Chapter 7
Short-circuit studies

7.1 Introduction and scope

Electrical power systems are, in general, fairly complex systems composed of a wide range of equipment devoted to generating, transmitting, and distributing electrical power to various consumption centers. The very complexity of these systems suggests that failures are unavoidable, no matter how carefully these systems have been designed. The feasibility of designing and operating a system with zero failure rate is, if not unrealistic, economically unjustifiable. Within the context of short-circuit analysis, system failures manifest themselves as insulation breakdowns that may lead to one of the following phenomena:

— Undesirable current flow patterns
— Appearance of currents of excessive magnitudes that could lead to equipment damage and downtime
— Excessive overvoltages, of the transient and/or sustained nature, that compromise the integrity and reliability of various insulated parts
— Voltage depressions in the vicinity of the fault that could adversely affect the operation of rotating equipment
— Creation of system conditions that could prove hazardous to personnel

Because short circuits cannot always be prevented, we can only attempt to mitigate and to a certain extent contain their potentially damaging effects. One should, at first, aim to design the system so that the likelihood of the occurrence of the short circuit becomes small. If a short circuit occurs, however, mitigating its effects consists of a) managing the magnitude of the undesirable fault currents, and b) isolating the smallest possible portion of the system around the area of the mishap in order to retain service to the rest of the system. A significant part of system protection is devoted to detecting short-circuit conditions in a reliable fashion. Considerable capital investment is required in interrupting equipment at all voltage levels that is capable of withstanding the fault currents and isolating the faulted area. It follows, therefore, that the main reasons for performing short-circuit studies are the following:

— Verification of the adequacy of existing interrupting equipment. The same type of studies will form the basis for the selection of the interrupting equipment for system planning purposes.
— Determination of the system protective device settings, which is done primarily by quantities characterizing the system under fault conditions. These quantities also referred to as "protection handles," typically include phase and sequence currents or voltages and rates of changes of system currents or voltages.
— Determination of the effects of the fault currents on various system components such as cables, lines, busways, transformers, and reactors during the time the fault persists. Thermal and mechanical stresses from the resulting fault currents should always be compared with the corresponding short-term, usually first-cycle, withstand capabilities of the system equipment.

— Assessment of the effect that different kinds of short circuits of varying severity may have on the overall system voltage profile. These studies will identify areas in the system for which faults can result in unacceptably widespread voltage depressions.
— Conceptualization, design and refinement of system layout, neutral grounding, and substation grounding.

Compliance with codes and regulations governing system design and operation, such as the National Electrical Code® (NEC®) (NFPA 70-1996) [B6],[1] article 110-9.

It is not the intention of this chapter to provide details on system modeling and computational procedures under fault conditions, since these topics are exhaustively treated in many comprehensive textbooks and articles (see bibliography) and other IEEE publications such as IEEE Std 141-1993,[2] IEEE Std 241-1990, and IEEE Std 242-1986. Rather, the intention is to address the subject of short-circuit analysis within the context of three-phase industrial and commercial power systems by focusing on the following:

a) The concerns and fundamental phenomena associated with short-circuit studies
b) Viable computational approaches and some aspects of system modeling
c) Various factors affecting the results and accuracy of short-circuit studies
d) The salient principles, methodologies, and computational procedures suggested by the North American IEEE and ANSI C37 standards, specifically, ANSI C37.06-1979, ANSI C37.06-1987, IEEE Std C37.010-1979, IEEE Std C37.5-1979, and IEEE Std C37.13-1990). Reference will, however, be made to the international standard, IEC 60909 (1988), because
    1) It features several significant conceptual and computational deviations from the C37 standards, and
    2) Equipment designed and built according to European specifications is being sold in North America, which should be analyzed on the equipment-tested ratings.
e) Computer-based solutions and related aspects of software dedicated to computerized fault analysis
f) The outline of a typical short-circuit study procedure through an example

7.2 Extent and requirements of short-circuit studies

Short-circuit studies are as necessary for any power system as other fundamental system studies such as power flow studies, transient stability studies, harmonic analysis studies, etc. Short-circuit studies can be performed at the planning stage in order to help finalize the system layout, determine voltage levels, and size cables, transformers, and conductors. For existing systems, fault studies are necessary in the cases of added generation, installation of extra rotating loads, system layout modifications, rearrangement of protection equipment, verification of the adequacy of existing breakers, relocation of already acquired switchgear in order to avoid unnecessary capital expenditures, etc. "Post-mortem" analysis may also

[1]The numbers in brackets correspond to those of the bibliography in 7.9.
[2]Information on references can be found in 7.8.

involve short-circuit studies in order to duplicate the reasons and system conditions that led to the system's failure.

The requirements and extent of a short-circuit study will depend on the engineering objectives sought. In fact, these objectives will dictate what type of short-circuit analysis is required. The amount of data required will also depend on the extent and the nature of the study. The great majority of short-circuit studies in industrial and commercial power systems address one or more of the following four kinds of short circuits:

— *Three-phase fault*. May or may not involve ground. All three phases shorted together.
— *Single line-to-ground fault*. Any one, but only one, phase shorted to ground.
— *Line-to-line fault*. Any two phases shorted together.
— *Double line-to-ground fault*. Any two phases connected together and then to ground.

These types of short circuits are also referred to as "shunt faults," since all four exhibit the common attribute of being associated with fault currents and MVA flows diverted to paths different from the prefault "series" ones.

Three-phase short circuits often turn out to be the most severe of all. It is thus customary to perform only three phase-fault simulations when seeking maximum possible magnitudes of fault currents. However, important exceptions do exist. For instance, single line-to-ground short-circuit currents can exceed three-phase short-circuit current levels when they occur in the vicinity of

— A solidly grounded synchronous machine
— The solidly grounded wye side of a delta-wye transformer of the three-phase core (three-leg) design
— The grounded wye side of a delta-wye autotransformer
— The grounded wye, grounded wye, delta-tertiary, three-winding transformer

For systems where any one or more of the above conditions exist, it is advisable to perform a single line-to-ground fault simulation. The fact that medium- and high-voltage circuit breakers have 15% higher interrupting capabilities for single line-to-ground faults should be taken into account, if elevated single line-to-ground fault currents are found. Line-to-line or double line-to-ground fault studies may also be required for protective device coordination requirements. It should be noted that, since only one phase of the line-to-ground fault can experience higher interrupting requirements, the three-phase fault will still contain more energy because all three phases will experience the same interrupting requirements.

Other types of fault conditions that may be of interest include the so-called "series faults" (Anderson [B1]) and pertain to one of the following types of system unbalances:

— *One line open*. Any one of the three phases may be open.
— *Two lines open*. Any two of the three phases may be open.
— *Unequal impedances*. Unbalanced line impedance discontinuity.

The term "series faults" is used because the above unbalances are associated with a redistribution of the prefault load current. Series faults are of interest when assessing the effects of snapped overhead phase wires, failures of cable joints, blown fuses, failure of breakers to open all poles, inadvertent breaker energization across one or two poles and other situations that result in the flow of unbalanced currents.

7.3 System modeling and computational techniques

7.3.1 AC and dc decrement

The basic physical phenomena that determine the magnitude and duration of the short-circuit currents are

a) The behavior of the rotating machinery in the system
b) The electrical proximity of the rotating machinery to the short-circuit location
c) The fact that the prefault system currents cannot change instantaneously, due to the significant system inductance

The first two can be conceptually linked to the ac decrement, while the third, to the dc decrement.

7.3.1.1 AC decrement and rotating machinery

AC decrement is characterized by the fact that the magnetic flux trapped in the windings of the rotating machinery cannot change instantaneously (constant flux theorem). This gradual change is a function of the nature of the magnetic circuits involved. That is why synchronous machines, under short-circuit conditions, feature different flux variation patterns as compared to induction machines. The flux dynamics dictates that the short-circuit current decays with time until a steady-state value is reached. Computationally convenient machine models, widely used for short-circuit studies, picture rotating machines as constant voltages behind time-varying impedances, as outlined in IEEE Std 141-1993 and IEEE Std 242-1986. For modeling purposes, these impedances increase in magnitude from the minimum post fault subtransient value X''_d, to the relatively higher transient value X'_d, and finally reach the even higher steady-state value X_d, assuming the fault persists long enough (in reality it is the voltage that decays). The rate of increase of machine reactances is different for synchronous generators/motors and induction motors, with the latter increasing more rapidly than the former. This modeling framework is fundamental in properly determining the symmetrical rms values of the short-circuit currents furnished by the rotating equipment for a short circuit anywhere in the system.

7.3.1.2 DC decrement and system impedances

DC decrement is also characterized by the fact that because the prefault system current cannot change instantaneously, a significant unidirectional component may be present in the fault current depending on the exact instant of the occurrence of the short circuit (Anderson [B1], Blackburn [B3], Roeper [B8], Stevenson [B10]). This unidirectional current component, often referred to as dc offset, decays with time exponentially. The rate of decay is closely related to the system reactances and resistances. Despite the fact that this decay is relatively rapid, the dc component could last long enough to be sensed by the interrupting equipment, particularly when rapid fault clearing is very desirable to maintain system stability or prevent the damaging thermal and mechanical effects of the short-circuit currents. Total fault currents interrupted by circuit breakers must take into account this unidirectional component, particularly for shorter interrupting times as clearly outlined in IEEE Std C37.010-1979, IEEE Std C37.13-1990, and IEEE Std C37.5-1979. The same component is equally important when assessing the ability of a circuit breaker to close against or withstand short-circuit currents. Fault currents containing high dc offsets, often present no zero crossings in the first few cycles immediately after fault initiation and are particularly onerous to the circuit breakers of large generators.

7.3.2 System modeling requirements

Industrial and commercial power systems are normally multimachine systems with many motors and possibly more than one generator, all interconnected through transformers, lines, and cables. There could also be one or more locations at which the local power system is interconnected to a larger grid. These locations are commonly known as “utility-interface” points. The objective of the short-circuit study is to properly determine the short-circuit currents and voltages at various system locations. In view of the dynamic nature of the short-circuit current, it is essential to relate any calculated fault currents to a particular instant in time from the onset of the short circuit. AC decrement analysis serves the purpose of correctly determining the symmetrical rms values of the fault currents, while dc decrement analysis will provide the necessary dc component of the fault current, thus yielding a correct estimate of the total fault current. It is the total fault current which, in general, must be used for breaker and switchgear rating and in some cases for protective device coordination. System topology considerations are equally important because the system layout and electrical proximity of the rotating machinery to the fault location will determine the actual magnitude of the short-circuit current. It therefore becomes necessary to devise a model for the system as a whole and analyze it as such in a flexible, accurate, and computationally convenient manner.

7.3.3 Three-phase vs. symmetrical components representation

It is customary for three-phase electrical systems to be represented on a single-phase basis. This simplification, successfully employed for power flow and transient stability studies, rests on the premise that the system is balanced or at least can be assumed to be so for practical purposes (Anderson [B1], Blackburn [B3] Stevenson [B10], Wagner and Evans [B13]). Modeling the system, however, on a single-phase basis is inadequate for analyzing phenomena that involve serious system unbalances (Anderson [B1], Arrilaga, Arnold, and Harker [B2]). Within the context of short-circuit analysis, only the three-phase shunt fault lends itself to single-phase analysis, because the fault condition is balanced involving all three phases, assuming a balanced three-phase system. Any other fault condition will introduce unbalances that require including in the analysis the remaining two phases. There are two alternatives to address the problem:

a) *Three-phase system representation.* When the system is represented on a three-phase basis, we explicitly retain the identity of all three phases. The advantage of three-phase representation is that any kind of fault unbalance can be readily analyzed, including simultaneous faults. Furthermore, the fault condition itself is specified with somewhat greater flexibility, particularly for arcing faults. The main disadvantages of the technique are the following:
    1) It is not tractable for hand calculations, even for small systems.
    2) Supposing that a suitable computer program is used, it can be data-intensive.
b) *Symmetrical components representation.* The symmetrical components analysis is a technique that, instead of requiring analysis of the unbalanced system, allows for the creation of three subsystems, the positive, the negative, and the zero-sequence systems, properly interconnected at the fault point, depending on the nature of the system unbalance. Once modeled, the fault currents and voltages, anywhere in the network, are then obtained by properly combining the results of the analysis of the three-sequence networks (Anderson [B1], Blackburn [B3] Stevenson [B10], Wagner and Evans [B13]). The distinct advantage of the symmetrical components approach is that it allows modeling unbalanced fault conditions, while still retaining the conceptual simplicity of the single-phase analysis. Another important advantage of the symmetrical components method is that system equipment impedances can be easily measured in the symmetrical components reference frame. This simplification is only true if the system is balanced in all three phases (except at the fault location which then becomes the interconnection point of the sequence networks), an assumption that can be entertained without introducing significant modeling errors for most systems. The main disadvantage of the technique is that for complicated fault conditions, it may introduce more problems than it solves. The symmetrical components technique remains the preferred analytical tool today for fault analysis for both hand and computer-based calculations.

7.3.4 System impedances and symmetrical components analysis

The symmetrical components theory dictates that for a three-phase system, three sequence systems need, in general, to be set up for the analysis of an unbalanced fault condition. The first is the positive sequence system, which is defined by a balanced set of voltages and currents, equal in magnitude, following the normal phase sequence of a, b, and c. The second is the negative sequence system, which is similar to the positive sequence system, but is defined by a balanced set of voltages and currents with a reverse phase sequence of a, c, and b. Finally, the zero sequence system is a system defined by a set of voltages and currents that are in phase with each other and not displaced by 120 degrees, as is the case with the other two systems. The topology of the zero sequence system can be quite different from that of the positive and negative sequence systems due to the fact that it depends heavily on the power transformer connections (Anderson [B1], Blackburn [B3] Stevenson [B10]) and system neutral grounding, factors which are not of importance when determining the topology of the other two sequence networks.

Static system equipment like transformers, lines, cables, busways, and static loads present, under balanced conditions, the same impedances to the flow of positive and negative sequence currents. The same components present, in general, different impedances to the flow of zero sequence currents. Rotating equipment like synchronous generators, motors, condensers, and induction motors have different impedances in all three sequence networks. The positive sequence impedances are the ones normally used for balanced power flow studies. All sequence impedances must be either calculated, measured, provided by the equipment manufacturers, or estimated. The zero sequence impedance may not exist for some rotating equipment, depending on the machine grounding.

For a balanced three-phase fault analysis, only the positive sequence system components impedances Z_1 ($R_1 + jX_1$) are required. For line-to-line faults, negative sequence impedances Z_2 ($R_2 + jX_2$) are also required. For all shunt faults involving ground, i.e., line-to-ground and double line-to-ground, the zero sequence system impedances Z_0 ($R_0 + jX_0$) are needed in addition to the other two. System neutral grounding equipment data like grounding resistors, reactors, transformers, etc., form an integral part of the zero sequence system impedance data.

AC decrement considerations dictate that rotating equipment impedances vary from the onset of the short circuit. This applies only to positive sequence impedances, which vary from subtransient through transient to steady-state values. The negative and zero sequence impedances for the rotating equipment are considered unchanged. The same holds true for the impedances of the static system equipment.

7.3.5 Computational approaches

7.3.5.1 Time domain fault analysis

Time-domain fault analysis pertains to techniques that allow for the calculation of the short-circuit current as a function of time from the moment of the fault inception. For large electric power systems, with many machines and generators contributing to the fault current, the contributions of many machines will have to be taken into account concurrently. Machine models have been developed that let predictions of considerable accuracy be made regarding the behavior of any machine for a fault either at or beyond its terminals. These models are rather complex because they tend to represent in detail not only the machine itself but also several nonlinear controllers, such as excitation systems and their related stabilization circuitry, with nonlinearities. It can therefore be seen that the calculating requirements could be stupendous, because the problem is reduced to simultaneously solving a large number of differential equations. Despite its inherent power, the use of time-domain fault analysis is not very widespread and is only used for special studies because it is data-intensive (data requirements can be at least as demanding as transient stability analysis) and it requires special software.

7.3.5.2 Quasi-steady-state fault analysis

Quasi-steady-state fault analysis pertains to techniques that represent the system at steady state. Phasors are used to represent system voltages, currents, and impedances at fundamental frequency. System modeling and the resulting computational techniques are based on the assumption that the system and its components can be represented by linear models. Retaining linearity simplifies considerably the necessary calculations (Anderson [B1], Arrillaga, Arnold, and Harker [B2], Blackburn [B3] Stevenson [B10], Wagner and Evans [B13]) as demonstrated in Chapter 3. Furthermore, linear algebra theory and the numerical advances in matrix computations make it possible to implement very elegant computer solutions for relatively large systems. These techniques have been favored by the various industry standards and will be briefly examined next.

7.4 Fault analysis according to industry standards

Industry standards dictate certain analytical techniques that adhere to specific guidelines, suited to address the questions of ac and dc decrement in multimachine systems in compliance with well-established, industry-accepted practices. They are also closely linked to and harmonize quite well with existing switchgear rating structures. Typical standards are the North American ANSI and IEEE C37 standards and recommended practices (see 7.4.1), the international standard, IEC 60909 (1988) and others, such as the German VDE 0102-1972 and the Australian AS 3851-1991 (see 7.8). The analytical and computational framework in the calculating procedures recommended by these standards remains algebraic and linear, and the calculations are kept tractable by hand for small systems. The extent of the data base requirements for computer-based solutions is carefully kept to a necessary maximum for the results to be acceptably accurate. This type of analysis represents the best compromise between solution accuracy and simulation simplicity. The great majority of commercial-grade short-circuit analysis programs fall under this category.

In 7.4.1, an outline of ANSI and IEEE standards is presented, while in 7.4.2, the relevant aspects of IEC 60909 (1988) are described. It is not the intent of these subclauses to fully explore and describe in detail all pertinent clauses of either standard. Instead, a rather brief summary is presented in an effort to make any potential user conscious of the salient aspects of each technique. Because only a brief summary is presented, it is strongly recommended that the standards be consulted for further clarifications and details.

7.4.1 The North American ANSI and IEEE standards

IEEE standards addressing fault calculations for medium and high voltage are IEEE Std C37.010-1979, IEEE Std C37.5-1979, IEEE Std 141-1993, IEEE Std 241-1990, and IEEE Std 242-1986. IEEE standards addressing fault calculations for low-voltage systems (below 1000 V), are the IEEE Std C37.13-1990, IEEE Std 141-1993, IEEE Std 241-1990, and IEEE Std 242-1986. Three types of short-circuit currents are defined, depending on the time frame of interest taken from the inception of the fault, as

a) First cycle currents
b) Interrupting currents
c) Time delayed currents

First-cycle currents, also called momentary currents, are the currents at 1/2 cycle after fault initiation; they relate to the duty circuit breakers face when “closing against” or withstanding short-circuit currents. That is why these currents are also called “close and latch” currents. Often these currents contain dc offset, and they are calculated on the premise of no ac decrement in the contributing sources (i.e., the machine reactances remain subtransient [see Table 7-1]). Since low-voltage breakers operate in the first cycle, their interrupting ratings are compared to these currents.

Table 7-1— Generic impedance types required for short-circuit studies

Electrical system equipment type	Momentary 1/2 cycle	Interrupting 3–5 cycles	Time delayed 6–30 cycles
Induction motor	X''_d, R	X''_d, R	Neglect
Synchronous motors	X''_d, R	X''_d, R	See Note 3
Synchronous generators	X''_d, R	X''_d, R	X'_d, X_d, R
Synchronous condensers: electric utility systems	X_s, R_s	X_s, R_s	X_s, R_s
Passive components: transformers, cables, etc.	X, R	X, R	X, R

where

- X''_d is the subtransient reactance. For induction motors, X''_d is approximately equal to the locked rotor reactance.
- X'_d is the transient reactance
- X_d is the synchronous reactance
- X is the equivalent reactance
- R is the equivalent modified resistance (see Table 7-2)
- X_s, R_s is the power company system equivalent reactance and resistance

NOTES

1—See Table 7-2 for exact values.

2—X''_d of synchronous machines is the rated voltage (saturated) direct axis subtransient reactance.

3—X'_d of synchronous machines is the rated voltage (saturated) direct axis transient reactance.

4—For calculations of minimum short-circuit current, contribution is neglected. For calculation of maximum short-circuit current values, use X'_d and R values.

5—For more details on IEEE-related induction motor modeling aspects, see Huening [B4].

Interrupting currents are the short-circuit currents in the time interval from 3 to 5 cycles after fault initiation. They relate to the currents sensed by the interrupting equipment when isolating a fault. Hence, they are also referred to as “contact-parting” currents. These currents are asymmetrical; i.e., they contain dc offset, but due consideration is now given to ac decrement because of the elapsed time from the fault inception. All contributing sources are taken into account when calculating interrupting currents by virtue of reactances that range from subtransient to transient (see Table 7-1). Interrupting currents in the 3 to 5 cycles interval are associated with medium- and high-voltage breakers.

Time delayed currents are the short-circuit currents that exist beyond 6 cycles (and up to 30 cycles) from the fault initiation. They are useful in determining currents sensed by time delayed relays and in assessing the sensitivity of overcurrent relays. These currents are assumed to contain no dc offset. Induction and synchronous motor contributions are neglected, and the contributing generators are assumed to have attained transient or higher value reactances (see Table 7-1).

7.4.1.1 Accounting for ac and dc decrement

In view of the classification of short-circuit currents in three duty types, different impedances are used for the rotating equipment for each of these duties. Tables 7-1 and 7-2 portray the recommended impedances for the system components and for the different types of analysis and duty currents sought. Once the desired duty type has been selected, the appropriate system impedances may be chosen in accordance with Table 7-2.

Table 7-2—Reactance values for first cycle and interrupting duty calculations

Duty calculation	System component	Reactance value for medium- and high-voltage calculations per IEEE Std C37.010-1979 and IEEE Std C37.5-1979	Reactance value for low-voltage calculations (see Note 2)
First cycle (momentary calculations)	Power company supply All turbine generators; all hydrogenerators with amortisseur windings; all condensers	X_S $1.0\ X''_d$	X_S $1.0\ X''_d$
	Hydrogenerators without amortisseur windings	$0.75\ X''_d$	$0.75\ X'_d$
	All synchronous motors	$1.0\ X''_d$	$1.0\ X''_d$
	Induction motors Above 1000 hp	$1.0\ X''_d$	$1.0\ X''_d$
	Above 250 hp at 3600 r/min	$1.0\ X''_d$	$1.0\ X''_d$
	All others, 50 hp and above	$1.2\ X''_d$	$1.2\ X''_d$
	All smaller than 50 hp	$1.67\ X''_d$ (see Note 6)	$1.67\ X''_d$

Table 7-2—Reactance values for first cycle and interrupting duty calculations (*Continued*)

Duty calculation	System component	Reactance value for medium- and high-voltage calculations per IEEE Std C37.010-1979 and IEEE Std C37.5-1979	Reactance value for low-voltage calculations (see Note 2)
Interrupting calculations	Power company supply All turbine generators; all hydrogenerators with amortisseur windings; all condensers	X_S 1.0 X''_d	N/A
	Hydrogenerators without amortisseur windings	0.75 X'_d	N/A
	All synchronous motors	1.5 X''_d	N/A
	Induction motors Above 1000 hp	1.5 X''_d	N/A
	Above 250 hp at 3600 r/min	1.5 X''_d	N/A
	All others, 50 hp and above	3.0 X''_d	N/A
	All smaller than 50 hp	Neglect	N/A

NOTES
1—First-cycle duty is the momentary (or close-and-latch) duty for medium-/high-voltage equipment and is the interrupting duty for low-voltage equipment.
2—Reactance (X) values to be used for low-voltage breaker duty calculations (see IEEE Std C37.13-1990 and IEEE Std 242-1986).
3—X''_d of synchronous-rotating machines is the rated-voltage (saturated) direct-axis subtransient reactance.
4—X'_d of synchronous-rotating machines is the rated-voltage (saturated) direct-axis transient reactance.
5—X''_d of induction motors equals 1 divided by per-unit locked-rotor current at rated voltage.
6—For comprehensive multivoltage system calculations, motors less than 50 hp are represented in medium-/high-voltage, short-circuit calculations (see IEEE Std 141-1993, Chapter 4).

The estimates of 1.2 X''_d and 1.67 X''_d for induction motor impedances to be used for the first cycle network are based on locked rotor impedances of 0.20 and 0.50 per unit, respectively, based on motor rating according to IEEE Std 242-1986. Similarly, the estimate of 3.0 X''_d, to be used for the induction motor impedance for interrupting duty calculations, is based on the assumption of a locked rotor impedance of 0.28 per unit based on the motor rating, as suggested in IEEE Std 141-1993.

The equivalent Thevenin system impedance at the fault location is then calculated by successive network reduction. Techniques for finding the equivalent short-circuit impedance (reactance) as seen from the fault location are well explained in chapters 3 and 4 of this recommended practice, in IEEE Std 141-1993, in IEEE Std 241-1990, and in IEEE Std 242-1986. The prefault system voltage, normally assumed to be 1.00 p.u. (rated), divided by the equivalent short-circuit impedance, will yield the desired symmetrical rms value of the desired three-phase fault current. The dc component of the fault current is obtained by considering the X/R ratio at the fault point. The X/R ratio is calculated by taking the ratio of the system reactance (Thevenin equivalent reactance) to the system resistance (Thevenin equivalent resistance) as seen from the fault location. The equivalent reactance must be calculated from the reactance network (X) which is the impedance network of the system under study with all resistances absent. Similarly, the equivalent resistance must be calculated from the resistance network (R), which is the impedance network of the system under study with all reactances absent.

It should be noted that the separate reactance and resistance network reduction technique will yield a different X/R ratio (usually higher) than the phasor X/R ratio of the complex fault impedances.

7.4.1.2 Calculated short-circuit currents and interrupting equipment

The calculating procedures briefly touched upon above are meant to address short-circuit calculations on Industrial power systems with several voltage levels comprising high-, medium-, and low-voltage circuits. First cycle currents are useful in calculating the interrupting requirements of low voltage fuses and breakers. Currents resulting from the same simulation are effectively used in calculating the first-cycle requirements for medium- and high-voltage fuses and circuit breakers. The currents resulting from the so-called interrupting network calculations are only used for medium- and high-voltage circuit breakers, which operate with a certain time delay due to relaying and operating requirements. It must be borne in mind that since low-voltage fuse and circuit breaker application standards like IEEE Std C37.13-1990 have adopted the symmetrical rating structure, calculating only the symmetrical rms fault currents and the X/R ratio may be sufficient, if the calculated X/R ratio is less than the X/R ratio of the circuit breaker test circuit.

A distinction has to be made between the various rating structures of medium- and high-voltage circuit breakers. Breakers rated with the older rating structure, covered by IEEE Std C37.5-1979, are assessed on the basis of the total asymmetrical fault current, or total prospective fault MVA, and calculations are normally restricted to minimum parting time for the sake of safety and simplicity. The more recent rating structure, covered by IEEE Std C37.010-1979, assumes breakers to be rated on a symmetrical basis. Depending on service conditions and the system X/R ratio, the calculated symmetrical short-circuit currents may be sufficient, because a certain degree of asymmetry is embedded in the breaker rating structure.

When calculation of the total fault current is warranted for medium- and high-voltage breaker calculations, IEEE Std C37.010-1979 and IEEE Std C37.5-1979 contain tabulated multipliers that can be applied to the symmetrical rms fault currents in order to obtain asymmetrical rms currents. For IEEE Std C37.5-1979, these currents are the total asymmetrical fault currents, whereas IEEE Std C37.010-1979 represents currents that are to be compared with the breaker interrupting capabilities. In both cases, these multipliers are obtained from curves normalized against breaker contact parting time. As of 1987, the ANSI C37.06-1987 introduced the peak fault current to the preferred ratings as an alternative to the earlier total asymmetrical fault currents (for first cycle withstand requirements) per ANSI C37.06-1979, in order to better harmonize with IEC standards.

In summary, it should be stressed that an essential step for the calculation of the total fault currents in medium- and high-voltage circuit breaker applications is the determination of portions of the fault current coming from "local" and "remote" sources as a means of obtaining a more reasonable estimate of the breaker interrupting requirements (Huening [B5]). The reason for this distinction is that fault currents from remote sources feature slower, or no, ac current decay as compared to currents coming from local sources. A "remote" contribution, as defined in IEEE Std C37.010-1979, IEEE Std C37.5-1979, IEEE Std 141-1993, and IEEE Std 242-1986, is the fault current that comes from a generator that

a) Is located two or more transformations away from the fault, or
b) Has a per unit X''_d that is 1.5 times less than the per unit external reactance on a common MVA basis.

Chapter 4 of IEEE Std 141-1993 provides details on the methods that can be used to determine the appropriate composite adjustment factors that account for local and remote short-circuit contributions. The ratio of the remote source contributions to the total short-circuit current is also known as the NACD ratio (Huening [B5]).

7.4.2 The international standard, IEC 60909 (1988)

IEC 60909 (1988) is similar to the German VDE 0102-1972 standard and to the Australian AS 3851-1991 standard. In what follows, only the very salient aspects are discussed in an effort to make the potential user conscious of its computational and modeling requirements. It is strongly recommended that interested readers consult the standard itself for further details.

IEC 60909 (1988) recognizes four duty types that result in four calculated fault currents:

— The initial short-circuit current I''_k
— The peak short-circuit current I_p
— The breaking short-circuit current I_b
— The steady-state fault current I_k

Although, the breaking and steady-state fault currents are conceptually similar to the interrupting and time-delayed currents, respectively, the peak currents are the maximum currents attained during the first cycle from a fault's inception and are significantly different from the first-cycle IEEE currents, which are total asymmetrical rms currents. The initial short-circuit current is defined as the symmetrical rms current that would flow at the fault point if no changes are introduced in the network impedances.

The IEC 60909 (1988) provides guidelines for calculating maximum and minimum fault currents. The former are to be used for breaker rating while the latter for protective device coordination. The major governing factors in calculating maximum and minimum fault currents are the prefault voltages at the fault point and the fact that minimum fault currents are calculated with minimum connected plant.

The phenomenon of ac decrement is addressed by considering the actual contribution of every source, depending on the voltage at its terminals during the short circuit. Induction motor ac decrement is modeled differently than synchronous machinery decrement, because an extra decrement factor representing the more rapid flux decay in induction motors is included. AC decrement is only modeled when breaking currents are calculated.

The phenomenon of dc decrement is addressed in IEC 60909 (1988) by applying the principle of superposition for the contributing sources in conjunction with giving due regard to the topology of the network and the relative locations of the contributing sources with respect to the fault position. In addition, the standard dictates that different calculating procedures be used when the contribution converges to a fault point via a meshed or radial path. These considerations apply to the calculation of peak and asymmetrical breaking currents.

Steady-state fault currents are calculated by assuming that the fault currents contains no dc component and that all induction motor contributions have decayed to zero. Synchronous motors may also have to be taken into account. Furthermore, provisions are taken not only for salient and round rotor synchronous machinery but, also for different excitation system settings.

Prefault system loading conditions are of concern to IEC 60909 (1988) as well. In an attempt to account for system loads leading to higher prefault voltages, the standard recommends that prefault system voltages other than 1.00 per unit be used, without requiring a prefault load flow solution. Furthermore, the standard recommends generator impedance correction factors that may be applicable to their unit transformers as well.

7.4.3 Differences between the ANSI and IEEE C37 standards and IEC 60909 (1988)

The differences between the two standards are numerous and significant (Rodolakis [B7]). Despite the conceptual association in the duty types, system modeling and computational procedures are quite different in the two standards. That is why results calculated using both standards can be quite dissimilar, with IEC 60909 (1988) having the tendency to yield higher fault current magnitudes. The essential generic differences between the two standards can be summarized in the following:

- AC decrement modeling in IEC 60909 (1988) is fault location-dependent and it quantifies the rotating machinery's proximity to the fault. The IEEE standard, on the other hand, recommends universal, system-wide ac decrement modeling.
- DC decrement for IEC 60909 (1988) does not always rely on a single X/R ratio. In general, more than one X/R ratio must taken into account. Furthermore, the notion of separate X and R networks for obtaining the X/R ratio(s) at the fault point is not applicable to IEC 60909 (1988).
- Steady-state fault current calculation in IEC 60909 (1988) takes into account synchronous machinery excitation settings.

In view of these important differences, computer simulations adhering to the ANSI and IEEE C37 standards cannot, in general, be used to cover the computational requirements of IEC 60909 (1988) and vice versa.

7.5 Factors affecting the accuracy of short-circuit studies

The accuracy of the calculated fault currents depends primarily on accurate modeling of the system configuration and the system impedances used for the calculations. Other very important factors include the correct modeling of system rotating load, connected generators, system neutral grounding, and other system components and operating conditions.

7.5.1 System configuration

System configuration consists of the following:

a) The location of all the potential sources of fault current, i.e., synchronous generators, synchronous motors, induction motors, and utility connection points, and
b) How these fault current sources are connected through transformers, lines, cables, busways, and reactors.

It is conceivable that more than one single-line diagram should be considered for a given system, depending on the system operating modes and on the nature of the study. If the study is done to assess switchgear adequacy and/or selection, maximum fault currents should be calculated. This entails that fault currents must be calculated under maximum rotating plant and closed bus-ties (whenever applicable), while any utility interconnections should be assumed to attain their highest fault levels. If the study is done to assess protection sensitivity requirements, some of these conditions may need to be relaxed. Different system service conditions may force the study of more than one system topology alternative, particularly in protective relaying studies.

7.5.2 System Impedances

AC and dc decrement modeling considerations are very important factors in properly selecting the impedances of the rotating equipment for short-circuit studies. It is important to consult manufacturer's catalogues, data sheets and, if necessary, to perform some calculations to ascertain reliable impedance values. Typical values can be used in the absence of any other information, but always with caution and a certain degree of conservatism. Table 7-3 portrays some typical values for induction motors.

The values used for the impedances should by no means yield lower fault currents than the ones the system will experience in reality. Underestimating the prospective fault currents can lead to the undersizing of system equipment and to the selection of circuit breakers with inadequate interrupting capabilities. On the other hand, grossly overestimating the fault currents may lead to uneconomical design and less sensitive protection settings. The equivalent impedances representing the power company interconnection points must properly reflect the anticipated fault MVA level. Any ambiguities concerning the impedances of in-plant equip-

Table 7-3—Typical values of motor impedances and kVA ratings to use when exact values are not known[a]

Induction motor Synchronous motor, 0.8 pf Synchronous motor, 1.0 pf	1 hp = 1 kVA 1 hp = 1 kVA 1 hp = 0.8 kVA
Motor type	X''_d (See Note)
Synchronous motors 2–6 poles 8–14 poles 16 poles or more	 0.15 0.20 0.28
Individual large induction motors, usually medium voltage All others, 50 hp and above All smaller than 50 hp, usually low voltage	0.67 0.67 0.67

NOTE—Motor impedances are in per unit on motor voltage and kVA rating. X''_d for induction motors is approximately equal to the locked-rotor reactance. For induction motors, the locked-rotor reactance is the reciprocal value of the locked-rotor current. Reactances and motor base kVA ratings listed were taken from data and assumptions in IEEE Std 141-1993.

[a]As specified in IEEE Std 141-1993.

ment should be resolved in favor of higher fault currents for the sake of safety in system design. Impedances of bus ducts, busways, etc., must be accounted for in lower voltage circuits because they effectively limit fault current magnitudes. It is also customary practice to use the saturated impedance values for synchronous machinery.

Last, but not least, the resistive components of the system impedances should be given proper regard if operating system temperature is a factor or if significant lengths of cable runs are present. Although resistance values can usually be omitted for fault current magnitude calculations (E/X calculation), they are important for calculating the system X/R ratio at the fault point. Generally speaking, the total complex system impedance, Z (R+jX) has to be calculated at the fault point to yield a more correct estimate of the fault current (E/Z calculation). This is particularly true for low-voltage systems, where the system resistance is comparable in magnitude to the system reactance and helps limit the fault current.

7.5.3 Neutral grounding

For faults necessitating the inclusion of zero sequence data, i.e., line-to-ground faults, double line-to-ground shunt faults, and series faults, the flow of fault currents is appreciably affected by the system grounding conditions. Of particular concern is the presence of multiple grounding points and the values of system grounding impedances. Grounding impedances can be used, to various degrees, to limit the value of the ground fault current to a minimum value, to suppress resulting overvoltages, and to provide “handles” for ground protection. System grounding can also play an important role in the proper simulation of the system zero sequence response. More specifically, for solidly, or low-impedance grounded systems, it is sufficient to include in the study only the occasional current limiting transformer and or generator grounding impedances, while disregarding zero sequence line/cable charging shunts. For high-impedance grounded, floating, and/or resonant-grounded systems, however, the latter will have to be taken into account (per IEC 60909 (1988), since the assumption that neglecting it yields conservative (higher) fault currents is no longer valid.

7.5.4 Prefault system loads and shunts

It is customary to assume that the system is at steady state before a short circuit occurs. The simplification of neglecting the prefault load is based on the premise that the magnitude of the prefault system load current is, usually, much smaller than the fault current. The importance of the prefault load current in the system increases with rated system voltage and certain system loading patterns. That is why it is still justifiable for typical industrial power system studies to assume a 1.00 per-unit prefault voltage for every bus. For systems in which prefault loading is a concern, a prefault load flow analysis should precede the fault simulations in order to ascertain a voltage profile for the system that will be consistent with the existing system loads, shunts, and transformer tap settings. If the actual prefault system condition is modeled, it is important to retain for the fault simulation all the system static loads (normally neglected when the system is assumed at rest) as well as the capacitive line/cable shunts.

Standards such as IEC 60909 (1988) and AS 3851-1991 attempt to address this issue by virtue of using elevated prefault voltages and impedance correction factors for the synchronous generators. The ANSI and IEEE C37 practice, however, is centered around considering the prefault voltage as being the nominal system voltage with the notable exception being the assessment of the interrupting requirements of circuit breakers.

7.5.5 Mutual coupling in zero sequence

This phenomenon is of importance when parallel circuits share the same right of way and their geometrical arrangement is such that current flow in one circuit causes a voltage drop in the other. A typical example is exposed overhead lines sharing the same support structure. It should be noted that in reality, mutual coupling exists between phases in the positive sequence as well. This form of mutual coupling, also known as “interphase coupling,” is not explicitly modeled in positive sequence because it is restricted within the same circuit of which only one phase is modeled. Zero sequence coupling, however, is extended between two (or more) circuits and has to be explicitly modeled in zero sequence (Anderson [B1], Arrillaga, Arnold, and Harker [B2], Blackburn [B3], Stagg and El-Abiad [B9], Wagner and Evans [B13]). The implications of neglecting or incorrectly modeling this phenomenon leads to erroneous calculation of ground fault currents and incorrect performance assessment of distance relays. Although relatively infrequent for industrial power system analysis, it should be borne in mind and treated accordingly.

7.5.6 Phase shifts in delta wye transformer banks

When calculating the distribution of the three-phase fault current throughout a system, it is often assumed that, going through transformer banks, the phase of the fault current from primary to secondary remains the same. This is true only if the transformer is connected wye-wye or delta-delta. When a delta-wye transformer is involved, a phase shift is introduced between the phase quantities of the primary and secondary. The phase shift is present in positive and negative sequence quantities only. Zero sequence quantities are not affected. North American practice dictates that the positive sequence high side line-to-ground voltage must lead the positive sequence low side line-to-ground voltage by 30 degrees. Earlier transformer connections and phase labeling may not comply with that requirement (Wagner and Evans [B13]). The same may also be true for transformers following overseas phasing standards. The computational consequence of not accounting for this phase shift for unbalanced faults is that different current magnitudes are obtained when going through a delta-wye bank because the sequence currents are manipulated vectorially to obtain phase currents. This can lead to inaccurate protective device settings which can, in turn, compromise the selectivity of an overcurrent protection scheme (see also IEEE Std 141-1993 and IEEE Std 242-1986).

7.6 Computer solutions

7.6.1 General

Short-circuit calculations are generally less computationally intensive than other basic power system studies like power flow or harmonic analysis. In view of the fact that short-circuit calculations are linear systems of small to medium sizes can be computationally tractable by hand, particularly if the system resistances are neglected to avoid complex arithmetic. Calculations are further simplified for radial systems. Practical industrial systems, however, can contain several hundred to over one thousand buses, particularly if representation of low-voltage circuits, smaller rotating loads and protective gear is warranted. Under these conditions, computer solutions are the only practical alternative. It should be noted, however, that the speed and reliability of computer-based calculations are rapidly rendering hand-calculations a rarity even for small systems.

7.6.2 Computerized network solutions: System matrices

Hand calculations for determining the equivalent system impedance at a fault point rely on successive and judiciously chosen combinations of the system branches, until the system is reduced to an equivalent Thevenin impedance. This has to be repeated for every new fault location. Since this is done by inspecting the network, the intuition of the analyst is essential. Computers do not have any intuition, that is why different techniques are used. These techniques do not rely on the analyst's inspection abilities, nor do they assume any system topology. That is why they lend themselves very well to both radial and looped systems and are capable of accommodating systems of practically any size. The notions of admittance and impedance matrices are central in realizing any computerized solution scheme.

7.6.2.1 The bus admittance matrix

The bus admittance matrix, also called the Y-matrix, is a square complex matrix (a matrix whose entries are complex numbers) with as many rows and columns as the system buses

(Anderson [B1], Arrilaga, Arnold, and Harker [B2], Stevenson [B10], Stagg and El-Abiad [B9]). The elements of this matrix are either component admittances or sums of component admittances. The term "component admittance" denotes the inverse of the component complex impedance with a component being a system branch, generator, motor, etc. Once the system buses have been identified, this matrix can be constructed as follows:

— Assign a diagonal matrix element to every system bus. The value of the matrix diagonal elements is the sum of the admittances of all the power system components connected to that bus.
— Assign a nondiagonal element to all the matrix elements that represent a system branch. For instance, if a branch is connected between buses i and j, the matrix entry Y_{ij} will be nonzero and equal to the negative sum of the admittances of all components directly connected between buses i and j.

Electric power systems are passive and have very few branches compared to all of the possible bus connections, and as a result, typical power system bus admittance matrices are

a) symmetric (assuming that transformers are not modeled in off-nominal tap positions) which means that $Y_{ij} = Y_{ji}$, and
b) sparse, i.e., they feature a lot of zero entries.

7.6.2.2 The bus impedance matrix

The bus impedance matrix, also called the Z-matrix, is defined as the inverse of the admittance matrix (Anderson [B1], Arrilaga, Arnold, and Harker [B2], Stevenson [B10], Stagg and El-Abiad [B9]). This complex matrix is also square and symmetric, i.e., the entry Z_{ij} equals the entry Z_{ji}, for passive networks. As the inverse of the sparse Y-matrix, however, this matrix is a full matrix having no zero entries. It can be proved that the diagonal entries, Z_{ii} for bus i, of this matrix are the equivalent Thevenin impedances used for fault calculations. The entry Z_{ij}, however, does not necessarily represent the value of the impedance of the physical connection between buses i and j. In fact, there is always an impedance Z_{ij} despite the fact that there may not be a branch between buses i and j. The diagonal entries of the Z-matrix are used in calculating fault currents, while the nondiagonal entries are useful for calculating branch contributions and system-wide voltage profiles under fault conditions.

7.6.2.3 System topology, matrix sparsity, and solution algorithms

The sparsity of the Y-matrix requires that special techniques be employed for storing the system data, because conceptually straightforward storage techniques may be quite wasteful. Storing, for instance, the entire Z-matrix is not only impractical but unnecessary because only a few of its elements may be needed. The development of solution algorithms, therefore, has been focusing on the efficient retrieval of the necessary Z-matrix entries with the smallest possible storage and calculation requirements. Modern vintage computer software employs calculation and system data storage schemes that center around the so-called "sparse vector" and/or "sparse matrix" solution techniques (Tinney, Brandwajn, Chan [B12]) which render very rapid and accurate solutions.

7.6.3 Computer software

7.6.3.1 General

The availability of commercial grade computer software on personal computers has been steadily increasing in variety and computational power since the early 1980s, although sophisticated software has existed for more powerful hardware platforms such as mainframes and minicomputers since the early 1960s (St. Pierre [B11]). The personal computer is now recognized as a credible computational tool due to the significant advances it has enjoyed in processor architecture, speed, memory capacity, and in user-friendly operating systems and environments. Computer programs that addressed short-circuit calculations were among the first to be developed in all platforms. All programs rely on matrix techniques and require the analyst to provide accurate system data so that the computer can proceed with the analysis and produce the results.

7.6.3.2 Selecting software

The great variety of commercially available computer programs for short-circuit calculations can be attributed to the wide variety of the analytical tasks they perform, the degree of sophistication in user-interface and user-friendliness, and the computer platform for which they are designed. Because the variety of the available computer software is accompanied by an equally impressive variation in prices, it is important to acquire software that best corresponds to the bulk of the engineering mandates for which it is purchased. It is questionable, from an investment point of view, to acquire expensive and very sophisticated software when the bulk of its analytical features will never be used. On the other hand, it could prove shortsighted to acquire inexpensive software that will rapidly be outgrown by the needs of its user, compromise the accuracy of the study, or result in a consistent waste of time and resources due to inherent functional inefficacies. It is also important to assess the degree of user-friendliness of the software versus the computer-literacy of the personnel who will be using it. Many engineers are reluctant to refamiliarize themselves with bulky user's guides only to perform studies with which they are very familiar. It pays to work with software that features easy data entry, meaningful and helpful diagnostic messages, and comprehensive reports. Last, it is essential to acquire software that is very well documented, promptly supported, and regularly updated and upgraded by its vendors.

7.6.3.3 Features of short-circuit analysis software

The previously mentioned general salient principles governing software selection are supplemented by a good number of other features that are particularly applicable to short-circuit analysis. A very important aspect in short-circuit studies is data preparation, a stage which, by itself, can be computationally demanding, particularly if the software accepts system data only on a per-unit basis. It is essential for the program to help the analyst prepare the data for the study and provide means of identifying and correcting obvious and common mistakes. Furthermore, whenever international standards are to be used, it is important for the software to provide sufficient information and results that are transparent enough to allow for more than one interpretation.

Table 7-4 contains several features that computer programs may or may not support. These features have been conceptually categorized as "very desirable," "desirable," and "optional." "Very desirable" means that the feature is widely encountered and rather indispensable. The category "desirable" addresses features that will prove of value to more demanding studies. The category "optional" covers features that may prove to be of value for special studies.

Table 7-4—Analytical features of short-circuit computer programs

Analytical feature	Very desirable	Desirable	Optional
Systems with more than one voltage level	Yes		
Looped and radial system topology	Yes		
Ground faults (LG and LLG)	Yes		
Series faults (See Note 1)		Yes	
Arcing faults (See Note 2)			Yes
Simultaneous faults			Yes
Complex arithmetic	Yes		
Explicit negative sequence (See Note 3)			Yes
Interface with power flow (See Note 1)		Yes	
Currents in all three phases (See Note 4)	Yes		
Currents in all three sequences (See Note 4)	Yes		
One-bus-away fault contributions	Yes		
Line monitors (See Note 5)		Yes	
Input data reports	Yes		
Protection coordination interface		Yes	
Voltages in nonfaulted buses (See Note 5)		Yes	
Summary reports		Yes	
Currents in all branches (See Note 5)		Yes	
Per-unitization of equipment data		Yes	
Rotating equipment impedance adjustment (IEEE Std C37.010-1979)	Yes		
Separate X and R reduction for X/R ratios (IEEE Std C37.010-1979)	Mandatory		

Table 7-4—Analytical features of short-circuit computer programs (*Continued*)

Analytical feature	Very desirable	Desirable	Optional
Remote and local fault contributions (IEEE Std C37.010-1979)	Mandatory		
First cycle fault currents (IEEE Std C37.010-1979)	Mandatory		
Interrupting fault currents (IEEE Std C37.010-1979)	Mandatory		
Time-delay fault currents (IEEE Std C37.010-1979)		Yes	
Symmetrical current multiplying factors (IEEE Std C37.010-1979)	Yes		
Total current multiplying factors (IEEE Std C37.5-1979 factors)	Yes		
Multiplying factors (IEEE Std C37.13-1990)	Yes		
X/*R*—dependent 1/2 cycle multipliers (IEEE Std C37.010-1979)	Yes		
X/*R*—dependent peak multipliers (IEEE Std C37.010-1979)	Yes		
Transformer phase shifts (See Note 4)	Yes		
Mutual coupling in zero sequence (See Note 6)			Yes
Methodology in accordance with IEC 60909 (1988) (See Note 7)		Yes	

NOTES
1—Series faults are normally modeled when a prefault power flow solution is available and prefault load can be taken into account.
2—Arcing faults can be of consequence when assessing the sensitivity of ground protection in solidly grounded systems. Conservative estimates of fault levels, however, will result by assuming bolted faults.
3—Negative sequence system representation is not warranted by ANSI and IEEE C37 standards, though it could be of significance when ground faults near large generating stations are calculated, or when simulations compatible with IEC 60909 (1988) require elevated accuracy.
4—It is important to have a good estimate of all three phase and sequence currents, particularly for protection requirements. In correctly estimating all these currents in magnitude and phase it is very helpful to take into account phase shifts in transformer banks.
5—When assessing the degree of severity of a fault, it is often of interest to see how nearby system areas are affected, and if protective devices will be activated as a result of the fault.
6—Mutual coupling in zero sequence normally affects overhead circuitry sharing a common right-of-way. For industrial power systems analysis, zero sequence mutual coupling can be of concern if such circuits are modeled and the performance of protective devices requiring zero sequence current compensation is investigated.
7—Support of the IEC 60909 (1988) may require dedicated software.

7.7 Example

In what follows, a short-circuit study is carried on a typical industrial system in order to illustrate typical steps, calculation requirements, and results. The system is composed of circuits of several voltage levels, local generation, a utility interconnection, and a variety of rotating loads. The study is carried out according to the ANSI and IEEE C37 standards (see 7.8).

7.7.1 Determination of the scope and extent of the study

Determination of the scope extent and the desired accuracy of the study is crucial, because these factors will dictate what types of faults are to be simulated and to what degree system modeling is to be undertaken. The type and number of fault studies for a given system is determined by engineering judgment, which is based on the various forms the system layout may assume during operation or the specific purpose of the study.

The study results may be used for recommending changes to existing plants or for proposing an initial design for a system in its planning and/or expansion stage. Some important questions for which fault studies may help provide answers are as follows:

a) Is circuit interrupting equipment adequate for the system interrupting requirements at all voltage levels? Can the medium- and high-voltage switchgear withstand the momentary and interrupting duties imposed by the system? Is this switchgear adequate for line to ground faults? If not, should new equipment be purchased or can some changes to the system be effected to avoid the extra capital expenditure?
b) Is there any reserve in the interrupting capability of the circuit breakers for accommodating future system expansion? If not, is it necessary to have a safety margin for future expansion? If so, how can the system be changed to accommodate these concerns?
c) Is noninterrupting equipment, i.e., reactors, cables, transformers, bus ducts, adequately rated to withstand short-circuit currents until cleared by the interrupting equipment?
d) Do load circuit breakers or disconnecting switches have sufficient momentary bracing and/or close-and-latch capabilities?
e) What will be the effect on the calculated short-circuit currents in the plant system if there is an increase in the power company's short-circuit level? Economically, what can be done to anticipate such an eventuality?
f) Is special protective equipment or circuitry necessary to provide protective device selectivity for both maximum and minimum value of short-circuit currents?
g) During faults, do the voltages on unfaulted buses in the system drop to levels that can cause motor-starter contactors to drop out or undervoltage relays to operate?

Every study will have to be assessed on its own merits and its results interpreted only for the purpose the study was conducted. The short-circuit study for the example in question is performed for the purposes of determining the interrupting requirements for low-, medium-, and high-voltage switchgear. It is not uncommon for these types of studies to consider only three-phase fault currents, since, as a rule, they yield the more severe interrupting requirements, as compared to other shunt faults, and the industrial power systems are often impedance-grounded. Line-to-ground fault simulations are necessary for circuit-breaker-adequacy evaluation and/or selection, if the system is such that line-to-ground fault currents may exceed three-phase fault currents (see 7.2). Only three-phase, bolted, shunt faults will be considered for the example.

7.7.2 Preparation of the system one-line diagram and collection of data

The one-line diagram of the system is shown in Figure 7-1. We will consider that both in-plant generators are connected and that both of the utility service entrance transformers are in service. The system rotating load, as shown in the one line diagram, represents an operating condition that is typical for the system operating at or near full capacity. Furthermore, it is known that the bus ties between buses 3 and 4 (13.8 kV) and between buses 1 and 2 (69 kV) are open. Cable runs between buses, 9 (FDR E) and 13 (T6 PRI), 28 (T10 SEC) and 38 (480 TIE), 30 (T12 SEC) and 38 (480 TIE), 10 (EMER) and 12 (T5 PRI), are also assumed to be open. It is this particular system layout that will be studied. In general, however, depending on the type of study, more than one single-line diagram may have to be considered in practice (see 7.5.1).

Data necessary for conducting a short-circuit study comprise the following:

a) Utility interconnection points and associated fault MVA levels (both three-phase and line-to-ground) in order to determine the equivalent impedance of the utility
b) In-plant generation data
c) Rotating load data comprising synchronous motors and induction motors, both stand-alone and grouped
d) Static system equipment data, such as transformers, cables, reactors, overhead lines, busways, bus ducts, etc., switching equipment and, in some cases, static loads (heaters, drives, etc.).

7.7.3 Determination and per-unitization of system impedances

7.7.3.1 Determination of the required system impedances

The choice of system impedances to be used depends on the type of study to be performed and the actual fault conditions to be simulated. Three-phase fault studies require only positive sequence impedances, whereas faults involving ground will require zero sequence system data as well as any neutral grounding data. Negative sequence impedances may also be necessary for line-to-line fault simulations. Impedances of both static and rotating system components are normally known from equipment nameplate data. In the absence of detailed information, typical values are assumed. Nameplate impedances of rotating equipment are modified from their rated values in order to account for ac decay, according to the North American practice (see 7.4.1).

7.7.3.2 Per-unitization of the system impedances

Power system equipment impedances are expressed on a unified per-unit basis because

a) Carrying out the calculations in ohms is not practical for systems composed of more than one voltage level, and
b) The impedances of the system components are expressed in terms of their rated voltage and power.

When the per-unitization of the system impedances to a common MVA base is done manually, caution is required because this is a common source of errors. It is also one of the most time-consuming tasks of a short-circuit study. Computer programs, in general, operate internally on per-unitized impedances, and many offer the facility to convert the "raw" system data to per-unit data in a form ready to be used by the program. If this is the case, it is important to comprehend how the per unitization is carried out. This will greatly facilitate any future "what if" analysis because of different system layouts or modified system impedances. In any case, any error in per unitizing the system impedances can seriously compromise the accuracy of the short-circuit study.

Per-unit impedances are defined as the ratio of the actual ohmic component impedances to a certain base impedance (see also Chapters 3 and 4). The base impedances are calculated from a common, arbitrarily chosen, apparent power base and from a base voltage (Anderson [B1], Stevenson [B10]).

$$Z_{\text{p.u.}} = \frac{Z_{\text{ohms}}}{Z_{\text{base}}}, \text{ with } Z_{\text{base}} = \frac{V_{\text{base}}^2}{S_{\text{base}}} \tag{7-1}$$

The power base is usually expressed in MVA and is applicable throughout the system. The base voltage is expressed in kilovolts (if base power is in MVA) and selected differently for every system section, following the nominal voltage ratios of the system power transformers. If single phase power is chosen, line-to-ground voltages should be used. Alternatively, if three phase power is chosen as base line to line voltages are in order. It is practical to select as base voltages the rated transformer voltages. All buses in the same network section must share the same voltage base. Equipment like transformers, generators, motors, etc., have their impedances given in percent (per unit × 100) of their rated voltage and power. It is often necessary to convert these impedances to new base quantities as follows:

$$Z_{\text{p.u., new}} = \frac{S_{\text{new}}}{S_{\text{old}}} \frac{V_{\text{old}}^2}{V_{\text{new}}^2} Z_{\text{p.u., old}} \tag{7-2}$$

In what follows, some per-unit impedances used in the example study are calculated.

7.7.3.3 Power company per-unit impedance

Assuming that the three-phase MVA fault level at bus 100-UTIL-69 is 1000 MVA, the per-unit impedance of the power company, for a 10 MVA base for the system, is calculated to be

$$Z_{\text{utility}} = \frac{\text{MVA}_{\text{base}}}{\text{MVA}_{\text{fault}}} = \frac{10}{1000} = 0.01 \text{ p.u.} \tag{7-3}$$

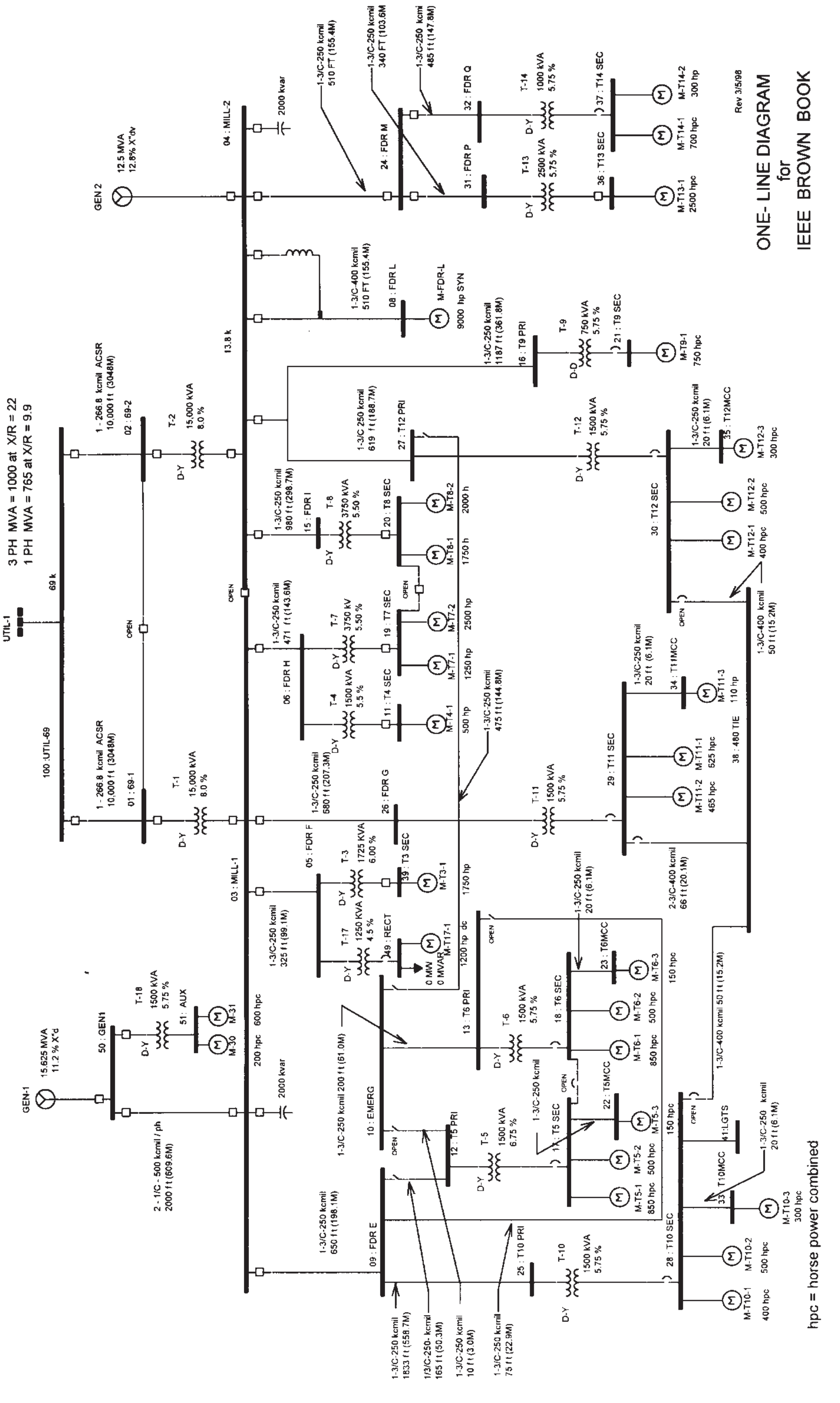

Figure 7-1—One-line diagram

Assuming a typical X/R ratio of 22.0, the utility equivalent impedance becomes

$$Z^2 = R^2 + \frac{X^2}{R^2}R^2 = R^2\left(1.0 + \frac{X^2}{R^2}\right), \text{ from which}$$

$$Z_{\text{utility}} = 0.000454 + \text{j}0.00999 \text{ p.u.}$$

This impedance will be applied for both first cycle and interrupting duty calculations because the power company is considered always to be a "remote" source, thus featuring no ac decrement.

7.7.3.4 Power cable per-unit impedance

Power cable impedances are normally provided in Ω/1000 ft. Consider, as an example, the cable connecting buses 3-MILL-1 and 9-FDRE, which is a 250MCM, 3-core, copper conductor, PVC-jacketed cable, and applied at 13.8 kV. The impedance of the cable is Z = 0.0440419 + j0.0366795 Ω/1000 ft. The cable conduit between the two buses spans 650 ft. The impedance of this cable expressed in per unit of system data will be

$$Z_{\text{cable p.u.}} = 0.650(0.0440419 + \text{j}0.0366795)\frac{10.00}{13.8^2} = 0.0015032 + \text{j}0.0012519 \text{ p.u.}$$

This impedance, as with all impedances of power cables and overhead circuitry, will be applied as is for both first cycle and interrupting calculations. Impedance correction decrement factors apply only to rotating induction and synchronous loads and in some cases to synchronous generators (see Table 7-2).

7.7.3.5 Synchronous generator per-unit impedance

The generator connected on bus 4-MILL-2 has a rated power of 12.5 MVA, a rated voltage of 13.8 kV, a subtransient reactance of 12.8%, and an X/R ratio of 35.7. The reactance of the generator on the common system MVA base of 10 MVA is found to be

$$X_{\text{p.u., new}} = \frac{\text{MVA}_{\text{new}}}{\text{MVA}_{\text{old}}}\frac{V^2_{\text{old}}}{V^2_{\text{new}}}\frac{13.8^2}{13.8^2}0.128 = 0.1024 \text{ p.u.}$$

The generator impedance, for the given X/R ratio, therefore becomes

$$Z_{\text{p.u.}} = \frac{0.1024}{35.7} + \text{j}0.1024 = 0.002868 + \text{j}0.1024 \text{ p.u.}$$

For the example at hand, it will be assumed that all generators are turbo generators, thus ac decrement impedance correction factors will be equal to 1.00 for interrupting duty calculations.

7.7.3.6 Synchronous motor per-unit impedance

Consider the synchronous motor connected at bus 8-FDR-L. This motor has a subtransient reactance of 20.00%, an X/R ratio of 34.00, and is rated 9000 kVA at 13.8 kV. The motor impedance, expressed on a 10 MVA, 13.8 kV base reference, will then be

$$Z_{\text{syn p.u.}} = \left(\frac{0.20}{3.40} + \text{j}0.20\right) \frac{10.00}{9.000} \frac{13.8^2}{13.8^2} = 0.006534 + \text{j}0.2222 \text{ p.u.}$$

The impedance calculated for the synchronous motor is applicable to both first cycle and interrupting calculations (see Table 7-2).

7.7.3.7 Induction motor per-unit impedances

7.7.3.7.1 Small induction motors

The motor load at bus 51-AUX partly consists of many small motors rated below 50 hp, totaling 570 hp, connected at 480 V, rotating at 1800 r/min. Assuming a total equivalent locked rotor reactance of 16.7% and an X/R ratio of 12.00, the per-unit impedance of the group of motors becomes

$$Z_{\text{p.u.}} = \left(\frac{0.167}{12.00} + \text{j}0.167\right) \frac{10.00}{0.570} \frac{0.48^2}{0.48^2} 1.67 = 0.40773 + \text{j}4.89278 \text{ p.u.}$$

Alternative interpretations of IEEE Std C37.010-1979 and IEEE Std C37.13-1990, governing first-cycle duty calculations, recommend omitting these motors for medium- and high-voltage, while considering them for low-voltage calculations. By applying the factor 1.67, both high- and how-voltage circuits are modeled in one network and a single computer simulation will suffice. For medium- and high-voltage interrupting duty calculations, these motors are neglected (see Table 7-2).

7.7.3.7.2 Medium-sized induction motors

The motor load at bus 51-AUX also comprises a medium-sized induction motor, rotating at 1800 r/min, rated 200 kVA (200 hp with 0.746 power factor) at 480 V, with a locked rotor reactance of 16.7% and an X/R ratio of 7.00. According to Table 7-2, the per-unit motor impedances to be used in first cycle (impedance adjustment factor of 1.2) and interrupting duty (impedance adjustment factor of 3.0) calculations are

$$Z_{\text{first cycle p.u.}} = \left(\frac{0.167}{7.00} + \text{j}0.167\right) \frac{10.00}{0.200} \frac{0.48^2}{0.48^2} 1.20 = 1.43143 + \text{j}10.0200 \text{ p.u.}$$

$$Z_{\text{inter. p.u.}} = \left(\frac{0.167}{7.00} + \text{j}0.167\right) \frac{10.00}{0.200} \frac{0.48^2}{0.48^2} 3.00 = 3.57858 + \text{j}25.0500 \text{ p.u.}$$

7.7.4 Example system data

The data for the example system components are shown in Tables 7-5 through 7-12. The data for rotating equipment and transformers are presented in raw form, as would typically be seen on the nameplates of the various apparatus.

Table 7-5—Example system generator data

GEN-ID	Rated kV	Rated MVA	X''_d (%)	X/R ratio	X_o (%)	X_o/R_o ratio
GEN-1	13.8	15.625	0.11200	37.4	5.7	37.4
GEN-2	13.8	12.50	12.8	35.7	5.80	35.7

Table 7-6—Example system utility interconnection data

Connection point	3PH-MVA	X/R ratio	L-G MVA level	X/R ratio
UTIL-1	1000.00	22.00	765.00	9.70

Table 7-7—Example system overhead line data (impedances in Ω/mi)

Line ID	Rated kV	Conductor size	R_1 (Ω/mi)	X_1 (Ω/mi)	Length (mi)
L-1	69.00	266.8 MCM	.34940	.744063	1.894
L-2	69.00	266.8 MCM	.34940	.744063	1.894

Table 7-8—Example system fixed-tap transformer data

XMR ID	Rated MVA	Primary		Secondary		Z_1 (%)	X_1/R_1 ratio	Z_o (%)	X_o/R_o ratio
		kV	Bus	kV	Bus				
T-1	15.0	69.00	01	13.80	03	8.00	17.000	7.20	17.000
T-10	1.50	13.80	25	0.48	28	5.75	6.500	5.75	6.500
T-11	1.50	13.80	26	0.48	29	5.75	6.500	5.50	6.500
T-12	1.50	13.80	27	0.48	30	5.75	6.500	5.50	6.500
T-13	2.50	13.80	31	2.40	36	5.75	10.000	50.00	10.000

Table 7-8—Example system fixed-tap transformer data (*Continued*)

XMR ID	Rated MVA	Primary		Secondary		Z_1 (%)	X_1/R_1 ratio	Z_0 (%)	X_0/R_0 ratio
		kV	Bus	kV	Bus				
T-14	1.00	13.80	32	0.48	37	5.75	5.500	50.00	5.500
T-17	1.25	13.80	05	0.48	49	4.50	6.000	4.50	6.000
T-18	1.50	13.80	50	0.48	51	5.75	5.914	5.75	5.910
T-2	15.0	69.00	02	13.80	04	8.00	17.00	7.40	17.000
T-3	1.725	13.80	05	4.16	39	6.00	8.000	6.00	8.000
T-4	1.50	13.80	06	2.40	11	5.50	6.500	5.50	6.500
T-5	1.50	13.80	12	0.48	17	6.75	6.500	6.75	6.500
T-6	1.50	13.80	13	0.48	18	5.75	6.500	5.75	6.500
T-7	3.75	13.80	06	5.50	19	5.50	12.000	5.50	12.000
T-8	3.75	13.80	15	2.40	20	5.50	12.000	5.50	12.000
T-9	0.75	13.80	16	0.48	21	5.75	5.000	5.50	5.000

Table 7-9—Example system busway data (impedances in Ω/100 ft)

Busway ID	Rated kV	Size (A)	R_1 (Ω)	X_1 (Ω)	Length (ft)	From bus	To bus
SQD-I-Li	0.48	1000	0.0016	0.0010	50.0	28	41

7.7.5 Results

It is not uncommon for computer programs to automatically perform the conversion of the raw system data to per-unit data ready to be used by the computer package. The results of such a conversion are illustrated in Figure 7-2, as reported by the computer program. These data consist of transformer, cable, and line data.

Furthermore, since the study is to follow IEEE Std 141-1993 and IEEE Std 242-1986 and is carried out for switchgear adequacy verification purposes, two separate studies are required. Both simulations will generate three-phase fault currents, the first, yielding the first-cycle fault currents (also known as momentary or close- and latch-currents), and the second, providing the interrupting currents. Strictly speaking, the same studies should be repeated for line-to-ground faults if system conditions conducive to the generation of line-to-ground fault currents could exceed the three-phase fault-interrupting requirements (see 7.2).

Table 7-10—Example system cable data (impedances in Ω/1000 ft)

Cable ID	kV	Length (ft)	From bus	To bus	R_1 (Ω)	X_1 (Ω)	R_0 (Ω)	X_0 (Ω)
C-E1	13.8	650	03	09	0.04404	0.03668	0.0808	0.07336
C-E2	13.8	1833	09	25	0.04404	0.03668	0.08808	0.07336
C-E3	13.8	75	09	13	0.04404	0.03668	0.08808	0.07336
C-E4	13.8	165.0	09	12	0.04404	0.03668	0.08808	0.07336
C-F1	13.8	325.0	03	05	0.04404	0.03668	0.08808	0.07336
C-G1	13.8	680.0	03	26	0.04404	0.03668	0.08808	0.07336
C-H1	13.8	471.0	03	06	0.04404	0.03668	0.08808	0.07336
C-I1	13.8	980.0	04	15	0.04404	0.03668	0.08808	0.07336
C-J2	13.8	619.0	04	27	0.04404	0.03668	0.08808	0.07336
C-J3	13.8	1187.0	16	04	0.04404	0.03668	0.08808	0.07336
C-J4	13.8	200.0	10	13	0.04404	0.03668	0.08808	0.07336
C-J5	13.8	10.0	10	12	0.04404	0.04214	0.08808	0.08429
C-J6	13.8	475.0	10	27	0.04404	0.03668	0.08808	0.07336
C-L1	13.8	510.0	04	08	0.02831	0.03424	0.05661	0.06847
C-M1	13.8	510.0	04	24	0.04404	0.03668	0.08808	0.07336
C-M2	13.8	340.0	24	31	0.04404	0.03668	0.08808	0.07336
C-M3	13.8	485.0	24	32	0.04404	0.03668	0.08808	0.07336
C-T10-1	0.48	50.0	28	38	0.02801	0.02699	0.05602	0.05399
C-T10-2	0.48	20.0	33	28	0.04393	0.02823	0.08786	0.05645
C-T11-1	0.48	66.0	29	38	0.04393	0.02699	0.05602	0.05399
C-T11-2	0.48	20.0	34	29	0.04393	0.02823	0.08786	0.05645
C-T12-1	0.48	50.0	38	30	0.02801	0.02699	0.05602	0.05399
C-T12-2	0.48	20.0	35	30	0.04393	0.02823	0.08786	0.05645
C-T5-1	0.48	20.0	22	17	0.04393	0.02823	0.08786	0.05645
C-T6-1	0.48	20.0	23	18	0.04393	0.02823	0.08786	0.05645
C1A	13.80	2000.0	50	03	0.02314	0.04622	0.02083	0.41595

Table 7-11—Example system synchronous motor data

Motor ID	Motor bus #	Rated kV	Rated kVA	Rated hp	r/min	X''_d (%)	X/R ratio
M-FDR-L	8	13.8	9000	9000	1800	20.0	34.0

Table 7-12—Example system induction motor data

Motor ID	Motor bus #	Total hp	Total kVA	r/min	Rated kV	X_M (%)	X/R ratio	Composition (hp)
M-30	51	200.0	200.0	1800	0.480	16.7	7.00	>50
M-31	51	600.0	570.0	1800	0.480	16.7	12.00	<50
M-T10-1	28	400.0	400.0	1800	0.480	16.7	10.00	<50
M-T10-2	28	500.0	500.0	1800	0.480	16.7	5.00	>50
M-T10-3	33	300.0	287.5	1800	0.480	16.7	12.00	<50
M-T11-1	29	625.0	625.0	1800	0.480	16.7	10.00	>50
M-T11-2	29	465.0	465.0	1800	0.480	16.7	5.00	<50
M-T11-3	34	110.0	110.0	1800	0.480	16.7	7.00	<50
M-T12-1	30	400.0	387.9	1800	0.480	16.7	12.00	>50
M-T12-2	30	500.0	500.0	1800	0.480	16.7	5.00	<50
M-T12-3	35	300.0	287.5	1800	0.480	16.7	12.00	<50
M-T13-1	36	2500.0	2250.0	1800	2.30	16.7	32.85	>50
M-T14-1	37	700.0	678.8	1800	0.480	16.7	12.00	>50
M-T14-2	37	300.0	300.0	1800	0.480	16.7	5.00	<50
M-T17-1	49	1250.0	1250.0	1800	0.460	33.0	10.00	>1000
M-T3-1	39	1750.0	1662.5	1800	4.160	16.7	29.74	>1000
M-T4-1	11	500.0	475.0	1800	2.400	16.7	12.00	>50
M-T5-1	17	850.0	824.2	1800	0.480	16.7	10.00	<50
M-T5-2	17	500.0	500.0	1800	0.480	16.7	5.00	>50
M-T5-3	22	150.0	142.5	1800	0.480	16.7	14.00	<50
M-T6-1	18	850.0	824.2	1800	0.480	16.7	10.00	<50
M-T6-2	18	500.0	500.0	1800	0.480	16.7	5.00	>50

Table 7-12—Example system induction motor data (*Continued*)

Motor ID	Motor bus #	Total hp	Total kVA	r/min	Rated kV	X_M (%)	*X*/*R* ratio	Composition (hp)
M-T6-3	23	150.0	142.5	1800	0.480	16.7	14.00	<50
M-T7-1	19	1250.0	1125.0	1800	2.400	16.7	26.10	>1000
M-T7-2	19	2500.0	2375.0	1800	2.400	16.7	15.00	>1000
M-T8-1	20	1750.0	1662.5	1800	2.400	16.7	15.00	>1000
M-T8-2	20	2000.0	1800.0	1800	2.400	28.0	26.00	>1000
M-T9-1	21	750.0	727.3	1800	0.480	16.7	12.00	<50

NOTE—The motor load M-T17-1 at bus 49 (RECT) signifies a dc rectifier load and has been modeled as an induction motor. The reactance was taken to be 33% (0.33 p.u.) considering the rated MVA of the associated converter transformer, in accordance with Internationally accepted recommendations. The dc rectifier load will be considered only for first-cycle simulation purposes and ignored for interrupting duty.

From bus #	To bus #	Crkt #	Impedances			From kV	To kV	Tap
			R(p.u.)	*X*(p.u.)	*R*(p.u.)			
1	3	1	.00313	.05324	0.0	69.00	13.800	1.00
2	4	1	.00313	.05324	0.0	69.00	13.800	1.00
5	39	1	.04314	.34514	0.0	13.80	4.160	1.00
5	49	1	.05918	.35510	0.0	13.80	.480	1.00
6	11	1	.05575	.36240	0.0	13.80	2.400	1.00
6	19	1	.01218	.14616	0.0	13.80	2.400	1.00
12	17	1	.06843	.44477	0.0	13.80	.480	1.00
13	18	1	.05829	.37888	0.0	13.80	.480	1.00
15	20	1	.01218	.14616	0.0	13.80	2.400	1.00
16	21	1	.15036	.75178	0.0	13.80	.480	1.00
25	28	1	.05829	.37888	0.0	13.80	.480	1.00
26	29	1	.05829	.37888	0.0	13.80	.480	1.00
27	30	1	.05829	.37888	0.0	13.80	.480	1.00

Figure 7-2—Positive sequence system branch data (p.u., 10 MVA)

From bus #	To bus #	Crkt #	Impedances			From kV	To kV	Tap
			R(p.u.)	*X*(p.u.)	*R*(p.u.)			
31	36	1	.02289	.22886	0.0	13.80	2.400	1.00
32	37	1	.10286	.56573	0.0	13.80	.480	1.00
50	51	1	.06395	.37796	0.0	13.80	.480	1.00
3	5	1	.00075	.00063	0.0			
3	6	1	.00109	.00091	0.0			
3	9	1	.00150	.00125	0.0			
3	26	1	.00157	.00131	0.0			
4	8	1	.00076	.00092	0.0			
4	15	1	.00227	.00189	0.0			
4	24	1	.00118	.00098	0.0			
4	16	1	.00274	.00229	0.0			
4	27	1	.00143	.00119	0.0			
9	12	1	.00038	.00032	0.0			
9	25	1	.00424	.00353	0.0			
10	13	1	.00046	.00039	0.0			
10	27	1	.00110	.00091	0.0			
17	22	1	.03813	.02451	0.0			
18	23	1	.03813	.02451	0.0			
24	31	1	.00079	.00065	0.0			
24	32	1	.00112	.00093	0.0			
28	33	1	.03813	.02451	0.0			
28	41	1	.03429	.02105	0.0			
29	34	1	.03813	.02451	0.0			
29	38	1	.08024	.07732	0.0			
29	38	2	.08024	.07732	0.0			
30	35	1	.03813	.02451	0.0			
50	3	1	.00243	.00485	0.0			
50	3	2	.00243	.00485	0.0			

Figure 7-2—Positive sequence system branch data (p.u., 10 MVA) (*Continued*)

From bus #	To bus #	Crkt #	Impedances			From kV	To kV	Tap
			R(p.u.)	*X*(p.u.)	*R*(p.u.)			
100	1	1	.00139	.00296	0.0			
100	2	1	.00139	.00296	0.0			

Figure 7-2—Positive sequence system branch data (p.u., 10 MVA) (*Continued*)

Both studies are needed for medium- and high-voltage breaker calculations (above 1kV) while only the first one is needed for low-voltage breakers (below 1 kV). The generator impedances utilized for the first cycle and interrupting duty studies are shown in Figure 7-3 (from Table 7-2). The motor impedances used for momentary and Interrupting calculations are shown in Figure 7-4 (from Table 7-2). It can be seen that small induction motors (individual motors or groups of motors composed from motors smaller than 50 hp) are neglected for interrupting duty calculations (Table 7-2).

Generator bus #	Bus kV	Generator impedances			
		R'_d	X'_d	R''_d	X''_d
4	13.80	0.003	0.102	0.003	0.102
50	13.80	0.002	0.072	0.002	0.072
100	69.00	0.000	0.010	0.000	0.010

Figure 7-3—Generator impedances for momentary and interrupting duty (p.u., 10 MVA)

Motor bus #	Bus kV	Motor		Motor MVA	Motor impedances			
		#	Type		R_{mom}	X_{mom}	R_{inter}	X_{inter}
11	2.40	1	IM	0.4750	0.352	4.219	0.879	10.547
17	0.48	1	IM	0.8242	0.338	3.384		
17	0.48	1	IM	0.5000	0.802	4.008	2.004	10.020
18	0.48	1	IM	0.8242	0.338	3.384		
18	0.48	1	IM	0.5000	0.802	4.008	2.004	10.020

Figure 7-4—Motor impedances for momentary and interrupting duty (p.u., 10 MVA)

Motor bus #	Bus kV	Motor		Motor MVA	Motor impedances			
		#	Type		R_{mom}	X_{mom}	R_{inter}	X_{inter}
19	2.40	1	IM	1.1250	0.057	1.484	0.085	2.227
19	2.40	1	IM	2.3750	0.047	0.703	0.070	1.055
20	2.40	1	IM	1.6625	0.067	1.005	0.100	1.507
20	2.40	1	IM	1.8000	0.060	1.556	0.090	2.333
21	0.48	1	IM	0.7273	0.320	3.835		
22	0.48	1	IM	0.1425	1.398	19.571		
23	0.48	1	IM	0.1425	1.398	19.571		
28	0.48	1	IM	0.5000	0.697	6.972		
28	0.48	1	IM	0.4000	0.802	4.008	2.004	10.020
29	0.48	1	IM	0.6250	0.321	3.206	0.802	8.016
29	0.48	1	IM	0.4650	1.199	5.998		
30	0.48	1	IM	0.3879	0.431	5.166	1.077	12.916
30	0.48	1	IM	0.5000	1.116	5.578		
33	0.48	1	IM	0.2875	0.809	9.701		
34	0.48	1	IM	0.1100	3.621	25.354		
35	0.48	1	IM	0.2875	0.809	9.701		
36	2.40	1	IM	2.2500	0.025	0.818	0.062	2.045
37	0.48	1	IM	0.6788	0.246	2.952	0.615	7.381
37	0.48	1	IM	0.3000	1.859	9.296		
39	4.16	1	IM	1.6625	0.034	1.005	0.051	1.507
49	0.48	1	IM	1.2500	0.264	2.640		
51	0.48	1	IM	0.2000	1.432	10.020	3.579	25.050
51	0.48	1	IM	0.5700	0.408	4.893		
8	13.80	1	SM	9.0000	0.006	0.222	0.010	0.333

Figure 7-4—Motor impedances for momentary and interrupting duty (p.u., 10 MVA) (*Continued*)

Typical information pertinent to first-cycle duty calculations is shown in Table 7-4. The symmetrical first cycle fault currents along with the total asymmetrical rms currents using the standard 1.6 multiplier (assuming an X/R ratio of 25 or less), as well as using the asymmetrical multiplier, calculated from the actual system *X*/*R* ratio at the fault point. Similar information is shown for the peak currents. First-cycle asymmetrical fault currents are used to assess the closing and latching duty of medium- and high-voltage circuit breakers. These currents can be either total asymmetrical rms currents (ANSI C37.06-1979) or peak currents (ANSI Std C37.06-1987).

Typical information pertinent to interrupting duty calculations is shown in Figure 7-6. The same type of information as in Figure 7-5 is essentially displayed, except that in this case the multipliers applicable to both local and remote contributions are reported with reference to both breaker rating structures covered in IEEE Std C37.010-1979 and IEEE Std C37.5-1979. Total asymmetrical interrupting currents are also reported, thus yielding the interrupting requirements.

Fault at bus			**Prefault**				
#	**ID**	**Zone**	**Voltage (kV)**		**Angle (degrees)**		
19	T7SEC	5	2.40		0.00		
Current during fault					**Voltage-to-ground during fault**		
Type	**p.u.**	**Degrees**	**Amperes**	**MVA**	**p.u.**	**Angle (degrees)**	**Module (kV)**
LLL-A	7.67	–85.54	18 449	77	0.00	0.00	0.00
Equivalent impedance (p.u.)			***X*/*R* (IEEE Std C37.010-1979)**		**X_{eq} (IEEE Std C37.010-1979)**		
ZQQ-1 = 0.0101 + j0.1300			13.69		0.1300		
Total asymmetrical first-cycle current							
Based on 1.6 multiplier (IEEE Std C37.010-1979)				**Based on actual *X*/*R* ratio**			
18 449 × 1.60 = 29 520 A				18 449 × 1.505 = 27 765 A			
Peak current							
Based on 2.7 multiplier				**Based on actual *X*/*R* ratio**			
18 449 × 2.70 = 49 812 A				18 449 × 2.541 = 46 879 A			
First ring contributions from:							
Bus			**Prefault**				
#	**ID**	**Zone**	**Voltage (kV)**		**Angle (degrees)**		
6	FDR-H 2	1	13.80		0.00		
Current during fault					**Voltage-to-ground during fault**		
Type	**p.u.**	**Degrees**	**Amperes**	**MVA**	**p.u.**	**Angle (degrees)**	**Module (kV)**
LLL-A	5.57	–85.11	13 418	56	0.82	–29.87	6.51
Transfer impedance (p.u.)							
ZQP-1 = 0.0021 + j0.0236							

Figure 7-5—Typical results for first cycle duty calculations

First ring contribution from:				
1 ind. motor(s) each rated 1.13 MVA				
Current during fault				
Type	**p.u.**	**Degrees**	**Amperes**	**MVA**
LLL-A	0.67	–87.81	1619	7
First ring contribution from:				
1 ind. motor(s) each rated 2.38 MVA				
Current during fault				
Type	**p.u.**	**Degrees**	**Amperes**	**MVA**
LLL-A	1.42	–86.19	3414	14

Figure 7-5—Typical results for first cycle duty calculations (*Continued*)

Fault at bus			Prefault				
#	**ID**	**Zone**	**Voltage (kV)**		**Angle (degrees)**		
10	EMERG	2	13.80		0.00		
Current during fault					**Voltage-to-ground during fault**		
Type	**p.u.**	**Degrees**	**Amperes**	**MVA**	**p.u.**	**Angle (degrees)**	**Module (kV)**
LLL-A	27.77	–83.05	11 616	278	0.00	0.00	0.00
Equivalent impedance (p.u.)				**X/R (IEEE Std C37.010-1979)**		**X_{eq} (IEEE Std C37.010-1979)**	
ZQQ-1 = 0.0044 + j0.0358				8.950		0.0360	
Local and remote contribution from generating stations							
Local/total				**Remote/total**			
49.2%				50.8%			
Asymmetrical multipliers for 5 cycle breakers/3 cycles parting time (IEEE Std C37.010-1979)							
IEEE Std C37.010-1979 (local)		**IEEE Std C37.010-1979 (remote)**		**IEEE Std C37.5-1979 (local)**		**IEEE Std C37.5-1979 (remote)**	
1.00		1.00		1.00		1.00	
Total asymmetrical interrupting fault currents							
IEEE Std C37.010-1979 (weighted)		**IEEE Std C37.010-1979 (remote)**		**IEEE Std C37.5-1979 (weighted)**		**IEEE Std C37.5-1979 (weighted)**	
11619 A		11619 A		11619 A		11619 A	
First ring contributions from:							
Bus			**Prefault**				
#	**ID**	**Zone**	**Voltage (kV)**		**Angle (degrees)**		
13	T6PRI	1	13.80		0.00		

Figure 7-6—Typical results for interrupting duty calculations

Current during fault					Voltage-to-ground during fault		
Type	p.u.	Degrees	Amperes	MVA	p.u.	Angle (degrees)	Module (kV)
LLL-A	0.09	–78.76	39	1	0.0	00.00	0.00
Transfer impedance (p.u.)							
ZQP-1 = 0.0021 + j0.0236							
First ring contribution from:							
Bus			Prefault				
#	ID	Zone	Voltage (kV)		Angle (degrees)		
27	T12PRI	1	13.80		0.00		
Current during fault					Voltage-to-ground during fault		
Type	p.u.	Degrees	Amperes	MVA	p.u.	Angle (degrees)	Module (kV)
LLL-A	27.67	–83.07	11577	277	0.04	–43.47	0.32
Transfer impedance (p.u.)							
ZQP-1 = 0.0033 + j0.0348							

Figure 7-6—Typical results for interrupting duty calculations (*Continued*)

Typical computer-generated results for first-cycle (fault at 3:MILL-1) and interrupting duty (fault at 5:FDR-F) are shown in Figures 7-7 and 7-8, respectively, in both tabular and graphical form.

7.8 References

This standard shall be used in conjunction with the following publications:

ANSI C37.06-1979, American National Standard for Switchgear—AC High-Voltage Breakers Rated on a Symmetrical Current Basis—Preferred Ratings and Related Interrupting Capabilities.[3]

ANSI C37.06-1987, American National Standard Preferred Ratings and Related Interrupting Capabilities for AC High-Voltage Breakers Rated on a Symmetrical Current Basis.

AS 3851-1991, The calculation of short-circuit currents in three-phase a.c. systems.[4]

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

[3]IEEE and ANSI C37 publications are available from the Institute of Electrical and Electronics Engineers, 445 Hoes Lane, P.O. Box 1331, Piscataway, NJ 08855-1331, USA.
[4]AS publications are available from Standards Australia, P.O. Box 1055, Strathfield, NSW 2135, Australia.

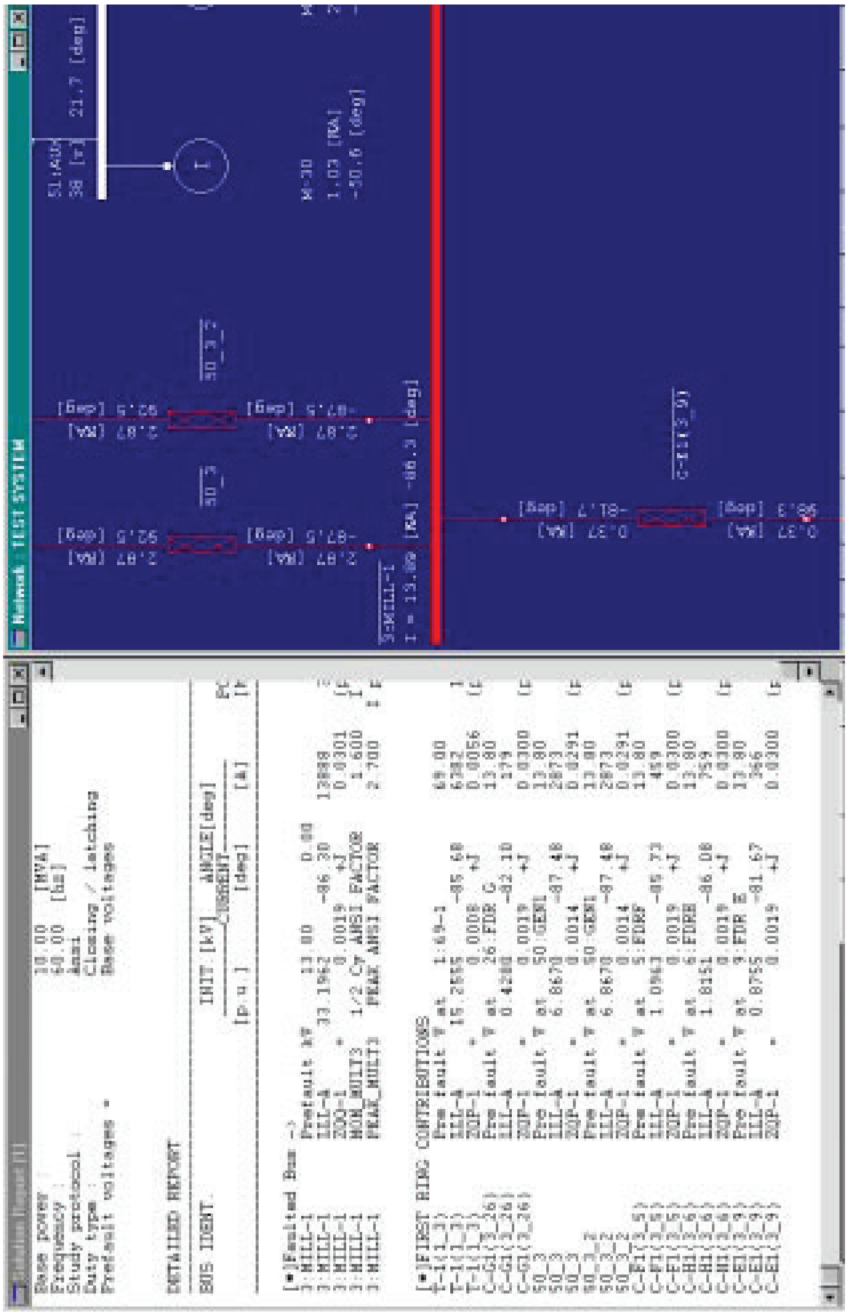

Figure 7-7—Typical computer reports for first-cycle duty calculations conformable to IEEE Std C37.010-1979

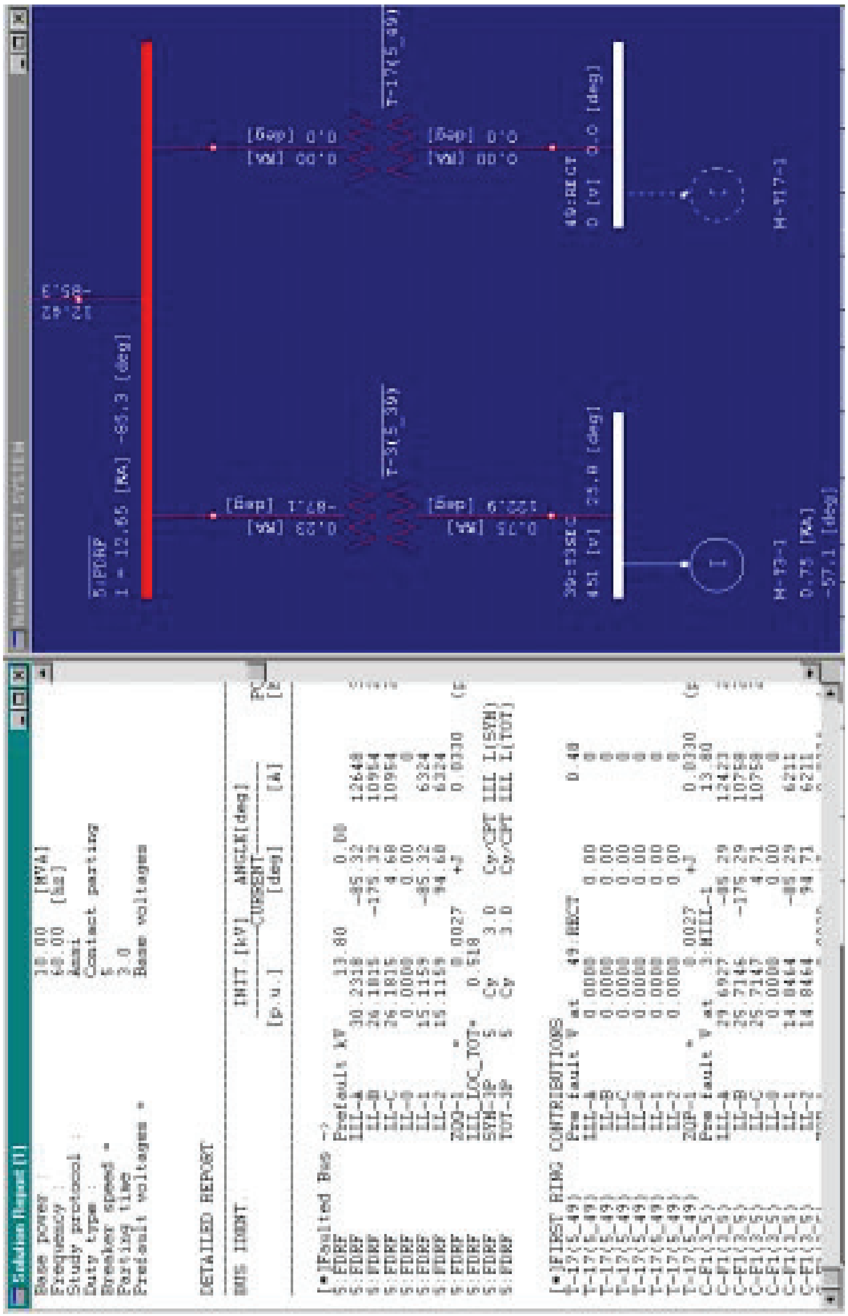

Figure 7-8—Typical computer reports for interrupting duty calculations conformable to IEEE Std C37.010-1979

IEEE Std 241-1990 (Reaff 1997), IEEE Recommended Practice for Electric Power Systems in Commercial Buildings (IEEE Gray Book).

IEEE Std 242-1986 (Reaff 1991), IEEE Recommended Practice for Protection and Coordination of Industrial and Commercial Power Systems (IEEE Buff Book).

IEEE Std C37.010-1979, IEEE Application Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis (includes supplement Std C37.010d).

IEEE Std C37.5-1979, IEEE Guide for Calculation of Fault Currents for Application of AC High-Voltage Circuit Breakers Rated on a Total Current Basis.[5]

IEEE Std C37.13-1990, IEEE Standard for Low-Voltage AC Power Circuit Breakers Used in Enclosures.

VDE 0102, Recommendation for the Calculation of Short Circuit Currents, Part 1: Three Phase systems of voltages above 1 KV, Issued by the Deutsche Elektrotechnische Kommission, Frankfurt, Germany, 1972 (VDE).

IEC 60909 (1988), Short-circuit current calculation in three phase a.c. systems.[6]

7.9 Bibliography

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[B2] Arrilaga J., Arnold, C. P, and Harker, B. J., *Computer Modelling of Electrical Power System*, New York: John Wiley & Sons, 1983.

[B3] Blackburn, L. J., *Symmetrical Components for Power Systems Engineering*, New York: Marcel Dekker, Inc., 1993.

[B4] Huening, W. C., Calculating short-circuit currents with contributions from induction motors, IEEE Transactions on Industry Applications, vol. IA-18, pp. 85–92, Mar./Apr. 1982.

[B5] Huening, W. C., Interpretation of new American National Standards for power circuit breaker applications. *IEEE Transactions on Industry and General Applications*, vol. IGA-5, Sep./Oct. 1969.

[B6] NFPA 70-1966, National Electric Code® (NEC®).

[5]This Standard has been withdrawn. Copies can be obtained for the IEEE Standards Department at (908) 562-3821.

[6]IEC publications are available from IEC Sales Department, Case Postale 131, 3, rue de Varembé, CH-1211, Genève 20, Switzerland/Suisse. IEC publications are also available in the United States from the Sales Department, American National Standards Institute, 11 West 42nd Street, 13th Floor, New York, NY 10036, USA.

[B7] Rodolakis, A. J., A comparison of North American (ANSI) and European (IEC) Fault calculation guidelines, *IEEE Transactions on Industry Applications*, vol. 29, No. 3, pp. 515–521, May/June 1993.

[B8] Roeper, R., *Short Circuit Currents in Three Phase Systems*, Siemens Actiengesellschaft, John Wiley & Sons, 1985.

[B9] Stagg, G. W., and El-Abiad, A. H., *Computer Methods in Power System Analysis*, New York: McGraw-Hill, 1968.

[B10] Stevenson, W. D., *Elements of Power System Analysis*, New York: McGraw-Hill, 1982.

[B11] St. Pierre, C. R., *Time Sharing Computer Programs (DATUMS) for Power Data Reduction*. Schenectady, NY: General Electric Company, 1973.

[B12] Tinney W., Brandwajn, V., and Chan, S., Sparse Vector Methods, *IEEE Transactions on Power Apparatus and Systems*, vol. PAS 104, pp. 295–301, Feb. 1985.

[B13] Wagner, C. F., and Evans, R. D., Symmetrical Components, New York: McGraw-Hill, 1933.