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15.1 Introduction

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Electric power quality has emerged as a major area of electric power engineering. The predominant reason for this emergence is the increase in sensitivity of end-use equipment. This chapter is devoted to various aspects of power quality as it impacts utility companies and their customers and includes material on (1) grounding, (2) voltage sags, (3) harmonics, (4) voltage flicker, and (5) long-term monitoring. While these five topics do not cover all aspects of power quality, they provide the reader with a broad-based overview that should serve to increase overall understanding of problems related to power quality.

Proper grounding of equipment is essential for safe and proper operation of sensitive electronic equipment. In times past, it was thought by some that equipment grounding as specified in the U.S. by the National Electric Code was in contrast with methods needed to insure power quality. Since those early times, significant evidence has emerged to support the position that, in the vast majority of instances, grounding according to the National Electric Code is essential to insure proper and trouble-free equipment operation, and also to insure the safety of associated personnel.

Other than poor grounding practices, voltage sags due primarily to system faults are probably the most significant of all power quality problems. Voltage sags due to short circuits are often seen at distances very remote from the fault point, thereby affecting a potentially large number of utility customers. Coupled with the wide-area impact of a fault event is the fact that there is no effective preventive for all power system faults. End-use equipment will, therefore, be exposed to short periods of reduced voltage which may or may not lead to malfunctions.

Like voltage sags, the concerns associated with flicker are also related to voltage variations. Voltage flicker, however, is tied to the likelihood of a human observer to become annoyed by the variations in the output of a lamp when the supply voltage amplitude is varying. In most cases, voltage flicker considers (at least approximately) periodic voltage fluctuations with frequencies less than about 30–35 Hz that are small in size. Human perception, rather than equipment malfunction, is the relevant factor when considering voltage flicker.

For many periodic waveform (either voltage or current) variations, the power of classical Fourier series theory can be applied. The terms in the Fourier series are called harmonics; relevant harmonic terms may have frequencies above or below the fundamental power system frequency. In most cases, nonfundamental frequency equipment currents produce voltages in the power delivery system at those same frequencies. This voltage distortion is present in the supply to other end-use equipment and can lead to improper operation of the equipment.

Harmonics, like most other power quality problems, require significant amounts of measured data in order for the problem to be diagnosed accurately. Monitoring may be short- or long-term and may be relatively cheap or very costly and often represents the majority of the work required to develop power quality solutions.

In summary, the power quality problems associated with grounding, voltage sags, harmonics, and voltage flicker are those most often encountered in practice. It should be recognized that the voltage and current transients associated with common events like lightning strokes and capacitor switching can also negatively impact end-use equipment. Because transients are covered in a separate chapter of this book, they are not considered further in this chapter.

15.2 Wiring and Grounding for Power Quality

Christopher J. Melhorn

Perhaps one of the most common problems related to power quality is wiring and grounding. It has been reported that approximately 70 to 80% of all power quality related problems can be attributed to faulty connections and/or wiring. This section describes wiring and grounding issues as they relate to power quality. It is not intended to replace or supercede the National Electric Code (NEC) or any local codes concerning grounding.

Definitions and Standards

Defining grounding terminology is outside the scope of this section. There are several publications on the topic of grounding that define grounding terminology in various levels of detail. The reader is referred to these publications for the definitions of grounding terminology.

The following is a list of standards and recommended practice pertaining to wiring and grounding issues. See the section on References for complete information.

National Electric Code Handbook, 1996 edition.
IEEE Std. 1100-1999. *IEEE Recommended Practice for Powering and Grounding Electronic Equipment.*
IEEE Std. 142-1991. *IEEE Recommended Practice for Grounding Industrial and Commercial Power Systems.*
FIPS-94 Publication
Electrical Power Systems Quality

The National Electric Code

NFPAs *National Electrical Code Handbook* pulls together all the extra facts, figures, and explanations readers need to interpret the 1999 NEC. It includes the entire text of the Code, plus expert commentary, real-world examples, diagrams, and illustrations that clarify requirements. Code text appears in blue type and commentary stands out in black. It also includes a user-friendly index that references article numbers to be consistent with the Code.

Several definitions of grounding terms pertinent to discussions in this article have been included for reader convenience. The following definitions were taken from various publications as cited.

From the *IEEE Dictionary — Std. 100*

Grounding: A conducting connection, whether intentional or accidental, by which an electric circuit or equipment is connected to the earth, or to some conducting body of relatively large extent that serves in place of the earth. It is used for establishing and maintaining the potential of the earth (or of the conducting body) or approximately that potential, on conductors connected to it; and for conducting ground current to and from the earth (or the conducting body).

Green Book (IEEE Std. 142) Definitions:

Ungrounded System: A system, circuit, or apparatus without an intentional connection to ground, except through potential indicating or measuring devices or other very high impedance devices.

Grounded System: A system of conductors in which at least one conductor or point (usually the middle wire or neutral point of transformer or generator windings) is intentionally grounded, either solidly or through an impedance.

NEC Definitions:

Refer to Figure 15.1.

Bonding Jumper, Main: The connector between the grounded circuit conductor (neutral) and the equipment-grounding conductor at the service entrance.

Conduit/Enclosure Bond: (bonding definition) The permanent joining of metallic parts to form an electrically conductive path which will assure electrical continuity and the capacity to conduct safely any current likely to be imposed.

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

Grounded Conductor: A system or circuit conductor that is intentionally grounded (the grounded conductor is normally referred to as the neutral conductor).

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

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

Grounding Electrode Conductor: The conductor used to connect the grounding electrode to the equipment-grounding conductor and/or to the grounded conductor of the circuit at the service equipment or at the source of a separately derived system.

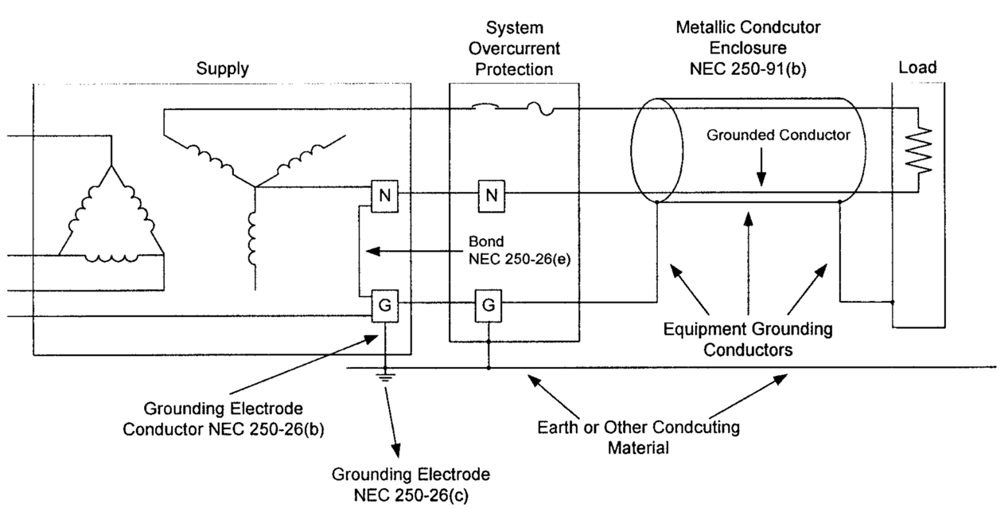

FIGURE 15.1 Terminology used in NEC definitions.

Grounding Electrode: The grounding electrode shall be as near as practicable to and preferably in the same area as the grounding conductor connection to the system. The grounding electrode shall be: (1) the nearest available effectively grounded structural metal member of the structure; or (2) the nearest available effectively grounded metal water pipe; or (3) other electrodes (Section 250-81 & 250-83) where electrodes specified in (1) and (2) are not available.

Grounding Electrode System: Defined in NEC Section 250-81 as including: (a) metal underground water pipe; (b) metal frame of the building; (c) concrete-encased electrode; and (d) ground ring. When these elements are available, they are required to be bonded together to form the grounding electrode system. Where a metal underground water pipe is the only grounding electrode available, it must be supplemented by one of the grounding electrodes specified in Section 250-81 or 250-83.

Separately Derived Systems: A premises wiring system whose power is derived from generator, transformer, or converter windings and has no direct electrical connection, including a solidly connected grounded circuit conductor, to supply conductors originating in another system.

Reasons for Grounding

There are three basic reasons for grounding a power system: personal safety, protective device operation, and noise control. All three of these reasons will be addressed.

Personal Safety

The most important reason for grounding a device on a power system is personal safety. The safety ground, as it is sometimes called, is provided to reduce or eliminate the chance of a high touch potential if a fault occurs in a piece of electrical equipment. Touch potential is defined as the voltage potential between any two conducting materials that can be touched simultaneously by an individual or animal.

Figure 15.2 illustrates a dangerous touch potential situation. The "hot" conductor in the piece of equipment has come in contact with the case of the equipment. Under normal conditions, with the safety ground intact, the protective device would operate when this condition occurred. However, in Fig. 15.2, the safety ground is missing. This allows the case of the equipment to float above ground since the case of the equipment is not grounded through its base. In other words, the voltage potential between the equipment case and ground is the same as the voltage potential between the hot leg and ground. If the operator would come in contact with the case and ground (the floor), serious injury could result.

In recent years, manufacturers of handheld equipment, drills, saws, hair dryers, etc. have developed double insulated equipment. This equipment generally does not have a safety ground. However, there is

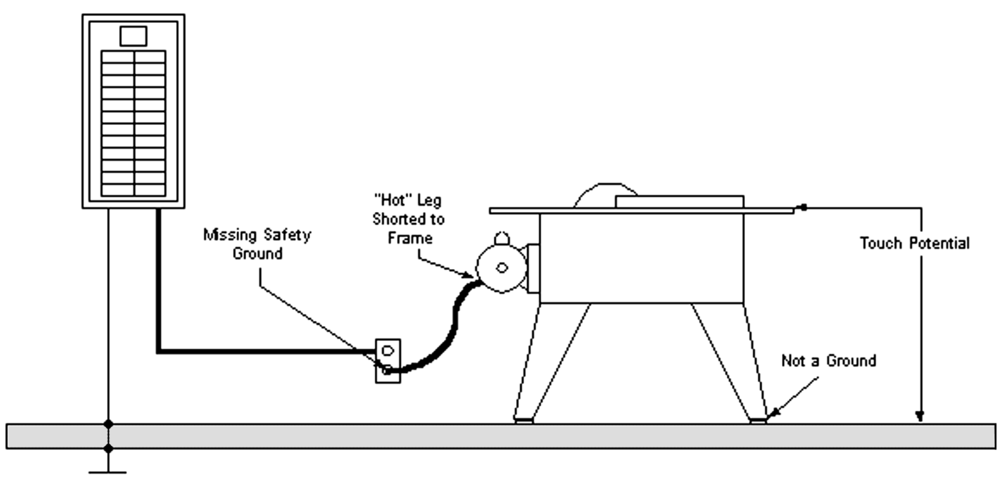

FIGURE 15.2 Illustration of a dangerous touch potential situation.

TABLE 15.1 Example Ground Impedance Values

Protective Device Rating	Voltage to Ground 120 Volts	Voltage to Ground 277 Volts
20 Amps	1.20 Ω	2.77 Ω
40 Amps	0.60 Ω	1.39 Ω
50 Amps	0.48 Ω	1.11 Ω
60 Amps	0.40 Ω	0.92 Ω
100 Amps	0.24 Ω	0.55 Ω

never any conducting material for the operator to contact and therefore there is no touch potential hazard. If the equipment becomes faulted, the case or housing of the equipment is not energized.

Protective Device Operation

As mentioned in the previous section, there must be a path for fault current to return to the source if protective devices are to operate during fault conditions. The National Electric Code (NEC) requires that an effective grounding path must be mechanically and electrically continuous (NEC 250-51), have the capacity to carry any fault currents imposed on it without damage (NEC 250-75). The NEC also states that the ground path must have sufficiently low impedance to limit the voltage and facilitate protective device operation. Finally, the earth cannot serve as the equipment-grounding path (NEC-250-91(c)).

The formula to determine the maximum circuit impedance for the grounding path is:

$$\text{Ground Path Impedance} = \frac{\text{Maximum Voltage to Ground}}{\text{Overcurrent Protection Rating} \times 5}$$

Table 15.1 gives examples of maximum ground path circuit impedances required for proper protective device operation.

Noise Control

Noise control is the third main reason for grounding. Noise is defined as unwanted voltages and currents on a grounding system. This includes signals from all sources whether it is radiated or conducted. As stated, the primary reason for grounding is safety and is regulated by the NEC and local codes. Any changes to the grounding system to improve performance or eliminate noise control must be in addition to the minimum NEC requirements.

When potential differences occur between different grounding systems, insulation can be stressed and circulating currents can be created in low voltage cables (e.g., communications cables). In today's electrical environment, buildings that are separated by large physical distances are typically tied together via a communication circuit. An example of this would be a college campus that may cover several square miles. Each building has its own grounding system. If these grounding systems are not tied together, a potential difference on the grounding circuit for the communication cable can occur. The idea behind grounding for noise control is to create an equipotential grounding system, which in turn limits or even eliminates the potential differences between the grounding systems. If the there is an equipotential grounding system and currents are injected into the ground system, the potential of the whole grounding system will rise and fall and potential differences will not occur.

Supplemental conductors, ground reference grids, and ground plates can all be used to improve the performance of the system as it relates to power quality. Optically isolated communications can also improve the performance of the system. By using the opto-isolators, connecting the communications to different ground planes is avoided. All improvements to the grounding system must be done in addition to the requirements for safety.

Separation of loads is another method used to control noise. Figure 15.3 illustrates this point. Figure 15.3 shows four different connection schemes. Each system from left to right improves noise control.

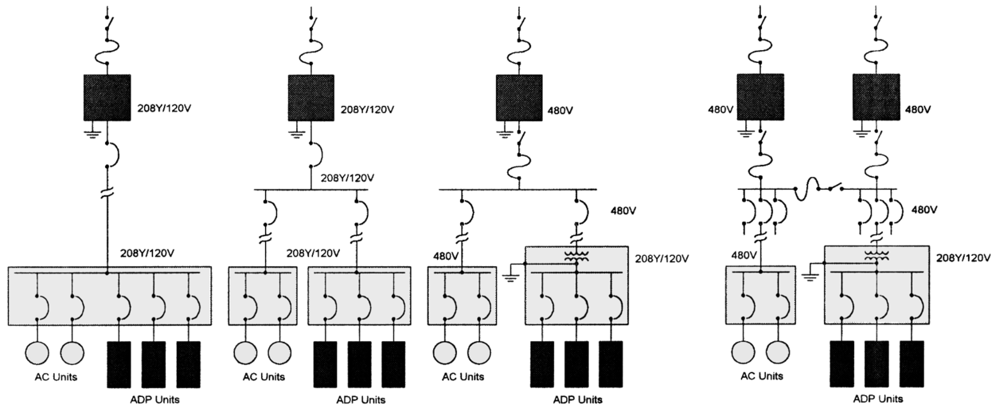

FIGURE 15.3 Separation of loads for noise control.

TABLE 15.2 Typical Wiring and Grounding Problems and Causes

Wiring Condition or Problem Observed	Possible Cause
Impulse, voltage drop out	Loose connections
Impulse, voltage drop out	Faulty breaker
Ground currents	Extra neutral-to-ground bond
Ground currents	Neutral-to-ground reversal
Extreme voltage fluctuations	High impedance in neutral circuit
Voltage fluctuations	High impedance neutral-to-ground bonds
High neutral to ground voltage	High impedance ground
Burnt smell at the panel, junction box, or load	Faulted conductor, bad connection, arcing, or overloaded wiring
Panel or junction box is warm to the touch	Faulty circuit breaker or bad connection
Buzzing sound	Arcing
Scorched insulation	Overloaded wiring, faulted conductor, or bad connection
Scorched panel or junction box	Bad connection, faulted conductor
No voltage at load equipment	Tripped breaker, bad connection, or faulted conductor
Intermittent voltage at the load equipment	Bad connection or arcing

As seen in Figure 15.3, the best case would be the complete separation (system on the far right) of the ADP units from the motor loads and other equipment. Conversely, the worst condition is on the left of Fig. 15.3 where the ADP units are served from the same circuit as the motor loads.

Typical Wiring and Grounding Problems

In this section, typical wiring and grounding problems, as related to power quality, are presented. Possible solutions are given for these problems as well as the possible causes for the problems being observed on the grounding system. (See Table 15.2.)

The following list is just a sample of problems that can occur on the grounding system.

- Isolated grounds
- Ground loops
- Missing safety ground
- Multiple neutral-to-ground bonds
- Additional ground rods
- Insufficient neutral conductors

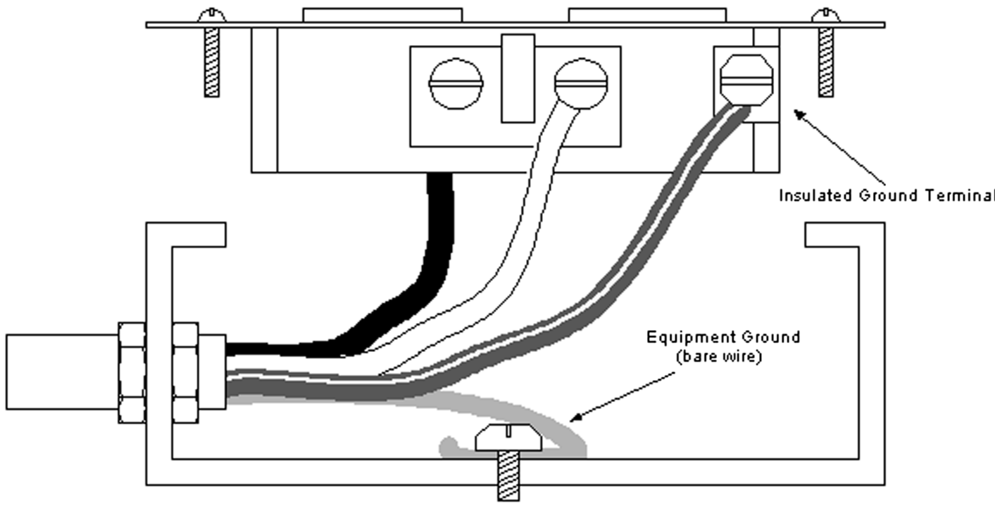

FIGURE 15.4 Properly wired isolated ground circuit.

Insulated Grounds

Insulated grounds in themselves are not a grounding problem. However, improperly used insulated grounds can be a problem. Insulated grounds are used to control noise on the grounding system. This is accomplished by using insulated ground receptacles, which are indicated by a "Δ" on the face of the outlet. Insulated ground receptacles are often orange in color. Figure 15.4 illustrates a properly wired insulated ground circuit.

The 1996 NEC has this to say about insulated grounds.

NEC 250-74. Connecting Receptacle Grounding Terminal to Box. An equipment bonding jumper shall be used to connect the grounding terminal of a grounding-type receptacle to a grounded box.

Exception No. 4. Where required for the reduction of electrical noise (electromagnetic interference) on the grounding circuit, a receptacle in which the grounding terminal is purposely insulated from the receptacle mounting means shall be permitted. The receptacle grounding terminal shall be grounded by an insulated equipment grounding conductor run with the circuit conductors. This grounding conductor shall be permitted to pass through one or more panelboards without connection to the panelboard grounding terminal as permitted in Section 384-20, Exception so as to terminate within the same building or structure directly at an equipment grounding conductor terminal of the applicable derived system or source.

(FPN): Use of an isolated equipment grounding conductor does not relieve the requirement for grounding the raceway system and outlet box.

NEC 517-16. Receptacles with Insulated Grounding Terminals. Receptacles with insulated grounding terminals, as permitted in Section 250-74, Exception No. 4, shall be identified; such identification shall be visible after installation.

(FPN): Caution is important in specifying such a system with receptacles having insulated grounding terminals, since the grounding impedance is controlled only by the grounding conductors and does not benefit functionally from any parallel grounding paths.

The following is a list of pitfalls that should be avoided when installing insulated ground circuits.

- Running an insulated ground circuit to a regular receptacle.
- Sharing the conduit of an insulated ground circuit with another circuit.
- Installing an insulated ground receptacle in a two-gang box with another circuit.

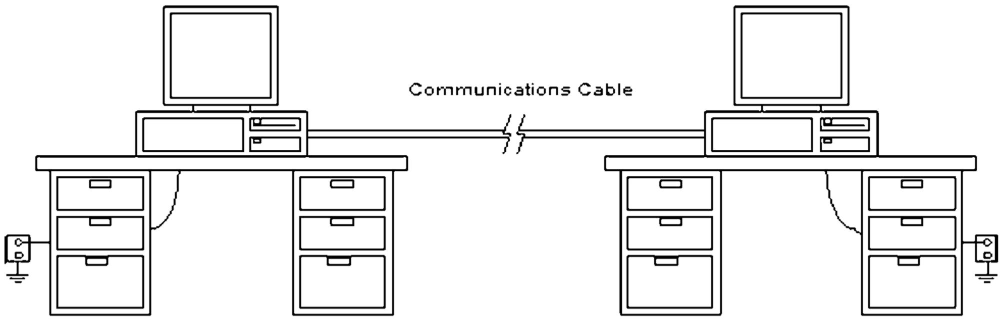

FIGURE 15.5 Circuit with a ground loop.

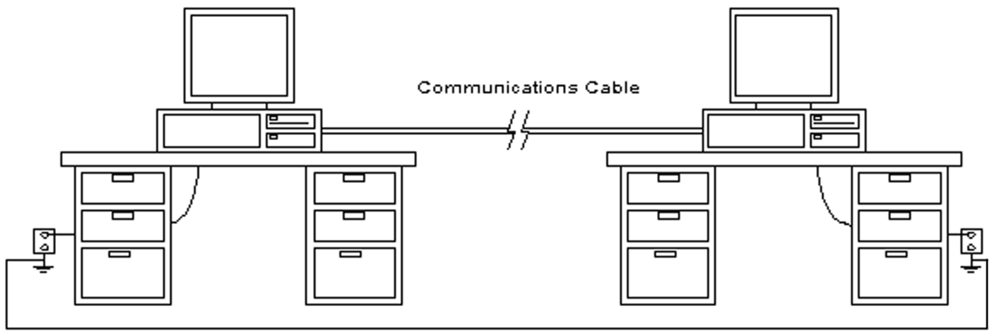

FIGURE 15.6 Grounding electrodes must be bonded together.

- Not running the insulated ground circuit in a metal cable armor or conduit.
- Do not assume that an insulated ground receptacle has a truly insulated ground.

Ground Loops

Ground loops can occur for several reasons. One is when two or more pieces of equipment share a common circuit like a communication circuit, but have separate grounding systems (Fig. 15.5).

To avoid this problem, only one ground should be used for grounding systems in a building. More than one grounding electrode can be used, but they must be tied together (NEC 250-81, 250-83, and 250-84) as illustrated in Fig. 15.6.

Missing Safety Ground

As discussed previously, a missing safety ground poses a serious problem. Missing safety grounds usually occur because the safety ground has been bypassed. This is typical in buildings where the 120-volt outlets only have two conductors. Modern equipment is typically equipped with a plug that has three prongs, one of which is a ground prong. When using this equipment on a two-prong outlet, a grounding plug adapter or "cheater plug" can be employed provided there is an equipment ground present in the outlet box. This device allows the use of a three-prong device in a two-prong outlet. When properly connected, the safety ground remains intact. Figure 15.7 illustrates the proper use of the cheater plug.

If an equipment ground is not present in the outlet box, then the grounding plug adapter should not be used. If the equipment grounding conductor is present, the preferred method for solving the missing safety ground problem is to install a new three-prong outlet in the outlet box. This method insures that the grounding conductor will not be bypassed. The NEC discusses equipment grounding conductors in detail in Section 250 — Grounding.

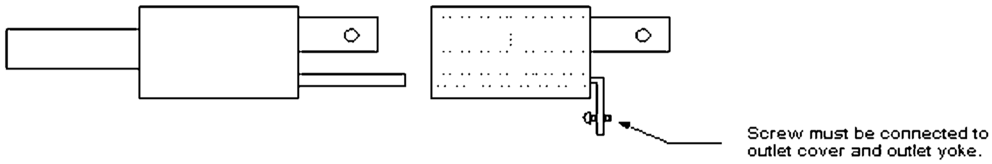

FIGURE 15.7 Proper use of a grounding plug adapter or "cheater plug."

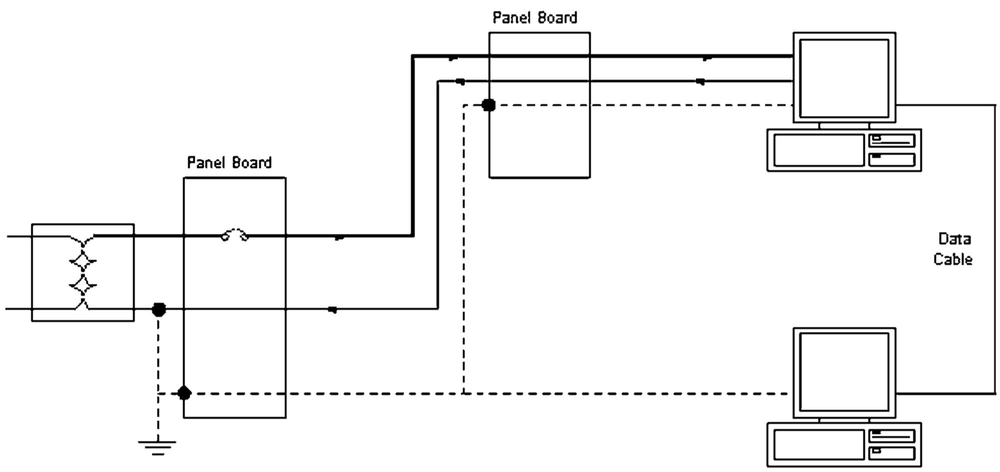

FIGURE 15.8 Neutral current flow with one neutral-to-ground bond.

Multiple Neutral to Ground Bonds

Another misconception when grounding equipment is that the neutral must be tied to the grounding conductor. Only one neutral-to-ground bond is permitted in a system or sub-system. This typically occurs at the service entrance to a facility unless there is a separately derived system. A separately derived system is defined as a system that receives its power from the windings of a transformer, generator, or some type of converter. Separately derived systems must be grounded in accordance with NEC 250-26.

The neutral should be kept separate from the grounding conductor in all panels and junction boxes that are downline from the service entrance. Extra neutral-to-ground bonds in a power system will cause neutral currents to flow on the ground system. This flow of current on the ground system occurs because of the parallel paths. Figures 15.8 and 15.9 illustrate this effect.

As seen in Fig. 15.9, neutral current can find its way onto the ground system due to the extra neutral-to-ground bond in the secondary panel board. Notice that not only will current flow in the ground wire for the power system, but currents can flow in the shield wire for the communication cable between the two PCs.

If the neutral-to-ground bond needs to be reestablished (high neutral-to-ground voltages), this can be accomplished by creating a separately derived system as defined above. Figure 15.10 illustrates a separately derived system.

Additional Ground Rods

Additional ground rods are another common problem in grounding systems. Ground rods for a facility or building should be part of the grounding system. The ground rods should be connected where all the building grounding electrodes are bonded together. Isolated grounds can be used as described in the

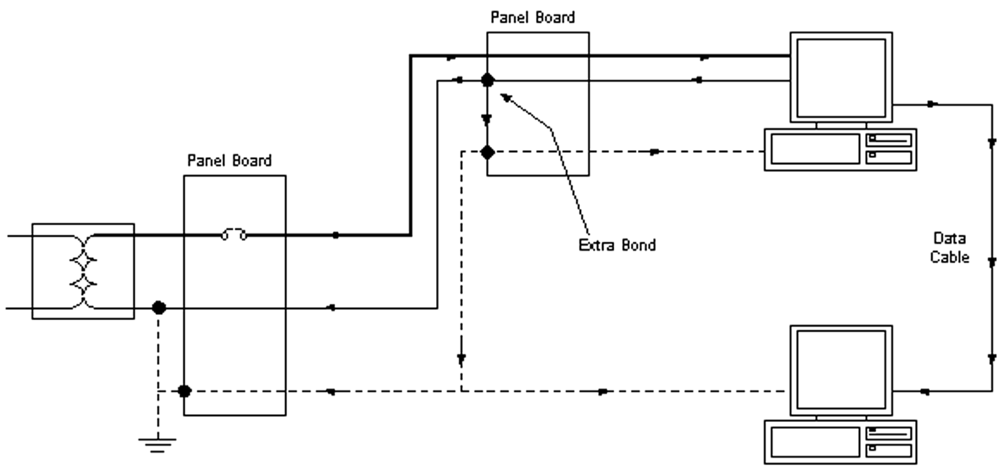

FIGURE 15.9 Neutral current flow with and extra neutral-to-ground bond.

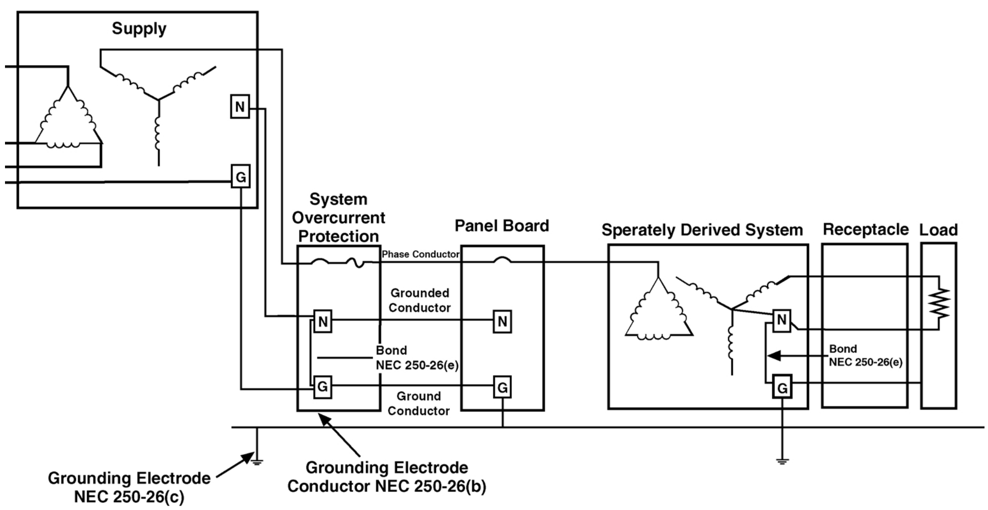

FIGURE 15.10 Example of the use of a separately derived system.

NEC's Isolated Ground section, but should not be confused with isolated ground rods, which are not permitted.

The main problem with additional ground rods is that they create secondary paths for transient currents, such as lightning strikes, to flow. When a facility incorporates the use of one ground rod, any currents caused by lightning will enter the building ground system at one point. The ground potential of the entire facility will rise and fall together. However, if there is more than one ground rod for the facility, the transient current enters the facility's grounding system at more than one location and a portion of the transient current will flow on the grounding system causing the ground potential of equipment to rise at different levels. This, in turn, can cause severe transient voltage problems and possible conductor overload conditions.

Insufficient Neutral Conductor

With the increased use of electronic equipment in commercial buildings, there is a growing concern for the increased current imposed on the grounded conductor (neutral conductor). With a typical three-phase load that is balanced, there is theoretically no current flowing in the neutral conductor, as illustrated in Fig 15.11.

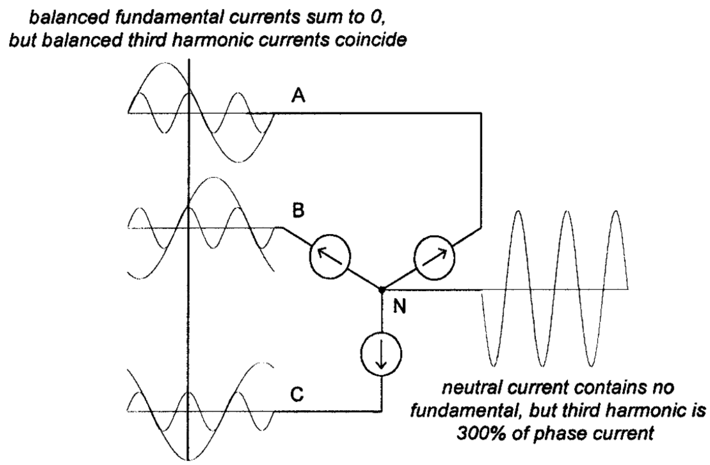

FIGURE 15.11 A balanced three-phase system.

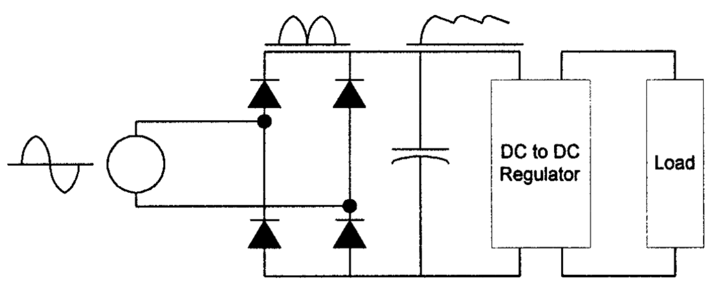

FIGURE 15.12 The basic one-line for a SMPS.

However, PCs, laser printers, and other pieces of electronic office equipment all use the same basic technology for receiving the power that they need to operate. Figure 15.12 illustrates the typical power supply of a PC. The input power is generally 120 volts AC, single phase. The internal electronic parts require various levels of DC voltage (e.g., ±5, 12 volts DC) to operate. This DC voltage is obtained by converting the AC voltage through some type of rectifier circuit as shown. The capacitor is used for filtering and smoothing the rectified AC signal. These types of power supplies are referred to as switch mode power supplies (SMPS).

The concern with devices that incorporate the use of SMPS is that they introduce triplen harmonics into the power system. Triplen harmonics are those that are odd multiples of the fundamental frequency component ($h = 3, 9, 15, 21, \ldots$). For a system that has balanced single-phase loads as illustrated in Fig. 15.13, fundamental and third harmonic components are present. Applying Kirchoff's current law at node N shows that the fundamental current component in the neutral must be zero. But when loads are balanced, the third harmonic components in each phase coincide. Therefore, the magnitude of third harmonic current in the neutral must be three times the third harmonic phase current.

This becomes a problem in office buildings when multiple single-phase loads are supplied from a three-phase system. Separate neutral wires are run with each circuit, therefore the neutral current will be equivalent to the line current. However, when the multiple neutral currents are returned to the panel or transformer serving the loads, the triplen currents will add in the common neutral for the panel and this can cause over heating and eventually even cause failure of the neutral conductor. If office partitions are used, the same, often undersized neutral conductor is run in the partition with three-phase conductors. Each receptacle is fed from a separate phase in order to balance the load current. However, a single

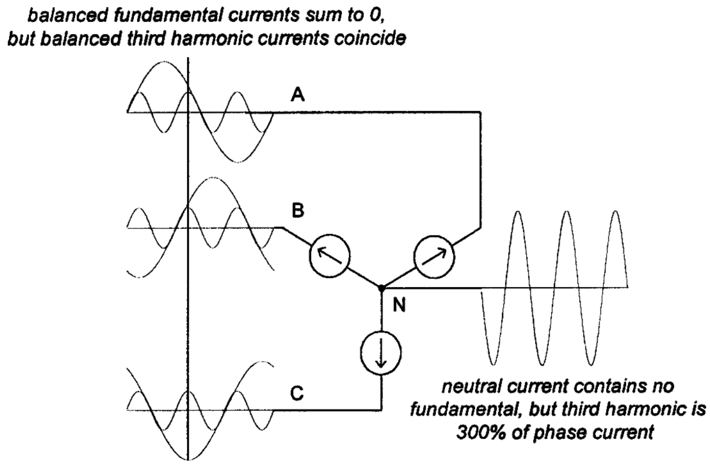

FIGURE 15.13 Balanced single-phase loads.

TABLE 15.3 Summary of Wiring and Grounding Issues

Summary Issues
Good power quality and noise control practices do not conflict with safety requirements.
Wiring and grounding problems cause a majority of equipment interference problems.
Make an effort to put sensitive equipment on dedicated circuits.
The grounded conductor, neutral conductor, should be bonded to the ground at the transformer or main panel, but not at other panel down line except as allowed by separately derived systems.

neutral is usually shared by all three phases. This can lead to disastrous results if the partition electrical receptacles are used to supply nonlinear loads rich in triplen harmonics.

Under the worst conditions, the neutral current will never exceed 173% of the phase current. Figure 15.13 illustrates a case where a three-phase panel is used to serve multiple single-phase SMPS PCs.

Summary

As discussed previously, the three main reasons for grounding in electrical systems are:

1. Personal safety
2. Proper protective device operation
3. Noise control

By following the guidelines found below, the objectives for grounding can be accomplished.

- All equipment should have a safety ground. A safety ground conductor
- Avoid load currents on the grounding system.
- Place all equipment in a system on the same equipotential reference.

Table 15.3 summarizes typical wiring and grounding issues.

Case Study

This section presents a case study involving wiring and grounding issues. The purpose of this case study is to inform the reader on the procedures used to evaluate wiring and grounding problems and present solutions.

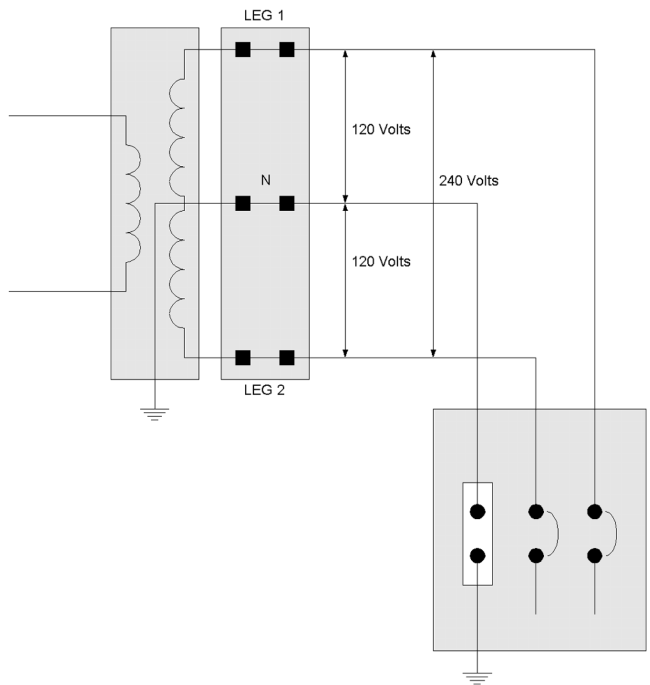

FIGURE 15.14 Split-phase system serving a residential customer.

Case Study — Flickering Lights

This case study concerns a residential electrical system. The homeowners were experiencing light flicker when loads were energized and deenergized in their homes.

Background

Residential systems are served from single-phase transformers employing a spilt secondary winding, often referred to as a single-phase three-wire system. This type of transformer is used to deliver both 120-volt and 240-volt single-phase power to the residential loads. The primary of the transformer is often served from a 12 to 15 kV distribution system by the local utility. Figure 15.14 illustrates the concept of a split-phase system.

When this type of service is operating properly, 120 volts can be measured from either leg to the neutral conductor. Due to the polarity of the secondary windings in the transformer, the polarity of each 120-volt leg is opposite the other, thus allowing a total of 240 volts between the legs as illustrated. The proper operation of this type of system is dependent on the physical connection of the neutral conductor or center tap of the secondary winding. If the neutral connection is removed, 240 volts will remain across the two legs, but the line-to-neutral voltage for either phase can be shifted, causing either a low or high voltage from line to neutral.

Most loads in a residential dwelling, i.e., lighting, televisions, microwaves, home electronics, etc., are operated from 120 volts. However, there are a few major loads that incorporate the use of the 240 volts available. These loads include electric water heaters, electric stoves and ovens, heat pumps, etc.

The Problem

In this case, there were problems in the residence that caused the homeowner to question the integrity of the power system serving his home. On occasion, the lights would flicker erratically when the washing machine and dryer were operating at the same time. When large single-phase loads were operated, low power incandescent light bulb intensity would flicker.

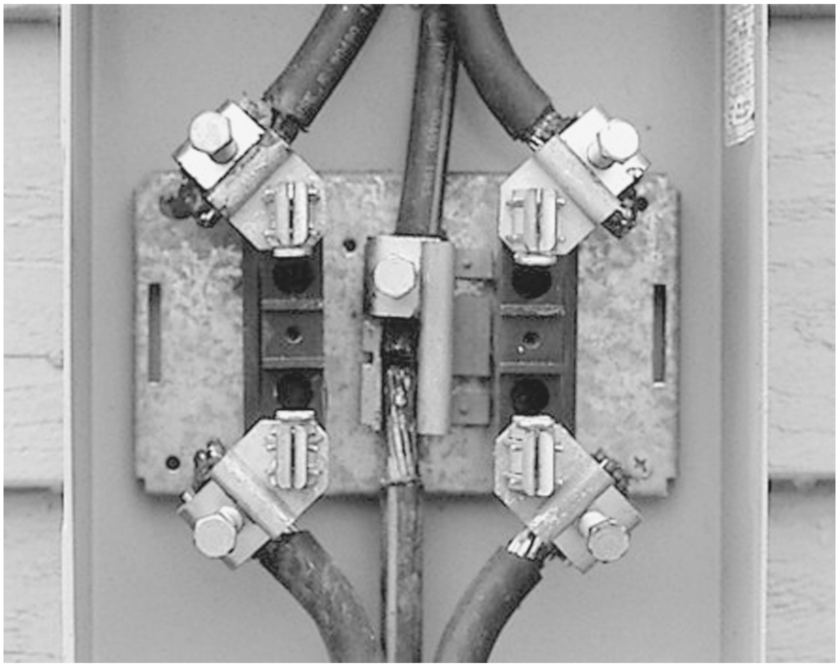

FIGURE 15.15 Actual residential meter base. Notice the missing neutral clamp on load side of meter.

Measurements were performed at several 120-volt outlets throughout the house. When the microwave was operated, the voltage at several of the 120-volt outlets would increase from 120 volts nominal to 128 volts. The voltage would return to normal after the microwave was turned off. The voltage would also increase when a 1500-Watt space heater was operated. It was determined that the voltage would decrease to approximately 112 volts on the leg from which the large load was served. After the measurements confirmed suspicions of high and low voltages during heavy load operation, finding the source of the problem was the next task at hand.

The hunt began at the service entrance to the house. A visual inspection was made of the meter base and socket after the meter was removed by the local utility. It was discovered that one of the neutral connectors was loose. While attempting to tighten this connector, the connector fell off of the meter socket into the bottom of the meter base (see Fig. 15.15). Could this loose connector have been the cause of the flickering voltage? Let's examine the effects of the loose neutral connection.

Figures 15.16 and 15.17 will be referred to several times during this discussion. Under normal conditions with a solid neutral connection (Fig. 15.16), load current flows through each leg and is returned to the source through the neutral conductor. There is very little impedance in either the hot or the neutral conductor; therefore, no appreciable voltage drop exists.

When the neutral is loose or missing, a significant voltage can develop across the neutral connection in the meter base, as illustrated in Fig. 15.17. When a large load is connected across Leg 1 to N and the other leg is lightly loaded (i.e., Leg 1 to N is approximately 10 times the load on Leg 2 to N), the current flowing through the neutral will develop a voltage across the loose connection. This voltage is in phase with the voltage from Leg 1 to N′ (see Fig. 15.17) and the total voltage from Leg 1 to N will be 120 volts. However, the voltage supplied to any loads connected from Leg 2 to N′ will rise to 128 volts, as illustrated in Fig. 15.17. The total voltage across the Leg 1 and Leg 2 must remain constant at 240 volts. It should be noted that the voltage from Leg 2 to N will be 120 volts since the voltage across the loose connection is 180° out of phase with the Leg 2 to N′ voltage.

Therefore, with the missing neutral connection, the voltage from Leg 2 to N′ would rise, causing the light flicker. This explains the rise in voltage when a large load was energized on the system.

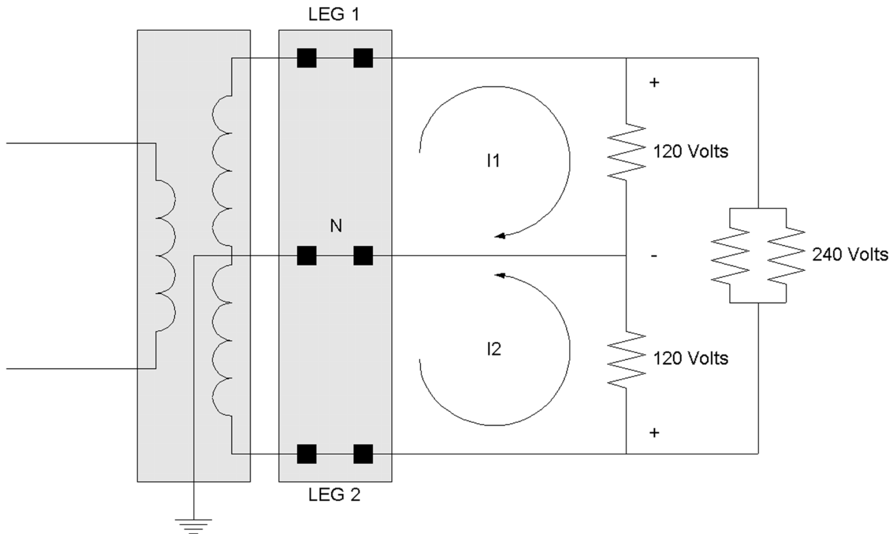

FIGURE 15.16 The effects of a solid neutral connection in the meter base.

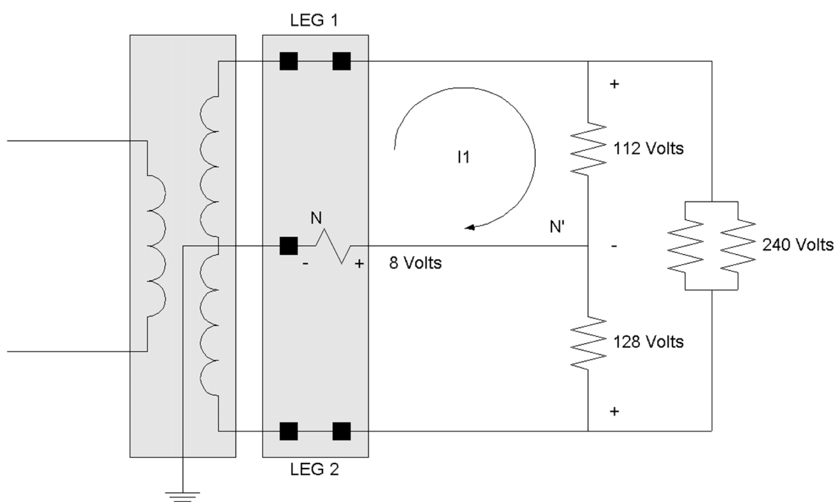

FIGURE 15.17 The effects of a loose neutral connection in the meter base.

The Solution

The solution in this case was simple — replace the failed connector.

Conclusions

Over time, the neutral connector had become loose. This loose connection caused heating, which in turn caused the threads on the connector to become worn, and the connector failed. After replacing the connector in the meter base, the flickering light phenomena disappeared.

On systems of this type, if a voltage rise occurs when loads are energized, it is a good indication that the neutral connection may be loose or missing.

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15.3 Harmonics in Power Systems

S. M. Halpin

Power system harmonics are not a new topic, but the proliferation of high-power electronics used in motor drives and power controllers has necessitated increased research and development in many areas relating to harmonics. For many years, high-voltage direct current (HVDC) stations have been a major focus area for the study of power system harmonics due to their rectifier and inverter stations. Roughly two decades ago, electronic devices that could handle several kW up to several MW became commercially viable and reliable products. This technological advance in electronics led to the widespread use of numerous converter topologies, all of which represent nonlinear elements in the power system.

Even though the power semiconductor converter is largely responsible for the large-scale interest in power system harmonics, other types of equipment also present a nonlinear characteristic to the power system. In broad terms, loads that produce harmonics can be grouped into three main categories covering (1) arcing loads, (2) semiconductor converter loads, and (3) loads with magnetic saturation of iron cores. Arcing loads, like electric arc furnaces and florescent lamps, tend to produce harmonics across a wide range of frequencies with a generally decreasing relationship with frequency. Semiconductor loads, such as adjustable-speed motor drives, tend to produce certain harmonic patterns with relatively predictable amplitudes at known harmonics. Saturated magnetic elements, like overexcited transformers, also tend to produce certain "characteristic" harmonics. Like arcing loads, both semiconductor converters and saturated magnetics produce harmonics that generally decrease with frequency.

Regardless of the load category, the same fundamental theory can be used to study power quality problems associated with harmonics. In most cases, any periodic distorted power system waveform (voltage, current, flux, etc.) can be represented as a series consisting of a DC term and an infinite sum of sinusoidal terms as shown in Eq. (15.1)where ω_0 is the fundamental power frequency.

$$f(t) = F_0 + \sum_{i=1}^{\infty} \sqrt{2} F_i \cos(i\omega_0 t + \theta_i) \tag{15.1}$$

A vast amount of theoretical mathematics has been devoted to the evaluation of the terms in the infinite sum in Eq. (15.1), but such rigor is beyond the scope of this section. For the purposes here, it is reasonable to presume that instrumentation is available that will provide both the magnitude F_i and the phase angle θ_i for each term in the series. Taken together, the magnitude and phase of the i^{th} term completely describe the i^{th} harmonic.

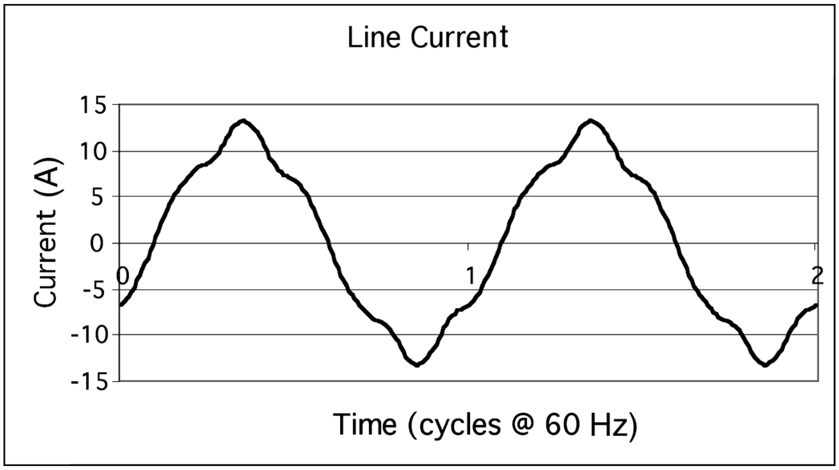

FIGURE 15.18 Current waveform.

It should be noted that not all loads produce harmonics that are integer multiples of the power frequency. These noninteger multiple harmonics are generally referred to as interharmonics and are commonly produced by arcing loads and cycloconverters. All harmonic terms, both integer and noninteger multiples of the power frequency, are analytically treated in the same manner, usually based on the principle of superposition.

In practice, the infinite sum in Eq. (15.1) is reduced to about 50 terms; most measuring instruments do not report harmonics higher than the 50^{th} multiple (2500–3000 Hz for 50–60 Hz systems). The reporting can be in the form of a tabular listing of harmonic magnitudes and angles or in the form of a magnitude and phase spectrum. In each case, the information provided is the same and can be used to reproduce the original waveform by direct substitution into Eq. (15.1) with satisfactory accuracy. As an example, Fig. 15.18 shows the (primary) current waveform drawn by a small industrial plant. Table 15.4 shows a table of the first 31 harmonic magnitudes and angles. Figure 15.19 shows a bar graph magnitude spectrum for this same waveform. These data are widely available from many commercial instruments; the choice of instrument makes little difference in most cases.

TABLE 15.4 Current Harmonic Magnitudes and Phase Angles

Harmonic #	Current (A_{rms})	Phase (deg)	Harmonic #	Current (A_{rms})	Phase (deg)
1	8.36	–65	2	0.01	–167
3	0.13	43	4	0.01	95
5	0.76	102	6	0.01	8
7	0.21	–129	8	0	–148
9	0.02	–94	10	0	78
11	0.08	28	12	0	–89
13	0.04	–172	14	0	126
15	0	159	16	0	45
17	0.02	–18	18	0	–117
19	0.01	153	20	0	22
21	0	119	22	0	26
23	0.01	–76	24	0	143
25	0	0	26	0	150
27	0	74	28	0	143
29	0	50	30	0	–13
31	0	–180			

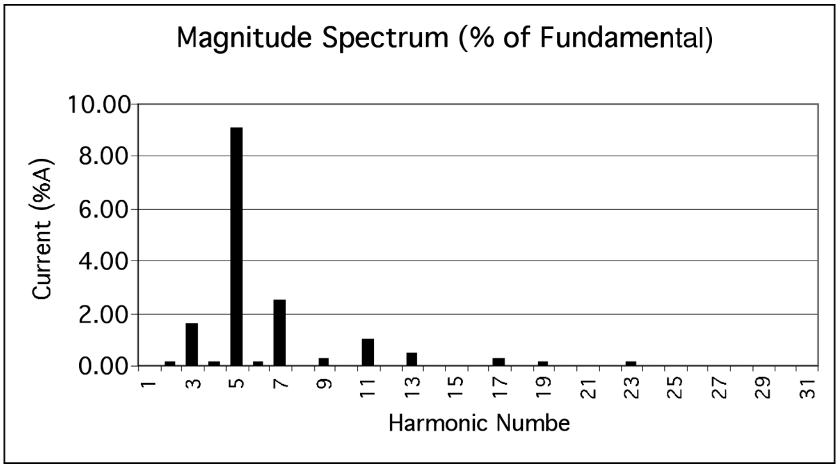

FIGURE 15.19 Harmonic magnitude spectrum.

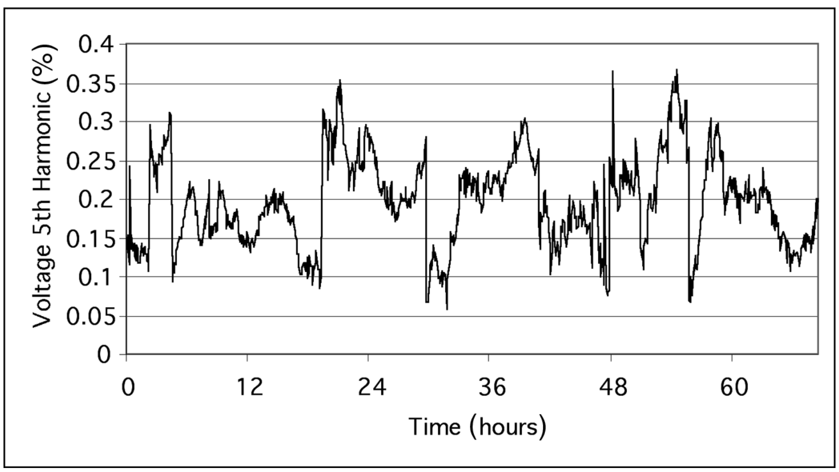

FIGURE 15.20 Example of time-varying nature of harmonics.

A fundamental presumption when analyzing distorted waveforms using Fourier methods is that the waveform is in steady state. In practice, waveform distortion varies widely and is dependent on both load levels and system conditions. It is typical to assume that a steady-state condition exists at the instant at which the measurement is taken, but the next measurement at the next time could be markedly different. As examples, Figs. 15.20 and 15.21 show time plots of 5th harmonic voltage and the total harmonic distortion, respectively, of the same waveform measured on a 115 kV transmission system near a five MW customer. Note that the THD is fundamentally defined in Eq. (15.2), with 50 often used in practice as the upper limit on the infinite summation.

$$\mathrm{THD}(\%) = \frac{\sqrt{\sum_{i=2}^{\infty} F_i^2}}{F_1} * 100\% \qquad (15.2)$$

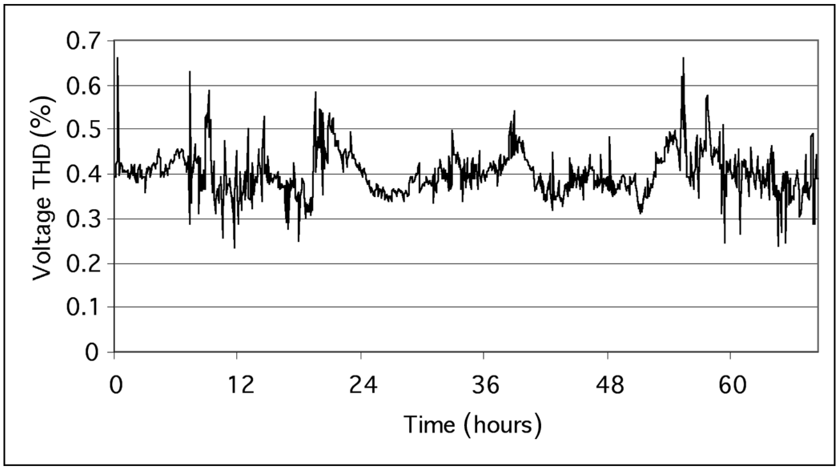

FIGURE 15.21 Example of time-varying nature of voltage THD.

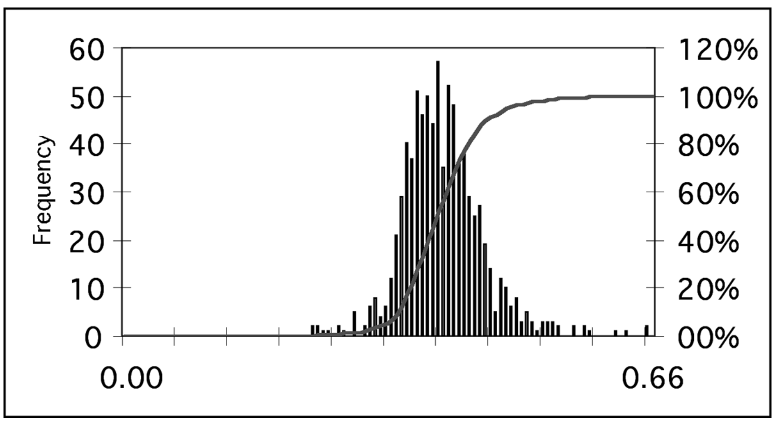

FIGURE 15.22 Probabilistic representation of voltage THD.

Because harmonic levels are never constant, it is difficult to establish utility-side or manufacturing-side limits for these quantities. In general, a probabilistic representation is used to describe harmonic quantities in terms of percentiles. Often, the 95th and 99th percentiles are used for design or operating limits. Figure 15.22 shows a histogram of the voltage THD in Fig. 15.21, and also includes a cumulative probability curve derived from the frequency distribution. Any percentile of interest can be readily calculated from the cumulative probability curve.

Both the Institute of Electrical and Electronics Engineers (IEEE) and the International Electrotechnical Commission (IEC) recognize the need to consider the time-varying nature of harmonics when determining harmonic levels that are permissible. Both organizations publish harmonic limits, but the degree to which the various limits can be applied varies widely. Both IEEE and IEC publish "system-level" harmonic limits that are intended to be applied from the utility point-of-view in order to limit power system harmonics to acceptable levels. The IEC, however, goes further and also publishes harmonic limits for individual pieces of equipment.

The IEEE limits are covered in two documents, IEEE 519-1992 and IEEE 519A (draft). These documents suggest that harmonics in the power system be limited by two different methods. One set of harmonic limits is for the harmonic current that a user can inject into the utility system at the point

TABLE 15.5 IEEE-519 Harmonic Current Limits

I_{SC}/I_L[a]	$h < 11$	$11 \le h < 17$	$17 \le h < 23$	$23 \le h < 35$	$35 \le h$	TDD
			$V_{supply} \le 69kV$			
<20[b]	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
			$69kV < V_{supply} \le 161$ kV			
<20[b]	2.0	1.0	0.75	0.3	0.15	2.5
20–50	3.5	1.75	1.25	0.5	0.25	4.0
50–100	5.0	2.25	2.0	1.25	0.35	6.0
100–1000	6.0	2.75	2.5	1.0	0.5	7.5
>1000	7.5	3.5	3.0	1.25	0.7	10.0
			$V_{supply} > 161$ kV			
<50	2.0	1.0	0.75	0.3	0.15	2.5
≥50	3.5	1.75	1.25	0.5	0.25	4.0

Note: Even harmonics are limited to 25% of the odd harmonic limits above. Current distortions that result in a DC offset, e.g., half wave converters, are not allowed.

[a] I_{SC} = maximum short-circuit current at PCC. I_L = maximum demand load current (fundamental frequency component) at PCC.

[b] All power generation equipment is limited to these values of current distortion, regardless of actual I_{SC}/I_L.

where other customers are or could be (in the future) served. (Note that this point in the system is often called the point of common coupling, or PCC.) The other set of harmonic limits is for the harmonic voltage that the utility can supply to any customer at the PCC. With this two-part approach, customers insure that they do not inject an "unreasonable" amount of harmonic current into the system, and the utility insures that any "reasonable" amount of harmonic current injected by any and all customers does not lead to excessive voltage distortion.

Table 15.5 shows the harmonic current limits that are suggested for utility customers. The table is broken into various rows and columns depending on harmonic number, short circuit to load ratio, and voltage level. Note that all quantities are expressed in terms of a percentage of the maximum demand current (I_L in the table). Total demand distortion (TDD) is defined to be the rms value of all harmonics, in amperes, divided by the maximum (12 month) fundamental frequency load current, I_L, with this ratio then multiplied by 100%.

The intent of the harmonic current limits is to permit larger customers, who in concept pay a greater share of the cost of power delivery equipment, to inject a greater portion of the harmonic current (in amperes) that the utility can absorb without producing excessive voltage distortion. Furthermore, customers served at transmission level voltage have more restricted injection limits than do customers served at lower voltage because harmonics in the high voltage network have the potential to adversely impact a greater number of other users through voltage distortion.

Table 15.6 gives the IEEE 519-1992 voltage distortion limits. Similar to the current limits, the permissible distortion is decreased at higher voltage levels in an effort to minimize potential problems for the majority of system users. Note that Tables 15.5 and 15.6 are given here for illustrative purposes only; the reader is strongly advised to consider additional material listed at the end of this section prior to trying to apply the limits.

The IEC formulates similar limit tables with the same intent: limit harmonic current injections so that voltage distortion problems are not created; the utility will correct voltage distortion problems if they exist and if all customers are within the specified harmonic current limits. Because the numbers suggested

TABLE 15.6 IEEE 519-1992 Voltage Harmonic Limits

Bus voltage at PCC (V_{L-L})	Individual Harmonic Voltage Distortion (%)	Total Voltage Distortion — THD_{Vn} (%)
$V_n \leq 69$ kV	3.0	5.0
69 kV $< V_n \leq 161$ kV	1.5	2.5
$V_n > 161$ kV	1.0	1.5

Note: 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.

by the IEC are similar (but not identical) to those given in Tables 15.5 and 15.6, the IEC tables for system-level harmonic limits given in IEC 1000-3-6 are not repeated here.

While the IEEE harmonic limits are designed for application at the three-phase PCC, the IEC goes further and provides limits appropriate for single-phase and three-phase individual equipment types. The most notable feature of these equipment limits is the "mA per W" manner in which they are proposed. For a wide variety of harmonic-producing loads, the steady-state (normal operation) harmonic currents are limited by prescribing a certain harmonic current, in mA, for each watt of power rating. The IEC also provides a specific waveshape for some load types that represents the most distorted current waveform allowed. Equipment covered by such limits include personal computers (power supplies) and single-phase battery charging equipment.

Even though limits exist, problems related to harmonics often arise from single, large "point source" harmonic loads as well as from numerous distributed smaller loads. In these situations, it is necessary to conduct a measurement, modeling, and analysis campaign that is designed to gather data and develop a solution. As previously mentioned, there are many commercially available instruments that can provide harmonic measurement information both at a single "snapshot" in time as well as continuous monitoring over time. How this information is used to develop problem solutions, however, can be a very complex issue.

Computer-assisted harmonic studies generally require significantly more input data than load flow or short circuit studies. Because high frequencies (up to 2–3 kHz) are under consideration, it is important to have mathematically correct equipment models and the data to use in them. Assuming that this data is available, there are a variety of commercially available software tools for actually performing the studies.

Most harmonic studies are performed in the frequency domain using sinusoidal steady-state techniques. (Note that other techniques, including full time-domain simulation, are sometimes used for specific problems.) A power system equivalent circuit is prepared for each frequency to be analyzed (recall that the Fourier series representation of a waveform is based on harmonic terms of known frequencies), and then basic circuit analysis techniques are used to determine voltages and currents of interest at that frequency. Most harmonic producing loads are modeled using a current source at each frequency that the load produces (arc furnaces are sometimes modeled using voltage sources), and network currents and voltages are determined based on these load currents. Recognize that at each frequency, voltage and current solutions are obtained from an equivalent circuit that is valid at that frequency only; the principle of superposition is used to "reconstruct" the Fourier series for any desired quantity in the network from the solutions of multiple equivalent circuits. Depending on the software tool used, the results can be presented in tabular form, spectral form, or as a waveform as shown in Table 15.4 and Figs. 15.18 and 15.19, respectively. An example voltage magnitude spectrum obtained from a harmonic study of a distribution primary circuit is shown in Fig. 15.23.

Regardless of the presentation format of the results, it is possible to use this type of frequency-domain harmonic analysis procedure to predict the impact of harmonic producing loads at any location in any power system. However, it is often impractical to consider a complete model of a large system, especially when unbalanced conditions must be considered. Of particular importance, however, are the locations of capacitor banks.

When electrically in parallel with network inductive reactance, capacitor banks produce a parallel resonance condition that tends to amplify voltage harmonics for a given current harmonic injection.

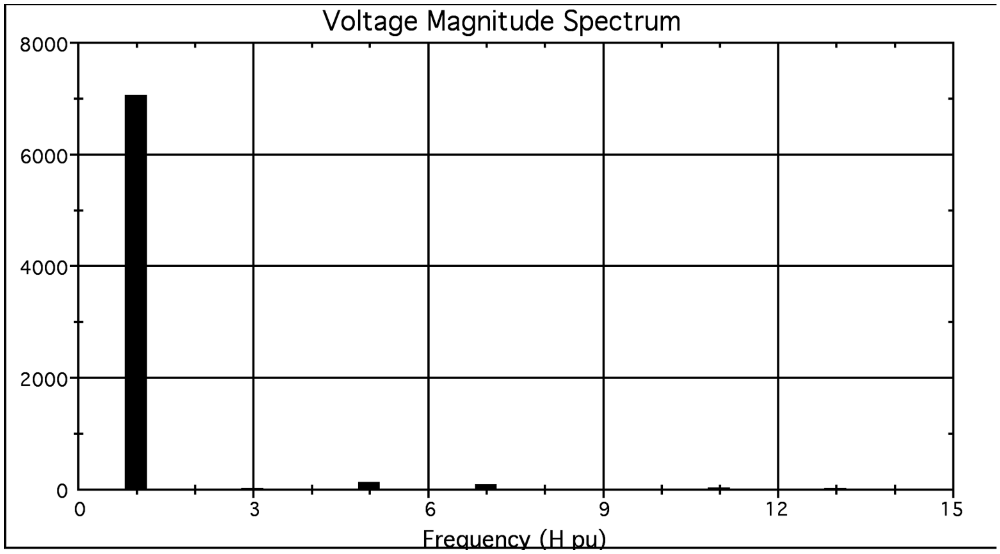

FIGURE 15.23 Sample magnitude spectrum results from a harmonic study.

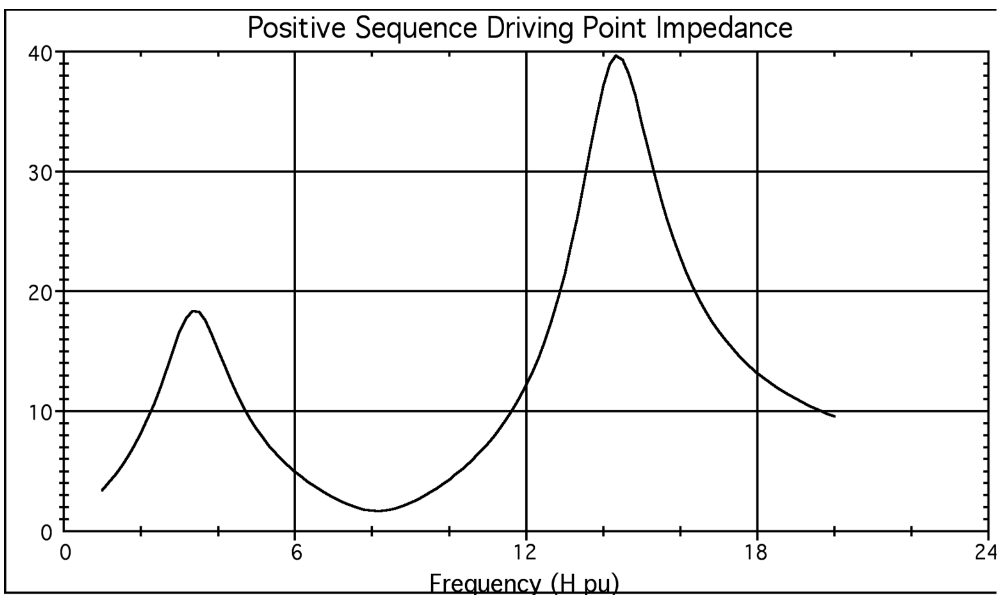

FIGURE 15.24 Sample frequency scan results.

When electrically in series with network inductive reactance, capacitor banks produce a series resonance condition that tends to amplify current harmonics for a given voltage distortion. In either case, harmonic levels far in excess of what are expected can be produced. Fortunately, a relatively simple calculation procedure called a frequency scan, can be used to indicate potential resonance problems. Figure 15.24 shows an example of a frequency scan conducted on the positive sequence network model of a distribution circuit. Note that the distribution primary included the standard feeder optimization capacitors.

A frequency scan result is actually a plot of impedance vs. frequency. Two types of results are available: driving point and transfer impedance scans. The driving point frequency scan shown in Fig. 15.24 indicates how much voltage would be produced at a given bus and frequency for a one-ampere current injection at that same location and frequency. Where necessary, the principle of linearity can be used to scale the one-ampere injection to the level actually injected by specific equipment. In other words, the driving point impedance predicts how a customer's harmonic producing load could impact the voltage at that load's terminals. Local maximums, or peaks, in the scan plot indicate parallel resonance conditions. Local minimums, or valleys, in the scan plot indicate series resonance.

A transfer impedance scan predicts how a customer's harmonic producing load at one location can impact voltage distortions at other (possibly very remote) locations. In general, to assess the ability of a relatively small current injection to produce a significant voltage distortion (due to resonance) at remote locations (due to transfer impedance) is the primary goal of every harmonic study.

Should a harmonic study indicate a potential problem (violation of limits, for example), two categories of solutions are available: (1) reduce the harmonics at their point of origin (before they enter the system), or (2) apply filtering to reduce undesirable harmonics. Many methods for reducing harmonics at their origin are available; for example, using various transformer connections to cancel certain harmonics has been extremely effective in practice. In most cases, however, reducing or eliminating harmonics at their origin is effective only in the design or expansion stage of a new facility. For existing facilities, harmonic filters often provide the least-cost solution.

Harmonic filters can be subdivided into two types: active and passive. Active filters are only now becoming commercially viable products for high-power applications and operate as follows. For a load that injects certain harmonic currents into the supply system, a DC to AC inverter can be controlled such that the inverter supplies the harmonic current for the load, while allowing the power system to supply the power frequency current for the load. Figure 15.25 shows a diagram of such an active filter application.

For high power applications or for applications where power factor correction capacitors already exist, it is typically more cost effective to use passive filtering. Passive filtering is based on the series resonance principle (recall that a low impedance at a specific frequency is a series-resonant characteristic) and can be easily implemented. Figure 15.26 shows a typical three-phase harmonic filter (many other designs are also used) that is commonly used to filter 5th or 7th harmonics.

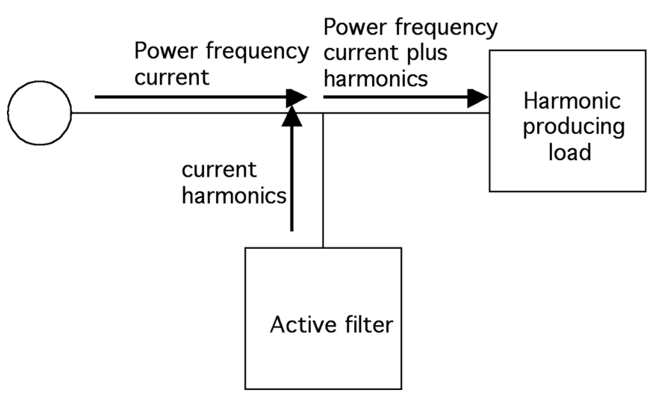

FIGURE 15.25 Active filter concept diagram.

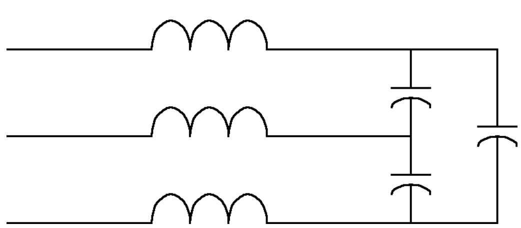

FIGURE 15.26 Typical passive filter design.

It should be noted that passive filtering cannot always make use of existing capacitor banks. In filter applications, the capacitors will typically be exposed continuously to voltages greater than their ratings (which were determined based on their original application). 600 V capacitors, for example, may be required for 480 V filter applications. Even with the potential cost of new capacitors, passive filtering still appears to offer the most cost effective solution to the harmonic problem at this time.

In conclusion, power system harmonics have been carefully considered for many years and have received a significant increase in research and development activity as a direct result of the proliferation of high-power semiconductors. Fortunately, harmonic measurement equipment is readily available, and the underlying theory used to evaluate harmonics analytically (with computer assistance) is well understood. Limits for harmonic voltages and currents have been suggested by multiple standards-making bodies, but care must be used because the suggested limits are not necessarily equivalent.

Regardless of which limit numbers are appropriate for a given application, multiple options are available to help meet the levels required. As with all power quality problems, however, accurate study on the "front end" usually will reveal possible problems in the design stage, and a lower-cost solution can be implemented before problems arise.

The material presented here is not intended to be all-inclusive. The suggested reading provides further documents, including both IEEE and IEC standards, recommended practices, and technical papers and reports that provide the knowledge base required to apply the standards properly.

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15.4 Voltage Sags

M. H. J. Bollen

Voltage sags are short duration reductions in rms voltage, mainly caused by short circuits and starting of large motors. The interest in voltage sags is due to the problems they cause on several types of equipment. Adjustable-speed drives, process-control equipment, and computers are especially notorious for their sensitivity (Conrad et al., 1991; McGranaghan et al., 1993). Some pieces of equipment trip when

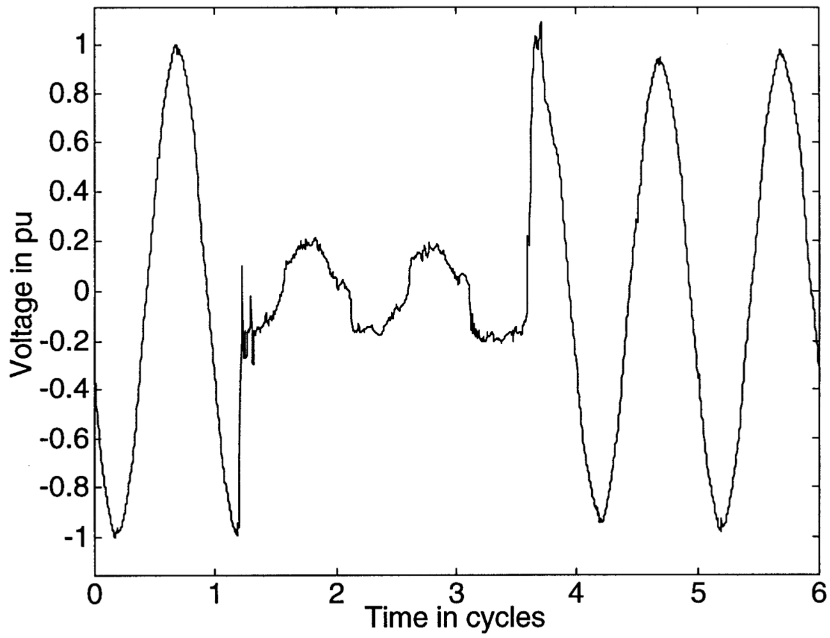

FIGURE 15.27 A voltage sag — voltage in one phase in time domain.

the rms voltage drops below 90% for longer than one or two cycles. Such a piece of equipment will trip tens of times a year. If this is the process-control equipment of a paper mill, one can imagine that the costs due to voltage sags can be enormous. A voltage sag is not as damaging to industry as a (long or short) interruption, but as there are far more voltage sags than interruptions, the total damage due to sags is still larger. Another important aspect of voltage sags is that they are hard to mitigate. Short interruptions and many long interruptions can be prevented via simple, although expensive measures in the local distribution network. Voltage sags at equipment terminals can be due to short-circuit faults hundreds of kilometers away in the transmission system. It will be clear that there is no simple method to prevent them.

Voltage Sag Characteristics

An example of a voltage sag is shown in Fig. 15.27.[1] The voltage amplitude drops to a value of about 20% of its pre-event value for about two and a half cycles, after which the voltage recovers again. The event shown in Fig. 15.27 can be characterized as a voltage sag down to 20% (of the pre-event voltage) for 2.5 cycles (of the fundamental frequency). This event can be characterized as a voltage sag with a magnitude of 20% and a duration of 2.5 cycles.

Voltage Sag Magnitude — Monitoring

The magnitude of a voltage sag is determined from the rms voltage. The rms voltage for the sag in Fig. 15.27 is shown in Fig. 15.28. The rms voltage has been calculated over a one-cycle sliding window:

$$V_{rms}(k) = \sqrt{\frac{1}{N} \sum_{i=k-N+1}^{i=k} v(i)^2} \tag{15.3}$$

[1]The datafile containing these measurements was obtained from a Website with test data set up for IEEE project group P1159.2: http://grouper.ieee.org/groups/1159/2/index.html.

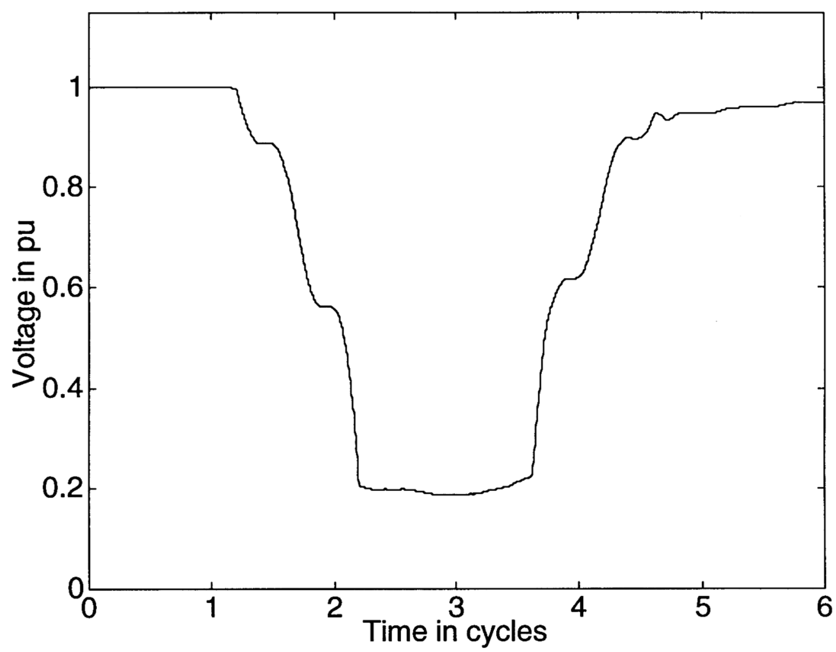

FIGURE 15.28 One-cycle rms voltage for the voltage sag shown in Fig. 15.27.

with N the number of samples per cycle, and $v(i)$ the sampled voltage in time domain. The rms voltage as shown in Fig. 15.28 does not immediately drop to a lower value, but takes one cycle for the transition. This is due to the finite length of the window used to calculate the rms value. We also see that the rms value during the sag is not completely constant and that the voltage does not immediately recover after the fault.

There are various ways of obtaining the sag magnitude from the rms voltages. Most power quality monitors take the lowest value obtained during the event. As sags normally have a constant rms value during the deep part of the sag, using the lowest value is an acceptable approximation.

The sag is characterized through the remaining voltage during the event. This is then given as a percentage of the nominal voltage. Thus, a 70% sag in a 230-V system means that the voltage dropped to 161 V. The confusion with this terminology is clear. One could be tricked into thinking that a 70% sag refers to a drop of 70%, thus a remaining voltage of 30%. The recommendation is therefore to use the phrase "a sag down to 70%." Characterizing the sag through the actual drop in rms voltage can solve this ambiguity, but this will introduce new ambiguities like the choice of the reference voltage.

Origin of Voltage Sags

Consider the distribution network shown in Fig. 15.29, where the numbers (1 through 5) indicate fault positions and the letters (A through D) loads. A fault in the transmission network, fault position 1, will cause a serious sag for both substations bordering the faulted line. This sag is transferred down to all customers fed from these two substations. As there is normally no generation connected at lower voltage levels, there is nothing to keep up the voltage. The result is that all customers (A, B, C, and D) experience a deep sag. The sag experienced by A is likely to be somewhat less deep, as the generators connected to that substation will keep up the voltage. A fault at position 2 will not cause much voltage drop for customer A. The impedance of the transformers between the transmission and the subtransmission system are large enough to considerably limit the voltage drop at high-voltage side of the transformer. The sag experienced by customer A is further mitigated by the generators feeding into its local transmission substation. The fault at position 2 will, however, cause a deep sag at both subtransmission substations and thus for all customers fed from here (B, C, and D). A fault at position 3 will cause a short or long

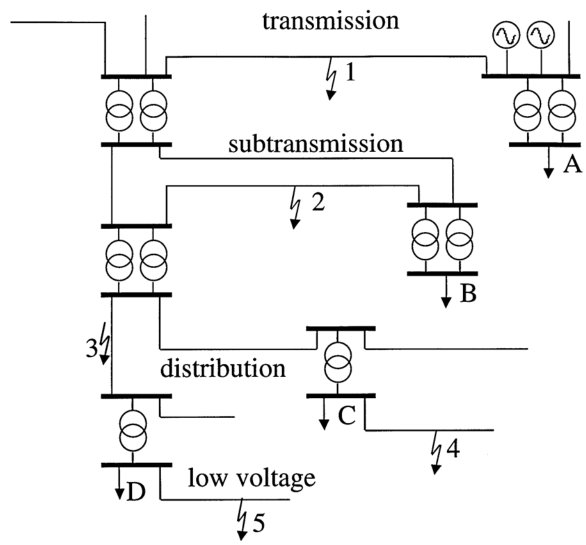

FIGURE 15.29 Distribution network with load positions (A through D) and fault positions (1 through 5).

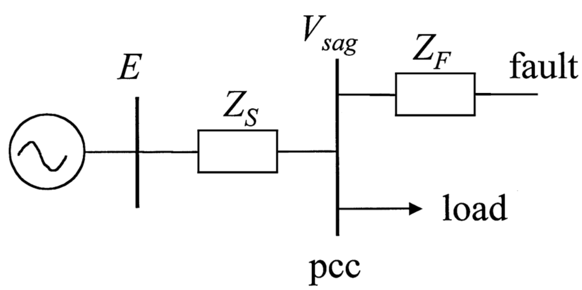

FIGURE 15.30 Voltage divider model for a voltage sag.

interruption for customer D when the protection clears the fault. Customer C will only experience a deep sag. Customer B will experience a shallow sag due to the fault at position 3, again due to the transformer impedance. Customer A will probably not notice anything from this fault. Fault 4 causes a deep sag for customer C and a shallow one for customer D. For fault 5, the result is the other way around: a deep sag for customer D and a shallow one for customer C. Customers A and B will not experience any significant drop in voltage due to faults 4 and 5.

Voltage Sag Magnitude — Calculation

To quantify sag magnitude in radial systems, the voltage divider model, shown in Fig. 15.30, can be used, where Z_S is the source impedance at the point-of-common coupling; and Z_F is the impedance between the point-of-common coupling and the fault. The point-of-common coupling (pcc) is the point from which both the fault and the load are fed. In other words, it is the place where the load current branches off from the fault current. In the voltage divider model, the load current before, as well as during the fault is neglected. The voltage at the pcc is found from:

$$V_{sag} = \frac{Z_F}{Z_S + Z_F} \tag{15.4}$$

where it is assumed that the pre-event voltage is exactly 1 pu, thus $E = 1$. The same expression can be derived for constant-impedance load, where E is the pre-event voltage at the pcc. We see from Eq. (15.4)

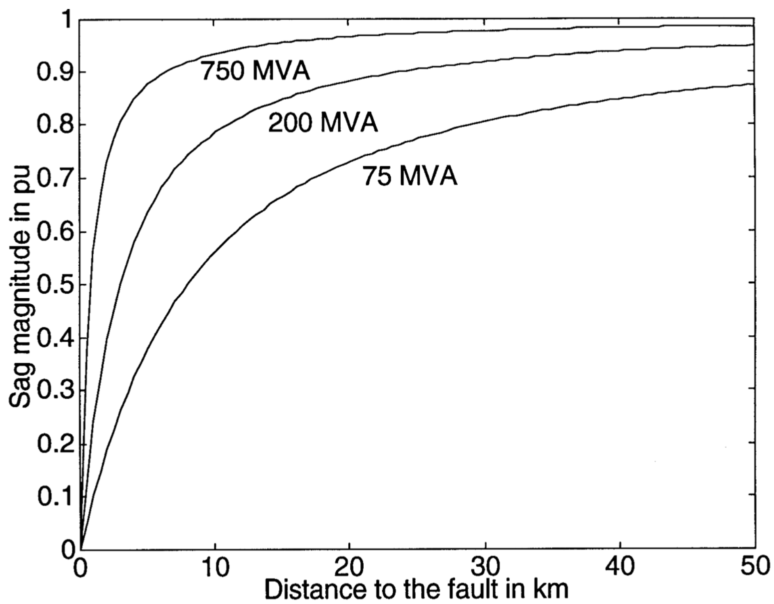

FIGURE 15.31 Sag magnitude as a function of the distance to the fault.

that the sag becomes deeper for faults electrically closer to the customer (when Z_F becomes smaller), and for weaker systems (when Z_S becomes larger).

Equation (15.4) can be used to calculate the sag magnitude as a function of the distance to the fault. Therefore, we write $Z_F = zd$, with z the impedance of the feeder per unit length and d the distance between the fault and the pcc, leading to:

$$V_{sag} = \frac{zd}{Z_S + zd} \tag{15.5}$$

This expression has been used to calculate the sag magnitude as a function of the distance to the fault for a typical 11 kV overhead line, resulting in Fig. 15.31. For the calculations, a 150-mm^2 overhead line was used and fault levels of 750 MVA, 200 MVA, and 75 MVA. The fault level is used to calculate the source impedance at the pcc and the feeder impedance is used to calculate the impedance between the pcc and the fault. It is assumed that the source impedance is purely reactive, thus Z_S = j 0.161Ω for the 750 MVA source. The impedance of the 150 mm^2 overhead line is z = 0.117 + j 0.315 Ω/km.

Propagation of Voltage Sags

It is also possible to calculate the sag magnitude directly from fault levels at the pcc and at the fault position. Let S_{FLT} be the fault level at the fault position and S_{PCC} at the point-of-common coupling. The voltage at the pcc can be written as:

$$V_{sag} = 1 - \frac{S_{FLT}}{S_{PCC}} \tag{15.6}$$

This equation can be used to calculate the magnitude of sags due to faults at voltage levels other than the point-of-common coupling. Consider typical fault levels as shown in Table 15.7. This data has been used to obtain Table 15.8, showing the effect of a short circuit fault at a lower voltage level than the pcc. We can see that sags are significantly “damped” when they propagate upwards in the power system. In a sags study, we typically only have to take faults one voltage level down from the pcc into account. And

TABLE 15.7 Typical Fault Levels at Different Voltage Levels

Voltage Level	Fault Level
400 V	20 MVA
11 kV	200 MVA
33 kV	900 MVA
132 kV	3000 MVA
400 kV	17,000 MVA

TABLE 15.8 Propagation of Voltage Sags to Higher Voltage Levels

	Point-of-Common Coupling at:				
Fault at:	400 V	11 kV	33 kV	132 kV	400 kV
400 V	—	90%	98%	99%	100%
11 kV	—	—	78%	93%	99%
33 kV	—	—	—	70%	95%
132 kV	—	—	—	—	82%

even those are seldom of serious concern. Note, however, that faults at a lower voltage level may be associated with a longer fault-clearing time and thus a longer sag duration. This especially holds for faults on distribution feeders, where fault-clearing times in excess of one second are possible.

Critical Distance

Equation (15.5) gives the voltage as a function of distance to the fault. From this equation we can obtain the distance at which a fault will lead to a sag of a certain magnitude *V*. If we assume equal X/R ratio of source and feeder, we get the following equation:

$$d_{crit} = \frac{Z_S}{z} \times \frac{V}{1-V} \tag{15.7}$$

We refer to this distance as the critical distance. Suppose that a piece of equipment trips when the voltage drops below a certain level (the critical voltage). The definition of critical distance is such that each fault within the critical distance will cause the equipment to trip. This concept can be used to estimate the expected number of equipment trips due to voltage sags (Bollen, 1998). The critical distance has been calculated for different voltage levels, using typical fault levels and feeder impedances. The data used and the results obtained are summarized in Table 15.9 for the critical voltage of 50%. Note how the critical distance increases for higher voltage levels. A customer will be exposed to much more kilometers

TABLE 15.9 Critical Distance for Faults at Different Voltage Levels

Nominal Voltage	Short-Circuit Level	Feeder Impedance	Critical Distance
400 V	20 MVA	230 mΩ/km	35 m
11 kV	200 MVA	310 mΩ/km	2 km
33 kV	900 MVA	340 mΩ/km	4 km
132 kV	3000 MVA	450 mΩ/km	13 km
400 kV	10000 MVA	290 mΩ/km	55 km

of transmission lines than of distribution feeder. This effect is understood by writing Eq. (15.7) as a function of the short-circuit current I_{flt} at the pcc:

$$d_{crit} = \frac{V_{nom}}{zI_{flt}} \times \frac{V}{1-V} \tag{15.8}$$

with V_{nom} the nominal voltage. As both z and I_{flt} are of similar magnitude for different voltage levels, one can conclude from Eq. (15.8) that the critical distance increases proportionally with the voltage level.

Voltage Sag Duration

It was shown before, the drop in voltage during a sag is due to a short circuit being present in the system. The moment the short circuit fault is cleared by the protection, the voltage starts to return to its original value. The duration of a sag is thus determined by the fault-clearing time. However, the actual duration of a sag is normally longer than the fault-clearing time.

Measurement of sag duration is less trivial than it might appear. From a recording the sag duration may be obvious, but to come up with an automatic way for a power quality monitor to obtain the sag duration is no longer straightforward. The commonly used definition of sag duration is the number of cycles during which the rms voltage is below a given threshold. This threshold will be somewhat different for each monitor but typical values are around 90% of the nominal voltage. A power quality monitor will typically calculate the rms value once every cycle.

The main problem is that the so-called post-fault sag will affect the sag duration. When the fault is cleared, the voltage does not recover immediately. This is mainly due to the reenergizing and reacceleration of induction motor load (Bollen, 1995). This post-fault sag can last several seconds, much longer than the actual sag. Therefore, the sag duration as defined before, is no longer equal to the fault-clearing time. More seriously, different power quality monitors will give different values for the sag duration. As the rms voltage recovers slowly, a small difference in threshold setting may already lead to a serious difference in recorded sag duration (Bollen, 1999).

Generally speaking, faults in transmission systems are cleared faster than faults in distribution systems. In transmission systems, the critical fault-clearing time is rather small. Thus, fast protection and fast circuit breakers are essential. Also, transmission and subtransmission systems are normally operated as a grid, requiring distance protection or differential protection, both of which allow for fast clearing of the fault. The principal form of protection in distribution systems is overcurrent protection. This requires a certain amount of time-grading, which increases the fault-clearing time. An exception is formed by systems in which current-limiting fuses are used. These have the ability to clear a fault within one half-cycle. In overhead distribution systems, the instantaneous trip of the recloser will lead to a short sag duration, but the clearing of a permanent fault will give a sag of much longer duration.

The so-called magnitude-duration plot is a common tool used to show the quality of supply at a certain location or the average quality of supply of a number of locations. Voltage sags due to faults can be shown in such a plot, as well as sags due to motor starting, and even long and short interruptions. Different underlying causes lead to events in different parts of the magnitude-duration plot, as shown in Fig. 15.32.

Phase-Angle Jumps

A short circuit in a power system not only causes a drop in voltage magnitude, but also a change in the phase angle of the voltage. This sudden change in phase angle is called a "phase-angle jump." The phase-angle jump is visible in a time-domain plot of the sag as a shift in voltage zero-crossing between the pre-event and the during-event voltage. With reference to Fig. 15.30 and Eq. (15.4), the phase-angle jump is the argument of V_{sag}, thus the difference in argument between Z_F and $Z_S + Z_P$. If source and feeder impedance have equal X/R ratio, there will be no phase-angle jump in the voltage at the pcc. This is the case for faults in transmission systems, but normally not for faults in distribution systems. The latter may have phase-angle jumps up to a few tens of degrees (Bollen, 1999; Bollen et al., 1996).

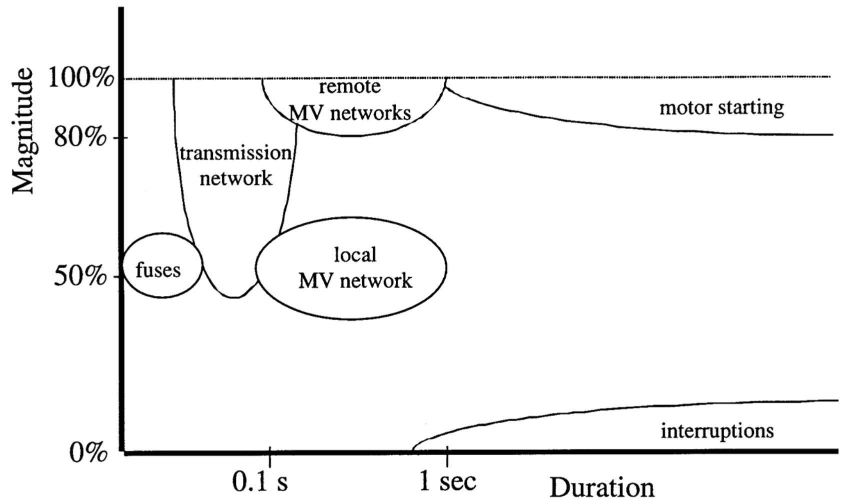

FIGURE 15.32 Sags of different origin in a magnitude-duration plot.

Figure 15.30 shows a single-phase circuit, which is a valid model for three-phase faults in a three-phase system. For nonsymmetrical faults, the analysis becomes much more complicated. A consequence of nonsymmetrical faults (single-phase, phase-to-phase, two-phase-to-ground) is that single-phase load experiences a phase-angle jump even for equal X/R ratio of feeder and source impedance (Bollen, 1999; Bollen, 1997).

To obtain the phase-angle jump from the measured voltage waveshape, the phase angle of the voltage during the event must be compared with the phase angle of the voltage before the event. The phase angle of the voltage can be obtained from the voltage zero-crossings or from the argument of the fundamental component of the voltage. The fundamental component can be obtained by using a discrete Fourier transform algorithm. Let $V_1(t)$ be the fundamental component obtained from a window $(t\text{-}T,t)$, with T one cycle of the power frequency, and let $t = 0$ correspond to the moment of sag initiation. In case there is no chance in voltage magnitude or phase angle, the fundamental component as a function of time is found from:

$$V_1(t) = V_1(0)e^{j\omega t} \tag{15.9}$$

The phase-angle jump, as a function of time, is the difference in phase angle between the actual fundamental component and the "synchronous voltage" according to Eq. (15.9):

$$\phi(t) = \arg\{V_1(t)\} - \arg\{V_1(0)e^{j\omega t}\} = \arg\left\{\frac{V_1(t)}{V_1(0)}e^{-j\omega t}\right\} \tag{15.10}$$

Note that the argument of the latter expression is always between –180° and +180°.

Three-Phase Unbalance

For three-phase equipment, three voltages need to be considered when analyzing a voltage sag event at the equipment terminals. For this, a characterization of three-phase unbalanced voltage sags is introduced. The basis of this characterization is the theory of symmetrical components. Instead of the three-phase voltages or the three symmetrical components, the following three (complex) values are used to characterize the voltage sag (Bollen and Zhang, 1999; Zhang and Bollen, 1998):

- The "characteristic voltage" is the main characteristic of the event. It indicates the severity of the sag, and can be treated in the same way as the remaining voltage for a sag experienced by a single-phase event.
- The "PN factor" is a correction factor for the effect of the load on the voltages during the event. The PN factor is normally close to unity and can then be neglected. Exceptions are systems with a large amount of dynamic load, and sags due to two-phase-to-ground faults.
- The "zero-sequence voltage," which is normally not transferred to the equipment terminals, rarely affects equipment behavior. The zero-sequence voltage can be neglected in most studies.

Neglecting the zero-sequence voltage, it can be shown that there are two types of three-phase unbalanced sags, denoted as types C and D. Type A is a balanced sag due to a three-phase fault. Type B is the sag due to a single-phase fault, which turns into type D after removal of the zero-sequence voltage. The three complex voltages for a type C sag are written as follows:

$$\begin{aligned} V_a &= F \\ V_b &= -\frac{1}{2}F - \frac{1}{2}jV\sqrt{3} \\ V_c &= -\frac{1}{2}F + \frac{1}{2}jV\sqrt{3} \end{aligned} \tag{15.11}$$

where V is the characteristic voltage and F the PN factor. The (characteristic) sag magnitude is defined as the absolute value of the characteristic voltage; the (characteristic) phase-angle jump is the argument of the characteristic voltage. For a sag of type D, the expressions for the three voltage phasors are as follows:

$$\begin{aligned} V_a &= V \\ V_b &= -\frac{1}{2}V - \frac{1}{2}jF\sqrt{3} \\ V_c &= -\frac{1}{2}V + \frac{1}{2}jF\sqrt{3} \end{aligned} \tag{15.12}$$

Sag type D is due to a phase-to-phase fault, or due to a single-phase fault behind a Δy-transformer, or a phase-to-phase fault behind two Δy-transformers, etc. Sag type C is due to a single-phase fault, or due to a phase-to-phase fault behind a Δy-transformer, etc. When using characteristic voltage for a three-phase unbalanced sag, the same single-phase scheme as in Fig. 15.30 can be used to study the transfer of voltage sags in the system (Bollen, 1999; Bollen, 1997).

Equipment Voltage Tolerance

Voltage Tolerance Requirement

Generally speaking, electrical equipment prefers a constant rms voltage. That is what the equipment has been designed for and that is where it will operate best. The other extreme is zero voltage for a longer period of time. In that case the equipment will simply stop operating completely. For each piece of equipment there is a maximum interruption duration, after which it will continue to operate correctly. A rather simple test will give this duration. The same test can be done for a voltage of 10% (of nominal), for a voltage of 20%, etc. If the voltage becomes high enough, the equipment will be able to operate on it indefinitely. Connecting the points obtained by performing these tests results in the so-called "voltage-tolerance curve" (Key, 1979). An example of a voltage-tolerance curve is shown in Fig. 15.33: the requirements for IT-equipment as recommended by the Information Technology Industry Council (ITIC, 1999).

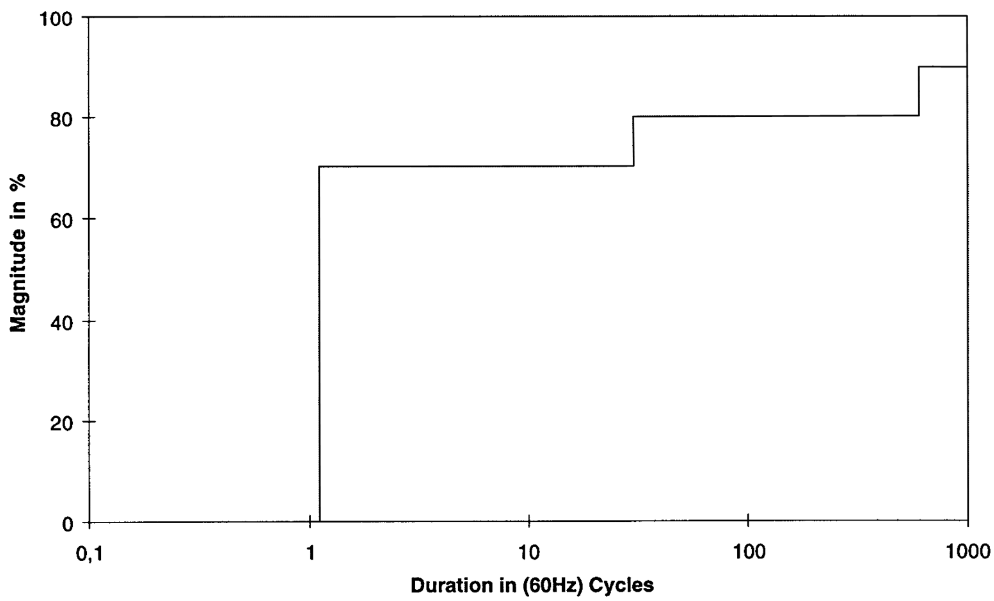

FIGURE 15.33 Voltage-tolerance requirement for IT equipment.

Strictly speaking, one can claim that this is not a voltage-tolerance curve as described above, but a requirement for the voltage tolerance. One could refer to this as a voltage-tolerance requirement and to the result of equipment tests as a voltage-tolerance performance. We see in Fig. 15.33 that IT equipment has to withstand a voltage sag down to zero for 1.1 cycle, down to 70% for 30 cycles, and that the equipment should be able to operate normally for any voltage of 90% or higher.

Voltage Tolerance Performance

Voltage-tolerance (performance) curves for personal computers are shown in Fig. 15.34. The curves are the result of equipment tests performed in the U.S. (EPRI, 1994) and in Japan (Sekine et al., 1992). The shape of all the curves in Fig. 15.34 is close to rectangular. This is typical for many types of equipment, so that the voltage tolerance may be given by only two values, maximum duration and minimum voltage, instead of by a full curve. From the tests summarized in Fig. 15.34 it is found that the voltage tolerance of personal computers varies over a wide range: 30–170 ms, 50–70% being the range containing half of the models. The extreme values found are 8 ms, 88% and 210 ms, 30%.

Voltage-tolerance tests have also been performed on process-control equipment: PLCs, monitoring relays, motor contactors. This equipment is even more sensitive to voltage sags than personal computers. The majority of devices tested tripped between one and three cycles. A small minority was able to tolerate sags up to 15 cycles in duration. The minimum voltage varies over a wider range: from 50% to 80% for most devices, with exceptions of 20% and 30%. Unfortunately, the latter two both tripped in three cycles (Bollen, 1999).

From performance testing of adjustable-speed drives, an "average voltage-tolerance curve" has been obtained. This curve is shown in Fig. 15.35. The sags for which the drive was tested are indicated as circles. It has further been assumed that the drives can operate indefinitely on 85% voltage. Voltage tolerance is defined here as "automatic speed recovery, without reaching zero speed." For sensitive production processes, more strict requirements will hold (Bollen, 1999).

Single-Phase Rectifiers

The sensitivity of most single-phase equipment can be understood from the equivalent scheme in Fig. 15.36. The power supply to a computer, process-control equipment, consumer electronics, etc. consists of a single-phase (four-pulse) rectifier together with a capacitor and a DC/DC converter. During

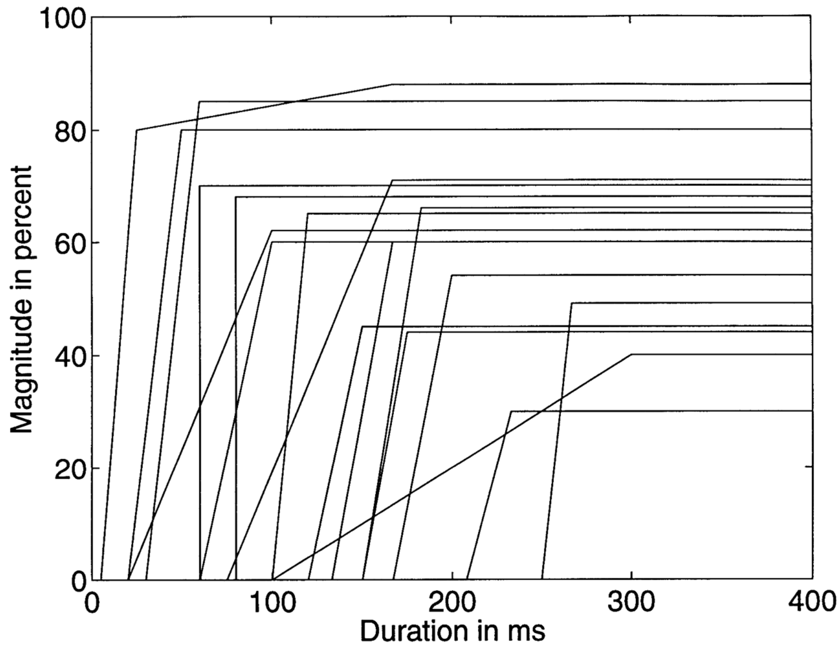

FIGURE 15.34 Voltage-tolerance performance for personal computers.

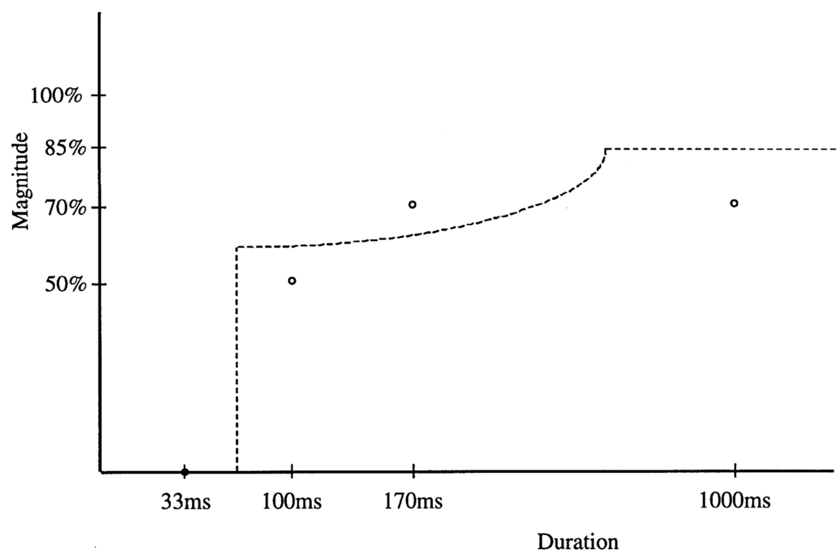

FIGURE 15.35 Average voltage-tolerance curve for adjustable-speed drives.

normal operation the capacitor is charged twice a cycle through the diodes. The result is a DC voltage ripple:

$$\varepsilon = \frac{PT}{2V_0^2 C} \tag{15.13}$$

with P the DC bus active-power load, T one cycle of the power frequency, V_0 the maximum DC bus voltage, and C the size of the capacitor.

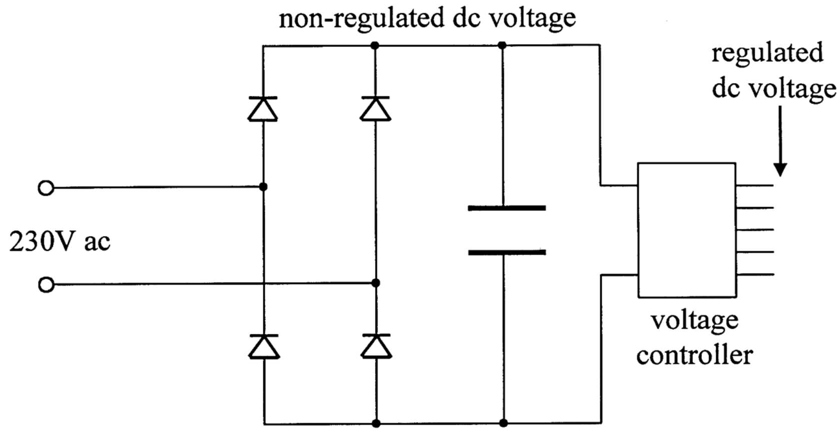

FIGURE 15.36 Typical power supply to sensitive single-phase equipment.

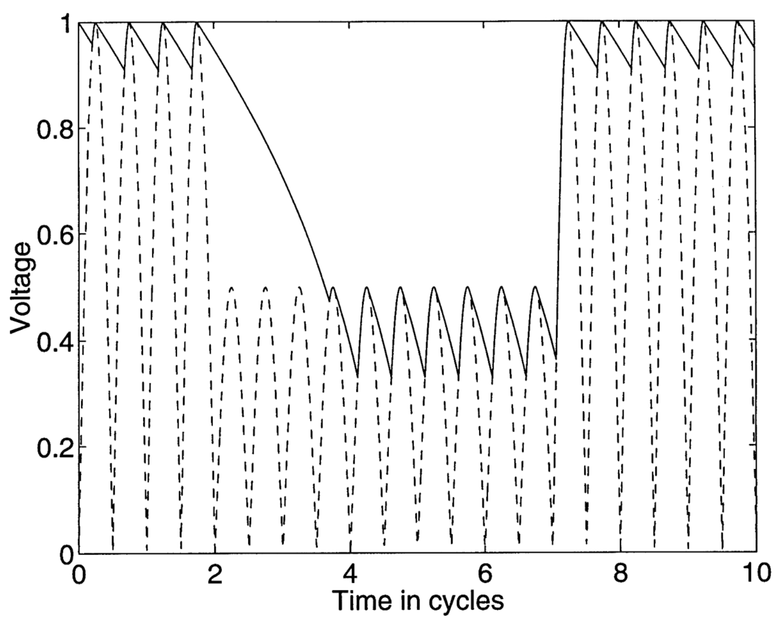

FIGURE 15.37 Absolute value of AC voltage (dashed) and DC bus voltage (solid line) for a sag down to 50%.

During a voltage sag or interruption, the capacitor continues to discharge until the DC bus voltage has dropped below the peak of the supply voltage. A new steady state is reached, but at a lower DC bus voltage and with a larger ripple. The resulting DC bus voltage for a sag down to 50% is shown in Fig. 15.37, together with the absolute value of the supply voltage. If the new steady state is below the minimum operating voltage of the DC/DC converter, or below a certain protection setting, the equipment will trip. During the decaying DC bus voltage, the capacitor voltage $V(t)$ can be obtained from the law of conservation of energy:

$$\frac{1}{2}CV^2 = \frac{1}{2}CV_0^2 - Pt \tag{15.14}$$

where a constant DC bus load P has been assumed. From Eq. (15.14) the voltage as a function of time is obtained:

$$V(t)=\sqrt{V_0^2-\frac{2P}{C}t} \tag{15.15}$$

Combining this with Eq. (15.13) gives the following expression:

$$V(t)=V_0\sqrt{1-4\varepsilon\frac{t}{T}} \tag{15.16}$$

The larger the DC ripple in normal operation, the faster the drop in DC bus voltage during a sag. From Eq. (15.16) the maximum duration of zero voltage t_{max} is calculated for a minimum operating voltage V_{min}, resulting in:

$$t_{\max}=\frac{1-\left(\frac{V_{\min}}{V_0}\right)^2}{4\varepsilon}T \tag{15.17}$$

Three-Phase Rectifiers

The performance of equipment fed through three-phase rectifiers becomes somewhat more complicated. The main equipment belonging to this category is formed by AC and DC adjustable-speed drives. One of the complications is that the operation of the equipment is affected by the three voltages, which are not necessarily the same during the voltage sag. For non-controlled (six pulse) diode rectifiers, a similar model can be used as for single-phase rectifiers. The operation of three-phase controlled rectifiers can become very complicated and application-specific (Bollen, 1996). Therefore, only noncontrolled rectifiers will be discussed here. For voltage sags due to three-phase faults, the DC bus voltage behind the (three-phase) rectifier will decay until a new steady state is reached at a lower voltage level, with a larger ripple. To calculate the DC bus voltage as a function of time, and the time-to-trip, the same equation as for the single-phase rectifier can be used.

For unbalanced voltage sags, a distinction needs to be made between the two types (C and D), as introduced in the section on Three-Phase Unbalance. Figure 15.38 shows AC and DC side voltages for a sag of type C with $V = 0.5$ pu and $F = 1$. For this sag, the voltage drops in two phases where the third phase stays at its presag value. Three capacitor sizes are used (Bollen and Zhang, 1999); a "large" capacitance is defined as a value that leads to an initial decay of the DC voltage equal to 10%, which is 433 μF/kW for a 620 V drive. In the same way, "small" capacitance corresponds to 75% per cycle initial decay, and 57.8 μF/kW for a 620 V drive. It turns out that even for the small capacitance, the DC bus voltage remains above 70%. For the large capacitance value, the DC bus voltage is hardly affected by the voltage sag. It is easy to understand that this is also the case for type C sags with an even lower characteristic magnitude V (Bollen, 1999; Bollen and Zhang, 1999).

Figure 15.39 shows the equivalent results for a sag of type D, again with $V = 0.5$ and $F = 1$. As all three AC voltages show a drop in voltage magnitude, the DC bus voltage will drop even for a large capacitor. But the effect is still much less than for a three-phase (balanced) sag.

The effect of a lower PN factor ($F < 1$) is that even the highest voltage shows a drop for a type C sag, so that the DC bus voltage will always show a small drop. Also for a type D sag, a lower PN factor will lead to an additional drop in DC bus voltage (Bollen and Zhang, 1999).

Mitigation of Voltage Sags

From Fault to Trip

To understand the various ways of mitigation, the mechanism leading to an equipment trip needs to be understood. The equipment trip is what makes the event a problem; if there are no equipment trips,

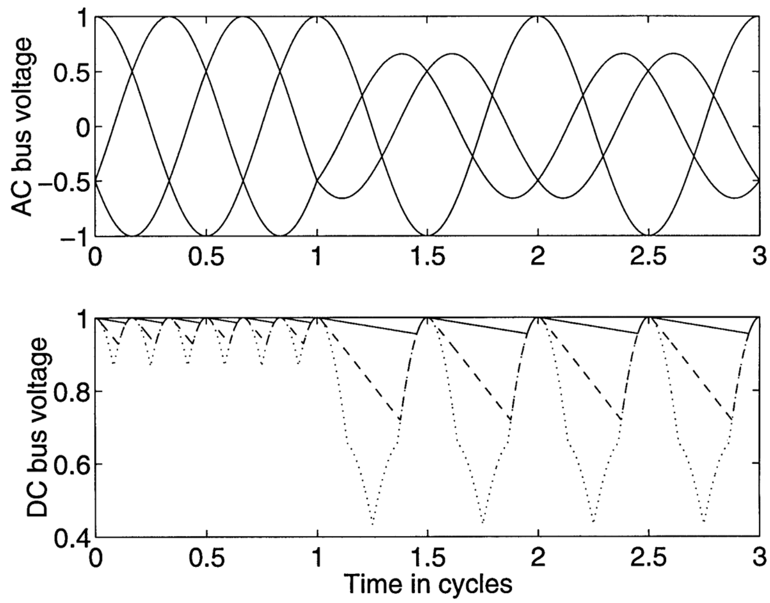

FIGURE 15.38 AC and DC side voltages for a three-phase rectifier during a sag of type C.

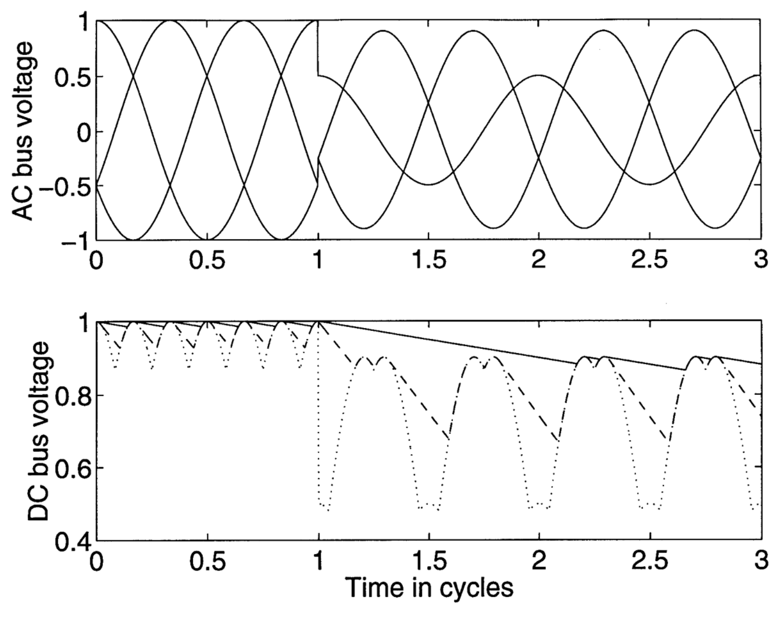

FIGURE 15.39 AC and DC side voltages for a three-phase rectifier during a sag of type D.

there is no voltage sag problem. The underlying event of the equipment trip is a short-circuit fault. At the fault position, the voltage drops to zero, or to a very low value. This zero voltage is changed into an event of a certain magnitude and duration at the interface between the equipment and the power system. The short-circuit fault will always cause a voltage sag for some customers. If the fault takes place in a radial part of the system, the protection intervention clearing the fault will also lead to an interruption. If there is sufficient redundancy present, the short circuit will only lead to a voltage sag. If the resulting event exceeds a certain severity, it will cause an equipment trip.

Based on this reasoning, it is possible to distinguish between the following mitigation methods:

- Reducing the number of short-circuit faults.
- Reducing the fault-clearing time.
- Changing the system such that short-circuit faults result in less severe events at the equipment terminals or at the customer interface.
- Connecting mitigation equipment between the sensitive equipment and the supply.
- Improving the immunity of the equipment.

Reducing the Number of Faults

Reducing the number of short-circuit faults in a system not only reduces the sag frequency, but also the frequency of long interruptions. This is thus a very effective way of improving the quality of supply and many customers suggest this as the obvious solution when a voltage sag or interruption problem occurs. Unfortunately, most of the time the solution is not that obvious. A short circuit not only leads to a voltage sag or interruption at the customer interface, but may also cause damage to utility equipment and plant. Therefore, most utilities will already have reduced the fault frequency as far as economically feasible. In individual cases, there could still be room for improvement, e.g., when the majority of trips are due to faults on one or two distribution lines. Some examples of fault mitigation are:

- Replace overhead lines by underground cables.
- Use special wires for overhead lines.
- Implement a strict policy of tree trimming.
- Install additional shielding wires.
- Increase maintenance and inspection frequencies.

One has to keep in mind, however, that these measures can be very expensive, especially for transmission systems, and that their costs have to be weighted against the consequences of the equipment trips.

Reducing the Fault-Clearing Time

Reducing the fault-clearing time does not reduce the number of events, but only their severity. It does not do anything to reduce to number of interruptions, but can significantly limit the sag duration. The ultimate reduction of fault-clearing time is achieved by using current-limiting fuses, able to clear a fault within one half-cycle. The recently introduced static circuit breaker has the same characteristics: fault-clearing time within one half-cycle. Additionally, several types of fault-current limiters have been proposed that do not actually clear the fault, but significantly reduce the fault current magnitude within one or two cycles. One important restriction of all these devices is that they can only be used for low- and medium-voltage systems. The maximum operating voltage is a few tens of kilovolts.

But the fault-clearing time is not only the time needed to open the breaker, but also the time needed for the protection to make a decision. To achieve a serious reduction in fault-clearing time, it is necessary to reduce any grading margins, thereby possibly allowing for a certain loss of selectivity.

Changing the Power System

By implementing changes in the supply system, the severity of the event can be reduced. Here again, the costs may become very high, especially for transmission and subtransmission voltage levels. In industrial systems, such improvements more often outweigh the costs, especially when already included in the design stage. Some examples of mitigation methods especially directed toward voltage sags are:

- Install a generator near the sensitive load. The generators will keep up the voltage during a remote sag. The reduction in voltage drop is equal to the percentage contribution of the generator station to the fault current. In case a combined-heat-and-power station is planned, it is worth it to consider the position of its electrical connection to the supply.

- Split buses or substations in the supply path to limit the number of feeders in the exposed area.
- Install current-limiting coils at strategic places in the system to increase the "electrical distance" to the fault. The drawback of this method is that this may make the event worse for other customers.
- Feed the bus with the sensitive equipment from two or more substations. A voltage sag in one substation will be mitigated by the infeed from the other substations. The more independent the substations are, the more the mitigation effect. The best mitigation effect is by feeding from two different transmission substations. Introducing the second infeed increases the number of sags, but reduces their severity.

Installing Mitigation Equipment

The most commonly applied method of mitigation is the installation of additional equipment at the system-equipment interface. Also recent developments point toward a continued interest in this way of mitigation. The popularity of mitigation equipment is explained by it being the only place where the customer has control over the situation. Both changes in the supply as well as improvement of the equipment are often completely outside of the control of the end user. Some examples of mitigation equipment are:

- *Uninterruptable power supply* (*UPS*). This is the most commonly used device to protect low-power equipment (computers, etc.) against voltage sags and interruptions. During the sag or interruption, the power supply is taken over by an internal battery. The battery can supply the load for, typically, between 15 and 30 minutes.
- *Static transfer switch*. A static transfer switch switches the load from the supply with the sag to another supply within a few milliseconds. This limits the duration of a sag to less than one half-cycle, assuming that a suitable alternate supply is available.
- *Dynamic voltage restorer* (*DVR*). This device uses modern power electronic components to insert a series voltage source between the supply and the load. The voltage source compensates for the voltage drop due to the sag. Some devices use internal energy storage to make up for the drop in active power supplied by the system. They can only mitigate sags up to a maximum duration. Other devices take the same amount of active power from the supply by increasing the current. These can only mitigate sags down to a minimum magnitude. The same holds for devices boosting the voltage through a transformer with static tap changer.
- *Motor-generator sets*. Motor-generator sets are the classical solution for sag and interruption mitigation with large equipment. They are obviously not suitable for an office environment but the noise and the maintenance requirements are often no problem in an industrial environment. Some manufacturers combine the motor-generator set with a backup generator; others combine it with power-electronic converters to obtain a longer ride-through time.

Improving Equipment Voltage Tolerance

Improvement of equipment voltage tolerance is probably the most effective solution against equipment trips due to voltage sags. But as a short-time solution, it is often not suitable. In many cases, a customer only finds out about equipment performance after it has been installed. Even most adjustable-speed drives have become off-the-shelf equipment where the customer has no influence on the specifications. Only large industrial equipment is custom-made for a certain application, which enables the incorporation of voltage-tolerance requirements in the specification.

Apart from improving large equipment (drives, process-control computers), a thorough inspection of the immunity of all contactors, relays, sensors, etc. can significantly improve the voltage tolerance of the process.

Different Events and Mitigation Methods

Figure 15.32 showed the magnitude and duration of voltage sags and interruptions resulting from various system events. For different events, different mitigation strategies apply.

Sags due to short-circuit faults in the transmission and subtransmission system are characterized by a short duration, typically up to 100 ms. These sags are very hard to mitigate at the source and improvements in the system are seldom feasible. The only way of mitigating these events is by improvement of the equipment or, where this turns out to be unfeasible, installing mitigation equipment. For low-power equipment, a UPS is a straightforward solution; for high-power equipment and for complete installations, several competing tools are emerging.

The duration of sags due to distribution system faults depends on the type of protection used — ranging from less than a cycle for current-limiting fuses up to several seconds for overcurrent relays in underground or industrial distribution systems. The long sag duration also enables equipment to trip due to faults on distribution feeders fed from other HV/MV substations. For deep long-duration sags, equipment improvement becomes more difficult and system improvement easier. The latter could well become the preferred solution, although a critical assessment of the various options is certainly needed.

Sags due to faults in remote distribution systems and sags due to motor starting should not lead to equipment tripping for sags down to 85%. If there are problems, the equipment needs to be improved. If equipment trips occur for long-duration sags in the 70–80% magnitude range, changes in the system have to be considered as an option.

For interruptions, especially the longer ones, equipment improvement is no longer feasible. System improvements or a UPS in combination with an emergency generator are possible solutions here.

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15.5 Voltage Fluctuations and Lamp Flicker in Power Systems

S. M. Halpin

Voltage flicker is a problem that has existed in the power industry for many years. Many types of end-use equipment can create voltage flicker, and many types of solution methods are available. Fortunately, the problem is not overly complex, and it can often be analyzed using fairly simple methods. In many cases, however, solutions can be expensive. Perhaps the most difficult aspect of the voltage flicker problem has been the development of a widely accepted definition of just what "flicker" is and how it can be quantified in terms of measurable quantities.

To electric utility engineers, voltage flicker is considered in terms of magnitude and rate of change of voltage fluctuations. To the utility customer, however, flicker is considered in terms of "my lights are flickering." The necessary presence of a human observer to "see" the change in lamp (intensity) output in response to a change in supply voltage is the most complex factor for which to account. Significant research, dating back to the early 20th century, has been devoted to establishing an accurate correlation between voltage changes and observer perceptions. This correlation is essential so that a readily measurable quantity, supply voltage, can be used to predict a human response.

The early work regarding voltage flicker considered voltage flicker to be a single-frequency modulation of the power frequency voltage. Both sinusoidal and square wave modulations were considered as shown mathematically in Eqs. (15.18) and (15.19), with most work concentrating on square wave modulation.

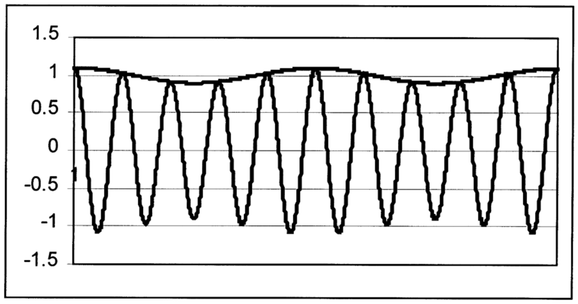

FIGURE 15.40 Sinusoidal voltage flicker.

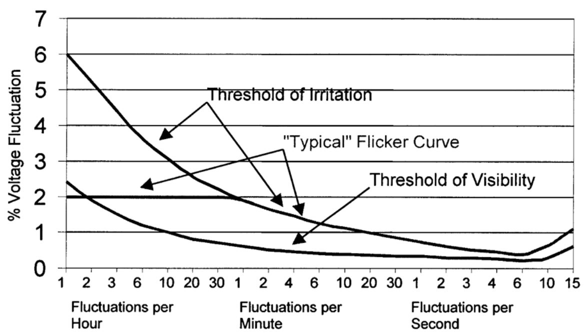

FIGURE 15.41 Typical flicker curves.

$$v(t) = \sqrt{2}V_{rms}\cos(\omega t)\{1.0 + V\cos(\omega_m t)\} \tag{15.18}$$

$$v(t) = \sqrt{2}V_{rms}\cos(\omega t)\{1.0 + V\mathrm{square}(\omega_m t)\} \tag{15.19}$$

Based on Eqs. (15.18) and (15.19), the voltage flicker magnitude can be expressed as a percentage of the root-mean-square (rms) voltage, where the term "V" in the two equations represents the percentage. While both the magnitude of the fluctuations ("V") and the "shape" of the modulating waveform are obviously important, the frequency of the modulation is also extremely relevant and is explicitly represented as ω_m. For sinusoidal flicker [given by Eq. (15.18)], the total waveform appears as shown in Fig. 15.40 with the modulating waveform shown explicitly. A similar waveform can be easily created for square-wave modulation.

To correlate the voltage change percentage, V, at a certain frequency, ω_m, with human perceptions, early research led to the widespread use of what is known as a flicker curve to predict possible observer complaints. Flicker curves are still in widespread use, particularly in the U.S. A typical flicker curve is shown in Fig. 15.41 and is based on tests conducted by the General Electric Company. It is important to realize that these curves are developed based on square wave modulation. Voltage changes from one level to another are considered to be "instantaneous" in nature, which may or may not be an accurate representation of actual equipment-produced voltage fluctuations.

The curve of Fig. 15.41 requires some explanation in order to understand its application. The "threshold of visibility" corresponds to certain fluctuation magnitude and frequency pairs that represent the borderline above which an observer can just perceive lamp (intensity) output variations in a 120 V, 60 Hz, 60 W incandescent bulb. The "threshold of irritation" corresponds to certain fluctuation magnitude and frequency pairs that represent the borderline above which the majority of observers would be irritated

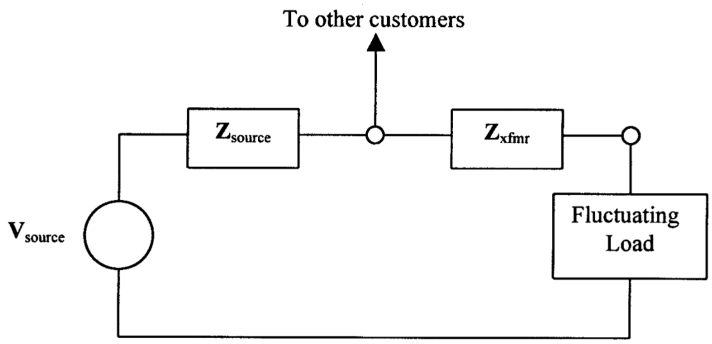

FIGURE 15.42 Example circuit for flicker calculations.

by lamp (intensity) output variations for the same lamp type. Two conclusions are immediately apparent from these two curves: (1) even small percentage changes in supply voltage can be noticed by persons observing lamp output, and (2) the frequency of the voltage fluctuations is an important consideration, with the frequency range from 6–10 Hz being the most sensitive.

Most utility companies do not permit excessive voltage fluctuations on their system, regardless of the frequency. For this reason, a "typical" utility flicker curve will follow either the "threshold of irritation" or the "threshold of visibility" curve as long as the chosen curve lies below some established value (2% in Fig. 15.41). By requiring that voltage fluctuations not exceed the "borderline of visibility" curve, the utility is insuring conservative criteria that should minimize potential problems due to voltage fluctuations.

For many years, the generic flicker curve has served the utility industry well. Fluctuating motor loads like car shredders, wood chippers, and many others can be fairly well characterized in terms of a duty cycle and a maximum torque. From this information, engineers can predict the magnitude and frequency of voltage changes anywhere in the supplying transmission and distribution system. Voltage fluctuations associated with motor starting events are also easily translated into a point (or points) on the flicker curve, and many utilities have based their motor starting criteria on this method for many years. Other loads, most notably arcing loads, cannot be represented as a single flicker magnitude and frequency term. For these types of loads, utility engineers typically presume either worst-case or most-likely variations for analytical evaluations.

Regardless of the type of load, the typical calculation procedure involves either basic load flow or simple voltage division calculations. Figure 15.42 shows an example positive sequence circuit with all data assumed in per-unit on consistent bases.

For fluctuating loads that are best represented by a constant power model (arc furnaces and load torque variations on a running motor), basic load flow techniques can be used to determine the full-load and no-load (or "normal condition") voltages at the "critical" or "point of common coupling" bus where other customers might be served. For fluctuating loads that are best represented by a constant impedance model (motor starting), basic circuit analysis techniques readily provide the full-load and no-load ("normal condition") voltages at the critical bus. Regardless of the modeling and calculation procedures used, equations similar to Eq. (15.20) can be used to determine the percentage voltage change for use in conjunction with a flicker curve. Of course, accurate information regarding the frequency of the assumed fluctuation is absolutely necessary. Note that Eq. (15.20) represents an over-simplification and should therefore not be used in cases where the fluctuations are frequent enough to impact the average rms value (measured over several seconds up to a minute). Other more elaborate formulas are available for these situations.

$$\%\ \text{Voltage Change} = \left(1.0 - \frac{V_{\text{full load}}}{V_{\text{normal}}}\right) * 100\% \tag{15.20}$$

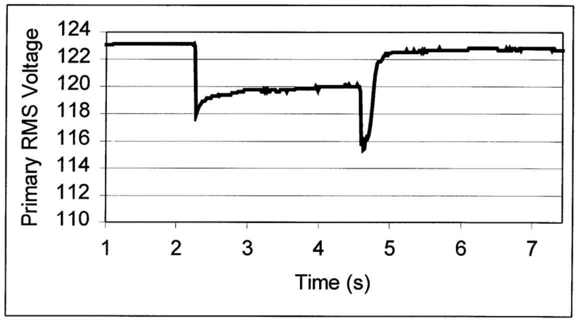

FIGURE 15.43 Poorly timed motor starter voltage fluctuation.

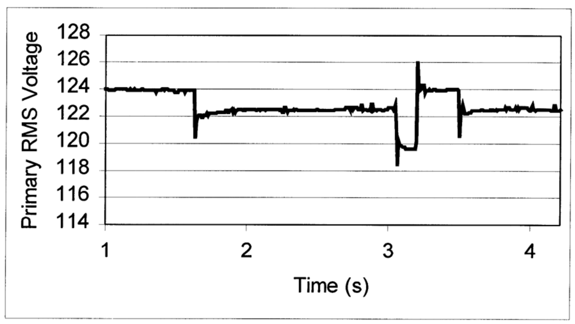

FIGURE 15.44 Adaptive-var compensator effects.

From a utility engineer's viewpoint, the decision to either serve or deny service to a fluctuating load is often based on the result of Eq. (15.20) [or a more complex version of Eq. (15.20)] including information about the frequency at which the calculated change occurs. From this simplified discussion, several questions arise:

1. How are fluctuating loads taken into account when the nature of the fluctuations is not constant in magnitude?
2. How are fluctuating loads taken into account when the nature of the fluctuations is not constant in frequency?
3. How are static compensators and other high response speed mitigation devices included in the calculations?

As examples, consider the rms voltage plots (on 120 V bases) shown in Figs. 15.43 and 15.44. Figure 15.43 shows an rms plot associated with a poorly timed two-step reduced-voltage motor starter. Figure 15.44 shows a motor starting event when the motor is compensated by an adaptive-var compensator. Questions 1–3 are clearly difficult to answer for these plots, so it would be very difficult to apply the basic flicker curve.

In many cases of practical interest, "rules of thumb" are often used to answer approximately these and other related questions so that the simple flicker curve can be used effectively. However, these assumptions and approaches must be conservative in nature and may result in costly equipment modifications prior to connection of certain fluctuating loads. In modern environment, it is imperative that end-users operate at the least total cost. It is equally important that end-use fluctuating loads not create problems for other users. Due to the conservative and approximate nature of the flicker curve methodology, there is often significant room for negotiation, and the matter is often not settled considering only engineering results.

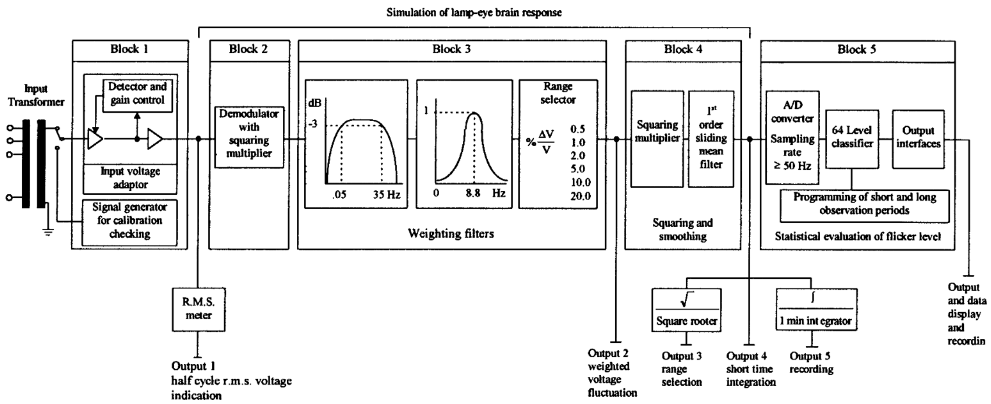

FIGURE 15.45 Flicker meter block diagram.

For roughly three decades, certain engineering groups have recognized the limitations of the flicker curve methods and have developed alternative approaches based on an instrument called a flicker meter. This work, driven strongly in Europe by the International Union for Electroheat (UIE) and the International Electrotechnical Commission (IEC), appears to offer solutions to many of the problems with the flicker curve methodology. Many years of industrial experience have been obtained with the flicker meter approach, and its output has been well-correlated with complaints of utility customers. At this time, the Institute of Electrical and Electronics Engineers (IEEE) is working toward adopting the flicker meter methodology for use in North America.

The flicker meter is a continuous time measuring system that takes voltage as an input and produces three output indices that are related to customer perception. These outputs are: (1) instantaneous flicker sensation, P_{inst}, (2) short-term flicker severity, P_{st}, and (3) long-term flicker severity, P_{lt}. A block diagram of an analog flicker meter is shown in Fig. 15.45.

The flicker meter takes into account both the physical aspects of engineering (how does the lamp [intensity] output vary with voltage?) and the physiological aspects of human observers (how fast can the human eye respond to light changes?). Each of the five basic blocks in Fig. 15.45 contribute to one or both of these aspects. While a detailed discussion of the flicker meter is beyond the scope of this section, the function of the blocks can be summarized as follows.

Blocks 1 and 2 act to process the input voltage signal and to partially isolate only the modulating term in Eqs. (15.18) or (15.19). Block 3 completes the isolation of the modulating signal through complex filtering and applies frequency-sensitive weighting to the "pure" modulating signal. Block 4 models the physiological response of the human observer, specifically the short-term memory tendency of the brain to correlate the voltage modulating signal with a human perception ability. Block 5 performs statistical analysis on the output of Block 4 to capture the cumulative effects of fluctuations over time.

The instantaneous flicker sensation is the output of Block 4. The short- and long-term severity indices are the outputs of Block 5. P_{inst} is available as an output quantity on a continuous basis, and a value of 1.0 corresponds with the threshold of visibility curve in Fig. 15.41. A single P_{st} value is available as an output every ten minutes, and a value of 1.0 corresponds to the threshold of irritation curve in Fig. 15.41. Of course, a comparison can only be made for certain inputs.

For square wave modulation, Fig. 15.46 shows a comparison of the "irritation level" given by IEEE Std. 141 (Red Book) and that level predicted by the flicker meter to be "irritating" ($P_{st} = 1.0$). For these comparisons, the lamp type used is a 120 V, 60 Hz, 60 W incandescent bulb. Note that the flicker curve taken from IEEE Std. 141 is essentially identical to the "borderline of irritation" curve given in Fig. 15.41.

As Fig. 15.46 clearly demonstrates, the square wave modulation voltage fluctuations that lead to irritation are nearly identical as predicted by either a standard flicker curve or a flicker meter.

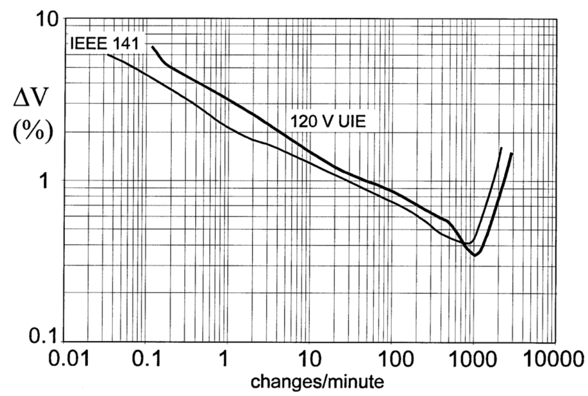

FIGURE 15.46 Threshold of irritation flicker curve and P_{st} = 1.0 curve from a flicker meter.

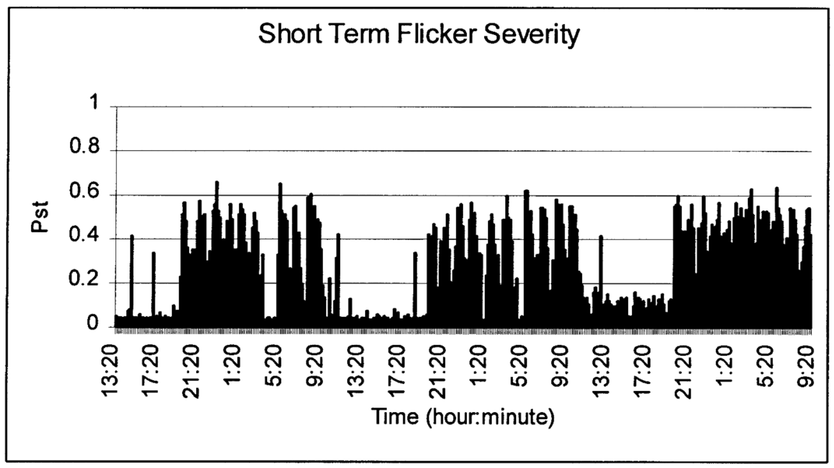

FIGURE 15.47 Short term flicker severity example plot.

The real advantage of the flicker meter methodology lies in that fact that the continuous time measurement system can easily predict possible irritation for arbitrarily complex modulation waveforms. As an example, Fig. 15.47 shows a plot of P_{st} over a three-day period at a location serving a small electric arc furnace. (Note: In this case, there were no reported customer complaints and P_{st} was well below the irritation threshold value of 1.0 during the entire monitoring period.)

Due to the very random nature of the fluctuations associated with an arc furnace, the flicker curve methodology cannot be used directly as an accurate predictor of irritation levels because it is appropriate only for the "sudden" voltage fluctuations associated with square wave modulation. The trade-off required for more accurate flicker prediction, however, is that the inherent simplicity of the basic flicker curve is lost.

For the basic flicker curve, simple calculations based on circuit and equipment models in Fig. 15.42 can be used. Data for these models is readily available, and time-tested assumptions are widely known for cases when exact data are not available. Because the flicker meter is a continuous-time system, continuous-time voltage input data is required for its use. For existing fluctuating loads, it is reasonable to presume that a flicker meter can be connected and used to predict whether or not the fluctuations are irritating. However, it is necessary to be able to predict potential flicker problems prior to the connection of a fluctuating load well before it is possible to measure anything.

There are three possible solutions to the apparent "prediction" dilemma associated with the flicker meter approach. The most basic approach is to locate an existing fluctuating load that is similar to the one under consideration and simply measure the flicker produced by the existing load. Of course, the engineer is responsible for making sure that the existing installation is nearly identical to the one proposed. While the fluctuating load equipment itself might be identical, supply system characteristics will almost never be the same.

Because the short-term flicker severity output of the flicker meter, P_{st}, is linearly dependent on voltage fluctuation magnitude over a wide range, it is possible to linearly scale the P_{st} measurements from one location to predict those at another location where the supply impedance is different. (In most cases, voltage fluctuations are directly related to the supply impedance; a system with 10% higher supply impedance would expect 10% greater voltage fluctuation for the same load change.) In evaluations where it is not possible to measure another existing fluctuating load, other approaches must be used.

If detailed system and load data are known, a time-domain simulation can be used to generate a continuous-time series of voltage data points. These points could then be used as inputs to a simulated flicker meter to predict the short-term flicker severity, P_{st}. This approach, however, is usually too intensive and time-consuming to be appropriate for most applications. For these situations, "shape factors" have been proposed that predict a P_{st} value for various types of fluctuations.

Shape factors are simple curves that can be used to predict, without simulation or measurement, the P_{st} that would be measured if the load were connected. Different curves exist for different "shapes" of voltage variation. Curves exist for simple square and triangular variations, as well as for more complex variations such as motor starting. To use a shape factor, an engineer must have some knowledge of (1) the magnitude of the fluctuation, (2) the shape of the fluctuation, including the time spent at each voltage level if the shape is complex, (3) rise time and fall times between voltage levels, and (4) the rate at which the shape repeats. In some cases, this level of data is not available, and assumptions are often made (on the conservative side). It is interesting to note that the extreme of the conservative choices is a rectangular fluctuation at a known frequency; which is exactly the data required to use the basic flicker curve of Fig. 15.41.

Using either the flicker curve for simple evaluations or the flicker meter methodology for more complex evaluations, it is possible to predict if a given fluctuating load will produce complaints from other customers. In the event that complaints are predicted, modifications must be made prior to granting service. The possible modifications can be made either on the utility side or on the customer (load) side (or both), or some type of compensation equipment can be installed.

In most cases, the most effective, but not least cost, ways to reduce or eliminate flicker complaints are to either (1) reduce the supply system impedance of the whole path from source to fluctuating load, or (2) serve the fluctuating load from a dedicated and electrically remote (from other customers) circuit. In most cases, utility revenue projections for customers with fluctuating loads do not justify such expenses, and the burden of mitigation is shifted to the consumer.

Customers with fluctuating load equipment have two main options regarding voltage flicker mitigation. In some cases, the load can be adjusted to the point that the frequency(ies) of the fluctuations are such that complaints are eliminated (recall the frequency-sensitive nature of the entire flicker problem). In other cases, direct voltage compensation can be achieved through high-speed static compensators. Either thyristor-switched capacitor banks (often called adaptive var compensators or AVCs) or fixed capacitors in parallel with thyristor-switched reactors (often called static var compensators or SVCs) can be used to provide voltage support through reactive compensation in about one cycle. For loads where the main contributor to a large voltage fluctuation is a large reactive power change, reactive compensators can significantly reduce or eliminate the potential for flicker complaints. In cases where voltage fluctuations are due to large real power changes, reactive compensation offers only small improvements and can, in some cases, make the problem worse.

In conclusion, it is almost always necessary to measure/predict flicker levels under a variety of possible conditions, both with and without mitigation equipment and procedures in effect. In very simple cases, a basic flicker curve will provide acceptable results. In more complex cases, however, an intensive measurement, modeling, and simulation effort may be required in order to minimize potential flicker complaints.

While this section has addressed the basic issues associated with voltage flicker complaints, prediction, and measurement, it is not intended to be all-inclusive. A number of relevant publications, papers, reports, and standards are given for further reading, and the reader should certainly consider these documents carefully in addition to what is provided here.

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15.6 Power Quality Monitoring

Patrick Coleman

Many power quality problems are caused by inadequate wiring or improper grounding. These problems can be detected by simple examination of the wiring and grounding systems. Another large population of power quality problems can be solved by spotchecks of voltage, current, or harmonics using hand held meters. Some problems, however, are intermittent and require longer-term monitoring for solution.

Long-term power quality monitoring is largely a problem of data management. If an RMS value of voltage and current is recorded each electrical cycle, for a three-phase system, about 6 gigabytes of data will be produced each day. Some equipment is disrupted by changes in the voltage waveshape that may not affect the rms value of the waveform. Recording the voltage and current waveforms will result in about 132 gigabytes of data per day. While modern data storage technologies may make it feasible to record every electrical cycle, the task of detecting power quality problems within this mass of data is daunting indeed.

Most commercially available power quality monitoring equipment attempts to reduce the recorded data to manageable levels. Each manufacturer has a generally proprietary data reduction algorithm. It is critical that the user understand the algorithm used in order to properly interpret the results.

Selecting a Monitoring Point

Power quality monitoring is usually done to either solve an existing power quality problem, or to determine the electrical environment prior to installing new sensitive equipment. For new equipment, it is easy to argue that the monitoring equipment should be installed at the point nearest the point of connection of the new equipment. For power quality problems affecting existing equipment, there is frequently pressure to determine if the problem is being caused by some external source, i.e., the utility. This leads to the installation of monitoring equipment at the service point to try to detect the source of the problem. This is usually not the optimum location for monitoring equipment. Most studies suggest that 80% of power quality problems originate within the facility. A monitor installed on the equipment being affected will detect problems originating within the facility, as well as problems originating on the utility. Each type of event has distinguishing characteristics to assist the engineer in correctly identifying the source of the disturbance.

What to Monitor

At minimum, the input voltage to the affected equipment should be monitored. If the equipment is single phase, the monitored voltage should include at least the line-to-neutral voltage and the neutral-to-ground voltages. If possible, the line-to-ground voltage should also be monitored. For three-phase equipment, the voltages may either be monitored line to neutral, or line to line. Line-to-neutral voltages are easier to understand, but most three-phase equipment operates on line-to-line voltages. Usually, it is preferable to monitor the voltage line to line for three-phase equipment.

If the monitoring equipment has voltage thresholds which can be adjusted, the thresholds should be set to match the sensitive equipment voltage requirements. If the requirements are not known, a good starting point is usually the nominal equipment voltage plus or minus 10%.

In most sensitive equipment, the connection to the source is a rectifier, and the critical voltages are DC. In some cases, it may be necessary to monitor the critical DC voltages. Some commercial power quality monitors are capable of monitoring AC and DC simultaneously, while others are AC only.

It is frequently useful to monitor current as well as voltage. For example, if the problem is being caused by voltage sags, the reaction of the current during the sag can help determine the source of the sag. If the current doubles when the voltage sags 10%, then the cause of the sag is on the load side of the current monitor point. If the current increases or decreases 10–20% during a 10% voltage sag, then the cause of the sag is on the source side of the current monitoring point.

Sensitive equipment can also be affected by other environmental factors such as temperature, humidity, static, harmonics, magnetic fields, radio frequency interference (RFI), and operator error or sabotage. Some commercial monitors can record some of these factors, but it may be necessary to install more than one monitor to cover every possible source of disturbance.

It can also be useful to record power quantity data while searching for power quality problems. For example, the author found a shortcut to the source of a disturbance affecting a wide area by using the power quantity data. The recordings revealed an increase in demand of 2500 KW immediately after the disturbance. Asking a few questions quickly led to a nearby plant with a 2500 KW switched load that was found to be malfunctioning.

Selecting a Monitor

Commercially available monitors fall into two basic categories: line disturbance analyzers and voltage recorders. The line between the categories is becoming blurred as new models are developed. Voltage recorders are primarily designed to record voltage and current stripchart data, but some models are able to capture waveforms under certain circumstances. Line disturbance analyzers are designed to capture voltage events that may affect sensitive equipment. Generally, line disturbance analyzers are not good voltage recorders, but newer models are better than previous designs at recording voltage stripcharts.

In order to select the best monitor for the job, it is necessary to have an idea of the type of disturbance to be recorded, and an idea of the operating characteristics of the available disturbance analyzers. For example, a common power quality problem is nuisance tripping of variable speed drives. Variable speed drives may trip due to the waveform disturbance created by power factor correction capacitor switching, or due to high or low steady state voltage, or, in some cases, due to excessive voltage imbalance. If the drive trips due to high voltage or waveform disturbances, the drive diagnostics will usually indicate an overvoltage code as the cause of the trip. If the voltage is not balanced, the drive will draw significantly unbalanced currents. The current imbalance may reach a level that causes the drive to trip for input overcurrent. Selecting a monitor for variable speed drive tripping can be a challenge. Most line disturbance analyzers can easily capture the waveshape disturbance of capacitor switching, but they are not good voltage recorders, and may not do a good job of reporting high steady state voltage. Many line disturbance analyzers cannot capture voltage unbalance at all, nor will they respond to current events unless there is a corresponding voltage event. Most voltage and current recorders can easily capture the high steady state voltage that leads to a drive trip, but they may not capture the capacitor switching waveshape disturbance. Many voltage recorders can capture voltage imbalance, current imbalance, and some of them will trigger a capture of voltage and current during a current event, such as the drive tripping off.

To select the best monitor for the job, it is necessary to understand the characteristics of the available monitors. The following sections will discuss the various types of data that may be needed for a power quality investigation, and the characteristics of some commercially available monitors.

Voltage

The most commonly recorded parameter in power quality investigations is the RMS voltage delivered to the equipment. Manufacturers of recording equipment use a variety of techniques to reduce the volume of the data recorded. The most common method of data reduction is to record Min/Max/Average data over some interval. Figure 15.48 shows a strip chart of rms voltages recorded on a cycle-by-cycle basis. Figure 15.49 shows a Min/Max/Average chart for the same time period. A common recording period is 1 week. Typical recorders will use a recording interval of 2–5 minutes. Each recording interval will produce three numbers: the rms voltage of the highest 1 cycle, the lowest 1 cycle, and the average of every cycle during the interval. This is a simple, easily understood recording method, and it is easily implemented

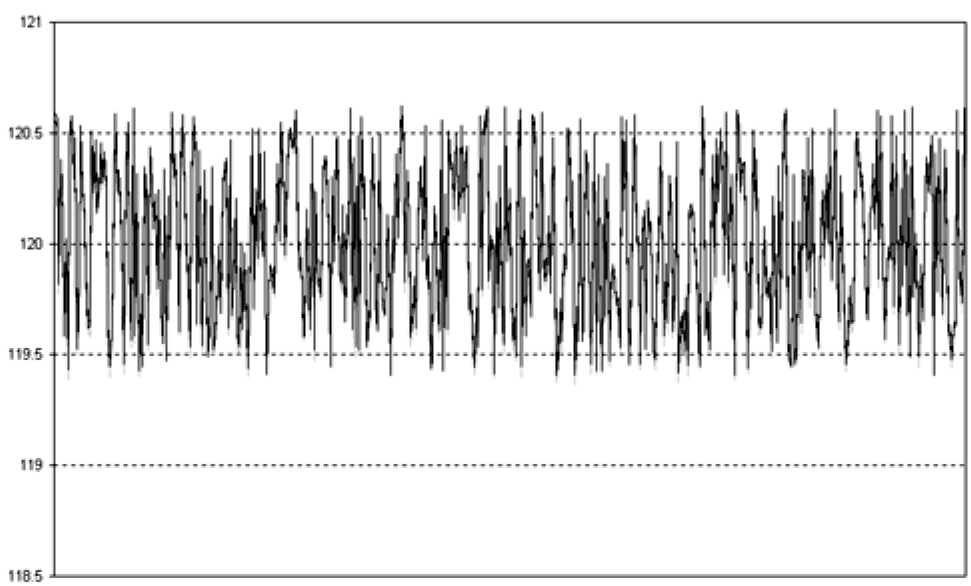

FIGURE 15.48 RMS voltage stripchart, taken cycle by cycle.

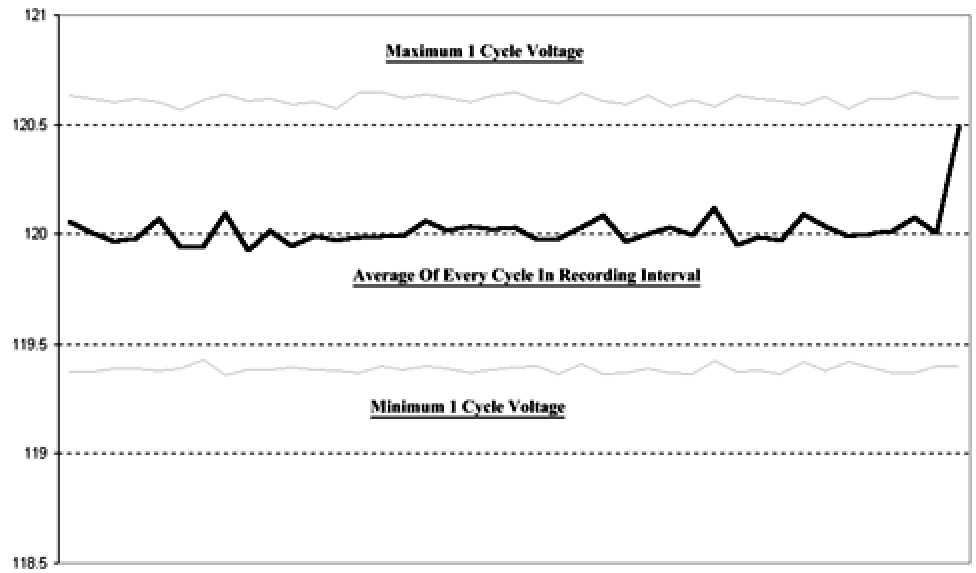

FIGURE 15.49 Min/Max/Average stripchart, showing the minimum single cycle voltage, the maximum single cycle voltage, and the average of every cycle in a recording interval. Compare to the Fig. 15.48 stripchart data.

by the manufacturer. There are several drawbacks to this method. If there are several events during a recording interval, only the event with the largest deviation is recorded. Unless the recorder records the event in some other manner, there is no time-stamp associated with the events, and no duration available. The most critical deficiency is the lack of a voltage profile during the event. The voltage profile provides significant clues to the source of the event. For example, if the event is a voltage sag, the minimum voltage may be the same for an event caused by a distant fault on the utility system, and for a nearby large motor start. For the distant fault, however, the voltage will sag nearly instantaneously, stay at a fairly constant level for 3–10 cycles, and almost instantly recover to full voltage, or possibly a slightly higher voltage if the faulted section of the utility system is separated. For a nearby motor start, the voltage will drop nearly instantaneously, and almost immediately begin a gradual recovery over 30–180 cycles to a voltage somewhat lower than before. Figure 15.50 shows a cycle-by-cycle recording of a simulated adjacent feeder fault, followed by a simulation of a voltage sag caused by a large motor start. Figure 15.51 shows a Min/Max/Average recording of the same two events. The events look quite similar when captured by the Min/Max/Average recorder, while the cycle-by-cycle recorder reveals the difference in the voltage recovery profile.

Some line disturbance analyzers allow the user to set thresholds for voltage events. If the voltage exceeds these thresholds, a short duration stripchart is captured showing the voltage profile during the event. This short duration stripchart is in addition to the long duration recordings, meaning that the engineer must look at several different charts to find the needed information.

Some voltage recorders have user-programmable thresholds, and record deviations at a higher resolution than voltages that fall within the thresholds. These deviations are incorporated into the stripchart, so the user need only open the stripchart to determine, at a glance, if there are any significant events. If there are events to be examined, the engineer can immediately "zoom in" on the portion of the stripchart with the event.

Some voltage recorders do not have user-settable thresholds, but rather choose to capture events based either on fixed default thresholds or on some type of significant change. For some users, fixed thresholds are an advantage, while others are uncomfortable with the lack of control over the meter function. In units with fixed thresholds, if the environment is normally somewhat disturbed, such as on a welder

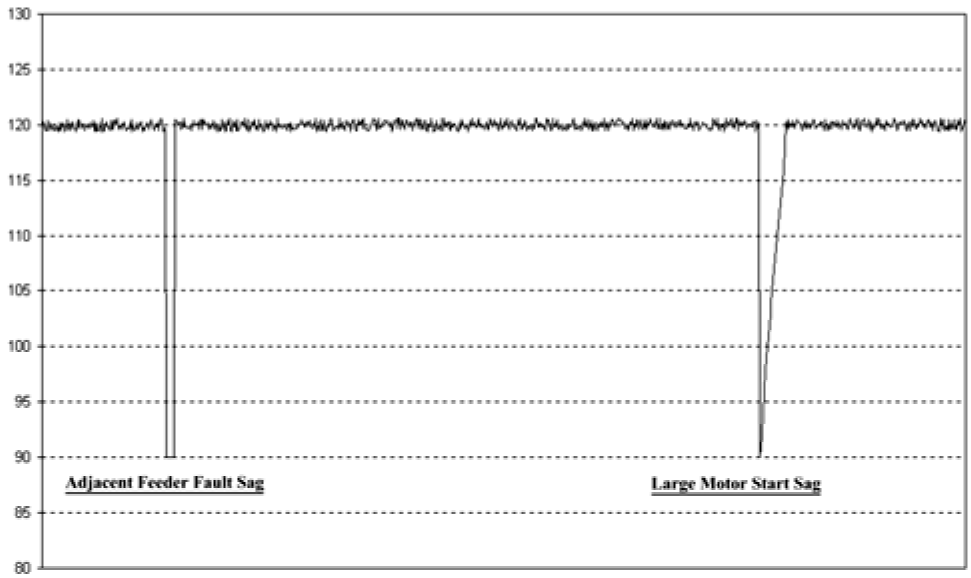

FIGURE 15.50 Cycle-by-cycle rms stripchart showing two voltage sags. The sag on the left is due to an adjacent feeder fault on the supply substation, and the sag on the right is due to a large motor start. Note the difference in the voltage profile during recovery.

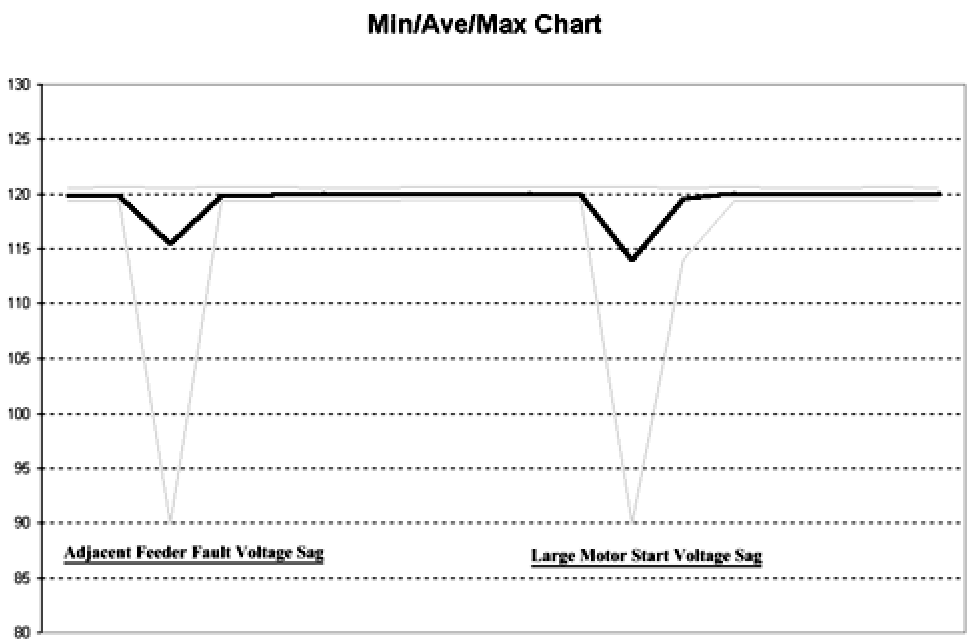

FIGURE 15.51 Min/Max/Average stripchart of the same voltage sags as Fig. 15.50. Note that both sags look almost identical. Without the recovery detail found in Fig. 15.50, it is difficult to determine a cause for the voltage sags.

circuit at a motor control center, the meter memory may fill up with insignificant events and the monitor may not be able to record a significant event when it occurs. For this reason, monitors with fixed thresholds should not be used in electrically noisy environments.

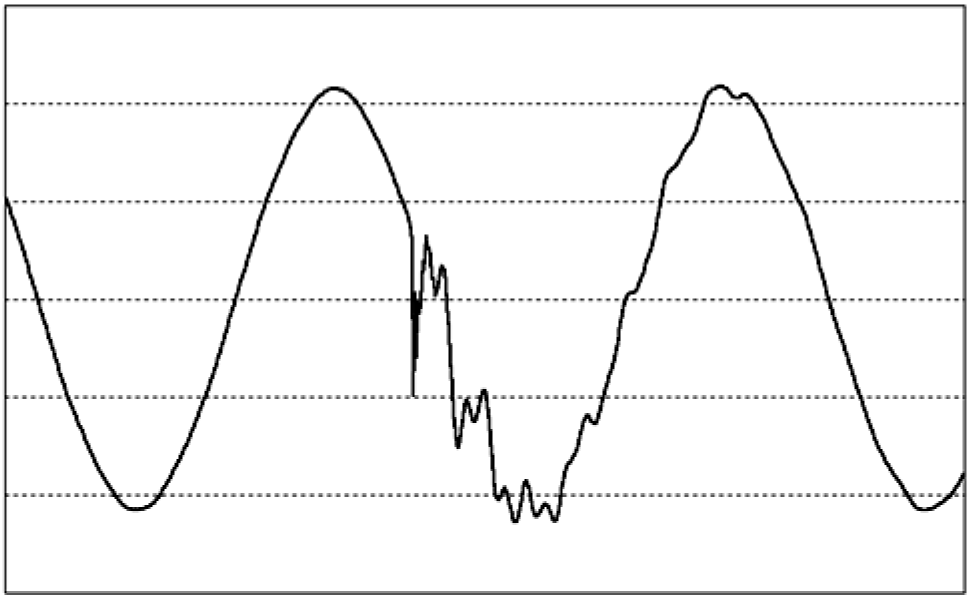

FIGURE 15.52 Typical voltage waveform disturbance caused by power factor correction capacitor energization.

Voltage Waveform Disturbances

Some equipment can be disturbed by changes in the voltage waveform. These waveform changes may not significantly affect the rms voltage, yet may still cause equipment to malfunction. An rms-only recorder may not detect the cause of the malfunction. Most line disturbance analyzers have some mechanism to detect and record changes in voltage waveforms. Some machines compare portions of successive waveforms, and capture the waveform if there is a significant deviation in any portion of the waveform. Others capture waveforms if there is a significant change in the rms value of successive waveforms. Another method is to capture waveforms if there is a significant change in the voltage total harmonic distortion (THD) between successive cycles.

The most common voltage waveform change that may cause equipment malfunction is the disturbance created by power factor correction capacitor switching. When capacitors are energized, a disturbance is created that lasts about 1 cycle, but does not result in a significant change in the rms voltage. Figure 15.52 shows a typical power factor correction capacitor switching event.

Current Recordings

Most modern recorders are capable of simultaneous voltage and current recordings. Current recordings can be useful in identifying the cause of power quality disturbances. For example, if a 20% voltage sag (to 80% of full voltage) is accompanied by a small change in current (plus or minus about 30%), the cause of the voltage sag is usually upstream (toward the utility source) of the monitoring point. If the sag is accompanied by a large increase in current (about 100%), the cause of the sag is downstream (toward the load) of the monitoring point. Figure 15.53 shows the rms voltage and current captured during a motor start downstream of the monitor. Notice the large current increase during starting and the corresponding small decrease in voltage.

Some monitors allow the user to select current thresholds that will cause the monitor to capture both voltage and current when the current exceeds the threshold. This can be useful for detecting over- and under-currents that may not result in a voltage disturbance. For example, if a small, unattended machine is tripping off unexpectedly, it would be useful to have a snapshot of the voltage and current just prior to the trip. A threshold can be set to trigger a snapshot when the current goes to zero. This snapshot can be used to determine if the input voltage or current was the cause of the machine trip.

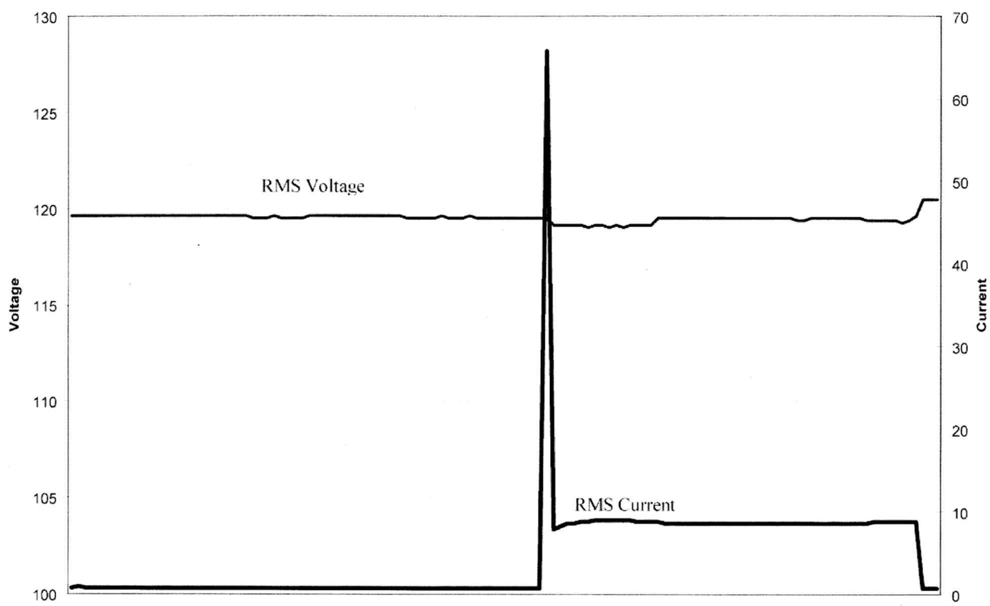

FIGURE 15.53 RMS stripcharts of voltage and current during a large current increase due to a motor start downstream of the monitor point.

Current Waveshape Disturbances

Very few monitors are capable of capturing changes in current waveshape. It is usually not necessary to capture changes in current waveshape, but in some special cases this can be useful data. For example, inrush current waveforms can provide more useful information than inrush current rms data. Figure 15.54 shows a significant change in the current waveform when the current changes from zero to

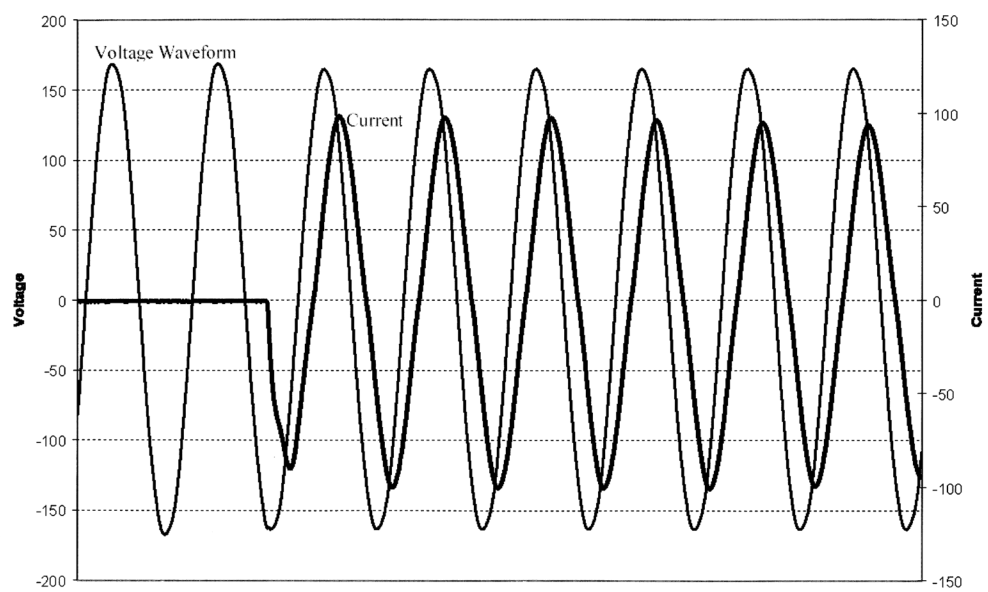

FIGURE 15.54 Voltage and current waveforms for the first few cycles of the current increase illustrated in Fig. 15.53.

nearly 100 amps peak. The shape of the waveform, and the phase shift with respect to the voltage waveform, confirm that this current increase was due to an induction motor start. Figure 15.54 shows the first few cycles of the event shown in Fig. 15.53.

Harmonics

Harmonic distortion is a growing area of concern. Many commercially available monitors are capable of capturing harmonic snapshots. Some monitors have the ability to capture harmonic stripchart data. In this area, it is critical that the monitor produce accurate data. Some commercially available monitors have deficiencies in measuring harmonics. Monitors generally capture a sample of the voltage and current waveforms, and perform a Fast Fourier Transform to produce a harmonic spectrum. According to the Nyquist Sampling Theorem, the input waveform must be sampled at least twice the highest frequency that is present in the waveform. Some manufacturers interpret this to mean the highest frequency of interest, and adjust their sample rates accordingly. If the input signal contains a frequency that is above the maximum frequency that can be correctly sampled, the high frequency signal may be "aliased," that is, it may be incorrectly identified as a lower frequency harmonic. This may lead the engineer to search for a solution to a harmonic problem that does not exist. The aliasing problem can be alleviated by sampling at higher sample rates, and by filtering out frequencies above the highest frequency of interest. The sample rate is usually found in the manufacturer's literature, but the presence of an antialiasing filter is not usually mentioned in the literature.

Flicker

Some users define flicker as the voltage sag that occurs when a large motor starts. Other users regard flicker as the frequent, small changes in voltage that occur due to the operation of arc furnaces, welders, chippers, shredders, and other varying loads. Nearly any monitor is capable of adequately capturing voltage sags due to occasional motor starts. The second definition of flicker is more difficult to monitor. In the absence of standards, several manufacturers have developed proprietary "flicker" meters. In recent years, an effort has been made to standardize the definition of "flicker," and to standardize the performance of flicker meters. At the time of this writing, several monitor manufacturers are attempting to incorporate the standardized flicker function into their existing products.

High Frequency Noise

Sensitive electronic equipment can be susceptible to higher frequency signals imposed on the voltage waveform. These signals may be induced on the conductors by sources such as radio transmitters or arcing devices such as fluorescent lamps, or they may be conductively coupled by sources such as power line carrier energy management systems. A few manufacturers include detection circuitry for high frequency signals imposed on the voltage waveform.

Other Quantities

It may be necessary to find a way to monitor other quantities that may affect sensitive equipment. Examples of other quantities are temperature, humidity, vibration, static electricity, magnetic fields, fluid flow, and air flow. In some cases, it may also become necessary to monitor for vandalism or sabotage. Most power quality monitors cannot record these quantities, but other devices exist that can be used in conjunction with power quality monitors to find a solution to the problem.

Summary

Most power quality problems can be solved with simple hand-tools and attention to detail. Some problems, however, are not so easily identified, and it may be necessary to monitor to correctly identify the problem. Successful monitoring involves several steps. First, determine if it is really necessary to monitor. Second, decide on a location for the monitor. Generally, the monitor should be installed close to the affected equipment. Third, decide what quantities need to be monitored, such as voltage, current, harmonics, and power data. Try to determine the types of events that can disturb the equipment, and select a meter that is capable of detecting those types of events. Fourth, decide on a monitoring period. Usually, a good first choice is at least one business cycle, or at least 1 day, and more commonly, 1 week. It may be necessary to monitor until the problem recurs. Some monitors can record indefinitely by discarding older data to make space for new data. These monitors can be installed and left until the problem recurs. When the problem recurs, the monitoring should be stopped before the event data is discarded.

After the monitoring period ends, the most difficult task begins — interpreting the data. Modern power quality monitors produce reams of data during a disturbance. Data interpretation is largely a matter of experience, and Ohm's law. There are many examples of disturbance data in books such as *The BMI Handbook of Power Signatures, Second Edition*, and the *Dranetz Field Handbook for Power Quality Analysis.*