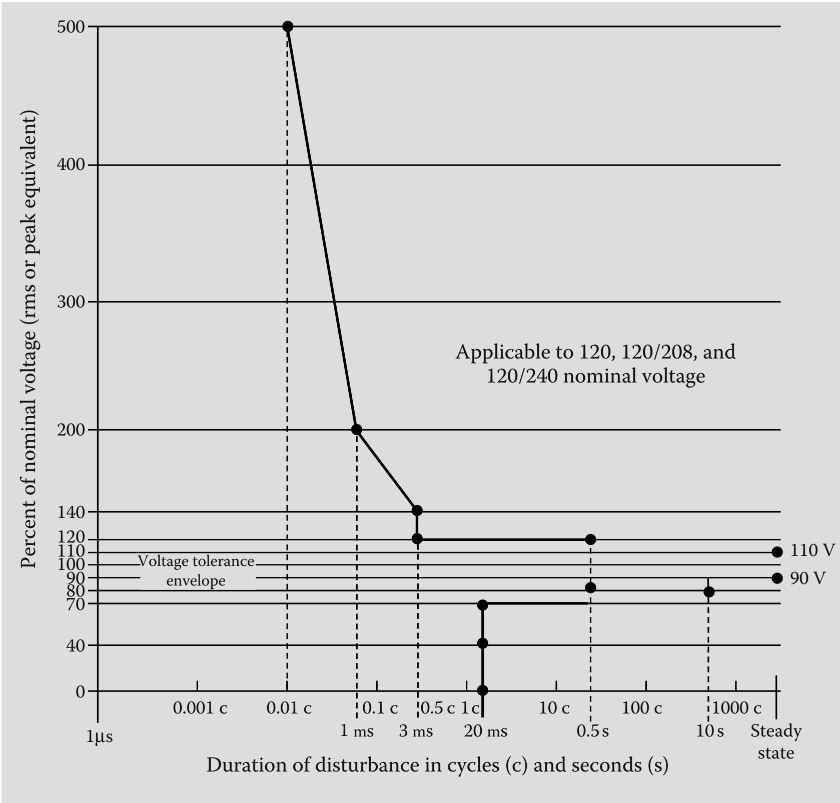


FIGURE 12.25
ITIC susceptibility profile (curve) for sensitive equipment (electronic equipment). (Courtesy of Fluke Corporation, Everett, WA.)

1449. UL 1449 rates TVSS devices by grade, class, and mode. As an example, the highest rating for a TVSS would be grade A (6000 V, 3000 A), class 1 (let-through voltage of 330 V max), and mode 1 (L–N suppression). The proper rating should be chosen based on the load's protection needs:

- A lower grade might result in a TVSS that lasts 1 year instead of 10 years. The solid-state components in a TVSS will themselves deteriorate as they keep on taking hits from transients.
- A lower class might permit too much let-through voltage that could damage the load. Class 1 is recommended for SMPS.
- A mode 2 device would pass transients to ground, where they could disrupt electronic circuit operation.

Voltage susceptibility profile: The new Information Technology Industry Council (ITIC) profile (Figure 12.25) is based on extensive research and updates of the Computer Business Equipment Manufacturers Association

(CBEMA) curve. The CBEMA curve now the ITIC curve was the original voltage susceptibility profile for manufacturers of computers and other sensitive equipment. Similar curves are being developed for 230 V/50 Hz equipment and for ASDs. Sensitive equipment should be able to survive events inside the curve. Events outside of the curve could require additional power conditioning equipment or other remedial action. A major change in ITIC is that the ride-through times for outages as well as the tolerance for sags have both been increased. The field troubleshooter must keep in mind that the profiles are recommendations and that a particular piece of equipment may or may not match the profile. The profiles are useful because, when recorded events are plotted against them, they give a general idea of the voltage quality at a particular site.

12.6.3.8 Lightning

Lightning protection plays a vital part in the overall PQ of an installation. Lightning occurrence varies by geography, with Florida being the lightning capital of the United States. Lightning does not have to score a direct hit to be disruptive. It has so much energy that it couples surges into conductors, both those exposed to air and those buried in the ground. Basic lightning protection has two main requirements:

Effective grounding: A low impedance of the grounding electrode system to earth is important. But, equally important is that all parts of the grounding system be bonded together: all ground electrodes are bonded (and extraneous ground rods removed), structural steel is tied to service entrance ground, all grounding connections are tight and free of corrosion, etc. This minimizes the phenomenon called transferred earth potential, where large surge currents create large voltage differences between two ground points with different impedances to earth. This same grounding practice is important for performance reasons, as it tends to minimize ground loop currents that circulate in an attempt to equalize ground potentials.

Surge arrestors: A surge arrestor "is a protective device for limiting surge voltages by discharging or bypassing surge current…," per NEC Article 280. Since the surge current is bypassed to ground, surge arrestors are only as effective as the grounding system. Surge arrestors are sized for the location where they are installed. Three categories are defined (ANSI/IEEE C62.41-2002).

A surge arrestor at an outside installation is closest to the lightning event and must absorb most of the energy. This is considered a Category C location (corresponding to CAT IV in IEC 61010). Category B refers to feeders and distribution panels (equivalent to CAT III in IEC 61010), and Category A refers to receptacle connected surge arrestors (equivalent to CAT II).

Surge arrestor or TVSS: A surge arrestor is there to protect the insulation and, ultimately, prevent failures that could lead to fires. It is not necessarily designed

TABLE 12.16

Inspection of Lightning Protection System

Check	Look for	Reason
Surge arrestors	Installed at main service panel, subpanels, and critical equipment	Lightning is high energy and needs multilevel protection
	To minimize high frequency impedance, leads should be short, with no bends	Lightning has high frequency components. Shorter leads have less X_L and less impedance at high frequency
Grounding electrode conductors at service entrance or at SDS	Grounding electrode connections are not loose or corroded	Ensure low impedance ground to minimize potential to ground with lightning induced surges
	Grounding conductor should not be coiled or have unnecessary bends	Minimize impedance to high-frequency components of lightning
Grounding electrode bonding	All grounding electrodes should be effectively bonded together (<0.1 W)	Prevent difference in earth potential between electrodes in event of lightning
Separately driven (isolated) electrode	Electrode and equipment ground should both be tied to building steel, and thereby to the service entrance ground	Same as above—entire grounding system should be an equipotential ground plane for lightning
Datacom cabling that runs between buildings	Surge arrestors on datacom cabling or use of fiber optic cables	Datacom cabling run between buildings can be a path for surge currents, due to differences between building earth potentials

Source: Courtesy of Fluke Corporation, Everett, WA.
Note: Lightning protection is covered in a number of standards and codes, including:
NEC*:* Articles 250 and 280
National Fire Protection Association: NFPA 780
Lightning Protection Institute: LPI-175
UL-96 and UL-96 A

to protect sensitive equipment. That's the job of the TVSS. Refer to an inspection guide on Inspection of Lightning Protection System which is given in Table 12.16.

12.6.3.9 Polyphase Induction Motors

About two-thirds of the electric power in the United States is consumed by motors, with industrial three-phase motors above 5 hp (7 kW) being by far the bulk of that load. They are linear loads and therefore do not contribute to harmonics. They are, however, the major contributor to reduced DPF, which is a measurement of the effective use of system capacity.

Measurements

Voltage unbalance: Voltage unbalance should not exceed 1%–2% (unless the motor is lightly loaded). The reason for such a small tolerance for voltage unbalance is because it has a very large effect on current unbalance, in the neighborhood of 8:1. In other words, a voltage unbalance of 1% can cause current unbalance of 8%. Current unbalance will cause the motor to draw more current than it otherwise would. Also, the unbalance voltage being delivered to motor terminals will cause the flow of negative sequence currents. Negative sequence currents produce opposing torque which the motor has to overcome therefore it will draw more current, thereby overheating the motor. For example a 3% voltage unbalance raises the motor winding temperature by 25% (refer to Section 10.10 in Chapter 10). The net effect of voltage unbalance is more heat and heat is the enemy of motor life, since it deteriorates the winding insulation.

Voltage unbalance can be caused by severe load unbalance but it could just as easily be caused by loose connections and worn contacts. Example of voltage unbalance calculation can be made as follows:

Example

$$\%V_{\text{unbalance}} = \frac{\text{Max deviation from average}}{\text{Average (of three phases)}} \times 100$$

$$\frac{3}{472} \times 100 = 0.64\% < 1\%$$

Voltage %THD and harmonic spectrum: Voltage THD should not exceed 5% on any phase. If the voltage distortion on any phase is excessive, it can cause current unbalance. The usual culprit is the fifth harmonic and therefore the harmonic spectrum should be examined for the fifth in particular. The fifth is a negative sequence harmonic which creates counter-torque in the motor. A motor fed by a voltage with high fifth harmonic content will tend to draw more current than otherwise. This is a major problem when across-the-line or soft-start motors share the same bus with VFDs.

Current unbalance: To find current unbalance, measure amps in all three phases. Do the same calculation as for voltage unbalance. In general, current unbalance should not exceed 10%. However, unbalance can usually be tolerated if the high leg reading does not exceed the nameplate full load amps (FLA) and service factor (SF). The FLA and SF are available on the motor nameplate. If the voltage unbalance and the voltage THD are within limits, high current unbalance can be an indication of motor problems, such as damaged winding insulation or uneven air gaps. Current measurement will also find single-phasing. If a three-phase motor loses a phase (perhaps caused by a blown fuse or loose connection), it may still try to run single-phase off the remaining two phases. Since the motor acts like a constant power device, it will simply draw additional current in an attempt to provide sufficient torque. A voltage measurement alone will not necessarily find this condition, since voltage is induced by the two powered windings into the nonpowered winding.

Loading: Measure current draw of the motor. If the motor is at or near its FLA rating (times the SF multiplier), it will be more sensitive to the additional heating from harmonics, as well as current unbalance. A motor that is only lightly loaded is usually safe from overheating. On the other hand, its efficiency and DPF are both less than optimal. Most motors reach maximum efficiency at 60%–80% of full load rating. DPF is maximum at rated load (including SF) and drops off, especially at less than 80% of rated load. This leads to the conclusion that, to the degree a motor load is constant and predictable, 80% of rated load is the most efficient operating range.

Inrush (lock rotor current): Motors which are started across-the-line (as opposed to those using soft-starts or drives) draw a current inrush, also called locked rotor current. This inrush tapers off to normal running current as the motor comes up to speed.

- Older motors draw an inrush of typically 500%–600% of the running current. Newer energy efficient designs draw brief inrushes as high as 1200% of running current, a direct result of the lower impedances which help make them more energy efficient in the first place.
- High torque, high horse power motor loads require proportionally higher inrush.
- Motor loads started at the same time will have a cumulative inrush. Another source of inrush is UPS and VFD systems with diode converters. They draw inrush current as their capacitor banks first charge.

Effects of inrush current:

1. Inrush causes voltage sags if the source voltage is not stiff enough. Therefore, relays and contactor coils might drop out (typically, the sag would have to get as bad as about 70% of normal line voltage); or, if they hold in, their contacts might chatter (especially if the additional load causes a long-term undervoltage). Control circuits might reset or lockup (at 90% and below). Drives might trip off-line (undervoltage trip).
2. High peak demand periods, which may cause higher utility bills.
3. Cycling loads can cause periodic sags, which might show up as flickering lights.
4. If the motor is required to start up a high torque load, the inrush can be relatively prolonged (e.g., 10 to 20 s or more) and this can cause nuisance tripping as the overload heaters trip the motor starter.

PF: If the PF of the motor is low, it can be improved by applying capacitors to supply the required reactive volt-amperes (kVAR). To size PF correction capacitors, it is necessary to measure the DPF and active power consumption (kW) of the motor load. These measurements assume that the motor voltage and current are balanced. Therefore, before undertaking PF correction, first make sure that voltage and current unbalance are within limits. Either problem can shorten motor life and should take priority over DPF correction.

12.6.3.10 PQ Measurements of VFDs

AC VFDs can be both a source and a victim of poor PQ. VFDs are also referred to as ASDs. Although ASDs are usually depicted as the culprit in the PQ scenario, there are ways in which they can be a victim load as well. ASDs can be affected as follows.

Capacitor switching transients: High-energy (relatively low frequency) transients that are characteristic of utility capacitor switching can pass through the service transformer, feeders, and converter front-end of the drive directly to the DC link bus, where it will often cause a DC link overvoltage trip. Input diodes could also be blown out by these transients.

Voltage distortion: If high-voltage distortion shows up as excessive flat-topping, it will prevent DC link capacitors from charging fully and will diminish the ride-through capability of the drive. Thus a voltage sag which would not normally affect a drive will cause the drive to trip on undervoltage.

Grounding: Improper grounding will affect the internal control circuits of the drive, with unpredictable results.

ASDs as culprit loads: A drive can definitely be a culprit load and have a major impact on system PQ. But before discussing the problems, let us put in perspective the positive effects of drives on PQ. First of all, they offer built-in soft-start capabilities. This means there will be no inrush current and no voltage sag effect on the rest of the system. Second, if the drive is of the PWM type, with a diode converter front-end, the DPF is high (commonly >95% at rated load) and more or less constant throughout the range. This means that drives can reduce energy usage and correct for DPF at the same time. It is a good thing too, because drives and PF correction capacitors do not mix. Capacitors are vulnerable to the higher frequency harmonic currents generated by drives, since their impedance decreases as frequency increases. The type of drive has a major impact on the PQ symptoms, because of the different converter designs (converters or rectifiers turn AC to DC and are the first stage of the drive). There are two major types of converter design.

1. *SCR converter with VSI/variable voltage inverter (VVI) drives*
Commonly called six-step drives, they use SCRs in their converter front-ends (the following discussion also applies to CSI drives, which also use SCRs). VSI (Figure 12.26) and CSI drive designs tended to be applied on larger drives

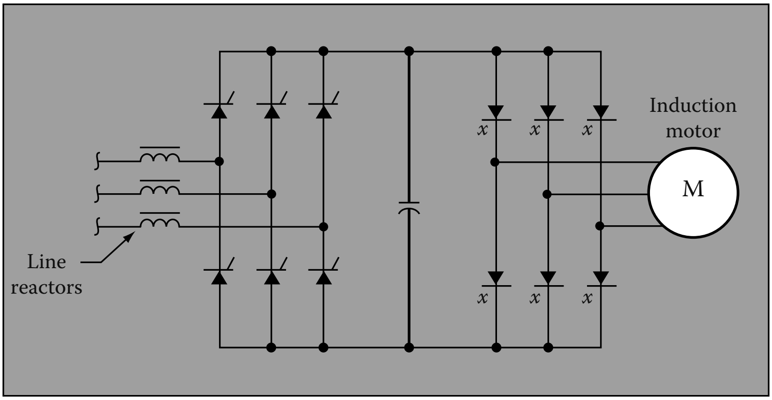


FIGURE 12.26
Electrical circuit of a VSI drive. (Courtesy of Fluke Corporation, Everett, WA.)

(>100 hp). SCR converters control the DC link voltage by switching on (or gating) current flow for a portion of the applied sine wave and switching off at the zero-crossing points. Unlike diodes, SCRs require control circuits for gate firing.

For the SCR converter, there are three main issues that affect line-side PQ:

- Commutation notches. SCR switching or commutation is such that there are brief moments when two phases will both be "ON." This causes what is in effect a momentary short circuit that tends to collapse the line voltage. This shows up as notches on the voltage waveform. These notches cause both high V-THD and transients. The solution is to place a reactor coil or isolation transformer in series with the drive's front end to clean up both problems.
- DPF declines as drive speed decreases. This is not as serious a problem as it sounds, because the power requirement of the drive-motor-load decreases even more.
- Harmonic currents, typically the fifth and seventh, are generated by VSI drives.

2. *Diode converter with PWM drives*

The other and more common converter design uses diodes and is used in the PWM drive (Figure 12.27). The diodes require no switching control circuitry. One of the main trends in the industry has been the proliferation of PWM drives, mainly due to the continued development of fast switching, efficient insulated gate bipolar transistors (IGBTs) used in the inverter section of the drive (inverters turn DC to AC). For all practical purposes, PWM drives are the industry standard. For the diode converter, the main PQ issue is harmonics. The actual harmonic orders being generated depend on the number of

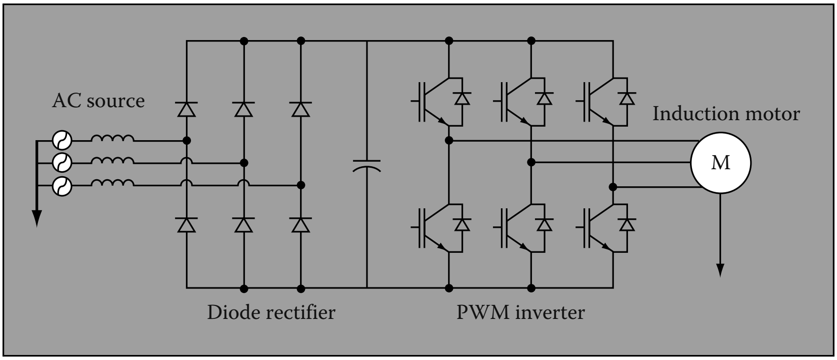


FIGURE 12.27
Electrical circuit of the PWM drive. (Courtesy of Fluke Corporation, Everett, WA.)

diodes in the front end. For three-phase conversion, a minimum set of six diodes is required. This six-pulse converter will generate fifth and seventh harmonics. If a 12-pulse converter were used, the 11th and 13th harmonics will be generated instead of the fifth and sixth—and, very importantly, for the same load, the amplitude of the 11th and 13th would be considerably less than the 5th and 6th. Therefore, the THD would be less. The vast majority of drives, however, are six-pulse PWM style, which is one reason we see so much fifth harmonic on the system.

Harmonics solutions: There are a number of solutions to mitigating drive-generated harmonics. They are the following:

1. Harmonic trap filters (Figure 12.28)
These are typically LC networks connected in parallel at the source of the harmonics (in other words, at the drive input). They are tuned to just below the fifth harmonic (typically 280 Hz) and will tend to sink both fifth and much of the seventh harmonic. Obviously, they must be sized to the harmonic-generating load.

2. Phase-shift transformers
This can be as simple as a delta–wye transformer feeding one drive(s) and a delta–delta feeding another drive(s). There is a 30° phase-shift effect between these two configurations, which effectively results in cancellation of harmonics at the closest upstream PCC. The cancellation effect is optimal when both loads are more or less equal.

12.6.3.11 Power System Resonance

Is it possible to install PF correction capacitors and have PF get worse? It certainly is and a starting place to understanding this puzzle lies in the distinction between DPF and total PF. The penalty for not understanding the

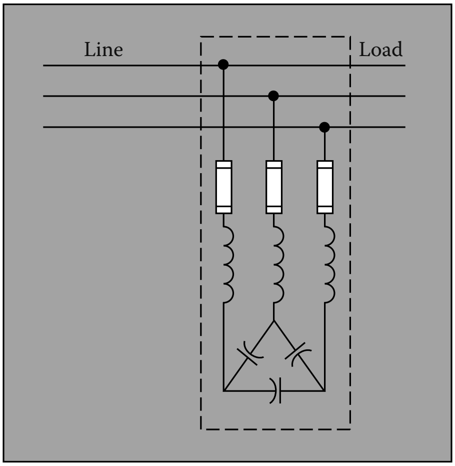


FIGURE 12.28
Harmonic trap filter. (Courtesy of Fluke Corporation, Everett, WA.)

difference can be blown capacitors and wasted investment. Total PF and DPF are the same in one basic sense: they are the ratio of real power to apparent power, or watts to VA. DPF is the classic concept of PF. It can be considered as the PF at the fundamental frequency. Total PF now includes the effects of fundamental and of harmonic currents (it is also referred to as true PF or DPF) (see Figure 12.13). It follows that with the presence of harmonics, PF is always lower than DPF and is also a more accurate description of total system efficiency than DPF alone. Strictly speaking, the term PF refers to total PF, but in practice can also be used to refer to DPF. Needless to say, this introduces some confusion into discussions of PF. You have to be clear which one you are talking about.

DPF: Lower DPF is caused by motor loads which introduce the need for reactive power (VARs). The system has to have the capacity, measured in VA to supply both VARs and watts. The more VARs needed, the larger the VA requirement and the smaller the DPF. The cost of VARs is accounted for in a PF penalty charge.

Utilities often levy additional charges for DPF below a certain level; the actual DPF number varies, but typical numbers are 0.85 to 0.9. To reduce VARs caused by motor loads, PF correction capacitors are installed. Upstream system capacity, both in the plant and at the utility level, is released and available for other uses (Figure 12.29). Historically, this has been the gist of the PF story: a relatively well-known problem with a relatively straightforward solution.

Harmonics and capacitors: Harmonics have had a dramatic impact on the application of PF correction. The motor and capacitor loads described above are all linear and for all practical purposes generate no harmonics. Nonlinear

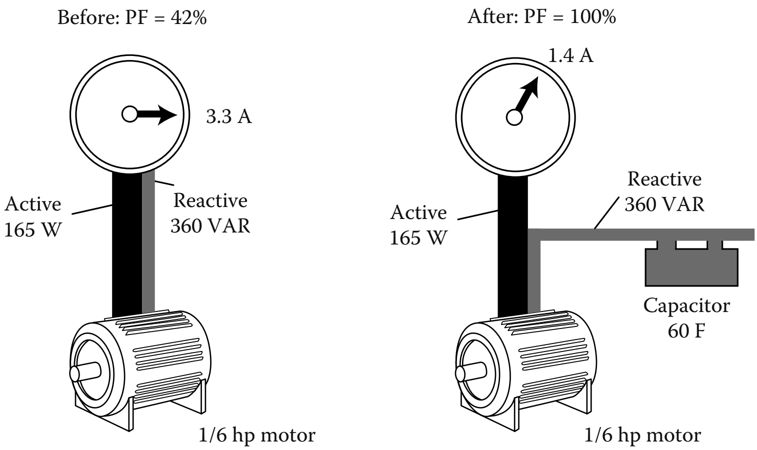


FIGURE 12.29
Capacitor corrects DPF. (Courtesy of Fluke Corporation, Everett, WA.)

loads such as VFDs, on the other hand, do generate harmonic currents. Take a plant which is step-by-step putting VFDs on its motor loads.

VFDs generate significant harmonic currents (fifth and seventh on six-pulse converter drives). Suddenly the fuses on existing PF correction caps start blowing. Since these are three-phase caps, only one of the three fuses might blow. Now you have got unbalanced currents, possibly unbalanced voltages. The electrician replaces the fuses. They blow again. He puts in larger fuses. Now the fuses survive, but the capacitor blows. He replaces the capacitor. Same thing happens. What is going on? Harmonics are higher frequency currents and higher the frequency, the lower the impedance of a cap. The cap acts like a sink for harmonic currents.

Power system resonance: In a worst-case scenario, the inductive reactance (X_L) of the transformer and the capacitive reactance (X_C) of the PF correction cap form a parallel resonant circuit: $X_L = X_C$ at a resonant frequency which is the same as or close to a harmonic frequency. The harmonic current generated by the load excites the circuit into oscillation. Currents that are many times greater than the exciting current then circulate within this circuit. This so-called tank circuit can severely damage equipment, and it will also cause a drop in PF. This resonant condition often appears only when the system is lightly loaded, because the damping effect of resistive loads is removed. In other words, we have what the audio buffs call a high Q circuit. (Figure 12.30).

Start with harmonics mitigation: The correct solution path starts with measuring and mitigating the harmonics generated by the drives. Harmonic trap filters would generally be called for. These trap filters are installed locally on the line side of the drive. Their effect is very much like the traditional PF correction cap, in two senses: they reduce DPF as well as PF, and also they

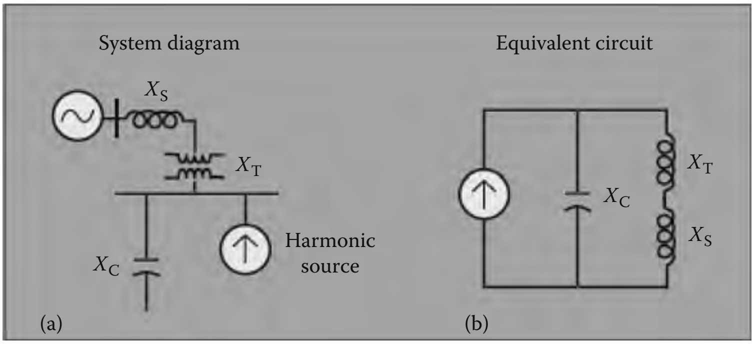


FIGURE 12.30
Resonant circuit when $X_C = (X_T + X_S)$. (Courtesy of Fluke Corporation, Everett, WA.)

localize the circulation of the problem harmonics (generally the fifth). Harmonics mitigation and traditional DPF correction should be addressed as one systems issue. In other words, manage total PF, not just DPF.

12.6.3.12 Commercial Lighting Load

Lighting loads are a major load for many large facilities. Evaluating these circuits is important for both energy conservation and PQ (see Table 12.17). Keep in mind that commercial lighting loads are wired single phase, with the loads connected from phase-to-neutral. Typically, the phase-to-phase voltage is 480 V, with the phase-to-neutral voltage at 277 V. Measurements must be taken at the lighting panel, one phase at a time, since power consumption and PF could vary on each phase. Consider the following factors from the PQ perspective.

TABLE 12.17
Measurements on Commercial Lighting Loads

Measurement	Look for	Instrument
1. Power consumption (kW)	Balance among three phases	Three-phase/ single-phase analyzer
2. DPF and PF	Magnetic ballast will have low DPF Electronic ballast may have low total PF, although new generations of ballast often have harmonic mitigation built-in	Same
3. %THD	Current %THD <20% is desirable	Same
4. Voltage stability	Unstable voltage can cause lights to flicker	Same

Source: Courtesy of Fluke Corporation, Everett, WA.

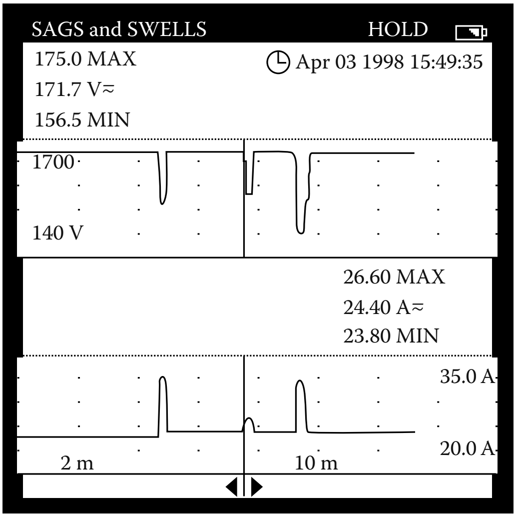


FIGURE 12.31
Fluke 43 trends voltage (*top*) and current (*bottom*) simultaneously. Current swells/inrush caused voltage sags, indicating that a load downstream from the measurement point is the cause of the disturbance. (Courtesy of Fluke Corporation, Everett, WA.)

Power consumption: Excessive phase unbalance can cause voltage unbalance, which in turn can affect three-phase motor loads.

PF: Ballast with low PF might have lower cost-of-purchase but higher cost-of-operation.

THD: Current THD should be considered when selecting ballast, especially if there is a possibility of transformer overloading.

Voltage stability: The sags and swells mode of the Fluke 43 (or similar instrument) is especially useful for recording repetitive voltage sags which can show up as flickering lights. Both current and voltage are monitored simultaneously (Figure 12.31). This helps us to tell if sags are downstream of the measuring point (load related) or upstream (source related). For example, if voltage sags while current swells, a downstream current inrush likely caused the sag. If both voltage and current sag at the same time then some event upstream has caused the sags. It could be an upstream load like a motor on a parallel branch circuit which drew down the feeder voltage. Or it could be source voltage related, for example, a lightning strike or breaker trip/reclosure on the utility distribution system.

12.6.3.13 Summary of PQ Problems

The following summary is provided of the PQ problems discussed in this section beginning from utility source all the way down to 120 receptacles. These PQ problems are:

Lightning: Can be extremely destructive if proper surge protection is not installed. It also causes sags and undervoltages on the utility line if far away. If close by, it causes swells and overvoltages. But in the final analysis, lightning is an act of nature and not in the same category as the damage man does to himself.

Utility automatic breaker reclosure: Causes short duration sags/outages, but better than the alternative, a longer-term outage.

Utility capacitor switching: Causes a high-energy voltage disturbance (looks like an oscillating transient riding on the wave). If the cap bank is near the facility, this transient can propagate all through the building.

Facility without enough distribution transformers: Trying to cut corners in the wrong places; running 208 V feeder up 20 stories is not the road to PQ.

Gen-sets not sized for harmonic loads: Excessive voltage distortion affects electronic control circuits. If SCR converter loads are present, notching can affect frequency control circuits.

PF correction capacitors and the effects of harmonics: Harmonics and caps do not mix. Those bulging capacitors are crying for help.

Inrush currents from high torque motor: Causes voltage sags if the load is too large or the source impedance too great. Staggered motor starts can help.

Undersized neutrals at panelboard: In the era of the third harmonic currents, neutrals can easily carry as much current or more current than the phase conductors. Keeping undersized neutral leads to overheated neutral and lugs, potential fire hazards, and high N–G voltage.

Running power and signal cables together: Think of the signal cable as a single-wire transformer secondary and the power cable as the primary. The opportunities for coupling are endless.

Loose conduit connections and lack of green wire grounding conductor: Causes open or high impedance ground circuit. Not good for PQ or safety.

Hi-frequency noise: The most effective high frequency grounding technique is the installation of a SRG.

IG rods (Figure 12.32): They are a safety hazard because the earth is a high impedance path and will prevent enough current from flowing to trip the breaker. They also cause ground loops; after all, every electron still has to go back where it came from. Further, if a person comes in contact with the ground where the step potential is high because of the high impedance path of the earth, the person will get shocked, injured or killed. One of the great mysteries of PQ is how some manufacturers get away with insisting that their equipment warranty is void unless an IG rod is installed. This installation is in violation of the NEC requirements for single point grounding.

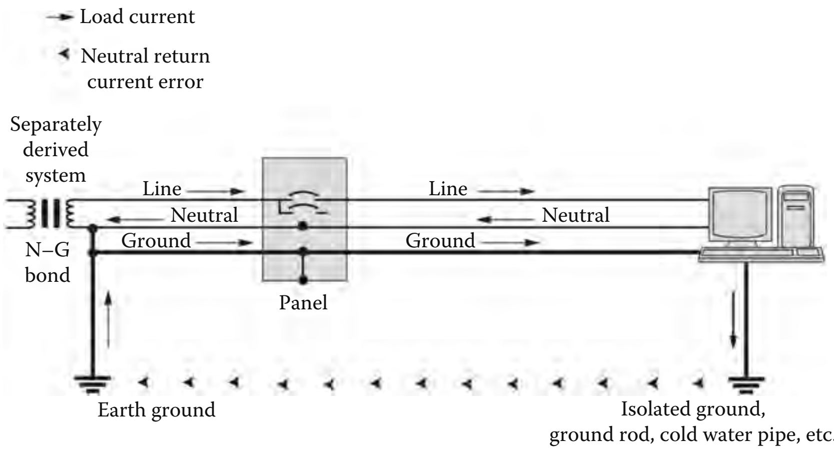


FIGURE 12.32
IG rod can cause ground loops. Common problem with machine tool installations. (Courtesy of Fluke Corporation, Everett, WA.)

Shared neutrals on branch circuits: Causes load interaction and overloaded neutrals.

Laser printers and copiers sharing branch circuits with sensitive loads: Guaranteed periodic voltage sags and switching transients.

Miswired receptacles (N–G swapped): Hard to believe, but they are very common in most facilities. Guaranteed to put return currents on the ground conductor and create a noisy ground.

Data cables connected to different ground references at each end: Shows up as voltage between equipment case and the data cable connector.

Illegal N–G bonds: Guaranteed to put return currents on ground. Not only is it a PQ problem, it is a plumbing problem. Circulating ground currents cause corrosion of water pipes.

12.7 PQ Solution and Power Treatment Devices

In Sections 12.1 through 12.5, we discussed concepts, origins, characteristics and effects of voltage disturbances, and HDs on power system equipment. In Section 12.6 a predictive maintenance and troubleshooting guide was presented to identify and quantify the PQ-related problems. Once the PQ problem is identified and its effects on power equipment are understood, the next obvious step is to find a solution to correct the offending problem? There is no one answer that fits all PQ-related solutions. Each type of PQ problem requires its very own solution or treatment. There are many power treatment devices that reflect different philosophies advocated by varying PQ professionals. To the user the wide variety of what is available on the market for resolving PQ problems can be confusing and frustrating. However, there are some basic considerations in selecting and applying PQ solutions that all agree upon. First, is there a single problem or multiple problems, and is the nature of the problem(s) understood so an informed solution can be implemented; second any solution or treatment device installed has to obey the laws of physics and must be implemented without adversely affecting the loads; third the installation of the treatment device must be done correctly because if improperly installed, it may be detrimental to the system operation as was the original problem; and last the treatment device must be compatible with the load otherwise it may interact with the load causing a condition that is actually worse than before. The solutions and power treatment devices for solving PQ problems can be classified into three problem categories:

1. Voltage disturbances and noise
2. HDs
3. Wiring and grounding

Treatment devices are applied to modify a given electrical power to improve its quality and reliability for correct functioning of its loads. They can perform a range of functions such as voltage regulation, noise elimination, and standby power supply (SPS), among others. Many different types of mitigating devices are available, but specification and selection of mitigating equipment is dependent upon two considerations. First, the type of load to be powered must be considered. Single loads are effectively regulated with the proper mitigating device. However, larger systems that support many loads are far more complex. Requirements of all loads require consideration, as well as the potential interaction between them to determine the proper mitigating devices required. Second, the equipment requirements for each application must be considered. Examples of such requirements include PQ requirements of the load, problems (improper wiring and grounding, temperature, humidity, ESD, etc.) which could interfere with proper operation of the critical load, type of conditioning required, future quality and reliability of the power supply, and cost to eliminate or mitigate power-related problems. The most commonly used mitigating devices and their characteristics for the three categories identified above are discussed as follows:

12.7.1 Voltage Disturbances and Noise

The voltage disturbance, such as impulses, transients, swells, voltage dips, and interruptions were discussed in Section 12.2. The treatment devices for mitigating voltage disturbances and noise may be grouped as follows:

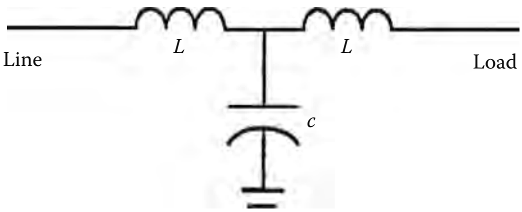


FIGURE 12.33
Basic noise filter without surge suppressors and tracking filters. (Courtesy of Fluke Corporation, Everett, WA.)

- Line (noise) filters
- TVSS
- Voltage regulators
- Isolation transformers
- Power conditioners
- UPS

12.7.1.1 Noise Filters (Electronic Filters)

Noise filters prevent interference (e.g., conducted EMI and/or RFI) from traveling into sensitive electronic equipment from the power source. These filters also prevent equipment that generates interference from feeding it back into the power line. Most sensitive electronic equipment utilize some type of noise filter. A basic noise filter is low pass LC filter, that is it passes line frequency (60 Hz) and blocks the very high frequencies or steep wave front transients (Figure 12.33). This is accomplished by series inductors followed by capacitors to ground. The inductor forms two impedance paths: one low for the 60 Hz power and one high for the high-frequency noise. The remaining high-frequency noise is conducted by the capacitor to ground before it reaches the load. Many line filters are based on surge suppression components, such as surge suppressors but also have components that provide frequency response and waveform tracking. Waveform tracking allows the filter to clamp impulses at lower voltages than TVSS. The line filters exert more control over normal mode events compared to CM event because of absence of ground isolation capabilities. The line filters are listed under UL 1012, Standard for Safety of Power Supplies.

12.7.1.2 TVSS

TVSS protect against voltage spikes and oscillatory-transient voltages. They are either gap type or the clamping type. The gap type is relatively slow acting (microseconds) with large energy handling ability. The clamping type is fast acting (nanoseconds) with somewhat smaller energy-handling ability. The gap type units are best used near the power source entrance where as clamping type units are used near the equipment being protected.

The four basic types of equipment used for protection from transients are crowbar devices, voltage-clamping devices, attenuation (filtering) devices, and hybrid devices. The crowbar devices include air gaps, gas discharge tubes, lightning arrestors, and switching devices. The voltage-clamping devices consist of varistors (nonlinear resistors), MOVs, zener diodes, and selenium rectifiers. These devices are unidirectional conductors until a breakdown voltage is reached, at which time they conduct in the reverse direction. Attenuation devices are inserted in a circuit to permit power at line frequency to pass, while attenuating transients. They are referred to as noise filters or low-pass filters. The attenuating devices are not truly suppression devices, but have applications when noise or transients at particular frequencies are found on a specific power or data line. Hybrid devices are transient suppressors that combine two or more technologies to provide transient suppression over a wide range of voltages, rates of rise, and energy content. Protecting computers and sensitive electronic equipment against transients is a good installation practice. Careful grounding is necessary for these devices to be effective. Power to computers also should be separated electrically as much as possible from the remainder of building power system. Incoming power lines, data and communications lines entering from outside the building, and those inside the building subjected to transients should have transient protection. Separate protection for individual units may be needed (unless already built into the equipment) for computers and sensitive electronic equipment. In selecting the transient suppression devices, careful consideration should be given to the voltage rating of the devices. The devices selected should have a minimum voltage rating that is higher than the system or data line voltage or phase-to-phase or phase-to-ground voltage. Selecting the energy dissipation rating required is somewhat more difficult since it is rarely possible to predict the energy content of the transient that might occur. The device selected must survive the worst possible transient and, at the same time, the clamping voltage must not exceed the withstand voltage rating of the equipment being protected. Transient devices should be installed using the shortest possible conductors, so that its inductive reactance is small at high transient frequencies. UL standard for safety, 1449 provides criteria for safety and performance testing of TVSS. TVSS tested and approved in accordance with this standard list the approval marking and maximum suppression voltage of the device.

12.7.1.3 Voltage Regulators

There are two types of voltage regulators that are available for maintaining correct voltage to the load. They are line voltage regulator and constant voltage regulator. The line voltage regulators maintain a relatively constant voltage output within a specified range, regardless of input voltage variations.

Although DC line voltage regulators are built into most sensitive electronic equipment, AC regulators are only now being built into some equipment. These regulators use the same ground reference on output as for the incoming power. They can only modify input line voltage amplitude and cannot establish a new signal. Solid-state devices (e.g., constant voltage and tap-changing transformers) are being used almost exclusively, rather than electromechanical types.

Line voltage regulators typically are used to protect against momentary and transient disturbances within a certain range. These regulators have a typical response time of 1 cycle. While many voltage problems can be handled by the appropriate application of a line voltage regulator, it is not suitable to protect sensitive electronic loads against rapid changes in voltage. They also do not have noise suppression capabilities. Regulators with switching power supplies actually create noise, and therefore are unsuitable for critical loads. The regulators also can become unstable if other regulators with similar response times are on the same circuit. Two types of line voltage regulators currently are available: tap changers and buck–boost.

The tap changers, also known as tap switchers or electronic tap switching transformers, regulate output voltage in response to fluctuations in input voltage or load (see Figure 12.34). This is accomplished with solid-state switches (SCRs or triacs) which automatically select appropriate taps on a power transformer (either isolating type or autotransformer type) at the zero current point of the output wave. Some of these devices are voltage switching type units that make the tap change at the voltage zero crossing. This causes a transient to be generated except when the load is at unity PF. The magnitude of this transient is determined by actual load conditions.

The buck–boost regulators assure smooth continuous output by regulating heavy inrush currents typically delivered by computer start-ups or disk drive motors. When power is fed into these regulators, they either add to (boosts)

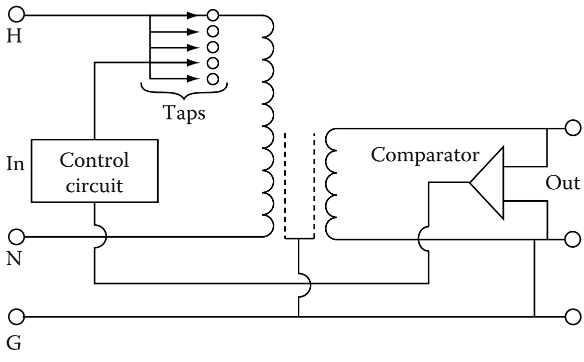


FIGURE 12.34
Tap changer voltage regulator. (Courtesy of Fluke Corporation, Everett, WA.)

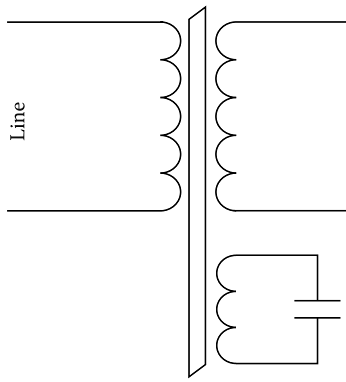


FIGURE 12.35
Basic constant voltage (ferroresonant) regulator.

or subtract from (bucks) the incoming voltage. These electronic devices eliminate use of steps as compared to the tap changer. Output is maintained constant for 15%–20% variations of input voltage. This is accomplished by comparing output voltage to the desired (set) level and by the use of feedback to modify the level of boost or buck. A path for nonlinear currents generated by the load and by the regulator itself is provided by a parametric filter. An advantage of buck–boost regulators is that they attenuate normal mode noise and surges. In addition, if they are built with isolation and shielding, the regulators can be separately derived source for power grounding, and can provide CM noise reduction.

The constant voltage regulator is typically referred to as ferroresonant regulators or constant voltage transformers (CVTs). This type of regulator is a relatively simple device because it has no moving or active electronic parts. It uses a saturating transformer with a resonant circuit made up of the transformer's inductance and a capacitor (Figure 12.35). The unit maintains a nearly constant voltage on the output for input swings of 20%–40%.

CVTs are susceptible to load imbalances and can become unstable. If the load current gets too high, these transformers tend to go out of resonance. They often can only supply 125%–200% of their full load rating. As a result, the CVTs cannot support starting current of motors exceeding these limits without a drastic dip in output voltage. CVTs are very inefficient at light loads and less efficient at all other load levels. Their poor efficiency is due to the resonant circuit which handles relatively large amounts of current all the time. As a result, the circuit causes the heat loss to be higher than other types of regulators. Noise can be a problem with these transformers requiring special enclosures. Because of its saturating elements, the CVT is a nonlinear device and introduces harmonic currents on the power source supplying it. The constant voltage regulators should be oversized in order to provide for heavy starting or in-rush currents. This is because output voltage is significantly reduced when these regulators are near their current limits.

The possibility also exists that the output voltage may not be compatible with some loads. In some cases, this can shut down other devices as a result of low output voltage of the CVT.

12.7.1.4 Isolation Transformers

Isolation transformers incorporate separate primary (or input) and secondary (or output) windings with electrostatic Faraday shielding around the windings. They perform two distinct functions. First, they transform or change the input to secondary output voltage level and/or to compensate for high or low voltage. Second, the transformers establish the power ground reference close to the point of use. Because of this, CM noise induced through ground loops or multiple current paths in the ground circuit upstream of the established reference ground point is significantly reduced.

Isolation transformers introduce minimal magnetizing current distortion into the input source. The delta-connected primary winding of the transformer can reduce the balanced third harmonic currents fed back to the source by single-phase nonlinear loads which are supplied from three-phase feeder systems. When a delta primary, wye secondary, isolation transformer is used to power a load such as a single-phase rectifier, the balanced third harmonic currents circulate in the delta primary so they are not seen by the power source. An isolation transformer may be designed with a simple electrostatic (Faraday) shield between the two sets of windings or they can be equipped with multi shields. Figure 12.36 shows an isolation transformer with three electrostatic Faraday shields, where primary and secondary winding are individually shield with an overall shield system. A single shield is normally adequate in most applications however additional shields increase the CM rejection capabilities of the transformer. This Faraday electrostatic shield comprises of conducting sheets of nonmagnetic material (copper or aluminum) connected to ground. They are designed to improve the isolation characteristics of the transformer. Electrostatic shielding adds little to the cost, size, and weight of the transformer. Isolation transformers can achieve efficiencies from 95% to 98%. These transformers generate little heat and are relatively quiet. They can be installed separately or with PDUs. Isolation transformers with distribution units have the advantage of being able to be located very close to the critical load.

12.7.1.5 Power Conditioners

Power line conditioners consist of one or more basic power treatment devices as previously discussed in this section. Some power conditioners may provide impulse attenuation, high-frequency filtering, isolation and voltage regulation others may not provide these features. Some of the power conditioners are: enhanced isolation transformer, ferroresonant power

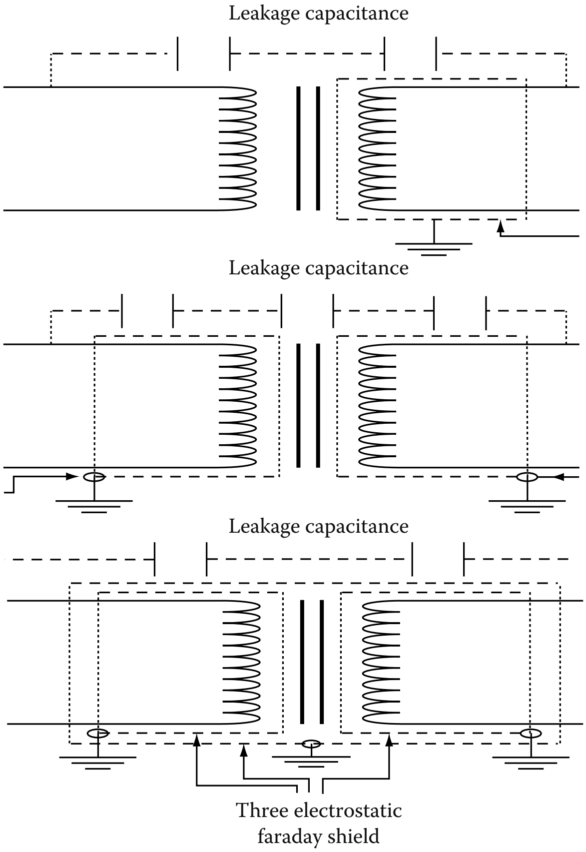


FIGURE 12.36
Isolation transformer with three electrostatic shields.

conditioner, tap switching power conditioner, magnetic synthesizer, and motor generator (M-G) sets. These conditioners also provide a locally derived source with isolation while providing voltage regulation. Some advanced conditioners contain noise reduction features of isolation transformers, filtering devices with voltage regulators, or surge suppressors to clamp high voltage surges.

The enhanced isolation transformer uses MOVs and air core wound chokes on the primary and a large capacitor across the secondary. These transformers were designed primarily for modern SMPS. The impedance of the transformer is kept low to ensure capability with the high inrush current of the power supply. The enhanced isolation transformers are available with single or multiple shields for improved CM noise attenuation.

The ferroresonant power conditioner is an isolation transformer operating in a saturated mode which was discussed in Section 12.7.1.3. It operates like a ferroresonant regulator with capability to regulate voltage and to a degree perform waveshaping. Also, shielding between the primary and secondary improves the high frequency attenuations capabilities.

The tap switching power conditioner is an isolation transformer with multiple taps for voltage correction. However, some tap switching power conditioners do not use isolation transformers, but instead use autotransformer. This power conditioner has the capability to regulate voltage, provide impulse attenuation and filtering.

The magnetic synthesizers consist of nonlinear inductors and capacitors in a parallel resonant circuit with six saturating pulse transformers. These synthesizers draw power from the source and generate their output voltage waveform by combining the pulses of the saturating transformers in a step wave manner. They provide noise and surge rejection and regulation of output voltage to within 10% over large swings (50%) input voltage. These units generally include additional filtering to eliminate self-induced harmonics and pulse transformer shielding to attenuate CM disturbances. The magnetic synthesizer inherently limits maximum current at full voltage to 125%–200% of the rating. With greater loads, voltage drops off rapidly, producing typically 200%–300% current at short circuit. Large step load changes, even within the unit's rating, can cause significant voltage and frequency transients in the output of this conditioner. These regulators work best when the load does not make large step changes. Due to the magnetics involved, these synthesizers tend to be large and heavy. They also can be acoustically noisy without special packaging. Some of the larger units display good efficiencies, as long as they are operated at close to full load. The magnetic synthesizer introduces current distortion on its input, due to its nonlinear elements, which is at its highest when the conditioner is lightly loaded.

The M-Gs transform AC electrical power to mechanical power, then back to AC electrical power. They consist of an AC powered electric motor driving an AC generator, which then supplies AC power to the load as shown in Figure 12.37. Two types of M-Gs are utilized today. These are shaft or belt isolated M-Gs and rotating transformer M-Gs. In the former, the motor and generator are coupled by a shaft or belts. The latter units have a common rotor, a motor stator, and a generator stator. They generally are small units and have excellent efficiency values. One disadvantage is that they do not provide the same level of noise and surge isolation between the input and the output as conventional M-Gs. Because of the coupling between the two stators (which are wound one on top of the other), the noise has a path through the unit. Shaft or belt isolated M-Gs are used widely as a source of 415 Hz power for large computers requiring this frequency. They can be easily powered by a single 60 Hz induction motor. As the induction motor speed varies, the output frequency varies with motor speed since the generator output is a function of its shaft speed. However, the output voltage is maintained by controlling the excitation of the field winding of the generator and the generator output voltage is independent of small motor speed changes.

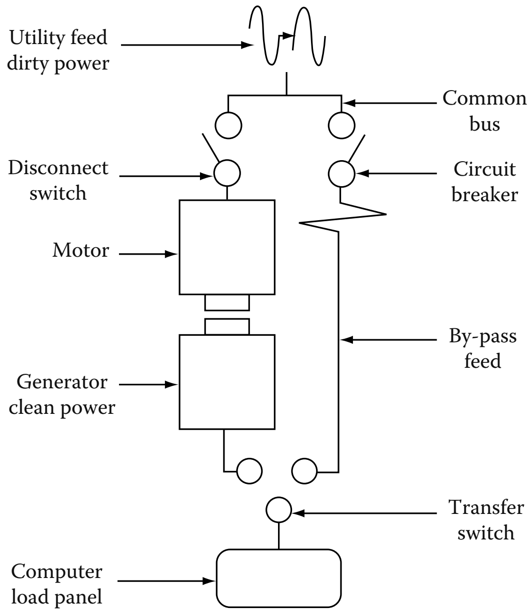


FIGURE 12.37
Motor-generator set.

12.7.1.6 UPS

An UPS conditions incoming power and provides continuous power in the event of a power failure (Figure 12.38). UPS typically contain batteries that can be used during power interruptions. They are either online or off-line and are available in a wide range of configurations, from battery backup to units backed by a standby generator that can supply power for days. Two types of UPS systems predominately used are static and rotary UPS (RUPS).

Static UPS systems: A majority of UPS systems used today are static. They are preferred over rotary systems because of lower cost, higher efficiency,

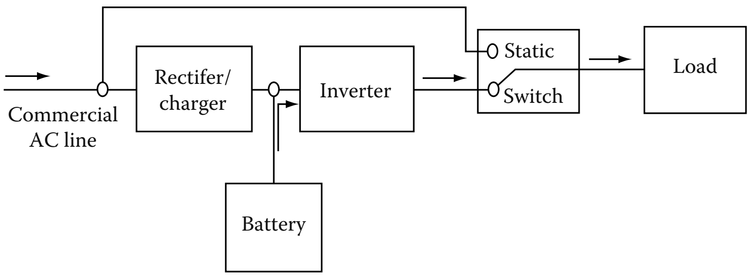


FIGURE 12.38
General configuration of an UPS.

ease of maintenance, and fewer moving parts. Static UPS systems instantly provide power from battery to the load in the event of a power failure. Batteries used for large installations usually are lead-acid wet cells. Some smaller units use gelled-electrolyte cell or immobilized-electrolyte cell (maintenance free) batteries. Cost is influenced considerably by the length of battery protection time required and load size. In most instances, 15 min of protective time is considered adequate because it permits an orderly shutdown of the load equipment. In many instances, however, the UPS system is used in conjunction with an engine-generator set. As such, the UPS provides instantaneous power until such time as load can be transferred to the engine-generator set. In the event of an inverter failure or while maintenance is being performed on the UPS, a bypass transfer switch is included to allow connection of the utility to the critical load. This load can be transferred without interruption because UPS output is kept in phase with the utility source under normal operation. Static UPS systems can be either float-type (online) or AC-input type.

The RUPS systems can be configured in several different ways. In one configuration, shown in Figure 12.39, the rectifier of a RUPS is supplied from the utility source while the battery floats online. The inverter's output frequency is slaved to the utility source and follows it exactly. The solid-state rectifier supplies DC to the inverter and also maintains the battery at appropriate float charge. The step function square wave AC output is used to drive the motor which, in turn, powers the generator. The M-G's output frequency is maintained at 60 Hz. When the incoming power is interrupted, the high-capacity batteries supply DC to the inverter which, in turn, supplies power to the M-G set. The inverter frequency control system maintains motor frequency within ±0.1% of rated 60 Hz while the batteries supply the load.

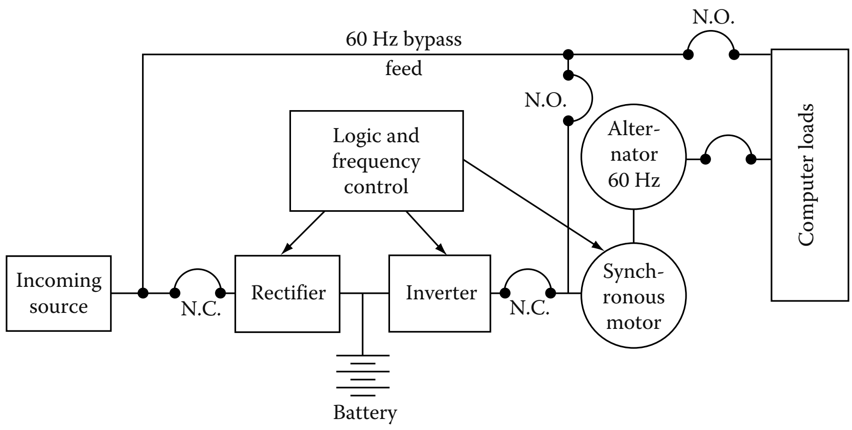


FIGURE 12.39
Rotary UPS.

Also, the UPS can be configured as SPS systems to provide energy that can be used during power interruptions. SPSs typically comprise of batteries and are either off-line or stand-by type. Two categories of SPSs that are used to supply backup power are rotary and static SPS systems. These systems are designed as standby systems such that during normal operation the power is supplied via the bypass circuit to the loads. If a power interruption occurs, the SPS switches to the battery to supply power to the inverter, which in turn supplies the load.

12.7.2 HDs

The effects of HD on power equipment and circuits were discussed in Section 12.5. High levels of stress due to HD can lead to problems for the utility's distribution system, plant distribution system and any power equipment serviced by that distribution system. Effects can range from spurious operation of equipment to a shutdown, such as machines or assembly lines, or catastrophic failure of equipment. Harmonics can lead to power system inefficiency as well because increase in HD will decrease true PF. Some of the negative ways that harmonics affect plant equipment are summarized below:

Conductor overheating: Conductor heating is a function of the square of the rms current per unit volume in the conductor. Harmonic currents on undersized conductors or cables can cause a skin effect, which increases with frequency.

Capacitors: Capacitors are affected by heat increases due to power loss (temperature rise) which will shorten life of capacitors. If a capacitor is tuned to one of the characteristic harmonics such as the fifth or seventh, overvoltages due to resonance can cause dielectric failure or rupture of capacitor.

Fuses and circuit breakers: Harmonics can cause false or spurious operations of relays, breakers and protective trips, damaging or blowing components.

Transformers: Transformers have increased iron and copper losses or eddy currents due to stray flux losses. This causes overheating of transformer windings and iron (core).

Generators: Generators experience similar problems as transformers. Sizing and coordination is critical to the operation of the voltage regulator and controls. Excessive harmonic voltage distortion will cause multiple zero crossings of the current waveform. Multiple zero crossings affect the timing of the voltage regulator, causing interference and operation instability.

Revenue meters: Revenue meters may record measurements incorrectly, resulting in higher billings to user.

Drives/power supplies: VFDs and power supplies can be affected by misoperation due to multiple zero crossings. Harmonics can cause failure of the commutation circuits, found in DC drives and AC drives with SCRs.

Computers/telephones: These devices may experience interference or failure.

12.7.2.1 Industry Standards on Limits of Harmonics

The most often quoted standard on harmonics in the United States is IEEE 519-1992, "Recommended practices and requirements for harmonic control in electric power systems." The IEEE 519-1992 attempts to establish reasonable harmonic goals for electrical systems that contain nonlinear (harmonic producing) loads. The objective is to propose steady state harmonic limits that are considered reasonable by both electric utilities and their customers. The underlying philosophy is that

- Customers should limit harmonic currents
- Electric utilities should limit harmonic voltages
- Both parties share the responsibility for holding harmonic levels in check

IEEE 519 applies to all voltage levels, including 120 V single-phase residential service, industrial and commercial entities, and utilities as well. While it does not specifically state the highest-order harmonic to limit, the generally accepted range of application is through the 50th harmonic for the industrial and commercial facilities. DC, which is not a harmonic, is also addressed and is prohibited. Since no differentiation is made between single-phase and three-phase systems, the recommended limits apply to both. It is important to remember that IEEE 519-1992 is a recommended practice and not an actual standard or legal document unless it is adopted by the local jurisdiction. Rather, it is intended to provide a reasonable framework within which engineers can address and control harmonic problems. It has been adopted by many electric utilities and by several state public utility commissions, such as Texas and Oklahoma states.

According to the IEEE 519-1992 standard, the industrial and commercial entity is responsible for controlling the harmonic currents created in their power systems. Since harmonic currents reflected through distribution system impedances generate harmonic voltages on the utility distribution systems, the standard proposes guidelines based on industrial distribution system design. The Table 10.3 in IEEE 519-1992, defines levels of harmonic currents that industrial and commercial customers can inject onto the utility distribution system. The contents of this table are shown in Table 12.18.

Table 11.1 of IEEE 519-1992 defines the voltage distortion limits that can be reflected back onto the utility distribution system. Usually if the industrial or commercial user controls the overall combined current distortion according to Table 10.3 of IEEE 519, this should help the customers meet the limitations set forth in the guidelines of IEEE 519 standard (Table 12.19).

12.7.2.2 Evaluating System Harmonics

In order to prevent or correct harmonic problems within an industrial or commercial facility an evaluation of system harmonics should be performed to quantify the problem. The harmonic evaluation can be conducted by either

TABLE 12.18

Current Distortion Limits for General Distribution Systems (120 V–69 kV)

Maximum Harmonic Current Distortion in % of I_L	**Individual Harmonic Order (Odd Harmonics)**[a,b]					
I_{SC}/I_L	**<11**	**$11 \leq h \leq 17$**	**$17 \leq h \leq 23$**	**$23 \leq h \leq 35$**	**$35 \leq h$**	**TDD**
<20[c]	4.0	2.0	1.5	0.6	0.3	5.0
20 < 50	7.0	3.5	2.5	1.0	0.5	8.0
50 < 100	10.0	4.5	4.0	1.5	0.7	12.0
100 < 1000	12.0	5.5	5.0	2.0	1.0	15.0
>1000	15.0	7.0	6.0	2.5	1.4	20.0

Source: From IEEE Std 519-1992, Recommended Practices and Requirements for Harmonic Control in Electric Power System, Table 10.3.

Note: I_{SC}/I_L, where I_{SC}, maximum short-circuit current at PCC and I_L, maximum demand load current (fundamental frequency component) at PCC.

[a] Even harmonics are limited to 25% of the odd harmonic limits above.

[b] Current distortions that result in a DC offset, e.g., half-wave converters, are not allowed.

[c] All power generation equipment is limited to these values of current distortion, regardless of actual.

performing an on-site measurement at the PCC, or by modeling the power system and performing a harmonic analysis study using a computer simulation. The evaluation should determine total harmonic voltage and current distortion (THD_V and THD_I), and investigate the existence of harmonic resonance conditions. The conditions listed below usually warrant a harmonic evaluation:

- The application of capacitor banks in systems where 20% or more of the load comprises of harmonic generating equipment
- The facility has a history of harmonic-related problems, including excessive capacitor fuse blowing
- In facilities where power company has restrictive limits for harmonic injection into their system than those recommended in the IEEE 519 standard

TABLE 12.19

Voltage Distortion Limits

Bus Voltage at PCC	**Individual Voltage Distortion (%)**	**Total Harmonic Voltage Distortion THD (%)**[a]
69 kV and below	3.0	5.0
69.0001 through 161 kV	1.5	2.5
161.001 kV and above	1.0	1.5

Source: From IEEE Std 519-1992, Recommended Practices and Requirements for Harmonic Control in Electric Power System, Table 11.1.

[a] High-voltage systems can have up to 2.0% THD where the cause is an HVDC terminal that will attenuate by the time it is tapped for a user.

- Plant expansions that add significant harmonic generating equipment operating in conjunction with capacitor banks
- When coordinating and planning to add an emergency standby generator as an alternate power source in an industrial facility

Performing a harmonic study
In order to perform a harmonic study, the power system requires modeling it in the harmonic analysis software program. To conduct this analysis, data are needed on the following as a minimum:

- One-line drawings of the power system, showing ratings and connections of all electrical equipment
- Location, connection, size, and control method of capacitors
- Conductor sizes, lengths, and impedances
- Location and type of nonlinear loads, including harmonic profile of the load. (This can be measured on the equipment or provided by manufacturer of the equipment.)
- Overall plant load and load at each bus
- Location, rating, connection, and impedance of transformers
- Available fault duty at PCC location (incoming point of connection from the utility)

12.7.2.3 Harmonic Solutions—Mitigation Devices and Methods

Harmonic solutions to solve harmonic problems may include using mitigation devices, such as current-limiting reactors, passive filters, active filters, or other devices that minimize the flow of harmonic currents onto the utility's distribution system and within the power system. Harmonic solution techniques fall into two broad categories, (1) preventive and (2) remedial.

Preventive measures: Preventive measures focus on minimizing the harmonic currents that are injected into power systems. Preventive measures include the following:

- Strict adherence to IEEE 519.
- Phase cancellation: The use of 12-pulse converters instead of six-pulse converters. Most harmonic problems with converters (VFDs and the like) are associated with high fifth and seventh harmonic currents, and if they are eliminated through phase cancellation, harmonic problems rarely develop. In situations where there are multiple six-pulse converters, serving half of them (in terms of power) through delta–delta or wye–wye transformers, and the other half through delta–wye or wye–delta transformers, achieves net 12-pulse operation.

- Use of low distorting loads: Because of IEEE 519, increasing attention is being given to the current THD of distorting loads. For example, 12-pulse (or higher) VFDs and low-distortion fluorescent lamp ballasts can be used to lower current distortion.
- Computer simulations: It is always better to simulate the impact of a large distorting load before it is ordered and installed. Solutions can be proposed and evaluated on paper, and implemented when the load is installed.

Remedial measures: Remedial measures include the following:

Circuit detuning: By using only field measurements, such as capacitor current waveforms, it is possible to identify the capacitor banks that are most affected by resonance. As a temporary measure the affected capacitor bank can be switched off to see if the resonance problem subsides. Of course, the problem may simply transfer to another capacitor bank, so measurements after switching at other capacitor banks must be made to see if the temporary solution is satisfactory. If switching a capacitor bank off temporarily solves the problem, computer simulations may be in order to test filtering options and possible relocation of the capacitor bank.

Passive harmonic filters: These are widely used to control harmonics, especially the fifth and seventh harmonics. Most filters consist of series L and C components that provide a single-tuned notch with a low-impedance ground path. At 50/60 Hz, these filters are, for all practical purposes, capacitors. Thus, passive filters provide both PF correction and voltage distortion control. Fifth harmonic filtering is usually adequate to solve most distribution system harmonic problems. However, in some cases it may be necessary to add 7th, 11th, and 13th harmonic filters, in that order. In general, harmonics may not be skipped. For example, if the problem harmonic is the seventh, both fifth and seventh harmonic filters must be added because the seventh filter alone would aggravate the fifth harmonic voltage. Filters tuned near the third harmonic must be avoided because transformers and machines located throughout distribution feeders are sources of third harmonics, and their currents will easily overwhelm third harmonic filters. Usually, the higher the harmonic, the fewer kVARs needed for a filter. For multiple filter installations, a good practice is to stairstep the kVAR as follows: if Q kVARs are used for the 5th harmonic, then $Q/2$ should be used for the 7th, $Q/4$ for the 11th, and $Q/8$ for the 13th. Of course, actual sizes must match standard kVAR sizes. For best performance, a filter should be at least 300 kVAR (three-phase). It may be possible to add low-voltage filters without performing computer simulations, as long as all shunt capacitors in the facility are filtered. However, in a utility distribution system, it is always prudent to perform computer simulations to make sure that a filter does not aggravate the harmonics situation at a remote point. This is especially true if the feeder also has unfiltered capacitors.

Harmonic current filters prevent input harmonics of nonlinear electronic loads from being fed back into the power service. Nonfiltered input harmonics

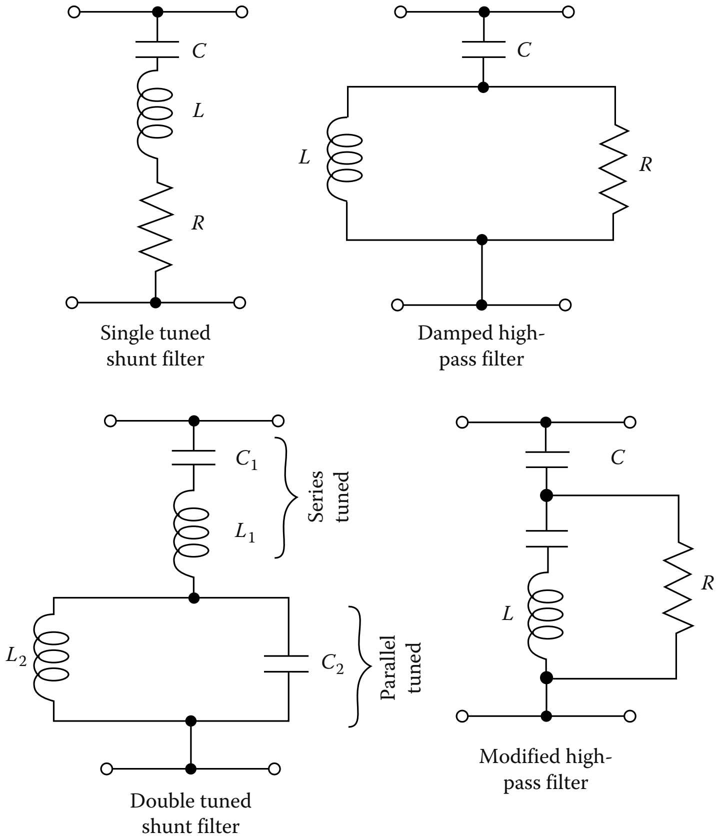


FIGURE 12.40
Various types of harmonic current filters.

can generate heat which can have an effect on conductors and transformers and cause voltage distortion. The filters vary in size from small units for plug-connected loads to larger devices for hard-wired loads. Different types of harmonic current filters are illustrated in Figure 12.40. Harmonic current filters typically are placed in parallel with the load. If installed and used properly, these filters work best at reducing harmonic currents at their source. They also eliminate the need for other changes to compensate for the problems caused by the harmonic currents.

Some problems associated with passive filters are that:

- Their effectiveness diminishes over time as their capacitors age, losing μF and thus raising their notch frequency.
- They attract harmonic currents from all sources in the network—new, known, and unknown, so that they may become overloaded.
- Active filters. This is a new and promising technology, but there are as yet few distribution feeder installations. Active filters are power

electronic converters that inject equal-but-opposite distortion to yield more sinusoidal voltage waveforms throughout a network. Active filters have the advantages of

- Time-domain operation so that they automatically tune to the problem harmonic or harmonics
- Current-limiting capability to prevent overload by new or unknown sources of harmonics on the network
- Multipoint voltage monitoring so that they can simultaneously minimize distortion at local and remote busses

The performance of mitigation equipment must be verified by extensive monitoring, both before and after commissioning. At least 2 days of recordings before commissioning, and one week after, should be made to assure that the mitigation equipment is performing as planned. One week of measurements is needed so that the entire weekly load cycle can be observed.

Monitoring should include time traces of voltage and current THD, spectra, sample waveforms, power, and harmonic power.

Delta–delta and delta–wye transformers: This configuration uses two separate utility feed transformers with equal nonlinear loads. This shifts the phase relationship to various six-pulse converters through cancellation techniques, similar to the 12-pulse configuration.

Isolation transformers: An isolation transformer provides a good solution in many cases. The advantage is the potential to voltage match by stepping up or stepping down the system voltage, and by providing a N–G reference for nuisance ground faults. This is the best solution when utilizing AC or DC drives that use SCRs as bridge rectifiers.

Line reactors: More commonly used for size and cost, the line reactor is the best solution for harmonic reduction when compared to an isolation transformer. AC drives that use diode bridge rectifier front ends are best suited for line reactors. Line reactors (commonly referred to as inductors) are available in standard impedance ranges from 1.5%, 3%, 5%, and 7.5%.

12.7.3 Wiring and Grounding Problems

In those facilities that are experiencing equipment problems that appear to be power-related, a on-site inspection will be required to verify that power disturbances are the cause of electronic equipment malfunction or failure. The specific objective of such an inspection is to determine condition and adequacy of the wiring and grounding system. This inspection should include the following checks:

Wiring and grounding: Wiring and grounding measurements detect problems in the feeders and branch circuits serving the critical load. The test instruments used to conduct these tests should be selected carefully. Use of commonly available three-light circuit testers is not recommended. These instruments have limitations and can provide a correct indication when the circuit being tested actually has one or more problems. They also are incapable of indicating the integrity of power conductors. Recommended instruments for these measurements include true-rms multimeter, true-rms clamp-on multimeter, and ground impedance testers. These instruments are described in Section 12.6.

Continuity of conduit/enclosure grounds: Electronic equipment should be grounded with a separate equipment grounding conductor. This conductor can be terminated in an IG system, insulated from the conduit ground, or in the conduit ground system. This is because both are ultimately connected to the building ground systems. However, the IG and conduit ground must terminate at the first upstream N–G bonding point. Ground impedance testers can be used to measure the quality of both the IG and conduit ground systems from the equipment to the power source. To achieve good performance from sensitive electronic loads, phase, neutral, and equipment grounding conductors should be routed through continuously grounded metallic conduit. Continuously grounded metal conduit provides a shield for radiated interference.

Load phase and neutral currents: Measurements of load phase and neutral currents are necessary to determine whether the load is sharing a neutral conductor with other loads. They also determine whether the neutral conductor sizing is adequate. When sizing neutral conductors, one should keep in mind that the current in the neutral can exceed current in the phase conductor. This is because three-phase circuits supplying single-phase loads have nonlinear current characteristics and share a common neutral. A true-rms reading clamp-on ammeter must be used to make phase and neutral conductor measurements. To determine whether the neutral serving the sensitive electronic load is shared with other loads, check the neutral current with the sensitive load turned off. If the current is not zero, a shared neutral is being used.

N–G bonds: The NEC requires bonding of the neutral and equipment grounding conductor at the main service panel (NEC 250-53) and the secondary side of SDSs (NEC 250-26(a)). If not properly bonded, N–G bonds create shock hazards for operating personnel, and degrade the performance of sensitive electronic equipment. These bonds can be detected using a wiring and grounding tester. A voltage measurement between neutral and ground at the outlets may indicate voltage from millivolt to few volts range under normal operating conditions. A zero voltage indicates the presence of a nearby N–G bond. Excessive current on equipment grounds in distribution panels also indicates the possibility of a load side N–G bond.

Equipment grounding conductor impedance: The impedance of the equipment grounding conductor is measured using a ground impedance tester. Properly installed and maintained equipment ground conductors exhibit very low impedance levels. A high impedance measurement indicates poor quality connections in the equipment grounding system or an improperly installed equipment grounding conductor. An open ground measurement reveals no equipment grounding conductor connection. Recommended practice is to verify an impedance level of 0.25 Ω or less. This also helps assure personnel protection under fault conditions.

Neutral conductor impedance: Neutral conductor impedance is measured because a low impedance neutral is essential to minimize N–G potentials at the load and reduce CM noise. A ground impedance tester can be used to conduct these measurements. It is necessary for neutral conductors to have low impedance.

Grounding electrode resistance: The grounding electrode system provides an earth reference point for the facility and a path for lightning and static electricity. This is important because the electrode serves as the connection between the building grounding system and the grounding electrode system. An accurate measurement can be taken only when the grounding electrode is disconnected from all other grounds. For new construction, the resistance of the grounding electrode system is measured with an earth ground tester using the fall-of-potential method. It is recommended that the measured resistance be in accordance with the design values and industry standards and codes. For more information on grounding and ground resistance measurements, refer to Chapter 11.

Current flow in the grounding electrode conductor can be measured using a clamp-on ammeter. In most cases, small current flow will exist. However, zero current flow usually indicates an open connection. Current flow on the order of the phase currents indicates serious problems or possible fault conditions.

IG and conduit ground systems: The quality of both the IG and conduit ground systems from the equipment to the ground source needs to be measured. This is to ensure that sensitive electronic loads are grounded with a separate equipment grounding conductor and are ultimately connected to the building grounding system. Both ground systems terminate at the first upstream N–G bonding point. The phase, neutral, and equipment grounding conductors should be routed through continuously grounded metallic conduit. As a result, better performance of sensitive electronic equipment is achieved. Another benefit is that safety codes are met.

Dedicated feeders and direct path routing: Measuring phase currents with the critical loads turned off is one way to determine if sensitive electronic loads are being served by dedicated branch feeders with conductor routing in as short and direct a path as possible. If there is any current flow, the feeder is being used to serve other loads.

SDSs: No direct electrical connection should exist between SDSs and output and input conductors. SDSs are required by the NEC to have a load-side N–G bond which is connected to the grounding electrode system. All equipment grounding conductors, any IG conductors, neutral conductors, and the metal enclosure of the SDSs are required to be bonded together and bonded to the grounding electrode conductor. Visual inspections and measurements with a ground impedance tester can determine the quality of these connections.

13

Electrical Safety, Arc-Flash Hazard, Switching Practices, and Precautions

13.1 Introduction

Safety in electrical systems concerns three different areas: protection of life, protection of property, and protection of uninterrupted productive output. The required investment to accomplish improved safety often consists merely of additional planning effort without any extra equipment investment. The protection of human life is paramount. Electrical plant property can be replaced and lost production can be made up, but human life can never be recovered nor human suffering compensated for. To achieve improved safety to personnel, special attention should be directed to energized equipment, adequate short-circuit protective devices, a good maintenance program, simplicity of the electrical system design, and proper training of personnel who work around electricity. Many of the items necessary to give improved protection to life will also secure improved protection to plant property and minimize breakdown of electrical system equipment. This chapter deals with electrical safety, switching practices, arc-flash hazard analysis, precautions, and accident prevention.

Most electrical companies and plants have safety programs and rules in the workplace and training programs for their employees. Most safety programs embody company safety rules and practices, national and local codes and standards, and federal and state laws. For individuals to carry out their duties, they must be knowledgeable of the rules and standards that apply to their workplace. Electrical safety standards and requirements are varied; some are voluntary while others are laws that are mandatory, and provide guidance for safely working around or on electrical energy. Since the standards are periodically revised, one should always refer to the most recent version of the standard when consulting such a standard. A brief discussion of the safety standards, arc-flash hazard analysis and labeling of equipment, and regulations related to these topics and electricity are covered below to familiarize the reader with them.

13.2 Industry Standards and Regulatory Requirements for Safety

13.2.1 ANSI C2: The National Electrical Safety Code-2007

The National Electrical Safety Code (NESC) is intended to provide practical rules for safeguarding personnel during the installation, operation, or maintenance of electrical supply and communications lines and associated equipment. The NESC rules cover supply and communications lines, equipment, and associated work practices used by both private and public electrical companies (utilities). The NESC covers five major areas as listed below.

- Grounding methods for electrical supply and communications facilities
- Rules for installation and maintenance of electrical supply stations and equipment
- Safety rules for the installation and maintenance of overhead electrical supply and communications lines
- Safety rules for the installation and maintenance of underground electric supply and communications lines
- Rules for the operation of electric supply and communications lines and equipment

Section 410, "General requirements" of NESC-2007 contains information and guidance on electric safety requirements that are necessary for safeguarding employees in the workplace. In accordance with Section 410 the employer is required to inform the employees on safety rules, safety training and arc hazard evaluation including wearing of arc-rated clothing. These requirements as stated in NESC-2007 standard are as follows:

1. The employer shall inform each employee working on or about communications equipment or electric supply equipment and the associated lines, of the safety rules governing the employee's conduct while so engaged. When deemed necessary, the employer shall provide a copy of such rules.
2. The employer shall provide training to all employees who work in the vicinity of exposed energized facilities. The training shall include applicable work rules required by this part and other mandatory referenced standards or rules. The employer shall ensure that each employee has demonstrated proficiency in required tasks. The employer shall provide retraining for any employee who, as a result of routine observance of work practices, is not following work rules.
3. Effective as of January 1, 2009, the employer shall ensure that an assessment is performed to determine potential exposure to an

electric arc for employees who work on or near energized parts or equipment. If the assessment determines a potential employee exposure greater than 2 cal/cm^2 exists, the employer shall require employees to wear clothing or a clothing system that has an effective arc rating not less than the anticipated level of arc energy. When exposed to an electric arc or flame, clothing made from the following materials shall not be worn: acetate, nylon, polyester, or polypropylene. The effective arc rating of clothing or a clothing system to be worn at voltages 1000 V and above shall be determined using Tables 410-1 and 410-2 or performing an arc hazard analysis. When an arc hazard analysis is performed, it shall include a calculation of the estimated arc energy based on the available fault current, the duration of the arc (cycles), and the distance from the arc to the employee.

Exception 1: If the clothing required by this rule has the potential to create additional and greater hazards than the possible exposure to the heat energy of the electric arc, then clothing with an arc rating or arc thermal performance value (ATPV) less than that required by the rule can be worn.

Exception 2: For secondary systems below 1000 V, applicable work rules required by this part and engineering controls shall be utilized to limit exposure. In lieu of performing an arc hazard analysis, clothing or a clothing system with a minimum effective arc rating of 4 cal/cm^2 shall be required to limit the likelihood of ignition.

Note 1: A clothing system (multiple layers) that includes an outer layer of flame-resistant (FR) material and an inner layer of non-FR material has been shown to block more heat than a single layer. The effect of the combination of these multiple layers can be referred to as the effective arc rating.

Note 2: It is recognized that arc energy levels can be excessive with secondary systems. Applicable work rules required by this part and engineering controls should be utilized.

13.2.2 ANSI/National Fire Protection Association (NFPA) 70, National Electrical Code (NEC)-2008

The NEC NFPA 70 is part of the NFPA codes. The NEC includes information on design, installation and other technical information of electrical facilities and its principle objective is to help minimize the possibility of electric fires. The NEC or portions of it are adopted as local law in many municipalities, cities, states, and other such areas. Since 2002, the NEC, article 110-16 requires flash hazard labels on electrical equipment to warn personnel of the potential electric arc-flash hazards and the personal protective equipment (PPE) they must wear when working on energized equipment. The NEC article 110-16 is listed below for reader's reference.

110.16—flash protection: Electrical equipment, such as switchboards, panelboards, industrial control panels, meter socket enclosures, and motor control centers, that are in other than dwelling occupancies, and are likely to require examination, adjustment, servicing, or maintenance while energized shall be field marked to warn qualified persons of potential electric arc-flash hazards. The marking shall be located so as to be clearly visible to qualified persons before examination, adjustment, servicing, or maintenance of the equipment.

FPN No. 1: NFPA 70E, *Standard for Electrical Safety in the Workplace-2004*, provides assistance in determining severity of potential exposure, planning safe work practices, and selecting PPE.

FPN No. 2: ANSI Z535.4-1998, *Product Safety Signs and Labels*, provides guidelines for the design of safety signs and labels for application to products.

13.2.3 ANSI/NFPA 70B, Standard for Electrical Equipment Maintenance-2006

The electrical equipment maintenance is a publication of the NFPA and it contains recommended practice information on maintenance of electric equipment and apparatus. The 70B document covers systems and equipment which are typically installed in industrial plants, commercial buildings, and large family dwellings.

13.2.4 ANSI/NFPA 70E, Standard for Electrical Safety in the Workplace-2004

The electrical safety requirement in workplaces is a publication of NFPA. This code contains information and guidance on electric safety requirements that are necessary for safeguarding employees in the workplace. The sixth edition, published in 2004, reflects several significant changes to the older versions of 70E. The major changes emphasize safe work practices. Clarity and usability of the document are also enhanced. The name of the document was changed to NFPA 70E, *Standard for Electrical Safety in the Workplace*. The existing Parts 1 through 4 were renamed as Chapters 1 through 4 and are reorganized as follows:

Chapter 1 Safety-related work practices

Chapter 2 Safety-related maintenance requirements

Chapter 3 Safety requirements for special equipment

Chapter 4 Installation safety requirements

This standard is compatible with corresponding provisions of the NEC, but is not intended to, nor can it, be used in lieu of the NEC. Chapter 4 of NFPA 70E is intended to serve a very specific need of OSHA and is in no way intended to be used as a substitute for the NEC. NFPA 70E is intended for use by employers, employees, and OSHA.

The chapter on safety-related work practices was reorganized to emphasize working on live parts as the last alternative work practice. Therefore it contains extensive requirements for working on or near electrical conductors or circuit parts that have not been put into an electrically safe work condition. When such work is to be performed, the required electrical hazard analysis has specific requirements for the analysis of shock and flash hazards. Other sections of the 70E provide guidance on selecting the proper PPE. The significant requirements for the analysis of shock and flash hazards are as follows:

The NFPA 70E, Article 110.8 (B) (1) Electrical hazard analysis: If the live parts operating at 50 V or more are not placed in an electrically safe work condition, other safety-related work practices shall be used to protect employees who might be exposed to the electrical hazards involved. Such work practices shall protect each employee from arc flash and from contact with live parts operating at 50 V or more directly with any part of the body or indirectly through some other conductive object. Work practices that are used shall be suitable for the conditions under which the work is to be performed and for the voltage level of the live parts. Appropriate safety-related work practices shall be determined before any person approaches exposed live parts within the limited approach boundary by using both shock hazard analysis and flash hazard analysis.

(a) Shock hazard analysis. A shock hazard analysis shall determine the voltage to which personnel will be exposed, boundary requirements, and the PPE necessary in order to minimize the possibility of electrical shock to personnel. (b) Flash hazard analysis. A flash hazard analysis shall be done in order to protect personnel from the possibility of being injured by an arc flash. The analysis shall determine the flash protection boundary and the PPE that people within the flash protection boundary shall use.

The NFPA 70E, Article 130.2 Approach boundaries to live parts:

A. *Shock hazard analysis:* A shock hazard analysis shall determine the voltage to which personnel will be exposed, boundary requirements, and the PPE necessary in order to minimize the possibility of electric shock to personnel.
B. *Shock protection boundaries:* The shock protection boundaries identified as limited, restricted, and prohibited approach boundaries are applicable to the situation in which approaching personnel are exposed to live parts.
C. *Approach to exposed live parts operating at 50 V or more:* No qualified person shall approach or take any conductive object closer to

exposed live parts operating at 50 V or more than the restricted approach boundary set forth in Table 130.2(C), unless any of the following apply:

1. The qualified person is insulated or guarded from the live parts operating at 50 V or more (insulating gloves or insulating gloves and sleeves are considered insulation only with regard to the energized parts upon which work is being performed), and no part of the qualified person's body crosses the prohibited approach boundary set forth in Table 130.2(C) which is shown in Table 13.1.
2. The live part operating at 50 V or more is insulated from the qualified person and from any other conductive object at a different potential.
3. The qualified person is insulated from any other conductive object as during live-line bare-hand work.

D. *Approach by unqualified persons:* Unqualified persons shall not be permitted to enter spaces that are required under 400.16(A) to be accessible to qualified employees only, unless the electric conductors and equipment involved are in an electrically safe work condition.

1. *Working at or close to the limited approach boundary:* Where one or more unqualified persons are working at or close to the limited approach boundary, the designated person in charge of the work space where the electrical hazard exists shall cooperate with the designated person in charge of the unqualified person(s) to ensure that all work can be done safely. This shall include advising the unqualified person(s) of the electrical hazard and warning him or her to stay outside of the Limited Approach Boundary.
2. *Entering the limited approach boundary:* Where there is a need for an unqualified person(s) to cross the limited approach boundary, a qualified person shall advise him or her of the possible hazards and continuously escort the unqualified person(s) while inside the limited approach boundary. Under no circumstance shall the escorted unqualified person(s) be permitted to cross the restricted approach boundary.

The requirements stated in NFPA 70E for shock protection and safe distances for qualified and unqualified personnel can be summarized as follows:

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 electric arc flash were to occur. Appropriate flash-flame protection equipment must be utilized for persons entering the flash protection region. This distance may be outside or inside the following shock protection distances.

TABLE 13.1

Approach Boundaries to Live Parts for Shock Protection

(1)	(2)	(3)	(4)	(5)
	Limited Approach Boundary[a]			
Nominal System Voltage Range, Phase-to-Phase	**Exposed Movable Conductor**	**Exposed Fixed Circuit Part**	**Restricted Approach Boundary[a]; Includes Inadvertent Movement Adder**	**Prohibited Approach Boundary[a]**
Less than	Not specified	Not specified	Not specified	Not specified
50 to 300	3.05 m (10 ft 0 in.)	1.07 m (3 ft 6 in.)	Avoid contact	Avoid contact
301 to 750	3.05 m (10 ft 0 in.)	1.07 m (3 ft 6 in.)	304.8 mm (1 ft 0 in.)	25.4 mm (0 ft 1 in.)
751 to 15 kV	3.05 m (10 ft 0 in.)	1.53 m (5 ft 0 in.)	660.4 mm (2 ft 2 in.)	177.8 mm (0 ft 7 in.)
15.1 to 36 kV	3.05 m (10 ft 0 in.)	1.83 m (6 ft 0 in.)	787.4 mm (2 ft 7 in.)	254 mm (0 ft 10 in.)
36.1 to 46 kV	3.05 m (10 ft 0 in.)	2.44 m (8 ft 0 in.)	838.2 mm (2 ft 9 in.)	431.8 mm (1 ft 5 in.)
46.1 to 72.5 kV	3.05 m (10 ft 0 in.)	2.44 m (8 ft 0 in.)	965.2 mm (3 ft 2 in.)	635 mm (2 ft 1 in.)
72.6 to 121 kV	3.25 m (10 ft 8 in.)	2.44 m (8 ft 0 in.)	991 mm (3 ft 3 in.)	812.8 mm (2 ft 8 in.)
138 to 145 kV	3.36 m (11 ft 0 in.)	3.05 m (10 ft 0 in.)	1.093 m (3 ft 7 in.)	939.8 mm (3 ft 1 in.)
161 to 169 kV	3.56 m (11 ft 8 in.)	3.56 m (11 ft 8 in.)	1.22 m (4 ft 0 in.)	1.07 m (3 ft 6 in.)
230 to 242 kV	3.97 m (13 ft 0 in.)	3.97 m (13 ft 0 in.)	1.6 m (5 ft 3 in.)	1.45 m (4 ft 9 in.)
345 to 362 kV	4.68 m (15 ft 4 in.)	4.68 m (15 ft 4 in.)	2.59 m (8 ft 6 in.)	2.44 m (8 ft 0 in.)
500 to 550 kV	5.8 m (19 ft 0 in.)	5.8 m (19 ft 0 in.)	3.43 m (11 ft 3 in.)	3.28 m (10 ft 9 in.)
765 to 800 kV	7.24 m (23 ft 9 in.)	7.24 m (23 ft 9 in.)	4.55 m (14 ft 11 in.)	4.4 m (14 ft 5 in.)

Source: From NFPA 70E, Standard for Electrical Safety in the Workplace-2004, Table 130.2(C).

Note: For flash protection boundary, see 130.3(A). All dimensions are distance from live part to employee.

[a] See definition in Article 100 and text in 130.2(D)(2) and Annex C for elaboration.

Limited approach boundary: An approach limit at a distance from an exposed live part within which a shock hazard exists. A person crossing the limited approach boundary and entering the limited region must be qualified to perform the job/task.

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. The person crossing the restricted approach boundary and entering the restricted space must have a documented work plan approved by authorized management, use PPE that is appropriate for the work being performed and is rated for voltage and energy level involved.

Prohibited approach boundary: An approach limit at a distance from an exposed live part within which work is considered the same as making contact with the live part. The person entering the prohibited space must have specified training to work on energized conductors or live parts. Any tools used in the prohibited space must be rated for direct contact at the voltage and energy level involved. The limits of approach are depicted in Figure 13.1.

The NFPA 70E, Article 130.3 Flash-hazard analysis: A flash hazard analysis shall be done in order to protect personnel from the possibility of being injured by an arc flash. The analysis shall

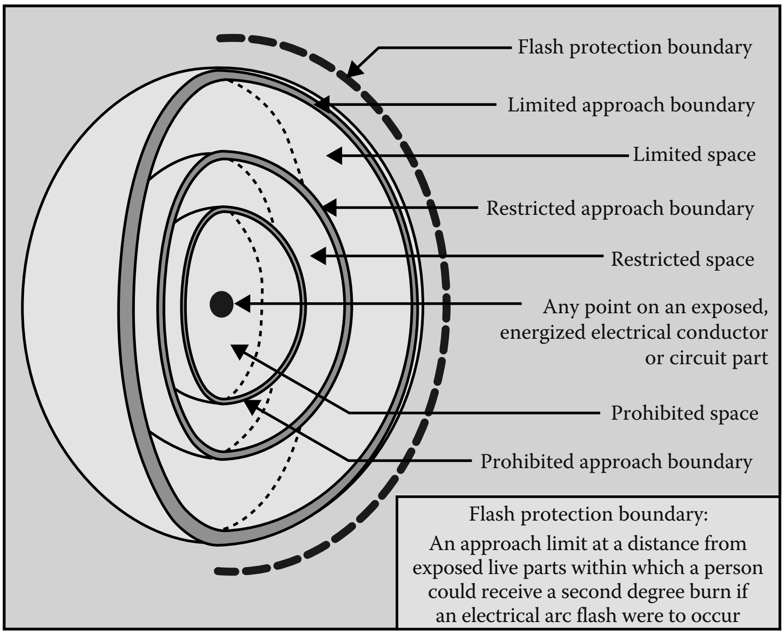


FIGURE 13.1
Limits of distance approach. (From NFPA 70E, Standard for Electrical Safety in the Workplace-2004.)

determine the flash protection boundary and the PPE that people within the flash protection boundary shall use.

Flash protection boundary: For systems that are 600 V or less, the flash protection boundary shall be 4.0 ft, based on the product of clearing times of six cycles (0.1 s) and the available bolted fault current of 50 kA or any combination not exceeding 300 kA cycles (5000 A s). For clearing times and bolted fault currents other than 300 kA cycles, or under engineering supervision, the flash protection boundary shall alternatively be permitted to be calculated in accordance with the following general formula:

$$D_c = [2.65 \times \mathrm{MVA}_{bf} \times t]^{1/2}$$

or

$$D_c = [53 \times \mathrm{MVA} \times t]^{1/2}$$

where

D_c distance (ft) from an arc source for a second-degree burn

MVA_{bf} is the bolted fault capacity available at point involved (in mega volt-amps)

MVA is the capacity rating of transformer (mega volt-amps). For transformers with MVA ratings below 0.75 MVA, multiply the transformer MVA rating by 1.25

t is the time of arc exposure (s)

At voltage levels above 600 V, the flash protection boundary is the distance at which the incident energy equals 5 J/cm^2(1.2 cal/cm^2). For situations where fault clearing time is 0.1 s (or faster), the flash protection boundary is the distance at which the incident energy level equals 6.24 J/cm^2(1.5 cal/cm^2).

Protective clothing and PPE for application with a flash hazard analysis: Where it has been determined that work will be performed within the flash protection boundary by NFPA 70E, Article 130.3(A), the flash hazard analysis shall determine, and the employer shall document, the incident energy exposure of the worker (cal/cm^2). The incident energy exposure level shall be based on the working distance of the employee's face and chest areas from a prospective arc source for the specific task to be performed. FR clothing and PPE shall be used by the employee based on the incident energy exposure associated with the specific task. Recognizing that incident energy increases as the distance from the arc flash decreases, additional PPE shall be used for any parts of the body that are closer than the distance at which the incident energy was determined. As an alternative, the PPE requirements of NFPA 70E, Article 130.7(C)(9)(a) shall be permitted to be used in lieu of the detailed flash hazard analysis approach described in NFPA 70E, Article 130.3(A).

The NFPA 70E, Article 130.7 (13), Arc flash protective equipment: All arc-rated PPE include the ATPV with units in cal/cm^2. The required

PPE at specific locations is determined by comparing the calculated incident energy to the ratings for specific combinations of PPE. NFPA 70E, Table 130.7(C)(11) lists examples of protective clothing systems and typical characteristics including the degree of protection for various clothing. The protective clothing selected for the corresponding hazard/risk category number shall have an arc rating of at least the value listed in the last column of NFPA 70E, Table 130.7(C)(11). The NFPA 70E, Table 130.7(C)(11) is shown in Table 13.2 below.

For actual applications, the calculated incident energy must be compared to specific PPE combinations used at the facility being evaluated. The exception to this is the upper limit of 40 cal/cm^2. While PPE is available in ATPV values of 100 cal/cm^2 or more, values above 40 cal/cm^2 are prohibited due to the sound, pressure, and concussive forces. The sound, pressure, and concussive forces are more severe than the thermal values of arc energy greater than 40 cal/cm^2. An examination of the categories listed in Table 13.2 implies that each category has range (spread) of arc rating, i.e., for example category 1 range is 4–7.999, category 2 range is 8–24.999, and so on. It should be noted that manufacturers are allowed to label their garments for a given PPE category as long as garment's thermal value falls within the category's range. For example, a garment with an 8 cal/cm^2 rating can be labeled category 2 even though the category 2 can go up to 24.99 cal.

TABLE 13.2
PPE Categories

	Typical Protective Clothing Systems	Required Minimum Arc Rating of PPE	
Hazard/Risk Category	**Clothing Description (Typical Number of Clothing Layers Is Given in Parentheses)**	**J/cm^2**	**cal/cm^2**
0	Nonmelting, flammable materials (i.e., untreated cotton, wool, rayon, or silk, or blends of these materials) with a fabric weight at least 4.5 oz/yd^2 (1)	N/A	N/A
1	FR shirt and FR pants or FR coverall (1)	16.74	4
2	Cotton underwear—conventional short sleeve and brief/shorts, plus FR shirt and FR pants (1 or 2)	33.47	8
3	Cotton underwear plus FR shirt and FR pants plus FR coverall, or cotton underwear plus two FR coveralls (2 or 3)	104.6	25
4	Cotton underwear plus FR shirt and FR pants plus multilayer flash suit (3 or more)	167.36	40

Source: From NFPA 70E-2004, Standard for Electrical Safety in the Workplace-2004, Table 130.7(C)(11).

Note: Arc rating is defined in Article 100 and can be either ATPV or E_{BT}. ATPV is defined in ASTM F 1959-99 as the incident energy on a fabric or material that results in sufficient heat transfer through the fabric or material to cause the onset of a second-degree burn based on the Stoll curve. E_{BT} is defined in ASTM F 1959-99 as the average of the five highest incident energy exposure values below the Stoll curve where the specimens do not exhibit break open. E_{BT} is reported when ATPV cannot be measured due to FR fabric break open.

It is inappropriate for some manufacturers to promote their safety equipment using lower calorie values for a given category of PPE. Therefore, when selecting PPE, the actual calculated incident energy at the specific work location must be compared to specific garment thermal rating within the given category to correctly protect the worker from a flash hazard.

The NFPA 70E, Article 400.11, Flash Protection: Switchboards, panelboards, industrial control panels, and motor control centers in other than dwelling occupancies and are likely to require examination, adjustment, servicing, or maintenance while energized shall be field marked to warn qualified persons of potential electric arc-flash hazards. The marking shall be located so as to be clearly visible to qualified persons before examination, adjustment, servicing, or maintenance of the equipment. This is the same requirement stated in Article 110-16 of the NEC-2002.

13.2.5 Occupational Safety and Health Administration (OSHA) Standards

OSHA standards are federal regulations and apply to all covered industries except those states which have adopted safety programs which are approved by the OSHA. A partial listing of industries covered by OSHA is General Industry, Construction Industry, Power Generation, Transmission and Distribution, and Telecommunications. OSHA safety standards are published in the Code of Federal Regulations, Title 29, Subtitle B, Chapter XVII. The OSHA electrical safety standards are in at least four categories similar to the four chapters of NFPA 70E.

These are

- Design and installation safety
- Safety-related work practices
- Safety-related maintenance requirements
- Special equipment

Electrical safety standards for general industry are found in Part 1910, Subpart S, I, and J. A partial listing of subpart S and I is given below.

Title	Paragraphs
Design safety standards for electrical equipment	1910.302–1910.308
Safety-related work practices	1910.331–1910.335
Safety-related maintenance requirements	1910.361–1910.380
Safety requirements for special equipment	1910.381–1910.398
Hazard assessment and equipment selection	1910.132–1910.139

In addition, part 1910.333(a)(1) states that live parts to which an employee may be exposed shall be de-energized before the employee works on or near them, unless the employer can demonstrate that de-energizing introduces additional or increased hazards or is infeasible due to design or operational limitations. When employees are required to work where there is a potential electrical hazard, part 1910.335 calls for the employer to provide electrical protective equipment that is appropriate for the specific parts of the body to be protected and for the work to be performed.

Employers are responsible for performing a hazard assessment in accordance with part 1910.132(d)(1) (i–iii). The requirements are as follows:

1910.132(d)(1): The employer shall assess the workplace to determine if hazards are present, or are likely to be present, which necessitate the use of PPE. If such hazards are present, likely to be present, the employer shall:

1910.132(d)(1)(i): Select, and have each affected employee use, the types of PPE that will protect the affected employee from the hazards identified in the hazard assessment

1910.132(d)(1)(ii): Communicate selection decisions to each affected employee

1910.132(d)(1)(iii): Select PPE that properly fits each affected employee.

The employer shall verify that the required workplace hazard assessment has been performed through a written certification that identifies the workplace evaluated; the person certifying that the evaluation has been performed; the date(s) of the hazard assessment; and, which identifies the document as a certification of hazard assessment.

1910.335(a)(1)(i) PPE: Employees working in areas where there are potential electrical hazards shall be provided with, and shall use, electrical protective equipment that is appropriate for the specific parts of the body to be protected and for the work to be performed.

1910.132(f) Training: The employer shall provide training to each employee who is required by this section to use PPE. Each such employee shall be trained to know at least the following: (1) When PPE is necessary; (2) What PPE is necessary; (3) How to properly don, doff, adjust, and wear PPE; (4) The limitations of the PPE; and (5) The proper care, maintenance, useful life, and disposal of the PPE.

Each affected employee shall demonstrate an understanding of the training specified in paragraph (f)(1) of this section, and the ability to use PPE properly, before being allowed to perform work requiring the use of PPE.

1910.132(f)(3) Proficiency and Retraining: When the employer has reason to believe that any affected employee who has already been trained, but does not have the understanding and skill required by paragraph (f)(2) of this section, the employer shall retrain each such employee. Circumstances where retraining is required include, but are not limited to, situations where: changes in the workplace render previous training obsolete; or changes in the types of PPE to be used render previous training obsolete; or inadequacies in an affected employee's knowledge or use of assigned PPE indicate that the employee has not retained the requisite understanding or skill. The employer shall verify that each affected employee has received and understood the required training through a written certification that contains the name of each employee trained, the date(s) of training, and that identifies the subject of the certification.

13.3 Arc-Flash Hazard and Regulatory Requirements

The regulatory requirements of OSHA, NFPA 70, and NFPA 70E pertaining to a worker's safety are described in Section 13.2. The regulatory requirements can be summarized as follows:

1. Determine the risk to personnel from exposure to incident energy released during an arc-flash event, i.e., the arc-flash hazard must be quantified.
2. Provide appropriate arc-flash hazard protection, i.e., correct PPE must be selected for nonprohibited work.
3. The arc flash assessment results must be documented and equipment labeled to inform and warn personnel of arc-flash hazard.
4. Personnel must be trained, understand the extent of arc-flash hazard, and take correct protective actions.

To quantify the hazard for each specific location, arc-flash analysis should be performed using either the IEEE 1584, *IEEE Guide for Performing Arc-Flash Hazard Calculations*, methodology or the alternate method given in 70E. The IEEE 1584 and 70E methodologies involve calculating available short-circuit currents for each location, determining the clearing time of protective relays and devices, equipment location type and working distance. See Sections 13.3.2 and 13.3.3 for more details on performing the arc-flash analysis study. The correct PPE category is selected based on the results of the arc-flash hazard analysis study. After completion of the steps 1 and 2, correct labeling is developed to label the equipment in accordance with NEC and 70E requirements to warn personnel of the hazard. The labels that are generated from the arc-flash analysis programs are color coded to signify the severity of the danger of the incident energy available at the particular location. For example, the label color codes range from color green for category 0 (minimum severity) to color red (maximum severity) for which no PPE category is available and where no work can be done on energized equipment. A sample of the two labels generated using an arc-flash analysis program is shown in Figures 13.2 and 13.3. It should be noted that the text and color of the label in Figure 13.2 signifies the "Danger" and states "energized work is prohibited" because the arc energy exceeds the 40 cal/cm^2 for which no PPE is available.

! DANGER

NO PPE AVAILABLE

ENERGIZED WORK PROHIBITED

1919 in.	Flash Hazard Boundary
57.2 cal/cm^2	Flash Hazard at 36 in.
	Dangerous !!! No FR Class Found
13,200 VAC	Shock Hazard when cover is removed
2	Glove Class
60 in.	Limited Approach (Fixed Circuit)
26 in.	Restricted Approach
7 in.	Prohibited Approach

Bus: 13.2 KV PRIM Prot: 125E PRIM FU

FIGURE 13.2
Arc-flash hazard label for no PPE category available.

! WARNING

Arc Flash and Shock Hazard

Appropriate PPE Required

125 in.	Flash Hazard Boundary
28.6 cal/cm^2	Flash Hazard at 18 in.
Class 4	Cotton Underwear + FR Shirt and Pant + Multilayer Flash Suit
480 VAC	Shock Hazard when cover is removed
00	Glove Class
42 in.	Limited Approach (fixed circuit)
12 in.	Restricted Approach
1 in.	Prohibited Approach

Bus: MAIN SWBD BUS Prot: 4000A MAIN BKR

FIGURE 13.3
Arc-flash hazard label for PPE category 4.

The label shown in Figure 13.3 indicates PPE category 4 that the worker must use to perform work at this location. Both labels show the calculated flash protection boundary, incident energy, PPE category, glove classification, and shock protection boundaries per NFPA 70 E. The final step in this process is to give training to the employees on the arc-flash hazard, and how they should protect themselves.

13.3.1 Summary of NFPA 70, 70E, and OSHA Requirements

NFPA 70E and OSHA part 1910-132 require a hazard assessment for electrical equipment and selection of appropriate PPE for the employees if they are to work on energized equipment. Further, NFPA 70 (National Electric Code) requires that the equipment has to be labeled to show the available arc energy and the category of PPE the person needs to wear before working on the equipment. The following overview is offered for the reader in order to understand what is required by the above stated NFPA and OSHA requirements.

13.3.2 Overview of Arc-Flash Hazard

Arc-flash hazard is defined as a dangerous condition associated with the release of energy caused by an electric arc. The arc current creates a brilliant flash of light, a loud noise, intense heat, and a rapidly moving pressure wave. The products of arc-fault are ionized gases, metal vapors, molten metal droplets, and shrapnel that shower the immediate vicinity of the arcing fault. The electrical arc burns make up a substantial portion of injuries from electrical malfunctions. The extremely high temperatures of the electrical arc can cause fatal and major burns at distances of 5–10 ft from the arcing equipment. Therefore, the focus of industry on electrical safety and recognition of arc-flash burns as having great significance highlighted the need for protecting employees from all arc-flash hazards. The NEC-2008, Article 110-16 Flash protection, states in part that switchboards, panelboards, industrial control panels, and motor control centers that are in other than dwelling occupancies and are likely to require examination, adjustment, servicing, or maintenance while energized shall be field marked to warn qualified persons of potential electric arc-flash hazards. It is implied that flash protection is required when examining, adjusting, servicing, or maintaining energized equipment. The equipment shall be field marked (labeled) to warn qualified persons of potential electric arc-flash hazards. Let us now take a look at how the requirements for field labeling of equipment can be accomplished.

In order to generate an arc flash hazard label, an arc-flash hazard analysis study has to be conducted to determine the arc energy available at a given equipment. Therefore an arc-flash hazard analysis is performed in conjunction with the short-circuit study and protective device coordination study. Results of the short-circuit study are used to calculate the three-phase fault current from which the arcing fault current is determined. Results of protective device coordination study are used to determine the time required for the electrical protective devices to clear the arcing fault current conditions.

Results of both short circuit and protective device coordination studies are used to perform an arc-flash hazard analysis. Results of arc-flash hazard analysis are used to identify the flash protection boundary and the incident energy at assigned working distances for the electrical equipment. The flash protection boundary and the incident energy calculated in the arc-flash hazard analysis evaluation are based on taking credit for the protective relays and devices in removing the arc. Therefore it is important that these protective devices be kept in good working condition to maintain the validity of the arc-flash hazard analysis results. Readers will find useful information in Section 1.9 in Chapter 1, where a discussion is provided on the bases of maintenance and testing of protective devices. In view of the requirements for arc-flash hazard analysis, it has become even more important now to maintain and test breakers and protective devices on a regular basis to ensure their reliability.

13.3.3 Arc-Flash Analysis

The arc-flash analysis is conducted by using a software program specifically developed to do the arc-flash analysis. The arc-flash software programs are based on the methodologies given in IEEE-1584-2002 and the NFPA 70E methodologies. The arc-flash software program is intended to provide guidance based on the methodologies given in IEEE-1584–2002 and the NFPA 70E for the calculation of incident energy and arc-flash protection boundaries. The results obtained from the arc-flash software program can be used as a basis to develop strategies that have the potential of minimizing burn injuries. These strategies include specifying the rating of PPE, working only when the equipment is not energized, applying arc-resistance switchgear, and following other good engineering techniques and work practices. The guide for arc-flash analysis presented in the IEEE-1584-2002, is based on testing and analysis of the hazard presented by incident energy. The potentially hazardous effects of molten metal splatter, projectiles, pressure impulses, and toxic arc by-products were not considered in the analysis methodology of IEEE-1584-2002. The software programs based on the IEEE-1584-2002, provide analysis only for the hazards presented by incident energy and do not cover the potential hazards from molten metal splatter, projectiles, pressure impulses, and toxic arc by-products. The PPE listing documented in the result of the arc-flash software program are not intended to prevent all injuries but to mitigate the impact of an arc flash upon a person, if one should occur. The selection of a level of PPE is based on NFPA 70E, Table 130.7(C)(11) using the results of the arc-flash analysis. For conducting an arc-flash analysis, the following steps are required:

- Collect the system data
- Determine the system modes of operation
- Calculate the bolted fault currents
- Determine the arcing fault currents
- Determine protective device characteristics and the duration of the arcs (clearing time of the protective devices)

- Determine the system voltages and classes of equipment
- Select the working distances
- Determine the incident energy for all equipment
- Determine the flash boundary for all equipment
- Select PPE from the NFPA 70E-2004

It should be noted that it takes an experienced engineer to implement the steps listed above for modeling the electrical power system, input the required system data, set the overcurrent relays and protective devices in the software program. After the short circuit and protective device coordination studies are completed then an arc flash hazard analysis study is conducted to calculate the various parameters of the arc flash hazard. The arc-flash software programs available on the market today will generate a report that provides detail information on the various aspects of arc flash hazard analysis. A typical arc flash evaluation report includes the information listed in Table 13.3.

TABLE 13.3

Typical Arc Flash Evaluation Report Information

Bus name	This is the location at which the equipment is being evaluated.
Prot device name	This is protective device that interrupts the arcing current.
Bus (kV)	The nominal voltage of the bus or equipment.
Bolted bus fault	This is the bolted three-phase fault at the bus or equipment.
Protective device bolted fault	This is the bolted fault current through the protective device.
Protective device arcing fault	This is the arching fault current through the protective device.
Trip/delay time	The protective device tripping delay time taken from the time current coordination study.
Breaker opening time	The breaker opening time (mechanical time).
Ground	The type of system grounding; yes, means solidly grounded; no, means high-resistance or ungrounded system.
Equipment type	This is taken from IEEE std 1584-2002, Table 2.
Gap (mm)	Typical bus-to-bus gap taken from IEEE std 1584-2002, Table 2.
Arc-flash boundary (in.)	This is an approach limit for flash protection from live parts operating at 50 V or more that are uninsulated or exposed within which a person could receive a second degree burn should an arc source develop.
Working distance (in.)	The working distance of the head and chest from a potential arc source.
Incident energy (cal/cm^2)	This is the incident energy calculated based on the arc current, the arc time, and the working distance.
Required protective FR clothing class	Based on the calculated incident energy, a hazard risk category class is determined for personnel protective clothing. Refer to NFPA 70E, Tables 130.7(C)(10) and 130.7(C)(11) for complete clothing equipment.

13.4 Electrical Safety Practices and Precautions

The methods and techniques discussed in this chapter are industry accepted practices for working in or around energized electric power lines and circuits, and should be used only as guidelines. National and local codes and rules and regulatory standards should always take precedence over the guidelines discussed in this chapter.

The following rules are basic to electrical accident prevention:

- Know the work to be done and how to do it.
- Review working area for hazards of environment or facility design that may exist in addition to those directly associated with the assigned work objective.
- Wear flame-retardant coveralls and safety glasses plus other recommended protective devices/equipment. Refer to the PPE categories specified under arc-flash hazard analysis for a specified task.
- Isolate (de-energize) the circuits and/or equipment to be worked.
- Lock out and tag all power sources and circuits to and from the equipment/circuit to be worked on.
- Test with two pretested testing devices for the presence of electrical energy on circuits and/or equipment (both primary and secondary) while wearing electrical protective gloves.
- Ground all sides of the work area with protective grounds applied with hot sticks. All grounds must be visible at all times to those in the work area.
- Enclose the work area with tape barrier.

13.4.1 Electrical Safety

The following general guidelines are provided on on-site safety, work area control, lock-out and/or tagging, protective apparel, testing of energized circuits and equipment, rubber gloves, voltage testers and detectors, grounds, circuit breaker maintenance safety checklist, and entering confined spaces. These guidelines should be supplemented as required to meet the applicable codes and regulations including the PPE required per arc-flash hazard analysis.

13.4.2 "On-Site" Electrical Safety

Prior to going on an "on-site" electrical assignment, each worker should receive the following rules and should review and abide by them while on the assignment.

A foreman or qualified employee should be designated for each on-site assignment to provide on-site work direction and safety coordination. All personnel assigned to on-site electrical work should comply with the following directions:

- Know the work content and work sequence, especially all safety measures.
- Know the proper tools and instruments required for the work, that they have the full capability of safely performing the work, and that they are in good repair and/or are calibrated.
- Check to determine that all de-energized circuits and equipment are locked out and that grounds are placed on all sides of the work area prior to beginning work.
- Segregate all work areas with barriers or tapes, confine all your activities to these areas, and prevent unauthorized access to the area.
- Insure that all energized circuits and equipment adjacent to the work area are isolated, protected, or marked by at least two methods (e.g., rubber mats, tapes, signs, etc.) for personnel protection.
- Do not perform work on energized circuits and equipment without the direct authorization of your unit manager. When work on energized circuits and equipment has been authorized, use appropriate PPE required for the task, safety-tested equipment (i.e., rubber gloves, sleeves, mats, insulated tools, etc.).
- Your foreman and qualified employee must inform you of all changes in work conditions. You then must repeat this information to your foreman and qualified employee to insure your recognition and understanding of the condition.
- Do not work alone; work with another worker or employee at all times. Do not enter an energized area without direct permission from your foreman and qualified employee.
- Discuss each step of your work with your foreman and qualified employee before it is begun.
- Do not directly touch an unconscious fellow worker since he or she may be in contact with an energized circuit and equipment. Use an insulated device to remove him or her from the suspect area.
- Do not perform, or continue to perform, any work when you are in doubt about the safety procedure to be followed, the condition of the equipment, or any potential hazards. Perform this work only after you have obtained directions from your foreman and qualified employee.
- Do not work on, or adjacent to, any energized circuits and equipment unless you feel alert and are in good health.

13.4.3 "On-Site" Safety Kit

The following are recommended protective tools to be used in preparation for and in the performance of on-site electrical work:

- Red safety tape (300 ft)
- Red flashing hazard lights (6)

- Safety cones (6)
- Red "Do Not Operate" tags (15)
- Padlocks, keys, and lock shackle (6)
- Ground fault circuit interrupter-15 A, 125 V (1)
- Fire extinguishers (2)
- PPE

  Flame-retardant coveralls

  Safety glasses

  Face shields

  Hard hats

  Other items required for protection on the job
- Combustible gas/oxygen detectors
- Portable ventilation blower
- Ground loop impedance tester, ohmmeter (1)
- Voltage detectors

  Statiscope

  1. Station type (1)
  2. Overhead extension type (1)

  Audio

  1. Tic Tracer
  2. ESP
- Voltage/ampere meter (1)

  Amprobe

  Simpson
- Rubber gloves and protectors of appropriate class
- Grounding clamps, cables
- Hot sticks

13.4.4 Work Area Control

When workers are setting up the control area, it should be standard procedure that the safety coordinator be present and provide the required information.

Tape—solid red: A red tape barrier (with safety cones and red flashing lights) must be used to enclose an area in which personnel will be working. Other persons may not enter the isolated area unless they are actively working in conjunction with the personnel on the assigned work.

The purpose of the solid red tape barrier is to enclose and isolate an area in which a hazard might exist for individuals unfamiliar with the equipment enclosed. The only persons permitted within the solid red barrier are individuals knowledgeable in the use and operation of the enclosed equipment.

For their safety, workers shall not interest themselves in nor enter any area not enclosed by the red tape barrier except for a defined route to enter and leave the site.

It is important that the tape barrier is strictly controlled and the restrictions regarding its use are enforced.

When any workers are using solid red tape to enclose an area, the following requirements must be satisfied:

- Place the tape so that it completely encloses the area or equipment where the hazard exists.
- Place the tape so that it is readily visible from all avenues of approach and at such a level that it forms an effective barrier.
- Be certain that the area enclosed by the tape is large enough to give adequate clearance between the hazard and any personnel working in the tape enclosed area.
- Arrange the tape so any test equipment for the setup can be operated safely from outside the enclosed area.
- Use the tape to prevent the area from being entered by persons unfamiliar with the work and associated hazards. Do not use the tape for any other purpose.
- Remove the tape when the hazard no longer exists and the work is completed.

It shall be standard procedure that the workers should consider all areas outside the red barrier work area as energized and undertake no investigation unless accompanied by a knowledgeable plant employee.

Tape—white with a red stripe: White tape with a red stripe is used to enclose and isolate a temporary hazard (mechanical or electrical). No one is to enter this enclosed area. Obviously, if the enclosing of a hazardous area with tape is to be protective, the use of the tape barrier should be controlled and the restrictions on entering the area strictly enforced.

When any personnel are using white tape with a red stripe, the following requirements must be satisfied:

- Place the tape so that it completely encloses the area or equipment where the hazard exists.
- Place the tape so that it is readily visible from all avenues of approach and at such a level that it forms an effective barrier.
- Be certain that the area enclosed is large enough to give adequate clearance between the hazard and any personnel outside the enclosed area.
- Arrange the tape so that the test equipment for the setup can be operated outside the enclosed area.
- Use the tape only to isolate a temporary mechanical or electrical hazard; do not use the tape for any other purpose.

Consider a striped tape area similar to an interlocked enclosure and treat as such.

Remove the tape when the hazard no longer exists.

13.4.5 Lock-Out and/or Tagging

For the protection of personnel working on electrical conductor and/or equipment, locks must be placed on all open isolation devices designed to receive them. "DANGER" tags signed by the foreman or qualified employee must also be placed on the open isolation device.

Danger Tags: Danger tags may be applied only by authorized personnel and the tags must be dated and signed by the person applying the tag. The following requirements must be satisfied when danger tags are used:

Danger tags are to be used only for personnel protection when the personnel are required to work on or near equipment that, if operated, might cause injury.

Danger tags are attached to primary disconnecting devices as a means of locking out equipment. Tag each source of power to the equipment and associated feeds (instrumentation circuits, PT's, CT's, etc.) to the equipment which is to be locked out.

Danger tags should be left on the equipment only while the personnel are working on the equipment or when a hazard to the personnel exists. A device bearing a danger tag must not be operated at any time (Figure 13.4).

Out of order tags: Out of order tags are used to restrict the operation of equipment which has a mechanical defect or for other reasons that are not related to the safety of personnel. Complete information concerning the reasons for the tag and a list of all persons authorized to operate the tagged device must be written on the tag (Figure 13.5).

Out of service tags: Out of service tags are used to indicate equipment that has been taken out of service. It is a white tag with letters on a black background.

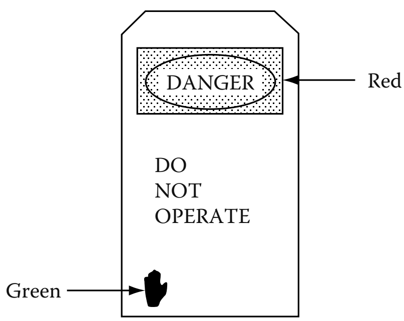


FIGURE 13.4
A sample of danger tag.