CHAPTER 1

UTILITY SOURCE

OBJECTIVES

- Be aware of the need to always exercise safety while working around electricity
- Understand the significance of the voltage level at the point of delivery to the industrial customer
- Be proficient in the use of one-line diagrams to represent a three-phase electrical system
- Understand the concept of protection zones
- Recognize various source configurations and know the advantages and disadvantages of each
- Calculate per-unit quantities, convert between actual and per-unit quantities, and be able to apply the per-unit system to do electrical calculations
- Understand the components of power in an AC system
- Be able to calculate voltage drop in a balanced three-phase system
- Understand the significance of short circuit availability, both from a fault interrupting standpoint and from a motor starting standpoint 2
- Comprehend the importance of properly sizing conductors and supply transformers

1.1 ELECTRICAL SAFETY

A 6-W night light bulb draws 50 mA of current. Even this small magnitude of current can kill a person. Humans can perceive an electric current as small as 0.5 mA. As the current magnitude rises to the 1–5 mA range, muscles will contract. Currents in the 3–10 mA range cause pain. Currents in the 10–40 mA range fall in the “let go” threshold, meaning they will cause muscles to contract so tightly that “letting go” of a grasped wire becomes impossible. Respiratory paralysis can occur in the 30–75 mA range. The heart will be affected with ventricular fibrillation occurring in the 75–100 mA range and heart paralysis occurring in the 250–300 mA range. Note that we have not yet reached one-third of an ampere! In the range of 5–6 A, organ burns will occur. These typical values are summarized in Figure 1.1.

Industrial Power Distribution, Second Edition. Ralph E. Fehr, III.

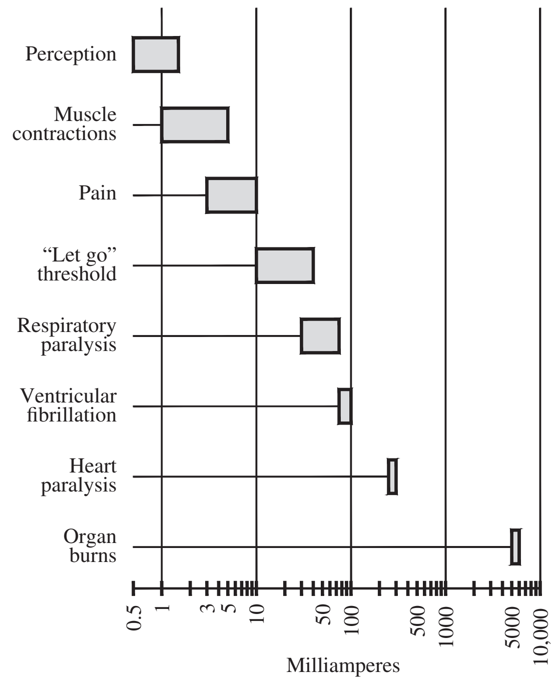


Figure 1.1 Effects of Electrical Current on the Human Body

Although electrocution is a major concern when working around electricity, most electrical injuries are the result of burns occurring when large amounts of thermal energy are released during arcing faults. *Electric arc flash* presents a hazard that is distinct from electric shock. The heat and blast released during a short circuit fault can injure or kill a person located many feet from the fault location and who never come in contact with an energized conductor. The arc flash hazard will be discussed in Section 7.5.

Because of the shock and burn hazards posed by electricity, safety must *always* be exercised and considered as the *highest* priority when working around electrical equipment. Nothing supersedes safety. Carelessness for even a moment could result in a serious injury—or worse.

Much of what is considered safe working practices falls soundly into the category of *common sense*. For example, do not assume a circuit is de-energized—test it and ground it to make sure. Follow all grounding and bonding requirements when performing maintenance of electrical equipment. Stringently adhere to all switching and tagging practices required by the owner of the facility in which you are working. Be aware of working clearances and approach boundaries (these topics will be discussed in Section 7.5). Be sure that all tools and equipment including personal protective equipment (PPE) are in good condition, are being used properly, and have current testing or certification credentials, if applicable. Adhere to all safety procedures, even if the procedure does not seem important to you. *It probably is* *important, but even if it is not, better safe than sorry.* And be sure to complete all required training, including refresher courses, required for your job.

Electricity need not be feared, but certainly does command respect. Safe working practices need to be standard operating procedure and never be compromised. Safety must also be considered when designing electrical systems. Engineering additional safety features beyond what is minimally required for a system is a hallmark of excellent design. If an unsafe condition is discovered, it needs to be reported and made safe as quickly as possible. Take safety seriously—your life depends on it!

1.2 DELIVERY VOLTAGE

Electricity for industrial facilities can be supplied by the local utility either at distribution voltages (2.4–34.5 kV) or at subtransmission or transmission voltages (46–230 kV) depending on the size of the load, the topology of the utility system, and the tariffs and rate schedules under which the service is supplied. Since the highest utilization voltage in the plant may be lower than the delivery voltage, a voltage transformation is often necessary at the point of delivery.

If the industrial facility is small enough to be fed from a single distribution transformer, the utility may serve the facility at *utilization voltage,* which is defined as the voltage at the line terminals of utilization equipment. This voltage is often 480Y/277 V, meaning that a four-wire wye-connected service is provided with a line-to-line voltage of 480 V and a line-to-neutral voltage of 277 V, as shown in Figure 1.2.

Three-phase 480 V and single-phase 240-V service also can be provided by a *high-leg delta* system as shown in Figure 1.3. One of the delta legs is center tapped and grounded to form the system neutral. Care must be taken not to connect load from the high leg phase of the delta to neutral, as this voltage (416 V) is not a normally utilized voltage.

Single-phase 120 V and three- or single-phase 208 V can be provided using dry-type transformers rated 480 – 208Y/120 V.

As the size of the industrial facility increases, it becomes necessary to supply the facility at a higher voltage to limit excessive voltage drop and to reduce losses.

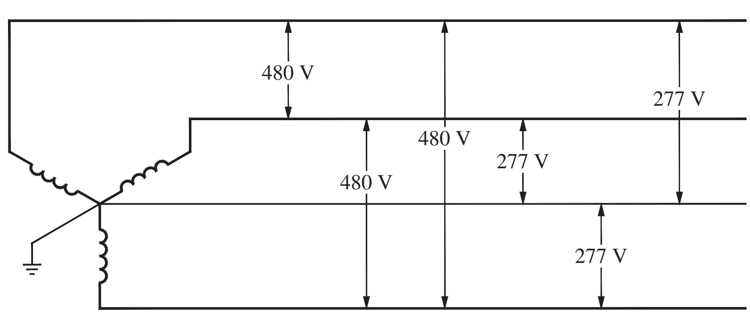


Figure 1.2 480Y/277 V System

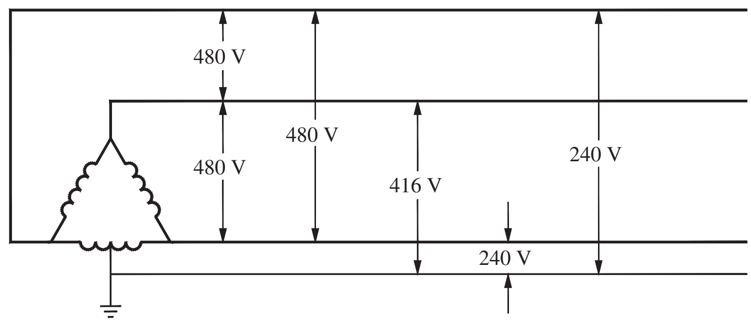


Figure 1.3 High-Leg Delta System

Loss reduction results in a reduced operating cost. The lower currents resulting from operating the system at a higher voltage also allow smaller conductor to be used, thereby reducing the system construction cost. Many times, a three-phase tap is built from a distribution feeder to the facility. At the facility, distribution transformers and their associated high- and low-voltage switching equipment are called *unit substations.* The unit substations are fed from the distribution tap, and in turn, feed the facility. Distribution feeders are typically in the 2.4–15 kV range, with a trend toward the higher part of that range. Some utilities are using distribution voltages higher than 15 kV, particularly if the load density is high or the feeders are very long. Equipment in the 25 kV class can be used on 22 and 24.9 kV systems, while 35 kV class equipment can be used on 33 and 34.5 kV systems.

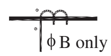
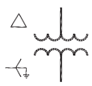
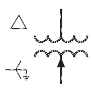
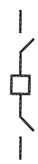
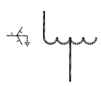
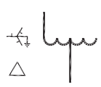
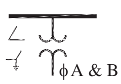
1.3 ONE-LINE DIAGRAMS

The one-line or single-line diagram is an important type of drawing used by power engineers to convey topological information about a power system. Most industrial power systems are three-phase systems, where each of the three phases is very similar to if not identical to the other two. This symmetry can be exploited by showing only one of the three phases, thus the term *one-line* diagram. Any asymmetries can be noted on the diagram.

Special forms of one-line diagrams can be produced to convey special information such as protection schemes or switching procedures. One-line diagrams frequently reference other drawings which provide details not shown on the one-line. Although not a necessity, one-line diagrams are usually drawn in such a way that they closely resemble the physical system they represent. Sometimes, a north arrow is shown to establish a physical orientation.

Similar to a schematic diagram, the one-line diagram uses fairly standardized symbols to represent system components. Although much standardization in one-line symbols has taken place over the years, differences will be found from drawing to drawing. Some of the more common symbols are shown in Table 1.1.

TABLE 1.1 Common One-Line Diagram Symbols

	Generator wye-connected impedance grounded		Bus
	Synchronous motor 7500 horsepower		Current transformer
	Induction motor 500 horsepower		Current transformer (phase b only)
	Power transformer delta - grounded wye		Lightning arrester
	Power transformer delta - grounded wye w/ load tap changer		Power circuit breaker and disconnect switches
	Autotransformer grounded wye		Switchgear circuit breaker and drawouts
	Autotransformer grounded wye w/ delta tertiary		
	Voltage transformer		
	2 voltage transformers connected open-delta - grounded open-wye		
	Broken delta		

1.4 ZONES OF PROTECTION

A short circuit fault is an unintentional connection of a phase to another phase or to ground through a low impedance, resulting in very high current magnitudes. The high current poses a serious compromise to safety and can cause severe equipment damage. The ability to quickly and accurately detect a short circuit fault and the means to reliably remove, or clear, that fault from the system are primary considerations

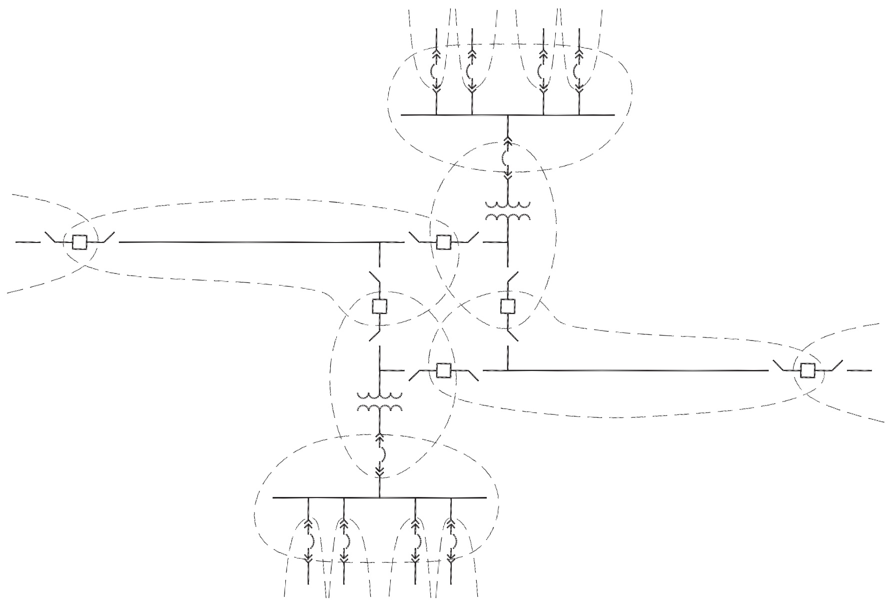


Figure 1.4 Zones of Protection

when designing any power distribution system. Fault detection is done using a variety of protective devices, such as protective relays and fuses. Some protective devices are able to detect faults within a certain proximity of the device. This limited range is necessary to prevent multiple devices from operating simultaneously. The range within which a device can detect a fault is known as the device's *zone of protection*.

When designing a power distribution system, it is mandatory that every portion of the system lies within a zone of protection; otherwise, that portion of the system would be *unprotected*. A fault occurring in an unprotected zone would not be cleared. It is also highly desirable to have *overlapping zones*, as in Figure 1.4, so that a fault occurring in a portion of the system included in multiple zones would be detected by multiple devices. By varying the time characteristics of the protective devices, it can be assured that only one device would operate. But by having multiple devices aware of the fault, backup protection exists in the event that the primary protection device is unable to clear the fault.

1.5 SOURCE CONFIGURATION

Early in the power system design process, a decision must be made regarding the configuration of the utility source. This decision is always a compromise between reliability and economics. The simplest and least expensive option is a single radial source as shown in Figure 1.5.

This option can be implemented at any voltage level. A single feed is provided to the industrial plant by the utility. Depending on the delivery voltage, the feed can

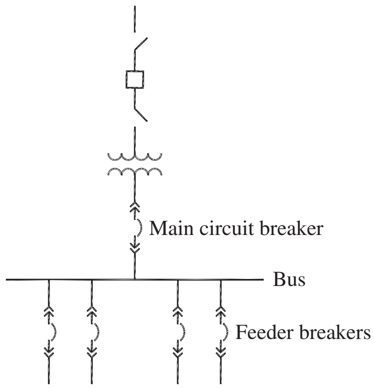


Figure 1.5 Radial System

either be transformed to a lower voltage or used to supply switchgear for subsequent distribution. Radial buses require one circuit breaker per element connected to the bus.

When a fault occurs on the radial bus, every breaker must *trip*, or open, to isolate the fault. This results in the complete de-energization of the bus, which is highly objectionable for many applications. Note that the main circuit breaker (shown between the transformer and the bus in Figure 1.5) is optional in a radial bus scheme. Its presence simplifies switching, but does so at the cost of an additional breaker.

When a fault occurs on a feeder leaving the radial bus, the feeder breaker should trip to clear the fault without interrupting any other loads. But if the feeder breaker fails to clear the fault, every breaker must open to clear the fault. This condition, known as *breaker failure*, also de-energizes the entire bus. With two fairly probable scenarios (bus fault and feeder breaker failure) resulting in complete de-energization of the bus, the radial bus should not be implemented when reliability is a concern, unless an alternate source and source transfer scheme is provided, as is discussed in Chapter 7.

The poor reliability of the radial bus can be improved greatly by adding a second source configured in a *ring bus* as shown in Figure 1.6.

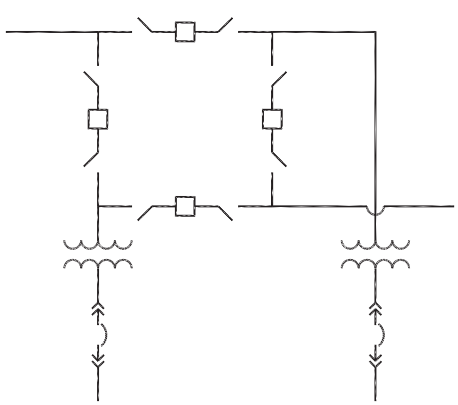


Figure 1.6 Ring Bus

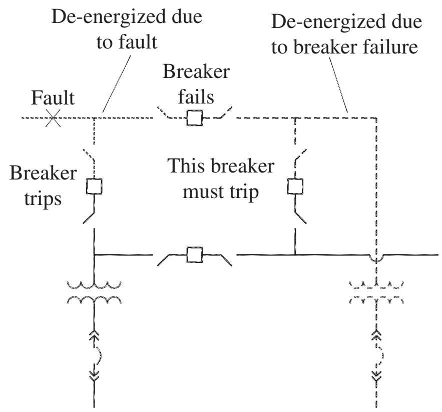


Figure 1.7 Ring Bus with Breaker Failure

The ring bus, like the radial bus, requires one circuit breaker per element connected to the bus. When a fault occurs on the ring bus, each bus section is protected by the protection for one of the elements connected to the bus. For example, if a fault occurs on the bus between the breakers at the 9 o'clock and 12 o'clock positions in Figure 1.6, the protection for the circuit leaving the upper left corner of the ring would detect the bus fault. That line would be de-energized, but the remainder of the bus would remain in service. Note that two breakers must trip to clear a fault in a ring bus topology. Also note that after two breakers open to clear a fault, the ring is no longer intact—the bus essentially becomes a radial configuration with what amounts to tie breakers in the bus.

In the event of breaker failure, the breaker in the next position in the ring must trip to clear the fault. This results in the de-energization of one circuit in addition to the faulted circuit, as seen in Figure 1.7.

When one breaker in the ring is opened, all circuits leaving the ring bus remain energized but the reliability of the ring is compromised. With one breaker open, losing another breaker will either de-energize a circuit or split the substation into two separate subsystems, as shown in Figure 1.8. Both of these scenarios are undesirable.

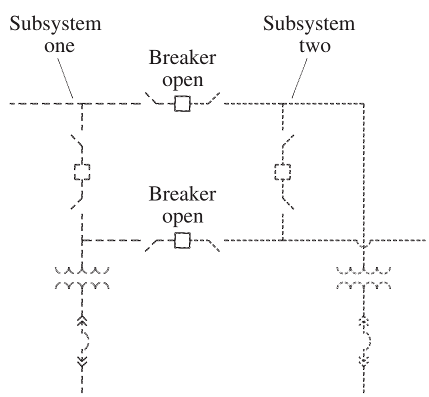


Figure 1.8 Split Ring Bus

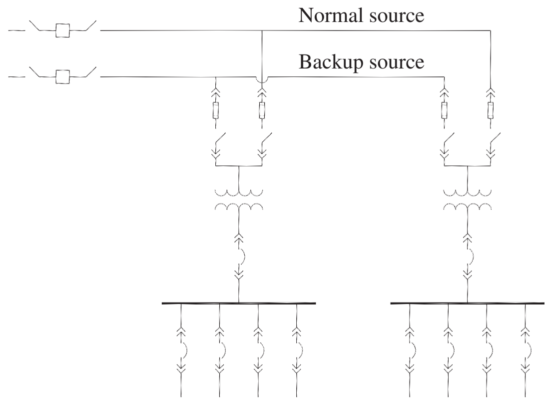


Figure 1.9 Primary Selective System

Because of this characteristic, care must be exercised when designing a ring bus. To minimize the risk of losing multiple sources or multiple loads in the event that a circuit breaker fails during a fault, source and load connections should alternate. Connecting two sources to adjacent ring bus positions would result in the loss of both sources if a fault occurred on one of the sources and the circuit breaker between the sources failed to open to clear the fault. Also, circuits terminated on the ring bus should have disconnected the switches installed which can be used to isolate the circuit so the ring breakers can be reclosed. Disconnect switches cannot break current; they can only be opened after circuit breakers de-energize the circuit.

The ring bus configuration allows multiple sources to feed multiple loads with automatic fault isolation and a great deal of flexibility. All circuit breakers in a ring bus are normally closed. Since ring buses increase short circuit availability (SCA) by paralleling sources, care must be taken so device short circuit capabilities are not exceeded.

Reliability also can be improved by adding a second source configured in a *primary selective* scheme as shown in Figure 1.9. Here, the primary selective topology is supplying two radial buses. One source is designated as the *normal* source and the second serves as a *backup* source. When the normal source fails, the backup source can be energized either by manual or automatic switching.

Referring to Figure 1.9, assume that the transformer on the left is normally fed from the top feeder (the bottom feeder is the backup source). Conversely, the transformer on the right is normally fed from the bottom feeder, with the top feeder serving as a backup source. This normal configuration is clarified in Figure 1.10.

When a fault occurs on the top feeder, the transformer on the left experiences an interruption in service when the top feeder breaker trips to clear the fault, while the transformer on the right is unaffected. To restore service to the transformer on the left, the normally closed switch just upstream from the transformer is opened, and the accompanying normally open switch is closed. This backup configuration is shown in Figure 1.11.

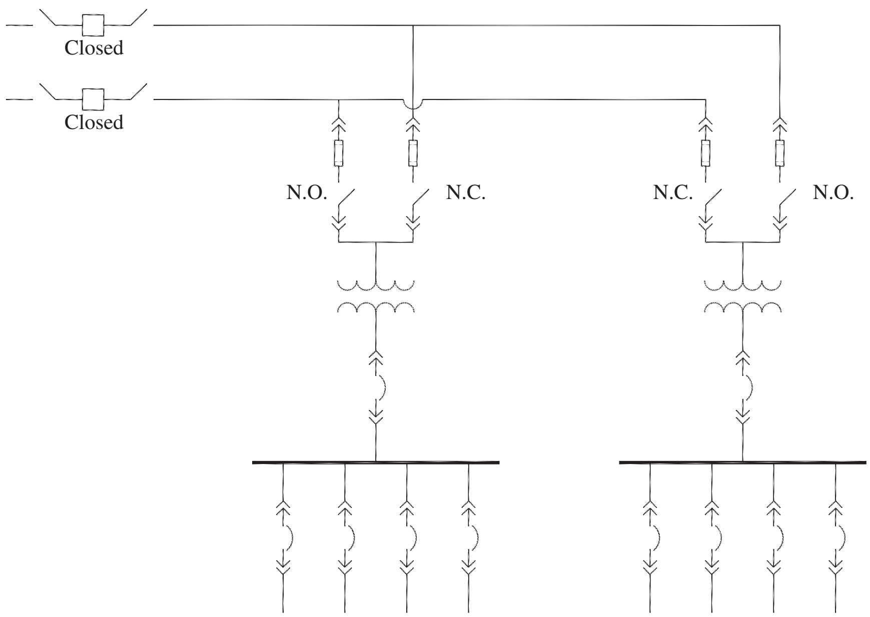


Figure 1.10 Primary Selective System Normal Configuration

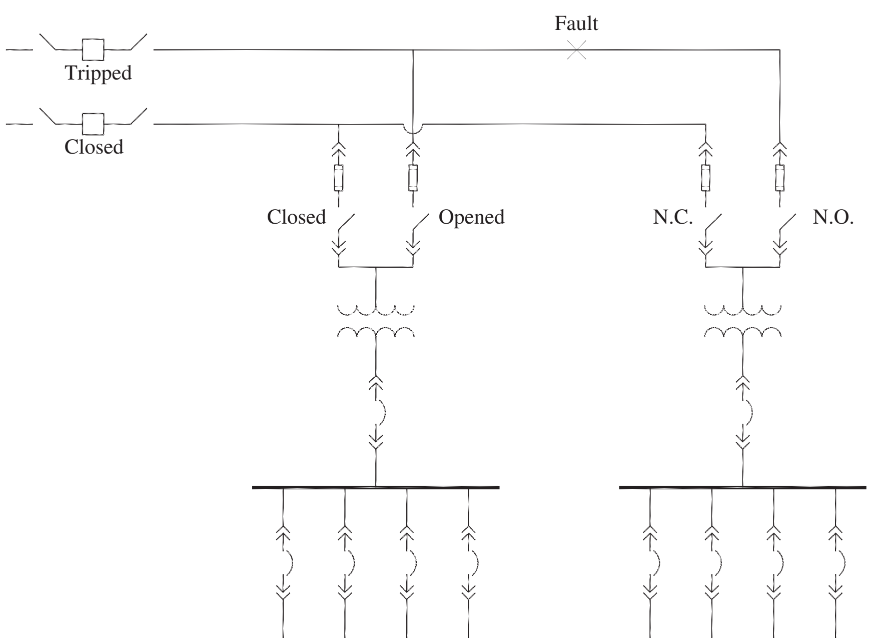


Figure 1.11 Primary Selective System Backup Configuration

The system can be designed such that the switches upstream from the transformers toggle automatically when necessary. This feature is called *automatic source transfer*. Automatic source transfer can be accomplished by a *fast transfer* or by an *open* or *closed transfer*. A *fast transfer* involves opening the first source breaker then closing the second source breaker very quickly. A brief de-energized period exists during the transfer. If most of the motor load is driving high-inertia loads such as fans, completing the transfer in less than six cycles (0.1 seconds) should prevent running motors from slowing to the point where an out-of-phase condition at re-energization produces dangerously high torques that could damage the driven loads. But if many of the motors are driving low-inertia loads such as centrifugal pumps, the transfer must be completed even faster to prevent damage due to transient torques. It is good practice to use specialized relays designed for motor bus transfers to assure that the transition does not produce dangerous torques.

If a fast transfer cannot be achieved, an *open transfer* can be used, where the first source breaker is opened and the running motors are allowed to slow down. When the residual voltage is 25% or less of the nominal system voltage, the second source breaker is closed. Torques generated during re-energization are tolerable because of the decayed residual voltage. A *closed transfer* briefly parallels the two sources before opening the first source breaker. Due to the reduced source impedance while the two sources are paralleled, interrupting requirements may be very high. A decision may be made to accept the risk of exceeding equipment-interrupting ratings during the transfer period, because the probability of a fault occurring during this brief period is very small. Closed transfers frequently are used to switch sources for maintenance purposes. Unless a closed transfer method is used, there will be an interruption of service until the backup source can be connected.

Because of the extra equipment required (cable, fuses, and switchgear), the primary selective scheme is more costly than the radial system. Depending on the voltage and the method of transfer, the primary selective scheme may be more or less costly than the ring bus. A detailed economic analysis is required to determine the lowest cost option.

Another method of increasing reliability is to implement a *primary loop* system. One variation of the primary loop system is shown in Figure 1.12. In this example, the primary loop supplies three radial bus substations. Circuit breakers supply both ends of the primary loop, and switches are installed in the loop for isolation purposes.

While similar to the primary selective system, this scheme utilizes two independent sources that are operated in parallel. This mode of operation greatly increases reliability and flexibility and also increases the complexity of the protection systems required. The reliability is high, and in many applications, justifies the cost.

If a fault occurs in or downstream from one of the transformers, the power fuses on the primary transformer will blow to clear the fault. If a fault occurs in the loop itself, both circuit breakers will trip, thus de-energizing the entire system. Next, the fault must be located, and a pair of switches must be opened to isolate the fault. Then, both breakers can be reclosed, energizing the unfaulted portions of the system.

Reliability, both a reduction in amount of load interrupted and a substantial reduction in the restoration time for the interrupted load, can be improved by taking one or more measures. Designating one of the isolation switches as a normally open

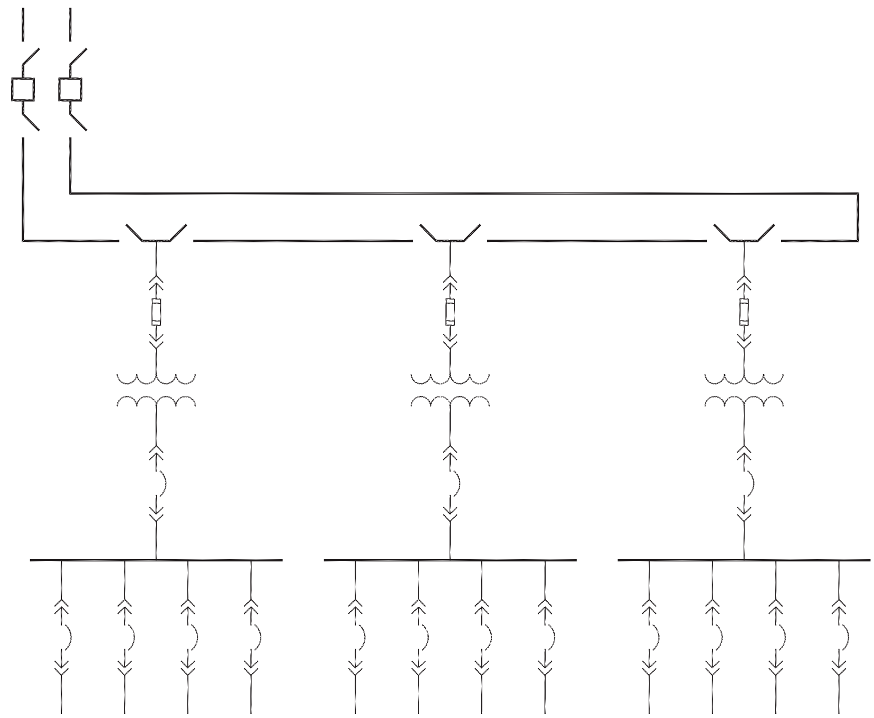


Figure 1.12 Primary Loop System

point, as in Figure 1.13, would result in dropping only half the load when a loop fault occurs. Theoretically, the normally open switch should be located near the null current point—the point on the loop where the current would equal zero if the loop were closed. Additionally, the isolation switches can be automated for automatic sectionalizing of the system after a fault. This measure reduces interruption time dramatically, possibly to less than a minute.

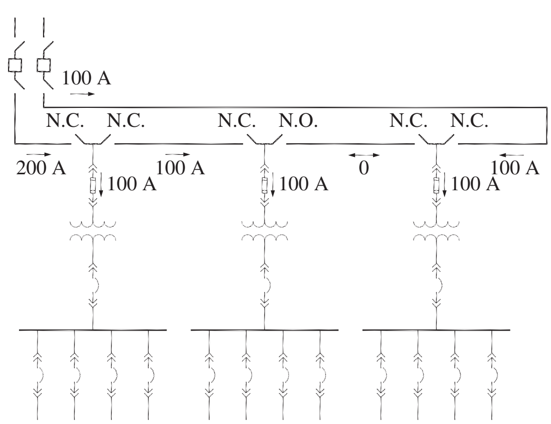


Figure 1.13 Primary Loop System with Normally Open Point

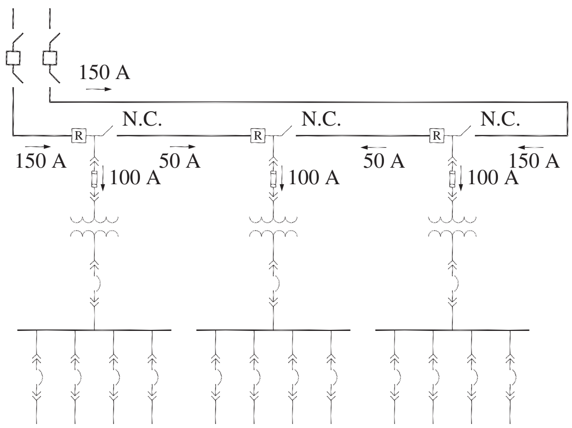


Figure 1.14 Primary Loop System with Reclosers

Another option would be to operate the loop in closed mode (with no normally open point) and install isolation devices capable of interrupting fault current, as in Figure 1.14. A recloser would be an example of an isolation device capable of interrupting fault current. Intelligent reclosers capable of communicating with other reclosers, relays, and motor-operated switches can be used to develop a highly reliable and fully automated system.

When a voltage transformation is made at the delivery point, reliability also can be increased by tying the secondaries of the source transformers together in either a *secondary selective* arrangement, a *secondary spot network*, or by utilizing *tie breakers* and/or *sparing transformers*.

The *secondary selective system*, shown in Figure 1.15, is essentially a normally open bus tie between two secondary buses which is closed either manually or automatically when one source fails.

When a transformer fault occurs, the high-side and low-side breakers trip to isolate the transformer. After the low-side bus is de-energized, the normally open tie breaker can close to re-energize the bus normally fed by the failed transformer.

With this system, both transformers must be sized such that each is capable of serving the entire secondary load for a predetermined period of time. Many

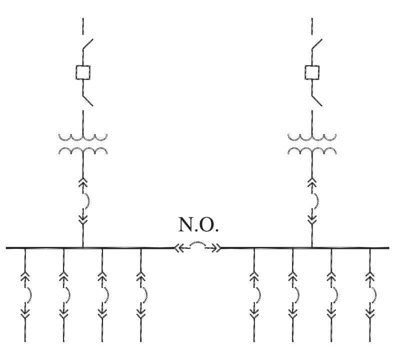


Figure 1.15 Secondary Selective System

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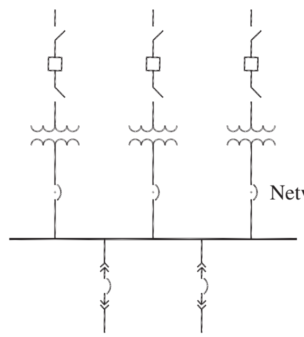

Figure 1.16 Secondary Spot Network

times, a degree of overloading is allowed and the resulting loss of transformer life is accepted.

The tie breaker can be operated normally closed, but this parallels the transformers which greatly increases the SCA. The increase in fault current magnitude usually requires more costly equipment with higher short circuit ratings.

A *secondary spot network*, shown in Figure 1.16, parallels multiple sources.

To prevent backfeeding from the secondary to the source, *network protectors* are used between the transformers and the secondary bus. A network protector is essentially a circuit breaker with a reverse-power relaying package incorporated. If a power flow from secondary to primary is sensed, the network protector opens. While this scheme is feasible when the load density is very high, the extra cost of the network protectors and redundant transformer capacity make this scheme quite expensive.

A *sparing transformer* can be used to protect against the loss of a source. In addition to the expense of the sparing transformer, which is normally not loaded, considerable cabling, circuit breakers, and a tie bus are all required. These items often make the sparing transformer scheme economically unattractive, but the increase in reliability afforded by a spare transformer installed and ready to supply load may offset the economics. The sparing transformer configuration is shown in Figure 1.17.

1.6 THE PER-UNIT SYSTEM

Due primarily to the abundance of transformers in power systems, many power system problems can be tedious to solve using electrical units. This is because, the transformer turns ratio changes the electrical quantities of voltage, current, and impedance differently. If the transformer turns ratio is n, as one moves from the high-voltage side of the transformer to the low-voltage side, the voltage changes by $1/n$, the current changes by n, and the impedance changes by $1/n^2$. These different factors can make even simple calculations rather complicated.

The complications introduced by the transformer turns ratios can be avoided by applying the *per-unit system*. The per-unit system uses dimensionless quantities instead of electrical units (volts, amps, ohms, watts, etc.). The per-unit system, when properly applied, also changes all transformer turns ratios to 1. This way, as one

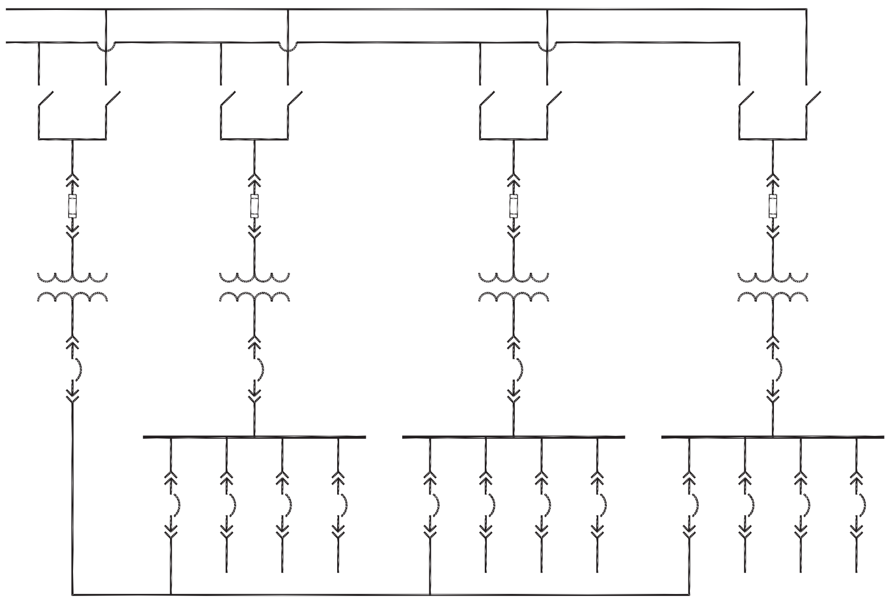

Figure 1.17 Sparing Transformer

moves from the high-voltage side of the transformer to the low-voltage side, the voltage, current, and impedance are all unaffected.

The per-unit system relies on the establishment of four *base quantities*. The required base quantities are *base power*, *base voltage*, *base current*, and *base impedance*. The base quantities are selected by the person doing the problem. The numeric values of these base quantities are arbitrary. This is because the per-unit system is a linear transformation. The problem to be solved is transformed into the per-unit system, solved, and then transformed back to electrical quantities. Since the transformation back to electrical quantities is the inverse of the transformation into the per-unit system, the base quantities which define the transformations can assume any numeric value, except zero.

Of the four base quantities, two are mathematically independent. The other two are then defined by the first two. For example, if voltage and current are assumed to be independent, power can be thought of as the product of voltage and current, and impedance as the quotient of voltage and current. The typical way to apply the per-unit system is to arbitrarily assign the power and voltage bases, then using the mathematical relationships between the electrical quantities to determine the current and impedance bases.

Typically, the base power (kVA or MVA base) is selected arbitrarily, often as 10 or 100 MVA. Or, the power base can be selected to match the kVA rating of a particular piece of equipment, such as a transformer. The power base is constant through the entire system. The base voltage (kV base) is arbitrary, but is frequently assigned as the nominal operating voltage at a given bus in the system. At every voltage transformation, the base voltage is adjusted by the transformer turns ratio.

Therefore, many different base voltages may exist throughout the system. The proper selection of voltage bases throughout the system found by multiplying the base voltage in one circuit by the turns ratio of the transformer connecting that circuit to another circuit effectively makes the transformer turns ratios equal to one and merges the two electric circuits into one.

After the power and voltage bases are chosen, the other two base quantities can be calculated from the established bases by using the formulas

$$\text{Base Current} = \frac{\text{Base kVA}_{3\Phi}}{\sqrt{3} \times \text{Base kV}_{\text{L-L}}} \tag{1.1}$$

and

$$\text{Base Impedance} = \frac{(\text{Base kV}_{\text{L-L}})^2}{\text{Base MVA}_{3\Phi}} \tag{1.2}$$

where the subscripts 3Φ and L–L respectively denote three-phase power and line-to-line voltage.

Actual electrical quantities are converted to dimensionless per-unit quantities using the formula

$$\text{Per-Unit Quantity} = \frac{\text{Actual Quantity}}{\text{Base Quantity}} \tag{1.3}$$

Often, a per-unit quantity must be converted from a particular base to a new base. Toward that end, we use the relationship

$$\begin{aligned}&\text{Per-Unit Quantity}_{\text{New}} = \\ &\text{Per-Unit Quantity}_{\text{Old}} \times \left(\frac{\text{kV Base}_{\text{Old}}}{\text{kV Base}_{\text{New}}}\right)^2 \times \left(\frac{\text{kVA Base}_{\text{New}}}{\text{kVA Base}_{\text{Old}}}\right).\end{aligned} \tag{1.4}$$

Examples

1. A generator has an impedance of 2.65 Ω. What is its impedance in per-unit, using bases of 500 MVA and 22 kV?

Solution:

Calculate the base impedance using Eq. (1.2).

$$\text{Base Impedance} = \frac{(\text{Base kV}_{\text{L-L}})^2}{\text{Base MVA}_{3\Phi}} = \frac{22^2}{500} = 0.968\ \Omega$$

Calculate per-unit impedance using Eq. (1.3).

$$\text{Per-unit impedance} = \frac{\text{Actual impedance}}{\text{Base impedance}} = \frac{2.65\ \Omega}{0.968\ \Omega} = 2.738 \text{ p.u.}$$

2. A transformer rated 12/16/20 MVA, 44/13.2 kV has an impedance of 6.25%. What is its percent impedance on 100 MVA and 46 kV bases?

Solution:

For transformers with multiple stages of cooling, the *self-cooled* (lowest) MVA rating (12 in this case) is always used.

Convert to new per-unit bases using Eq. (1.4).

$$\text{Per-Unit Quantity}_{\text{New}} = \text{Per-Unit Quantity}_{\text{Old}} \times \left(\frac{\text{kV Base}_{\text{Old}}}{\text{kV Base}_{\text{New}}}\right)^2 \times \left(\frac{\text{kVA Base}_{\text{New}}}{\text{kVA Base}_{\text{Old}}}\right)$$

$$= 6.25\% \times \left(\frac{44\ \text{kV}}{46\ \text{kV}}\right)^2 \times \left(\frac{100\ \text{MVA}}{12\ \text{MVA}}\right) = 47.65\%$$

3. Consider the power system shown in Figure 1.18:

Rated Voltages:
- Utility Source: 12.47 kV
- Generator: 460 V

Transformers
- T1: 13.2 kV/4.16 kV
- T2: 460 V/4 kV
- T3: 4.16 kV/480 V

Motors
- M1: 4000 V
- M2: 460 V

Let the base voltage at Bus 1 be 4.16 kV. Find the base voltage at

a. the utility connection point;
b. the generator terminals; and
c. Bus 2.

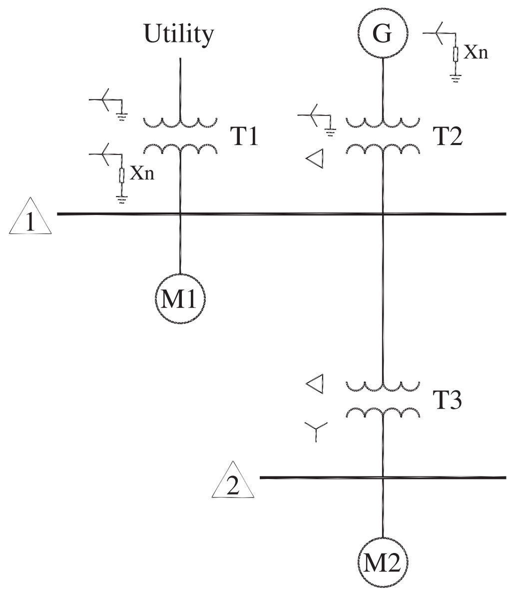

Figure 1.18 Per-Unit Example

Solution:

a. Starting with the given base voltage at Bus 1 and applying the turns ratio of transformer T1,

$$\mathrm{V}_{\text{base (Utility)}} = 4.16\ \mathrm{kV}\left(\frac{13.2\ \mathrm{kV}}{4.16\ \mathrm{kV}}\right) = 13.2\ \mathrm{kV}$$

b. Starting with the given base voltage at Bus 1 and applying the turns ratio of transformer T2,

$$\mathrm{V}_{\text{base (Generator)}} = 4.16\ \mathrm{kV}\left(\frac{460\ \mathrm{V}}{4000\ V}\right) = 478.4\ \mathrm{V}$$

c. Starting with the given base voltage at Bus 1 and applying the turns ratio of transformer T3,

$$\mathrm{V}_{\text{base (Bus 2)}} = 4.16\ \mathrm{kV}\left(\frac{480\ \mathrm{V}}{4160\ \mathrm{V}}\right) = 480\ \mathrm{V}$$

Notice that the base voltage is independent of rated voltage, nominal voltage, actual voltage, or any other voltage quantity. It is simply a number to use in a mathematical transformation—nothing more. Since the same numeric value is used when performing the inverse transformation (per-unit back to electrical units), its value is arbitrary. It is essential, however, that after a base voltage is arbitrarily assigned at one bus, the other voltage bases are determined based on that voltage using transformer turns ratios, as in this example.

1.7 POWER IN AC SYSTEMS

Power in AC systems is calculated like in DC systems as the product of voltage and current. But since voltage and current each vary sinusoidally with time, this seemingly simple multiplication is worthy of some analysis. Begin in the time domain by letting

$$v(t) = V_{\mathrm{m}} \cos(\omega t + \theta_v) \tag{1.5}$$

and

$$i(t) = I_{\mathrm{m}} \cos(\omega t + \theta_i) \tag{1.6}$$

Then the total (or *complex*) power $s(t)$ is

$$s(t) = v(t) \cdot i(t) = V_{\mathrm{m}} I_{\mathrm{m}} \cos(\omega t + \theta_v) \cos(\omega t + \theta_i) \tag{1.7}$$

Applying the product of cosines property,

$$s(t) = \frac{V_{\mathrm{m}}\, I_{\mathrm{m}}}{2}[\cos(\theta_v - \theta_i) + \cos(2\omega t + \theta_v + \theta_i)]. \tag{1.8}$$

Notice that the first cosine term in Eq. (1.8) is not a sinusoid but a constant, and the second cosine term is a sinusoid that oscillates at twice the frequency of the voltage and the current. Noting that the 2 in the denominator can be factored into

$\sqrt{2} \times \sqrt{2}$ and rearranging the argument terms in the second cosine function to force a $(\theta_v - \theta_i)$ term as in the first cosine function,

$$s(t) = \frac{V_{\mathrm{m}}}{\sqrt{2}} \cdot \frac{I_{\mathrm{m}}}{\sqrt{2}} \cdot \{\cos(\theta_v - \theta_i) + \cos[2(\omega t + \theta_v) - (\theta_v - \theta_i)]\}. \tag{1.9}$$

Writing the magnitudes as RMS values and applying the cosine of a difference property,

$$\begin{aligned} s(t) = V_{\mathrm{rms}}\, I_{\mathrm{rms}} \langle \cos(\theta_v - \theta_i) + \{&\cos[2(\omega t + \theta_v)] \cos(\theta_v - \theta_i) \\ &+ \sin[2(\omega t + \theta_v)] \sin(\theta_v - \theta_i)\}\rangle \end{aligned} \tag{1.10}$$

The first term $\{V_{\mathrm{rms}}\ I_{\mathrm{rms}} \cos\ (\theta_v - \theta_i)\}$ represents the constant component of the real power (P), a DC offset with a magnitude equal to half the peak-to-peak magnitude of the second term. This DC offset keeps the real power sinusoid positive or zero at all times.

The second term $\{V_{\mathrm{rms}}\ I_{\mathrm{rms}} \cos\ (\theta_v - \theta_i)\cos[2(\omega t + \theta_v)]\}$ represents the oscillating component of the real power. When the second term is added to the first term, the resulting expression for the real power component oscillates at twice the frequency of the voltage and current sinusoids and is positive or zero at all times.

The third term $\{V_{\mathrm{rms}} I_{\mathrm{rms}} \sin(\theta_v - \theta_i)\sin[2(\omega t + \theta_v)]\}$ represents the reactive power (Q). The reactive power oscillates at twice the frequency of the voltage and current sinusoids, is centered about the x-axis, and lags the real power sinusoid by 90°.

Therefore, $s(t) = P + P\cos[2(\omega t + \theta_v)] + Q\sin[2(\omega t + \theta_v)]$. The total power $s(t)$ and its real and reactive components are shown in Figure 1.19 for $V_{\mathrm{m}} = 10$ V, $I_{\mathrm{m}} = 7$ A, and $\theta_i = -26°$. The voltage $v\ (\omega t)$ and the current $i\ (\omega t)$ are shown as a reference.

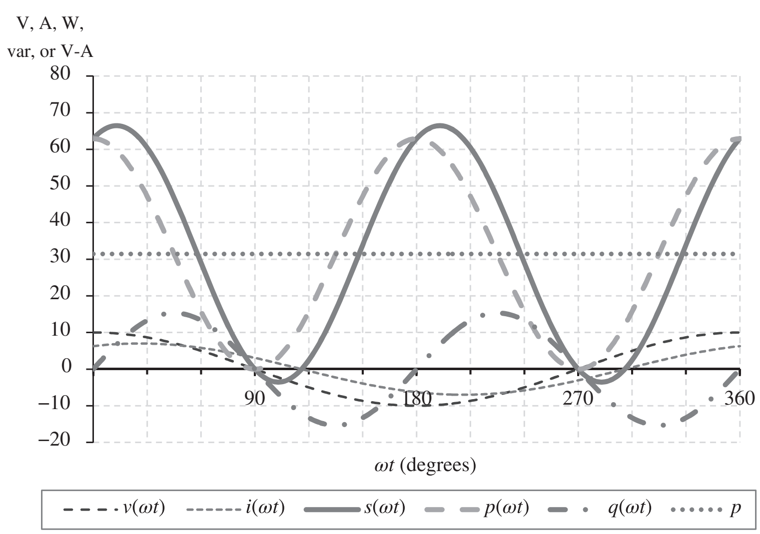

Figure 1.19 Components of AC Power

The total power curve $S(t)$ dips below the x-axis as the power factor drops from unity. This is significant, as the area under the power curve represents energy and any area below the x-axis deducts from the total energy.

Expressing $s(t)$ as a phasor, the DC offset is ignored since it does not vary with time. Using the second and third terms of the total power expression and realizing that the cos $[2\,(\omega t + \theta_v)]$ and sin $[2\,(\omega t + \theta_v)]$ terms merely provide time variation, the phasor expression for total power can be written as

$$\begin{aligned}\tilde{S} &= \tilde{P} + j\tilde{Q} = V_{\text{rms}} I_{\text{rms}} \cos(\theta_v - \theta_i) + jV_{\text{rms}} I_{\text{rms}} \sin(\theta_v - \theta_i)\\ &= V_{\text{rms}} I_{\text{rms}} [\cos(\theta_v - \theta_i) + j \sin(\theta_v - \theta_i)]\end{aligned} \tag{1.11}$$

Applying Euler's formula,

$$\begin{aligned}\tilde{S} &= V_{\text{rms}} I_{\text{rms}} e^{j(\theta_v - \theta_i)} = V_{\text{rms}} e^{j\theta_v} \cdot I_{\text{rms}} e^{-j\theta_i} = V_{\text{rms}} \angle \theta_v \cdot I_{\text{rms}} \angle -\theta_i\\ &= \tilde{V}_{\text{rms}} \cdot \tilde{I}^*_{\text{rms}}\end{aligned} \tag{1.12}$$

Note that it is the current phasor that is conjugated while the voltage phasor is used directly.

1.8 VOLTAGE DROP CALCULATIONS

Voltage drop in an AC power system occurs as predicted by Ohm's law. As a current flows through an impedance, a voltage drop occurs:

$$V_{\text{drop}} = I \times Z \tag{1.13}$$

Recalling that the current I is a phasor and the impedance Z consists of a real component (resistance) and an imaginary component (reactance), Eq. (1.13) can be restated as

$$\begin{aligned}V_{\text{drop}} &= I \times Z = (I_{\text{R}} + jI_{\text{X}}) \times (R + jX)\\ &= (I_{\text{R}} \times R) + (I_{\text{R}} \times jX) + (jI_X \times R) + (jI_{\text{X}} \times jX)\\ &= (I_{\text{R}} R - I_{\text{X}} X) + j(I_{\text{R}} X + I_{\text{X}} R)\end{aligned} \tag{1.14}$$

Since the imaginary term is in quadrature with the real component of the voltage, its effect on the overall voltage magnitude is much smaller than that of the first term. So a reasonable approximation for voltage drop is to consider only the real part of the total voltage drop:

$$V_{\text{drop}} \approx \text{Re}\{V_{\text{drop}}\} = I_{\text{R}} \times R - I_{\text{X}} \times X = \text{Re}\{I\} \times R - \text{Im}\{I\} \times X \tag{1.15}$$

Note that the real component of the current, or the component of the current in-phase with the voltage, produces a voltage drop across the resistance, and the reactive component of the current, or the component of the current in quadrature with the voltage, produces a voltage drop across the reactance. These fundamental concepts are important to remember when doing many types of calculations, power factor correction to name one.

When calculating voltage drop in power systems, the per-unit system is very advantageous, particularly when transformers are present. As current flows through a

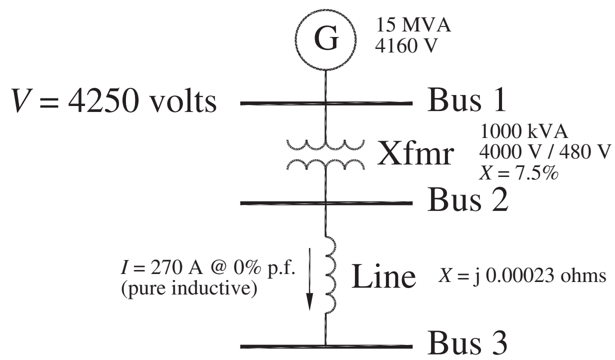

Figure 1.20 Voltage Drop Example

transformer, it effectively exits one electric circuit and enters another. In addition, the transformer windings, through which the current flows, have impedance (generally $X \gg R$). This means a change in voltage occurs due to both the turns ratio of the transformer and the voltage drop across the transformer impedance. The per-unit system makes capturing both of these voltage drop components very easy. Consider the example shown in Figure 1.20.

To calculate the voltage on Bus 3, the per-unit system can be used as follows. First, choose an MVA base to use for this problem. This selection is arbitrary, so a convenient value of 10 MVA is chosen. Keep in mind that this base MVA applies to the entire system being studied.

Next, a voltage base is selected for one of the buses. This choice, too, is arbitrary, so we will define the nominal voltage of Bus 1 (4160 V) as the base voltage of Bus 1. That voltage base of 4160 V applies to the entire circuit containing Bus 1, which in this case is Bus 1 and the generator.

Moving through the transformer takes us to a second electric circuit. That circuit, consisting of Bus 2, the line, and Bus 3, must also have a base voltage assigned, but this assignment is not arbitrary. In order to essentially make the transformer turns ratio become 1:1, the base voltage of Bus 2 must be a function of both the Bus 1 voltage base and the transformer turns ratio. Specifically,

$$V_{\text{base (Bus 2)}} = V_{\text{base (Bus 1)}} \times \frac{480}{4000} = 4160 \times \frac{480}{4000} = 499.2\ \text{V} \tag{1.16}$$

This base voltage of 499.2 V applies to the entire circuit containing Bus 2.

Next, all impedances must be converted to per-unit values. The transformer reactance is given as 7.5%, or 0.075 p.u., but this per-unit value was determined on the transformer's power and voltage bases (1 MVA and 4000 V/480 V), not the bases we are using in this problem (10 MVA and 4160 V/499.2 V). So we can use Eq. (1.4) to convert the 0.075 p.u. to the appropriate bases:

$$X_{\text{xfmr}} = 0.075 \times \left(\frac{4000}{4160}\right)^2 \times \left(\frac{10}{1}\right) = 0.6934\ \text{p.u.} \tag{1.17}$$

Note that the voltage correction term of Eq. (1.17) could have been the quotient squared of 480 and 499.2 instead of 4000 and 4160, as each represents the same value.

Then, the reactance of the line (j 0.00023 Ω) can be converted to per-unit by dividing it by the base impedance in this circuit. The base impedance is found using Eq. (1.2). The per-unit reactance of the line is

$$X_{\text{line}} = \frac{0.00023}{\left(\dfrac{0.4992^2}{10}\right)} = 0.00023 \times \left(\frac{10}{0.4992^2}\right) = 0.0092 \text{ p.u.} \tag{1.18}$$

Now the Bus 1 voltage can be converted to per-unit by dividing the actual voltage by the base voltage.

$$V_{\text{Bus 1}} = \frac{4250}{4160} = 1.0216 \text{ p.u.} \tag{1.19}$$

Next, the current can be converted to per-unit by dividing the actual current by the base current:

$$I = \frac{270}{\left(\dfrac{10{,}000}{0.4992\ \sqrt{3}}\right)} = 270 \times \left(\frac{0.4992\ \sqrt{3}}{10{,}000}\right) = 0.0233 \text{ p.u.} \tag{1.20}$$

Now that every electrical quantity has been converted to per-unit, the voltage drop calculation can be done easily using Ohm's law:

$$V_{\text{Bus 3}} = 1.0216 - 0.0233(0.6934 + 0.0092) = 1.0052 \text{ p.u.} \tag{1.21}$$

The final step is to convert the per-unit answer back to electrical units (volts) by multiplying it by the base voltage.

$$V_{\text{Bus 3}} = 1.0052 \text{ p.u.} \times 0.4992 \text{ V} = 501.8 \text{ V} \tag{1.22}$$

1.9 SHORT-CIRCUIT AVAILABILITY

The major source of short circuit current in an industrial plant is the utility source. Remote utility generators are often located in very large generating stations far from the industrial plant. When a short circuit occurs in the industrial plant, the fault current appears as an additional increment of load current to the remote generators, so the station simply furnishes the extra power requirement.

Some depression of voltage will occur at the utility level when a fault occurs in the industrial plant. To model the "stiffness" of the utility source, a Thévenin equivalent is derived for the source. An ideal voltage source, or *infinite bus*, is modeled in series with a *system impedance.* The system impedance consists of a resistance in series with an inductive reactance. In a typical power system, the reactance component is much larger than the resistance component, so the X to R ratio (X/R) is high—X many times exceeding R by more than an order of magnitude. If the utility X/R is not known, it can be assumed to be infinite ($X = Z$, $R = 0$). This Thévenin equivalent accurately represents the voltage drop seen at the utility level when a fault occurs downstream.

The system impedance varies considerably throughout the interconnected power system. The lower the system impedance, the stronger or *stiffer* the system is at that location. In other words, the voltage at a stiff location in the system will drop less than the voltage at a less stiff location for the same fault. One would expect lower system impedances on higher voltage systems close to strong generation sources than on lower voltage systems far removed from strong generation sources. Starting a motor on a stiff system produces less of a voltage drop than on a weaker system. But fault currents will be higher on a stiff system than on a weaker system.

System impedances frequently are expressed in per-unit values. An arbitrary MVA base is selected, often 10 MVA or 100 MVA. A kV base is chosen equal to the nominal operating voltage at the delivery point. From these two bases, all other per-unit bases are derived.

The system impedance is inversely related to the SCA of the source: the lower the system impedance, the higher the fault current contribution from the source. In fact, when doing per-unit calculations, the per-unit system impedance is the base MVA divided by the SCA in MVA.

$$Z_{\text{p.u.}-\text{system}} = \frac{\text{MVA}_{\text{base}}}{\text{SCA}_{\text{MVA}}} \tag{1.23}$$

The lower the system impedance, the larger the load can be without excessively depressing the source voltage. This is a key factor when starting large motors since the heavy starting current can cause large voltage drops if the system impedance is too high.

The system impedance represents the Thévenin (effective) impedance located between the remote generator bus and the bus of interest. It is the Thévenin impedance that determines the SCA at any point in the system as well as the voltage drop experienced when a given amount of current flows past any point in the system.

1.10 CONDUCTOR SIZING

Electrical conductors are sized in such a way to produce a specific temperature rise at a particular loading. Heating of a conductor is a function of its resistance and the current passing through it according to the relationship

$$P = I^2R \tag{1.24}$$

where

P represents the power dissipated in the form of heat

I is the current passing through the conductor

R is the resistance of the conductor.

Resistance is determined by the equation

$$R = \frac{\rho L}{A} \tag{1.25}$$

where

ρ is the *resistivity* of the conductor,

L represents the conductor's length, and

A represents the conductor's cross-sectional area.

Resistivity depends on the material of which the conductor is made. The resistivity of hard-drawn copper at 20°C is 1.77×10^{-8} Ω-m. This value is lower than that of aluminum at 20°C (2.83×10^{-8} Ω-m), since copper is the better conductor of the two metals. Silver, the best conducting metal known, has a resistivity of 1.59×10^{-8} Ω-m. Because of its very low resistivity, silver plating is often used where resistance must be minimized such as switchgear bus joints and circuit breaker terminals, as long as the environment in which the equipment is installed is chemical friendly toward silver (more on this in Chapter 7).

The resistance of a conductor is directly proportional to its length, but since physical requirements typically determine the required length of a conductor, length usually cannot be varied to control resistance. The cross-sectional area of the conductor is a parameter that can be varied to change the conductor's resistance. By increasing the cross-section of the conductor, the resistance decreases proportionally. This means that for a given temperature rise, a larger conductor can carry more current than a smaller conductor. While this is a rather obvious conclusion, good judgment should be exercised when applying this principle. As conductors become very large, they become unwieldy and difficult to install. Insulated cables require more insulation to cover large conductors, which greatly increases the cost of the cable. Also, the tendency for current density to be higher near the surface of a conductor than closer to the center, or *skin effect*, becomes an important consideration with very large conductors, since the skin depth at 60 Hz is on the order of 1 cm. These concerns suggest that using multiple smaller conductors per phase may be a more practical option than using one large conductor per phase.

Skin depth (δ) is defined as the depth below the surface of the conductor at which the current density falls to 1/e or about 36.8% of its density at the conductor surface. The classical formula for calculating skin depth in meters is

$$\delta = \frac{1}{\sqrt{\pi f \sigma \mu}} \text{ (meters)} \tag{1.26}$$

where

f is the frequency in hertz

σ is the conductivity of the conductor in meters/ohm-meter^2

μ is the permeability of the conductor in henrys/meter.

Equation (1.26) can be manipulated to incorporate more readily available values. Replacing conductivity with the reciprocal of resistivity (ρ),

$$\delta = \frac{1}{\sqrt{\pi f \frac{1}{\rho} \mu}} \tag{1.27}$$

Rearranging terms,

$$\delta = \frac{1}{\sqrt{\pi}} \sqrt{\frac{\rho}{f\,\mu}} \tag{1.28}$$

Expressing the permeability as the product of permeability of free space (μ_o) and the relative permeability of the conductor (μ_r),

$$\delta = \frac{1}{\sqrt{\pi}} \sqrt{\frac{\rho}{f\,\mu_o\,\mu_r}} \tag{1.29}$$

Normalizing the resistivity to the resistivity of copper (ρ_{cu}),

$$\delta = \sqrt{\frac{\rho_{cu}}{\pi}} \sqrt{\frac{\frac{\rho}{\rho_{cu}}}{f\,\mu_o \mu_r}} \tag{1.30}$$

Rearranging terms,

$$\delta = \sqrt{\frac{\rho_{cu}}{\pi \mu_o}} \sqrt{\frac{\frac{1}{\mu_r} \cdot \frac{\rho}{\rho_{cu}}}{f}} \tag{1.31}$$

Substituting numerical values into the first radical of Eq. (1.31) and expressing length units in centimeters, skin depth can be calculated using Eq. (1.32):

$$\delta = 6.6 \sqrt{\frac{\frac{1}{\mu_r} \cdot \frac{\rho}{\rho_{cu}}}{f}} \text{ (centimeters)} \tag{1.32}$$

where

μ_r is the relative permeability of the conductor (typically 1.0)

ρ is the resistivity of the conductor in ohm-meters

ρ_{cu} is the resistivity of copper (1.77×10^{-8} Ω-m)

f is the frequency in hertz

Using Eq. (1.32), the skin depth of aluminum at 60 Hz is found to be 1.049 cm, while the skin depth of copper at 60 Hz is 0.853 cm. Current density more than 1 cm beneath the surface of the conductor will be very low, so ampacity does not increase linearly with conductor size for very large conductors.

Large conductors can be avoided by paralleling two or more smaller conductors per phase. Using too many paralleled conductors can present installation problems; therefore, sound engineering judgment must be used when determining how many cables of what size should be paralleled in a given situation. Sound judgment is best developed by working closely with field personnel and experiencing firsthand which cable configurations work well and which are problematic.

The National Electrical Code (NEC), published by the National Fire Protection Association as NFPA standard 70, is used to size electrical conductors in industrial, commercial, and residential applications. Article 310 of the NEC stipulates minimum conductor sizes for given ampacities. The type of cable and the type of raceway into which the cable is installed affect the allowable ampacity given by the Code. It should be emphasized that these sizes are minimum values and may have to be increased if substantial cable lengths result in large voltage drops. Tables D.1 through D.24 in Appendix D are reprinted from the 2014 edition of the NEC.

Particular attention must be paid to the type of insulation used in the cable, as this determines the maximum allowable conductor temperature. The maximum conductor temperature can range from 60°C to 250°C depending on the materials used in the cable insulation.

Ambient temperature is also an important factor in determining the ampacity of a cable. The NEC ampacity tables are developed for an ambient temperature of 30°C (86°F) or 40°C (104°F), depending on the installation parameters for which the table was derived. As the ambient temperature increases, the cables must be derated per the correction factors shown in the NEC tables. Conversely, as the ambient temperature falls below the referenced ambient temperature, the ampacities can be increased.

1.11 TRANSFORMER SIZING

Determining the kVA rating of any transformer represents a critical decision in the design process. In the case of a main transformer supplying an industrial facility, many unknowns must be assumed prior to ordering the transformer. If the installation is new, the connected kVA load is known but the *diversity* of that load probably is not known. Diversity represents the percentage of the connected load that will be energized at one given time. For example, a switchgear bus may supply six 250-hp motors, but because of the design and operating procedures of the plant, if no more than four of these motors can run at one time, it would be overly conservative to design the electrical system to feed all six motors concurrently. On the other hand, if plant operating practices change, all motors may have to run simultaneously. This dilemma can be difficult to resolve.

Also uncertain are future changes that will occur both in the plant and in the utility system. Although utilities typically prepare planning documents that project 5–10 years into the future, plans can change suddenly and unexpectedly. If an independent power producer builds a 500-MW generating plant near your industrial plant, the SCA at the plant could increase dramatically. Transmission system enhancements could have a similar effect. In addition, business factors could force plant expansions that were not anticipated. All of these scenarios impact the rating of the plant's supply transformer.

A good approach when sizing a main transformer is to make conservative yet realistic assumptions about system change and then determine an expansion plan that can be executed when the main transformer becomes inadequate.

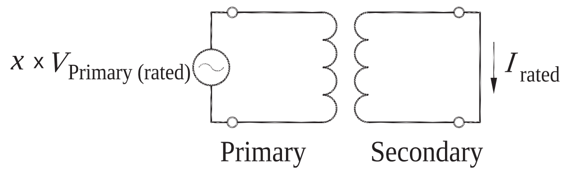

Figure 1.21 Definition of Transformer Impedance

The main transformer at an industrial installation represents substantial impedance in series with the utility (system) impedance. This can be crucial in limiting fault current in the plant to acceptable levels. If the impedance of the main transformer is too high, its voltage regulation will be poor. This will cause unacceptably high voltage drops when starting large motors, or perhaps even during times of heavy load.

A transformer's impedance is an important parameter that helps determine its suitability for a given application. Transformer impedance is expressed in percent based on the self-cooled kVA rating. The impedance is numerically equal to the percentage of rated voltage that would have to be applied across the primary winding to cause rated current to flow in the short-circuited secondary winding. This concept is illustrated in Figure 1.21, where x equals the nameplate value $\%Z$ of the transformer.

Transformer impedance varies according to design parameters, particularly kVA rating and basic lightning impulse insulation level (BIL). In general, impedance increases with kVA rating and also increases with BIL. Most distribution class transformers have an impedance in the 2–10% range, with many falling in the 5.5–7.5% range. Specific designs can cause the impedance to lie outside this range. Since transformer impedance is critical for calculating voltage drop and short circuit magnitudes, actual nameplate data should be used whenever possible.

Two basic types of distribution class transformers exist, each with a different type of insulation system. Insulation must be provided to prevent the winding conductor from short circuiting to the transformer core, to the tank or case, or to an adjacent winding.

Liquid immersed transformers, as shown in Figure 1.22, contain the windings in a tank filled with a dielectric liquid, typically mineral oil. Synthetic materials such as polyalpha olefins and silicone compounds also can be used as dielectric fluids, but mineral oil is the least expensive option. Although mineral oil is the most economical dielectric, it is very flammable. Over the years, attempts have been made to reduce its flammability.

Beginning in 1929, polychlorinated biphenyls (PCBs) were added to mineral oil to raise substantially its flash point, greatly reducing the risk of fire. PCBs were sold in the United States under the trade names *Askarel* (Westinghouse Electric Corporation), and *Pyranol* and *Chrorinol* (General Electric Company). The PCBs, manufactured in the United States solely by Monsanto Company, worked well to reduce fire hazard, but were eventually identified as potential carcinogens. Concern over the toxicity and environmental persistence of PCBs led Congress in 1976 to enact Section 6(e) of the Toxic Substances Control Act (TSCA) that included among other things, prohibitions on the manufacture, processing, and distribution in commerce of PCBs.

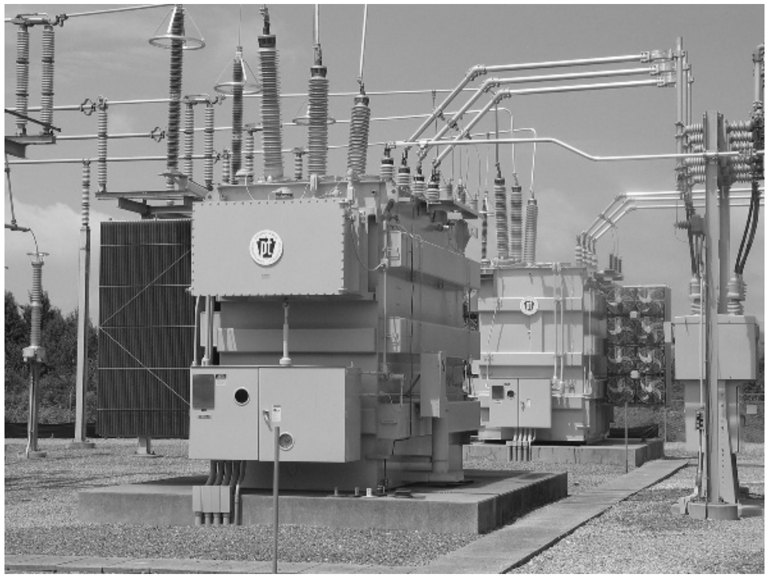

Figure 1.22 Liquid-Immersed Transformer (*Photo courtesy of Pennsylvania* Transformer Technology, Inc.)

The TSCA required "cradle to grave" management of PCBs in the United States, meaning that the equipment owners were completely responsible for any damages that may result from improper handling of the fluids, even after the equipment is discarded. All materials with PCB levels over 50 parts per million were prohibited under the TSCA, and as a result, all electrical equipment containing dielectric fluids with more than 50 parts per million of PCBs could no longer be used in the United States. Other less-flammable synthetic dielectric fluids do not contain PCBs, but because these fluids are very expensive compared to mineral oil, they are used only where the risk of fire must be kept to an absolute minimum.

An alternative to mineral oil that has been gaining popularity in recent years is biodegradable vegetable oil. Although spills are still an environmental concern and oil containment is still required, spilled vegetable oil is not considered a hazardous waste and can be disposed of by ordinary means. Sunflower and safflower seeds are the chief source for these oils, which because of their high percentage content of mono-unsaturated fatty acids, they tend to be very stable when exposed to oxygen. In addition to excellent dielectric properties, vegetable oils have a flash point of around 330°C, which exceeds the flash point of mineral oil by more than 180°C. Because of their better high-temperature performance than mineral oil, vegetable oils show little thermal decomposition in the vicinity of hot-spot locations and when the transformer is overloaded.

The insulation in a liquid immersed transformer is usually a paper or a similar cellulose-based material. This is why the winding temperature of a transformer is so critical. Cellulose breaks down at high temperatures, producing gases such as carbon monoxide and carbon dioxide. Arcing under oil produces acetylene, and other hydrocarbon gases and hydrogen. An overheated steel core will cause hydrogen,

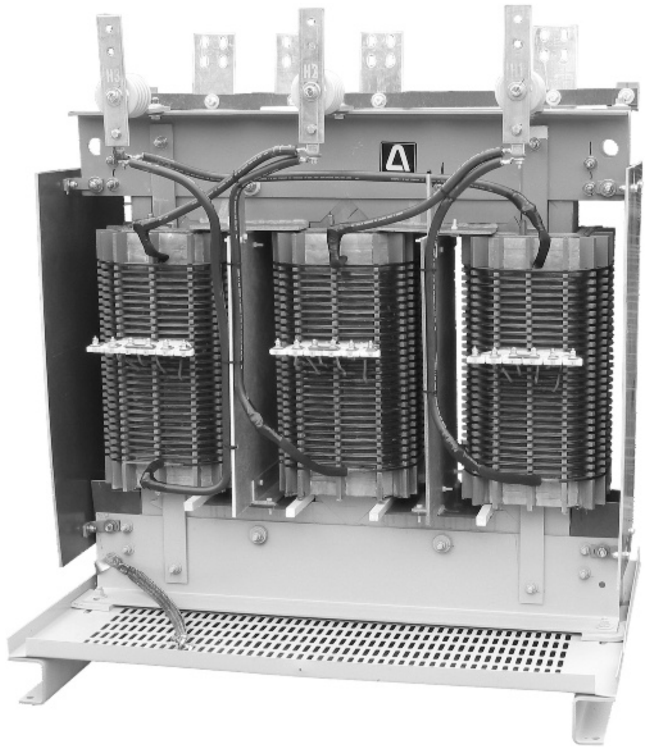

Figure 1.23 Dry-Type Transformer (*Photo courtesy of Alfa Transformer*)

methane, ethane, and ethylene to form in the oil. Low-current sparking under oil forms methane and ethane without increasing acetylene, ethylene, or hydrogen levels. Excessive corona generates hydrogen without increasing hydrocarbon gas levels. By monitoring the levels and types of dissolved gases in transformer oil, the health of the machine can be tracked. It is usually not the amount of a gas, but the rate of increase of a gas level that indicates problems. This is why a regularly scheduled oil analysis program is important. Often, serious problems can be detected before failure occurs, greatly reducing repair cost and equipment downtime.

Dry-type transformers, as shown in Figure 1.23, typically are used in indoor applications, but as environmental restrictions safeguarding against mineral oil leaks become more stringent, dry-type transformers are applied more frequently in environmentally sensitive outdoor locations as well.

Different classifications of dry-type transformers are built including *cast coil, ventilated, enclosed non-ventilated, sealed gas-filled*, and *vacuum pressure impregnated*. Cast coil transformers are more resistant to moisture and airborne dust contamination than other dry types and commonly are used in outdoor or harsh industrial environments. Dry-type transformers typically have lower BIL ratings and are less durable than comparably sized liquid-immersed units, although some manufacturers provide BIL ratings comparable to liquid-immersed units. In spite of these drawbacks, dry-type transformers usually are chosen for indoor and environmentally sensitive outdoor applications, because installing liquid immersed transformers indoors involves very elaborate provisions including fire suppression systems and vault construction.

1.12 LIQUID-IMMERSED TRANSFORMER kVA RATINGS

In theory, many factors limit the amount of power, actually current, that can be handled by a transformer. Current density in the windings and flux density in the core certainly impose limits on power transfer, but these limits are usually academic in practical transformer designs. Long before current density or flux density becomes a problem, thermal issues arise, driving the winding insulation above its design temperature. These thermal issues can be mitigated by improving the heat transfer away from the windings.

Installing radiators as a heat exchanger between the dielectric oil and the air surrounding the transformer enhance heat transfer, thereby increasing the kVA rating of the transformer. As the oil in the main tank heats, it rises and makes its way to the radiators through the upper radiator inlets. When the hot oil enters the radiator, it cools due to enhanced heat transfer with the surrounding air. The cool oil gains density and drops through the radiator tubes to the bottom, where it is drawn back into the main tank by thermosyphonic flow.

The addition of fans on the radiators, as shown in Figure 1.24, and oil pumps, as shown in Figure 1.25, to assist the thermosyphonic flow by forcing the cooled oil back into the transformer tank further enhance heat transfer away from the windings.

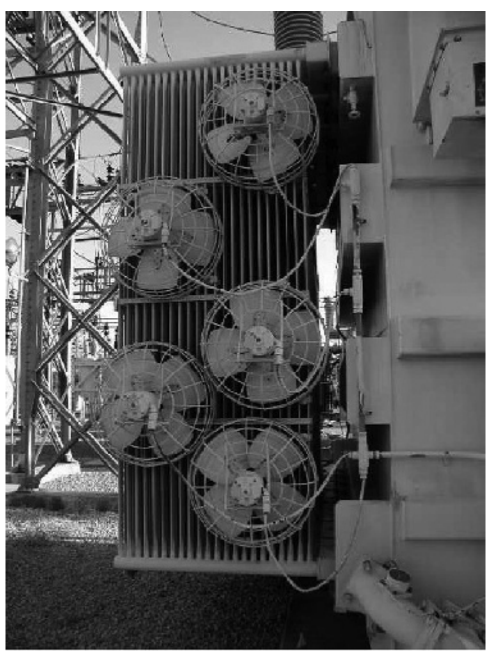

Figure 1.24 Radiator with Fans (*Photo courtesy of Progress Energy*)

JWBS167-c01 JWBS167-Fehr Printer: Yet to Come October 29, 2015 20:29 6.125in×9.25in

Figure 1.25 Oil Pump with Flow Gauge (*Photo courtesy of Progress Energy*)

A four-letter designation is used to describe the cooling class of a liquid-immersed transformer. The first letter describes the internal cooling medium in contact with the windings. The second letter denotes the circulation mechanism for the internal cooling medium. The third and fourth letters indicate the external cooling medium and the circulation method for that medium, respectively. Each level of cooling stipulates a different kVA rating. The lowest (self-cooled) kVA rating is always the value used in per-unit calculations. Institute of Electrical and Electronics Engineers (IEEE) standard C57.12.00 specifies liquid-immersed transformer kVA ratings. Prior to the year 2000, a different designation method was used for cooling classification. The older method was sometime ambiguous, as two different cooling mechanisms could have the same designation. The present cooling designations are more descriptive of the cooling mechanisms used and are shown in Table 1.2, while Table 1.3 shows the designations used prior to the year 2000.

TABLE 1.2 Liquid-Immersed Transformer Cooling Class Letter Designations

Position	Letter	Description
1st	O	Mineral oil or synthetic insulating liquid with fire point ≤300°C
	K	Insulating liquid with fire point >300°C
	L	Insulating liquid with no measurable fire point
2nd	N	Natural convection flow through cooling equipment and in windings
	F	Forced circulation through cooling equipment (i.e., pumps), natural convection flow in windings (also called *nondirected flow*)
	D	Forced circulation through cooling equipment, directed from the cooling equipment into at least the main windings
3rd	A	Air
	W	Water
4th	N	Natural convection
	F	Forced circulation (fans for air, pumps for water)

TABLE 1.3 Comparison of Cooling Class Designations (IEEE Std. C57.12.00-2000 to C57.12.00-1993 and Before)

IEEE Std. C57.12.00-2000 Designation	Previous Designation
ONAN	OA
ONAF	FA
ONAN/ONAF/ONAF	OA/FA/FA
ONAN/ONAF/OFAF	OA/FA/FOA
ONAN/ODAF	OA/FOA
ONAN/ODAF/ODAF	OA/FOA/FOA
OFAF	FOA
OFWF	FOW
ODAF	FOA
ODWF	FOW

SUMMARY

Electricity for an industrial facility is provided by the local utility at a voltage determined by the size of the load and the topology of the utility's system. In general, if the load is small enough to be fed from a single distribution transformer, the facility will likely be served at *utilization voltage*, which is often 480Y/277 V. As the load becomes larger, utilities opt to serve it at subtransmission or transmission voltages as high as 230 kV.

One-line diagrams are used as a simplified means of describing the topology of a power system. Although not truly a circuit diagram, one-lines are often used as a starting point for constructing circuit diagrams. Commonly used one-line diagram symbols were introduced.

Zones of protection are used to assure that a short circuit fault occurring anywhere on the power system can be detected by at least one, and ideally by multiple protective devices. Protection zones must overlap to assure 100% protection coverage.

The configuration of the utility source has a large bearing on the reliability of the service and the cost of the installation. A thorough economic analysis must be done to determine which configuration option provides the best balance between cost and reliability of service. Configurations discussed were the *radial system*, *ring bus*, *primary selective*, *primary loop*, *secondary selective*, *secondary spot network*, and *sparing transformer* schemes.

The *per-unit system* of calculation is used in power systems where transformers are present. The per-unit system effectively makes the turns ratio of each transformer 1:1, allowing the entire power system to be represented as a single electrical circuit. Typically, *base power* and *base voltage* are arbitrarily assigned, and *base current* and *base impedance* are calculated by the formulas provided.

Power in an AC system is the product of two sinusoidally varying terms—voltage and current. The power sinusoid has a frequency twice that of the voltage or current and has three distinct terms: a *constant component of real power*, an *oscillating component of real power*, and *reactive power*. A phasor representation of power, $\tilde{S} = \tilde{V} \cdot \tilde{I}^*$, was also developed.

Voltage drop was examined and the useful approximation of $V_{\text{drop}} \approx \text{Re}\{V_{\text{drop}}\} = I_R \times R - I_X \times X = \text{Re}\{I\} \times R - \text{Im}\{I\} \times X$ was derived.

The utility connection is the largest source of short circuit current. A Thévenin equivalent circuit consisting of an ideal voltage source, or *infinite bus*, in series with a resistance and inductive reactance, or *system impedance*, is derived which describes the *stiffness* of the utility source, or how much voltage drop occurs at the point of delivery. The lower the system impedance, the stiffer the source and the higher the SCA. High SCA is desirable when starting large motors, so the resulting voltage drop is tolerable.

A distribution transformer in series with the utility source greatly reduces SCA by adding considerable impedance to the system. Although transformer impedances lie in a relatively narrow range, it is important to select wisely the proper impedance for a transformer to sufficiently limit fault current without producing an excessive voltage drop. In addition to impedance, the kVA rating of the transformer must be adequate for planned electrical system expansions. Liquid-immersed transformers have multiple kVA ratings based on cooling stages. BIL is also an important consideration when specifying a transformer to assure that insulation levels throughout the system are properly coordinated.

FOR FURTHER READING

IEEE Guide for Performing Arc Flash Hazard Calculations, IEEE Standard 1584, 2002.

IEEE Recommended Practice for Electric Power Distribution for Industrial Plants (Red Book), IEEE Standard 141, 1993.

IEEE Standard General Requirements for Liquid-Immersed Distribution, Power, and Regulating Transformers, IEEE Standard C57.12.00, 1993.

IEEE Standard General Requirements for Liquid-Immersed Distribution, Power, and Regulating Transformers, IEEE Standard C57.12.00, 2000.

Joffe, E. B., and Lock, K. *Grounds for Grounding: A Circuit to System Handbook*. Wiley-IEEE Press, 2010. ISBN: 978-0-471-66008-8.

Nabours, R. E. Dalziel revisited. *Industry Applications Magazine, IEEE*, vol. 15, no. 3, pp. 18–21, May–June 2009.

National Electrical Code, National Fire Protection Association, NFPA 70, 2014.

Standard for Electrical Safety in the Workplace, National Fire Protection Association, NFPA 70E, 2015.

QUESTIONS

1. Propose a methodology for determining the configuration of the utility source for a specific industrial facility.
2. What physical characteristic of a generator limits its ability to produce short circuit current?
3. As more generators are connected to a bus, the SCA rises. Eventually, the SCA will exceed the interrupting ratings of the circuit breakers on the bus. How can this be avoided?

4. A small industrial facility is supplied from a single radial feed through a 10 MVA, 69/4.16 kV transformer. The local utility has a second 69 kV circuit nearby. A major expansion is planned which will triple the facility's electrical demand, so two additional transformers, identical to the first, must be added. Because of the expansion, reliability will be more critical in the future than at present. Propose and justify a new source configuration for this facility.
5. Dissolved gas analysis can be a useful diagnostic tool in determining the health of oil-filled equipment. What are some procedures and practices necessary for a good dissolved gas analysis program?
6. Would you expect the dissolved gas levels to be similar in all oil-filled transformers? In an oil-filled transformer versus an oil circuit breaker? Discuss.
7. Why is fault detection and isolation more complicated with a networked distribution system than with a radial distribution system?
8. In the first six decades of the twentieth century, power system calculations were typically done using *percent* values instead of per-unit values. What were the advantages and disadvantages of using percent values, and why do you suppose the change was made to per-unit values?
9. Explain why the sinusoid representing reactive power is centered about the x-axis, but the sinusoid representing real power is offset by a DC component above the x-axis?
10. Why might a vegetable-based dielectric oil be preferred to a mineral-based oil?
11. What concern must be addressed when operating a secondary selective scheme with its tie breaker normally closed?
12. Why is it essential that zones of protection overlap?
13. List some nonpower engineering examples of applications of the per-unit system.
14. What are some advantages of using a one-line diagram to describe a power system over other types of representations?
15. Explain how the configuration of the electrical source affects both the reliability and the cost of the system.

PROBLEMS

1. A 600 A three-phase four-wire 12.47Y/7.2 kV service is fed from a 69 kV utility source having an SCA of 1800 A. The three-phase fault current at the main 12.47 kV switchgear must be limited to 5500 A. What is the minimum impedance for a 14 MVA transformer that will sufficiently limit the fault current?
2. A transformer has the following nameplate data:

   138/13.8 kV

   12/16/20 MVA

   Reactance = 5.42%

   This transformer will be connected to a 138 kV source to supply a 13.8 kV bus. Calculate the per-unit impedance of this transformer using a 10 MVA base.

3. An industrial plant is to be supplied by three identical transformers. A decision must be made whether to purchase a fourth transformer to build a sparing transformer system as shown in Figure 1.16, or to configure the source as a secondary selective system as shown in Figure 1.14. If the secondary selective option is chosen,

a. how much larger must each transformer in the secondary selective option be compared to each transformer in the sparing transformer option if each transformer is to be able to supply the full plant load in the event that one transformer fails?

b. how many additional circuit breakers must be purchased to provide the necessary bus tie capability for the secondary selective option compared to the sparing transformer option?

4. Source configurations can be combined to increase operating and maintenance flexibility. Sketch a hybrid primary/secondary selective system by combining Figures 1.8 and 1.14. Describe how the system would operate in the event of

a. loss of one of the sources and

b. loss of one of the transformers.

5. A factory currently has six large induction motors connected to 4.16 kV switchgear supplied radially from a single transformer, as in Figure 1.3. A plant expansion is planned, where four more large 4 kV motors must be added. The current switchgear cannot supply all 10 motors, because both the switchgear bus rating and the transformer rating would be exceeded. Propose a 4.16 kV system design to accommodate the new and existing motors.

6. A 1500-ft-long 4.16 kV distribution feeder has an impedance of $(0.02 + j\,0.12)$ Ω/1000 ft. Find its per-unit impedance on a 10 MVA base.

7. A three-phase, 480-V, 100 kVA constant-impedance load operates at 85% lagging power factor. Find its per-unit impedance on a 10 MVA base.

8. Refer to Figure 4.5. Assuming a base power of 10 MVA and a base voltage of 13.8 kV at Bus 1, find the base voltage, base current, and base impedance at Buses 2 and 3, and in the high-voltage circuit of transformer T_1.

9. Repeat Problem 8 assuming a base power of 25 MVA and a base voltage of 13.2 kV at Bus 1.

10. If $v(t) = 170 \cos(377t)$ and $i(t) = 5 \cos(377t - 31.8°)$, find $s(t)$, $\tilde{P}$, $\tilde{Q}$, and $\tilde{S}$. Also sketch the power triangle and calculate the power factor.

11. If $v(t) = 680 \cos(377t + 10°)$ and $i(t) = 25 \cos(377t + 35.8°)$, find $s(t)$, $\tilde{\mathrm{P}}$, $\tilde{\mathrm{Q}}$, and $\tilde{\mathrm{S}}$. Also sketch the power triangle and calculate the power factor.

12. Calculate the voltage drop across a 50 MVA transformer with an impedance of 5% when the transformer is loaded to 90% of its MVA rating at 90% lagging power factor. Assume an X/R ratio of 25.

13. Repeat Problem 12 if the loading is changed to 120% of the transformer's MVA rating at 70% lagging power factor.

14. Calculate the skin depth at 400 Hz of an alloy with a resistivity of 3.25×10^{-8} Ω-m. Assume a relative permeability of 1.

15. Refer to Figure 4.5. Show the necessary zones of protection.