IEEE Std 141-1993
(Revision of IEEE Std 141-1986)

IEEE Recommended Practice for Electric Power Distribution for Industrial Plants

Sponsor

Power Systems Engineering Committee
of the
Industrial and Commercial Power Systems Department
of the
IEEE Industry Applications Society

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IEEE Standards Board

Abstract: A thorough analysis of basic electrical-systems considerations is presented. Guidance is provided in design, construction, and continuity of an overall system to achieve safety of life and preservation of property; reliability; simplicity of operation; voltage regulation in the utilization of equipment within the tolerance limits under all load conditions; care and maintenance; and flexibility to permit development and expansion. Recommendations are made regarding system planning; voltage considerations; surge voltage protection; system protective devices; fault calculations; grounding; power switching, transformation, and motor-control apparatus; instruments and meters; cable systems; busways; electrical energy conservation; and cost estimation.
Keywords: energy management, grounding, industrial power system, industrial power system economics, industrial power system planning, industrial power system protection, power cables, power distribution, power transformers, power system measurements, switches/switchgear, wiring

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Figure 6-11 from D. L. Beeman, Ed., *Industrial Power Systems Handbook,* McGraw-Hill, New York, NY, 1955.

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Introduction

(This introduction is not part of IEEE Std 141-1993, IEEE Recommended Practice for Electric Power Distribution for Industrial Plants.)

Development of the IEEE Red Book has been an evolving process. With the publication of IEEE Std 141-1993, the Red Book has been in print for about fifty years. Work began on the seventh edition in 1987 with the participation of more than seventy electrical engineers from industrial plants, consulting firms, equipment manufacturers, and academe. It was sponsored and the final version approved by the Power Systems Design Subcommittee of the Power Systems Engineering Committee, Industrial and Commercial Power Systems Department, IEEE Industry Applications Society. The seventh edition was approved by the IEEE Standards Board in 1993 as an IEEE Recommended Practice. It provides pertinent information and recommended practices for the design, construction, operation, and maintenance of electric power systems in industrial plants.

The first publication was developed in 1945 by the Committee on Industrial Power Applications of the American Institute of Electrical Engineers (AIEE). It was entitled *Electric Power Distribution for Industrial Plants* and sold for $1.00 a copy. It became known by the nickname "Red Book" because of its red cover, and a precedent was established for the present IEEE Color Book series, which now encompasses ten books.

The second edition was published in 1956. The committee responsible for its preparation had become a subcommittee of the Industrial Power Systems Committee of the AIEE. This edition was identified as AIEE Number 952.

By 1964, the AIEE had become the Institute of Electrical and Electronics Engineers and the third edition was identified as IEEE No. 141. The fourth edition was produced in 1969, approved as an IEEE Recommended Practice, and identified as IEEE Std 141-1969. The fifth edition, published in 1976, was IEEE Std 141-1976, and the sixth edition, published in 1986, became an American National Standard as well as an IEEE Recommended Practice, and was identified as ANSI/IEEE Std 141-1986.

The authors of this 1993 edition wish to acknowledge their indebtedness to the several hundred engineers whose expertise and work culminated in the six previous editions. The present stature of the Red Book would not have been achieved without their efforts.

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IEEE Recommended Practice for Electric Power Distribution for Industrial Plants

Chapter 1
Overview

1.1 Scope and general information

This publication provides a recommended practice for the electrical design of industrial facilities. It is likely to be of greatest value to the power-oriented engineer with limited industrial plant experience. It can also be an aid to all engineers responsible for the electrical design of industrial facilities. However, it is not intended as a replacement for the many excellent engineering texts and handbooks commonly in use, nor is it detailed enough to be a design manual. It should be considered a guide and general reference on electrical design for industrial plants and buildings.

Tables, charts, and other information that have been extracted from codes, standards, and other technical literature are included in this publication. Their inclusion is for illustrative purposes; where technical accuracy is important, the latest version of the referenced document should be consulted to assure use of complete, up-to-date, and accurate information.

It is important to establish, at the outset, the terms describing voltage classifications. Table 1-1, adapted from IEEE Std 100-1992 [B5],[1] indicates these voltage levels. The National Electrical Code, described in 1.5.1, uses the term *over 600 volts* generally to refer to what is known as *high voltage*. Many IEEE Power Engineering Society (PES) standards use the term *high voltage* to refer to any voltage higher than 1000. All nominal voltages are expressed in terms of root-mean-square (rms). For a detailed explanation of voltage terms, see Chapter 3. ANSI C84.1-1977 [B1] lists voltage class designations applicable to industrial and commercial buildings where medium voltage extends from 1000 V to 69 kV nominal.

1.2 Industrial plants

The term *industrial plants,* as used in this chapter, refers to industrial plants, buildings, and complexes where manufacturing, industrial production, research, and development are performed. It does not include commercial buildings, such as institutional, governmental, public, health-related office buildings, nor apartment and residential buildings.

If commercial buildings are included in industrial complexes, then the use of IEEE Std 241-1990 (the Gray Book) would be appropriate for these specific buildings. If medical facilities

[1]The numbers in brackets preceded by the letter B correspond to those of the bibliography in 1.21.

Table 1-1—Voltage classes

Voltage class	ANSI class	Nominal system voltage: Two wire	Three wire	Four wire	Maximum voltage
			Single-Phase Systems		
LOW VOLTAGE	SYSTEMS	*(120)*			*127*
			120/240		*127/254*
			Three-Phase Systems		
				208Y/120	220Y/127
			(240)	240/120	245/127
			480	480Y/277	508Y/293
			(600)		635
MEDIUM VOLTAGE	ANSI C84.1-1989 no voltage class stated		(2400)		2540
			4160	4160Y/2400	4400Y/2540
			(4800)		5080
			(6900)		7260
				(8320Y/4800)	8800Y/5080
				(12000Y/6930)	12700Y/7330
				12470Y/7200	13200Y/7620
				13200Y/7620	13970Y/8070
			13800	(13800Y/7970)	14520Y/8380
				(20780Y/12000)	22000Y/12700
				(22860Y/13200)	24200Y/13970
			(23000)		24340
				24940Y/14400	26400Y/15240
			(34500)	34500/19920	36510Y/21080
HIGH VOLTAGE	ANSI C84.1-1989 HIGHER VOLTAGE SYSTEMS		(46 kV)		48.3 kV
			69 kV		72.5 kV
			115 kV		121 kV
			138 kV		145 kV
			(161 kV)		169 kV
			230 kV		242 kV
EHV	ANSI C92.2-1987		345 kV		362 kV
EHV			500 kV		550 kV
EHV			765 kV		800 kV
			1100 kV		1200 kV

IEEE Std for Industrial & Commercial Power Systems

are included, IEEE Std 602-1986 (the White Book), should be consulted. (See 1.3.2 for a complete listing of the IEEE Color Books.)

The specific use of the facility or area in question, rather than the overall nature of the facility, determines its electrical design category. While industrial plants are primarily machine- and production-oriented; commercial, residential, and institutional buildings are primarily people- and public-oriented. The fundamental objective of industrial plant design is to provide a safe, energy-efficient, and attractive environment for the manufacturing, research, development, and handling of industrial products. The electrical design must satisfy these criteria if it is to be successful.

Today's industrial plants, because of their increasing size, more complex processes, and newer technologies, have become more and more dependent upon adequate and reliable electrical systems. The complex nature of modern industrial plants can be better understood by examining the systems, equipment, and facilities listed in 1.2.1.

1.2.1 System requirements for industrial plants

The systems and equipment that must be provided in order to satisfy functional requirements will vary with the type of facility, but will generally include some, or all, of the following:

— Building electric service;
— Power distribution systems for manufacturing and process equipment. Plant distribution system for "house loads";
— Power outlet systems for movable equipment: receptacles, trolley systems, plug-in and trolley-busways, festoon-cable systems, and heavy portable cord systems;
— Process control systems, including computer-based equipment such as programmable controllers, robotic equipment, and special-purpose controllers of the relay or solid-state types. On-line, real-time computer systems;
— Materials handling systems: cranes, hoists, distribution systems, automated systems that identify and distribute products (as well as update production data bases);
— Lighting: interior and exterior, security and decorative, task and general lighting;
— Communications: telephone, facsimile, telegraph, satellite link, building-to-building communications (including microwave), computer link, radio, closed-circuit television, code call, public-address paging, fiber-optic and electronic intercommunication, pneumatic tube, medical alert, emergency and medical call, and a variety of other signal systems;
— Fire alarm systems: fire pumps and sprinklers, smoke and fire detection, alarm systems, and emergency public-address systems. Emergency alarm systems relating to dangerous process control failure conditions;
— Transportation: passenger and freight elevators, moving stairways, and dumbwaiters;
— Space-conditioning: heating, ventilation, and air-conditioning. Ambient temperature and dew-point controls relating to the specific manufacturing processes;
— Sanitation: garbage and rubbish storage, recycling, compaction and removal, document disposal equipment, incinerators, and sewage handling. Handling and storage of environmentally hazardous and sensitive waste materials;
— Environmental containment of materials classified as hazardous to the environment, including maintenance of containment systems (e.g., pressure, temperature);
— Plumbing: hot and cold water systems and water-treatment facilities;
— Security watchmen, burglar alarms, electronic access systems, and closed-circuit surveillance television;

— Business machines: typewriters, computers, calculating machines, reproduction machines, and word processors;
— Refrigeration equipment;
— Compressed air, vacuum systems, process gas storage and handling systems;
— “Clean or secure areas” for isolation against contaminants and/or electromagnetic and radio-frequency interference (EMI/RFI);
— Food handling, dining and cafeteria, and food preparation facilities;
— Maintenance facilities;
— Lightning protection;
— Automated facility control systems;
— Showrooms, training areas;
— Medical facilities;
— Employee rest and recreational areas;
— In-plant generation, cogeneration, and total energy provisions. Legally required and optional standby/emergency power and peak-shaving systems;
— Signing, signaling, and traffic control systems. Parking control systems, including automated parking systems.

1.2.2 Electrical design elements

In spite of the wide variety of industrial buildings, some electrical design elements are common to all. These elements, listed below, will be discussed generally in this chapter and in detail in the remaining chapters of this Recommended Practice. The principal design elements considered in the design of the power, lighting, and auxiliary systems include the following:

— Magnitudes, quality, characteristics, demand, and coincidence or diversity of loads and load factors;
— Service, distribution, and utilization voltages and voltage regulation;
— Flexibility and provisions for expansion;
— Reliability, continuity;
— Safety of personnel and property;
— Initial and maintained cost (“own-and-operate” costs);
— Operation and maintenance;
— Fault current and system coordination;
— Power sources;
— Distribution systems;
— Legally required and optional standby/emergency power systems;
— Energy conservation, demand, and control;
— Conformity with regulatory requirements;
— Special requirements associated with industrial processes;
— Special requirements of the site related to seismic requirements [B5], altitude, sound levels, security, exposure to physical elements, fire hazards [B6], and hazardous locations. Power conditioning and uninterruptible power supplies (UPS) systems.

1.3 Industry Applications Society (IAS)

The IEEE is divided into 37 societies and technical councils that specialize in various technical areas of electrical and electronics engineering. Each group or society conducts meetings and publishes papers on developments within its specialized area.

The IAS currently encompasses 20 technical committees that cover the specific aspects of electrical engineering listed in 1.3.1, below. Papers of interest to electrical engineers and designers involved in the fields covered by the IEEE Red Book are, for the most part, contained in the *Transactions of the IAS*.

1.3.1 Committees within the IAS

The IAS is concerned with the power and control aspects of industrial plant and commercial buildings. To that end, in addition to the more general Power Systems Engineering and Power Systems Protection Committees within the Industrial and Commercial Power Systems Department, the following committees are involved with specific types of industries:

- Appliance Industry
- Cement Industry
- Electric Machines
- Electrostatic Processes
- Glass Industry
- Industrial Drives
- Industrial Automation and Control
- Industrial Power Converter
- Marine Transportation
- Metal Industry
- Mining Industry
- Petroleum and Chemical Industry
- Power Electronics Devices and Components
- Pulp and Paper Industry
- Rubber and Plastics Industry
- Rural Electric Power
- Textile, Fiber, and Film Industry

The Production and Application of Light (PALC), Power Systems Engineering, Power Systems Protection, Codes and Standards, Energy Systems, and Mining Safety Standards Committees of the IAS are involved with industrial power activities, and some publish material applicable to many types of industrial facilities.

All of the committees mentioned develop standards and articles for conference records and for the IAS Transactions. These publications deal with specialized electrical aspects of manufacturing and with electrical power and control systems for specific industries in greater detail than is possible in the Red Book.

1.3.2 The IEEE Color Books

The IEEE Red Book is one of a series of standards that are published by IEEE and are known as the IEEE Color Books. These standards are prepared by the Industrial and Commercial Power Systems Department of the IEEE Industry Applications Society. They are as follows:

— IEEE Std 141-1993, IEEE Recommended Practice for Electric Power Distribution for Industrial Plants (IEEE Red Book).
— IEEE Std 142-1991, IEEE Recommended Practice for Grounding of Industrial and Commercial Power Systems (IEEE Green Book).
— IEEE Std 241-1990, IEEE Recommended Practice for Power Systems in Commercial Buildings (IEEE Gray Book).
— IEEE Std 242-1986, IEEE Recommended Practice for Protection and Coordination of Industrial and Commercial Power Systems (IEEE Buff Book).
— IEEE Std 399-1990, IEEE Recommended Practice for Industrial and Commercial Power System Analysis (IEEE Brown Book).
— IEEE Std 446-1987, IEEE Recommended Practice for Emergency and Standby Power Systems for Industrial and Commercial Applications (IEEE Orange Book).
— IEEE Std 493-1990, IEEE Recommended Practice for the Design of Reliable Industrial and Commercial Power Systems (IEEE Gold Book).
— IEEE Std 602-1986, IEEE Recommended Practice for Electric Systems in Health Care Facilities (IEEE White Book).
— IEEE Std 739-1984, IEEE Recommended Practice for Energy Conservation and Cost-Effective Planning in Industrial Facilities (IEEE Bronze Book).
— IEEE Std 1100-1992, IEEE Recommended Practice for Powering and Grounding Sensitive Electronic Equipment (IEEE Emerald Book).

1.4 Professional registration

Most regulatory agencies require that design for public and other buildings be prepared under the jurisdiction of state-licensed professional architects or engineers. Information on such registration may be obtained from the appropriate state agency or from the local chapter of the National Society of Professional Engineers.

To facilitate obtaining registration in different states under the reciprocity rule, a National Professional Certificate is issued by the Records Department of the National Council of Engineering Examiners[2] to engineers who obtained their home-state license by examination. All engineering graduates are encouraged to start on the path to full registration by taking the engineer-in-training examination as soon after graduation as possible. The final written examination in the field of specialization is usually conducted after four years of progressive professional experience.

[2]P.O. Box 1686, Clemson, SC 29633-1686.

1.5 Professional liability

Recent court and regulatory decisions have held the engineer and designer liable for situations that have been interpreted as malpractice. These decisions have involved safety, environmental concerns, specification and purchasing practice, and related items. Claims for accidents, purportedly resulting from poor design or operating practice (e.g., too low lighting levels), have resulted in awards against engineering firms and design staff. Practicing engineers are encouraged to determine policies for handling such claims and to evaluate the need for separate professional liability insurance.

1.6 Codes and standards

1.6.1 National Electrical Code

The electrical wiring requirements of the National Electrical Code (NEC) (ANSI/NFPA 70-1993 [B1]), are vitally important guidelines for electrical engineers. The NEC is revised every three years. It is published by and available from the National Fire Protection Association (NFPA).[3] It is also available from the American National Standards Institute (ANSI)[4] and from each State's Board of Fire Underwriters (usually located in the State Capital). It does not represent a design specification but does identify minimum requirements for the safe installation and utilization of electricity. It is strongly recommended that the introduction to the NEC, Article 90, covering purpose and scope, be carefully reviewed.

The *NFPA Handbook of the National Electrical Code,* No. 70HB, sponsored by the NFPA, contains the complete NEC text plus explanations. This book is edited to correspond with each edition of the NEC. McGraw Hill's *Handbook of the National Electrical Code,* and other handbooks, provide explanations and clarification of the NEC requirements.

Each municipality or jurisdiction that elects to use the NEC must enact it into law or regulation. The date of enactment may be several years later than issuance of the code, in which event, the effective code may not be the latest edition. It is important to discuss this with the inspection or enforcing authority. Certain requirements of the latest edition of the Code may be interpreted as acceptable by the authority.

1.6.2 Other NFPA standards

The NFPA publishes the following related documents containing requirements on electrical equipment and systems:

— NFPA HFPE and Society of Fire Protection Engineers' *SFPE Handbook of Fire Protection Engineering*
— NFPA 101H, Life Safety Code Handbook
— NFPA 20, Centrifugal Fire Pumps, 1987

[3]Batterymarch Park, Quincy, MA 02269.
[4]11 West 42nd Street, 13th Floor, New York, NY 10036.

— NFPA 70B, Electrical Equipment Maintenance, 1990
— NFPA 70E, Electrical Safety Requirements for Employee Workplaces, 1988
— NFPA 72, National Fire Alarm Code
— NFPA 75, Protection of Electronic Computer/Data Processing Equipment, 1992
— NFPA 77, Static Electricity, 1993
— NFPA 78, Lightning Protection Code, 1992
— NFPA 79, Electrical Standard for Industrial Machinery, 1991
— NFPA 92A, Smoke Control Systems, 1993
— NFPA 99, Health Care Facilities, 1990: Chapter 8: Essential Electrical Systems for Health Care Facilities; Appendix E: The Safe Use of High Frequency Electricity in Health Care Facilities
— NFPA 101, Life Safety Code, 1991
— NFPA 110, Emergency and Standby Power Systems, 1993
— NFPA 130, Fixed Guideway Transit Systems, 1990

1.6.3 Local, state, and federal codes and regulations

While most municipalities, counties, and states use the NEC (either with or without modifications), some have their own codes. In most instances, the NEC is adopted by local ordinance as part of the building code. Deviations from the NEC may be listed as addenda. It is important to note that only the code adopted by ordinance as of a certain date is official, and that governmental bodies may delay adopting the latest code. Federal rulings may require use of the latest NEC rulings, regardless of local rulings, so that reference to the enforcing agencies for interpretation on this point may be necessary.

Some city and state codes are almost as extensive as the NEC. It is generally accepted that in the case of conflict, the more stringent or severe interpretation applies. Generally the entity responsible for enforcing (enforcing authority) the code has the power to interpret it. Failure to comply with NEC or local code provisions, where required, can affect the owner's ability to obtain a certificate of occupancy, may have a negative effect on insurability, and may subject the owner to legal penalty.

Legislation by the U.S. federal government has had the effect of giving standards, such as certain American National Standards Institute (ANSI) standards, the impact of law. The Occupational Safety and Health Act, administered by the U.S. Department of Labor, permits federal enforcement of codes and standards. The Occupational Safety and Health Administration (OSHA) adopted the 1971 NEC for new electrical installations and also for major replacements, modifications, or repairs installed after March 5, 1972. A few articles and sections of the NEC have been deemed by OSHA to apply retroactively. The NFPA created an NFPA 70E (Electrical Requirements for Employee Workplaces) Committee to prepare a consensus standard for possible use by OSHA in developing their standards. Major portions of NFPA 70E have been included in OSHA regulations.

OSHA requirements for electrical systems are covered in 29 CFR Part 1910 of the Federal Register.[5]

The U.S. National Institute of Occupational Safety and Health (NIOSH) publishes "Electrical Alerts" to warn of unsafe practices or hazardous electrical equipment.[6]

The U.S. Department of Energy, in Building Energy Performance Standards, has advanced energy conservation standards. A number of states have enacted energy conservation regulations. These include ASHRAE/IES legislation embodying various energy conservation standards, such as ASHRAE/IES 90.1P, Energy Efficient Design of New Buildings Except Low Rise Residential Buildings. These establish energy or power budgets that materially affect architectural, mechanical, and electrical designs.

1.6.4 Standards and Recommended Practices

A number of organizations, in addition to the NFPA, publish documents that affect electrical design. Adherence to these documents can be written into design specifications.

The American National Standards Institute (ANSI) coordinates the review of proposed standards among all interested affiliated societies and organizations to assure a consensus approval. It is, in effect, a clearing house for technical standards. Not all standards are ANSI-approved. Underwriters Laboratories, Inc. (UL), and other independent testing laboratories may be approved by an appropriate jurisdictional authority (e.g., OSHA) to investigate materials and products, including appliances and equipment. Tests may be performed to their own or to another agency's standards and a product may be "listed" or "labeled." The UL publishes an Electrical Construction Materials Directory, an Electrical Appliance and Utilization Equipment Directory, a Hazardous Location Equipment Directory, and other directories. It should be noted that other testing laboratories (where approved) and governmental inspection agencies may maintain additional lists of approved or acceptable equipment; the approval must be for the jurisdiction where the work is to be performed. The Electrification Council (TEC),[7] representative of investor-owned utilities, publishes several informative handbooks, such as the Industrial and Commercial Power Distribution Handbook and the Industrial and Commercial Lighting Handbook, as well as an energy analysis computer program, called AXCESS, for forecasting electricity consumption and costs in existing and new buildings.

The National Electrical Manufacturers Associations (NEMA)[8] represents equipment manufacturers. Their publications serve to standardize certain design features of electrical equipment and provide testing and operating standards for electrical equipment. Some NEMA

[5]The Federal Register is available from the Superintendent of Documents, U.S. Government Printing Office, Washington, DC 20402, (202) 783-3238 on a subscription or individual copy basis.

[6]Copies of the bulletin are available from NIOSH Publications Dissemination, 4676 Columbia Parkway, Cincinnati, OH 45226.

[7]1111 19th Street, NW, Washington, DC 20036.

[8]2101 L Street, NW, Suite 300, Washington, DC 20037.

standards contain important application information for equipment such as motors and circuit breakers.

The IEEE publishes several hundred electrical standards relating to safety, measurements, equipment testing, application, maintenance, and environmental protection. Also published are standards on more general subjects, such as the use of graphic symbols and letter symbols. The IEEE Standard Dictionary of Electrical and Electronics Terms is of particular importance.

The Electric Generating Systems Association (EGSA)[9] publishes performance standards for emergency, standby, and cogeneration equipment.

The Intelligent Buildings Institute (IBI)[10] publishes standards on the essential elements of "high-tech" buildings.

The Edison Electric Institute (EEI)[11] publishes case studies of electrically space-conditioned buildings as well as other informative pamphlets.

The International Electrotechnical Commission (IEC) is an electrical and electronic standards generating body with a multinational membership. The IEEE is a member of the U.S. National Committee of the IEC.

1.7 Handbooks

The following handbooks have, over the years, established reputations in the electrical field. This list is not intended to be all-inclusive; other excellent references are available but are not listed here because of space limitations.

— Fink, D. G. and Beaty, H. W., *Standard Handbook for Electrical Engineers,* 12th edition, McGraw-Hill,[12] 1987. Virtually the entire field of electrical engineering is treated, including equipment and systems design.
— Croft, T., Carr, C. C., and Watt, J. H., *American Electricians Handbook,* 11th edition, New York, McGraw-Hill, 1987. The practical aspects of equipment, construction, and installation are covered.
— *Lighting Handbook,* Illuminating Engineering Society (IES).[13] This handbook is in two volumes (Applications, 1987; Reference, 1984). All aspects of lighting, including visual tasks, recommended lighting levels, lighting calculations, and lighting design are included in extensive detail in this comprehensive text.

[9]P.O. Box 9257, Coral Springs, FL 33065.
[10]2101 L Street, NW, Washington, DC 20037.
[11]1111 19th Street, NW, Washington, DC 20036.
[12]1221 Avenue of the Americas, New York, NY 10020.
[13]345 East 47th Street, New York, NY 10017.

— *Electrical Transmission and Distribution Reference Book,* Westinghouse Electric Corporation,[14] 1964. All aspects of transmission, distribution, performance, and protection are included in detail.
— *Applied Protective Relaying,* Westinghouse Electric Corporation, 1976. The application of protective relaying to customer-utility interconnections, protection of high-voltage motors, transformers, and cable are covered in detail.
— *ASHRAE Handbook,* American Society of Heating, Refrigerating, and Air-Conditioning Engineers (ASHRAE).[15] This series of reference books in four volumes, which are periodically updated, details the electrical and mechanical aspects of space conditioning and refrigeration.
— *Motor Applications and Maintenance Handbook,* 2nd edition, Smeaton, R. S., editor, McGraw-Hill, 1987. Contains extensive, detailed coverage of motor load data and motor characteristics for coordination of electric motors with machine mechanical characteristics.
— *Industrial Power Systems Handbook,* Beeman, D. L., editor, McGraw-Hill, 1955. A text on electrical design with emphasis on equipment, including that applicable to commercial buildings.
— *Electrical Maintenance Hints,* Westinghouse Electric Corporation, 1984. The preventive maintenance procedures for all types of electrical equipment and the rehabilitation of damaged apparatus are discussed and illustrated.
— *Lighting Handbook,* Philips Lighting Company,[16] 1984. The application of various light sources, fixtures, and ballasts to interior and exterior commercial, industrial, sports, and roadway lighting projects.
— *Underground Systems Reference Book,* Edison Electric Institute, 1957. The principles of underground construction and detailed design of vault installations, cable systems, and related power systems are fully illustrated; cable splicing design parameters are thoroughly covered.
— *Switchgear and Control Handbook,* 2nd edition, Smeaton, R. S., editor, McGraw Hill, 1987. Concise, reliable guide to important facets of switchgear and control design, safety, application, and maintenance, including high- and low-voltage starters, circuit breakers, and fuses.
— *Handbook of Practical Electrical Design,* J. M. McPartland, Editor, McGraw Hill, 1984.

A few of the older texts may no longer be available for purchase but are available in most professional offices and libraries.

1.8 Periodicals

Spectrum, the monthly magazine of the IEEE that is circulated to all of its members, contains articles that cover current developments in all areas of electrical and electronics engineering. It contains references to IEEE books; technical publication reviews; technical meetings and

[14]Printing Division, Forbes Road, Trafford, PA 15085.
[15]1791 Tullie Circle, NE, Atlanta, GA 30329.
[16]200 Franklin Square Drive, P.O. Box 6800, Somerset, NJ 08875-6800.

conferences; IEEE group, society, and committee activities; abstracts of papers and publications of the IEEE and other organizations; and other material essential to the professional advancement of the electrical engineer.

The Transactions of the IAS of the IEEE are directly useful to industrial facility electrical engineers. Some other well-known periodicals follow:

— *ASHRAE Journal,* American Society of Heating, Refrigerating and Air-Conditioning Engineers
— *Electrical Construction and Maintenance (EC&M).* Intertec Publishing Corp.[17]
— *Fire Journal,* National Fire Protection Association (NFPA)
— *IAEI News,* International Association of Electrical Inspectors
— *Lighting Design and Application (LD&A),* Illuminating Engineering Society
— *Electrical Systems Design,* Andrews Communications, Inc.[18]
— *Engineering Times,* National Society of Professional Engineers (NSPE)[19]
— *Consulting-Specifying Engineer,* Cahners Publishing Co.[20]
— *Plant Engineering,* Cahners Publishing Co.

1.9 Manufacturers' Data

The electrical industry, through its associations and individual manufacturers of electrical equipment, issues many technical bulletins, data books, and magazines. While some of this information is difficult to obtain, copies should be available to each major design unit. The advertising sections of electrical magazines contain excellent material, usually well illustrated and presented in a clear and readable form, concerning the construction and application of equipment. Such literature may be promotional; it may present the advertiser's equipment or methods in a best light and should be carefully evaluated. Manufacturers' catalogs are a valuable source of equipment information. Some manufacturers' complete catalogs are quite extensive, covering several volumes. However, these companies may issue condensed catalogs for general use. A few manufacturers publish regularly scheduled magazines containing news of new products and actual applications. Data sheets referring to specific items are almost always available from marketing offices.

1.10 Safety

Safety of life and preservation of property are two of the most important factors in the design of the electrical system. In industrial facilities, continuity of the production and related processes may be critical. The loss of production may result in financial loss because of idle time for employees and machinery, the inability to meet schedules for deliveries, and materials handling and spoilage of materials in process. Safety considerations may be aggravated by

[17]1221 Avenue of the Americas, New York, NY 10020.
[18]5123 West Chester Pike, P.O. Box 556, Edgemont, PA 19028.
[19]1420 King Street, Alexandria, VA 22314.
[20]Cahners Plaza, 1350 East Touhy Avenue, P.O. Box, 508, Des Plaines, IL 60017-8800.

the sheer amount of complex electrical connections and the nature of the machinery. The poor quality or failure of electric power to equipment can cause, in some industrial processes, conditions that can result in hazardous situations. Electromagnetic interference (EMI) can cause safety controls to fail in marginally designed systems.

Various codes provide rules and regulations as minimum safeguards of life and property. The electrical design engineer may often provide greater safeguards than outlined in the codes, according to his or her best judgment, while also giving consideration to utilization and economics.

Personnel safety may be divided into two categories:

— Safety for maintenance and operating personnel;
— Safety for others, including visitors, production staff, and non-production staff in the vicinity.

Safety for maintenance and operating personnel is achieved through proper design and selection of equipment with regard to enclosures, key-interlocking, circuit breaker and fuse interrupting capacity, the use of high-speed fault detection and circuit-opening devices, clearances, grounding methods, and identification of equipment.

Safety for others requires that all circuit-making-and-breaking equipment, as well as other electrical apparatus, be isolated from casual contact. This is achieved by using dead-front equipment, locked rooms and enclosures, proper grounding, limiting of fault levels, installation of barriers and other isolation (including special ventilating grilles), proper clearances, adequate insulation, and similar provisions outlined in this standard.

The U.S. Department of Labor has issued the “OSHA Rule on Lockout/Tagout” published in the Federal Register (53 FR 1546, January 2, 1990), which is concerned with procedures for assuring the safety of workers directly involved in working with or near energized conductors or conductors which, if energized, could be hazardous.

The National Electrical Safety Code (NESC) (Accredited Standards Committee C2-1993) is available from the IEEE. It covers basic provisions for safeguarding from hazards arising from the installation operation or maintenance of a) conductors in electric supply stations, and b) overhead and underground electric supply and communication lines. It also covers work rules for construction, maintenance, and operation of electric supply and communication equipment. Part 4 deals specifically with safe working methods.

Circuit protection is a fundamental safety requirement of all electrical systems. Adequate interrupting capacities are required in services, feeders, and branch circuits. Selective, automatic isolation of faulted circuits represents good engineering. Fault protection, covered in Chapters 5 and 6, should be designed and coordinated throughout the system. Physical protection of equipment from damage or tampering, and exposure of unprotected equipment to electrical, chemical, and mechanical damage is necessary.

1.10.1 Appliances and equipment

Improperly applied or inferior materials can cause electrical failures. The use of appliances and equipment listed by UL, OSHA, or other approved laboratories is recommended. The Association of Home Appliance Manufacturers (AHAM)[21] and the Air-Conditioning and Refrigeration Institute (ARI)[22] specify the manufacture, testing, and application of many common appliances and equipment. High-voltage equipment and power cable is manufactured in accordance with UL, NEMA, ANSI, and IEEE standards. Engineers should make sure that the equipment they specify and accept conforms to these standards. Properly prepared specifications can prevent the purchase of inferior or unsuitable equipment. The lowest initial purchase price may not result in the lowest cost after taking into consideration operating, maintenance, and owning costs. Value engineering is an organized approach to the identification of unnecessary costs, which utilizes such methods as life-cycle cost analysis, and related techniques.

1.10.2 Operational considerations

When design engineers lay out equipment rooms and locate electrical equipment, they cannot always avoid having some areas accessible to unqualified persons. Dead-front construction should be utilized whenever practical. Where dead-front construction is not available, as may be the case for certain industrial configurations or in existing installations, all exposed electrical equipment should be placed behind locked doors or gates or otherwise suitably guarded. Proper barricading, signing, and guarding should be installed and maintained on energized systems or around machinery that could be hazardous, or is located in occupied areas. Work rules, especially in areas of medium or high voltage, should be established.

Work on energized power systems or equipment should be permitted only where qualified staff is available to perform such work and only if it is essential. This is foremost a matter of safety, but is also required to prevent damage to equipment. A serious cause of failure, attributable to human error, is unintentional grounding or phase-to-phase short circuiting of equipment that is being worked on. By careful design, such as proper spacing and barriers, and by enforcement of published work-safety rules, the designer can minimize this hazard. Unanticipated backfeeds through control circuitry, from capacitors, instrument transformers, or test equipment, presents a danger to the worker.

Protective devices, such as ground-fault relays and ground-fault detectors (for high-resistance or ungrounded systems), will minimize damage from electrical failures. Electrical fire and smoke can cause maintenance staff to disconnect all electric power, even if there is not direct danger to the occupants. Electrical failures that involve smoke and noise, even though occurring in unoccupied areas, may cause confusion to the working population. Nuisance tripping, which may interrupt industrial processes, can be minimized by careful design and selection of protective equipment.

[21]20 North Wacker Drive, Chicago, IL 60606.

[22]815 North Fort Myer Drive, Arlington, VA 22209.

1.11 Maintenance

Maintenance is essential to proper operation. The installation should be so designed that maintenance can be performed with normally available maintenance personnel (either in-house or contract). Design details should provide proper space, accessibility, and working conditions so that the systems can be maintained without difficulty and excessive cost.

Generally, the external systems are operated and maintained by the electrical utility, though at times they are a part of the plant distribution system. Where continuity of service is essential, suitable transfer equipment and alternate sources should be provided. Such equipment is needed to maintain minimum lighting requirements for passageways, stairways, and critical areas as well as to supply power to critical loads. These systems usually include automatic or manual equipment for transferring loads on loss of normal supply power or for putting battery or generator-fed equipment into service.

Annual or other periodic shut-down of electrical equipment may be necessary to perform required electrical maintenance. Protective relaying systems, circuit breakers, switches, transformers, and other equipment should be tested on appropriate schedules. Proper system design can facilitate this work.

1.12 Design considerations

Electrical equipment usually occupies a relatively small percentage of the total plant space and, in design, it may be easier to relocate electrical service areas than mechanical areas or structural elements. Allocation of space for electrical areas is often given secondary consideration by plant engineering, architectural, and related specialties. In the competing search for space, the electrical engineer is responsible for fulfilling the requirements for a proper electrical installation while recognizing the flexibility of electrical systems in terms of layout and placement.

It is essential that the electrical engineer responsible for designing plant power systems have an understanding of the manufacturing processes and work flow to the extent that he can form part of the planning team and assure that the optimum design is provided. In manufacturing areas, considerations of architectural finishes and permanence are usually secondary to production efficiency and flexibility. Special provisions could be required, as part of the manufacturing process, for reduction of EMI (see 1.19.3), for continuity of supply, and for complex control systems.

1.12.1 Coordination of design

Depending on the type and complexity of the project, the engineer will need to cooperate with a variety of other specialists. These potentially include mechanical, chemical, process, civil, structural, industrial, production, lighting, fire protection, and environmental engineers; maintenance planners; architects; representatives of federal, state, and local regulatory agencies; interior and landscape designers; specification writers; construction and installation contractors; lawyers; purchasing agents; applications engineers from major equipment suppliers and the local electrical utility; and management staff of the organization that will operate the facility.

The electrical designer must become familiar with local rules and know the authorities having jurisdiction over the design and construction. It can be inconvenient and embarrassing to have an electrical project held up at the last moment because proper permits have not been obtained; for example, a permit for a street closing to allow installation of utilities to the site or an environmental permit for an on-site generator.

Local contractors are usually familiar with local ordinances and union work rules and can be of great help in avoiding pitfalls. In performing electrical design, it is essential, at the outset, to prepare a checklist of all the design stages that have to be considered. Major items include temporary power, access to the site, and review by others. Certain electrical work may appear in non-electrical sections of the specifications. For example, furnishing and connecting of electric motors and motor controllers may be covered in the mechanical section of the specifications. For administrative control purposes, the electrical work may be divided into a number of contracts, some of which may be under the control of a general contractor and some of which may be awarded to electrical contractors. Among items with which the designer will be concerned are preliminary cost estimates, final cost estimates, plans or drawings, technical specifications (the written presentation of the work), materials, manuals, factory inspections, laboratory tests, and temporary power. The designer may also be involved in providing information on electrical considerations that affect financial justification of the project in terms of owning and operating costs, amortization, return on investment, and related items.

1.12.2 Flexibility

Flexibility of the electrical system means adaptability to development and expansion as well as to changes to meet varied requirements during the life of the facility. Sometimes a designer is faced with providing power in a plant where the loads may be unknown. For example, some manufacturing buildings are constructed with the occupied space designs incomplete (shell and core designs). In some cases, the designer will provide only the core utilities available for connection by others to serve the working areas. In other cases, the designer may lay out only the basic systems and, as the tenant requirements are developed, fill in the details. A manufacturing division or tenant may provide working space designs.

Because it is usually difficult and costly to increase the capacity of feeders, it is important that provisions for sufficient capacity be provided initially. Industrial processes, including manufacturing, may require frequent relocations of equipment, addition of production equipment, process modifications, and even movement of equipment to and from other sites; therefore, a high degree of system flexibility is an important design consideration.

Extra conductors or raceway space should be included in the design stage when additional loads are added. In most industrial plants, the wiring methods involve exposed conduits, cable trays, and other methods where future changes will not affect architectural finishes. When required, space must be provided for outdoor substations, underground systems including spare ducts, and overhead distribution.

Flexibility in an electrical wiring system is enhanced by the use of oversize or spare raceways, cables, busways, and equipment. The cost of making such provisions is usually relatively small in the initial installation. Space on spare raceway hangers and openings (sealed until needed) between walls and floors may be provided at relatively low cost for future work. Consideration should be given to the provision of electrical distribution areas for future expansion. Openings through floors should be sealed with fireproof (removable) materials to prevent the spread of fire and smoke between floors. For computer rooms and similar areas, flexibility is frequently provided by raised floors made of removable panels, providing access to a wiring space between the raised floor and the slab below.

Industrial facilities most frequently use exposed wiring systems in manufacturing areas for greater economy and flexibility. Plug-in busways and trolley-type busways can provide a convenient method of serving machinery subject to relocation. Cable trays for both power and control wiring are widely used in industrial plants. Exposed armored cable is a possible convenient method of feeding production equipment.

1.12.3 Specifications

A contract for installation of electrical systems consists of both a written document and drawings. The written document contains both legal (non-technical) and engineering (technical) sections. The legal section contains the general terms of the agreement between contractor and owner, such as payment, working conditions, and time requirements, and it may include clauses on performance bonds, extra work, penalty clauses, and damages for breach of contract.

The engineering section includes the technical specifications. The specifications give descriptions of the work to be done and the materials to be used. It is common practice in larger installations to use a standard outline format listing division, section, and subsection titles or subjects of the Construction Specifications Institute (CSI).[23] Where several specialties are involved, Division 16 covers the electrical installation and Division 15 covers the mechanical portion of the work. The building or plant automation system, integrating several building control systems, is covered in CSI Division 13—Special Construction. It is important to note that some electrical work will almost always be included in CSI Divisions 13 and 15. Division 16 has a detailed breakdown of various items, such as switchgear, motor starters, and lighting equipment, specified by CSI.

To assist the engineer in preparing contract specifications, standard technical specifications (covering construction, application, technical, and installation details) are available from technical publishers and manufacturers (which may require revision to avoid proprietary specifications). Large organizations, such as the U.S. Government General Services Administration and the Veterans Administration, develop their own standard specifications. The engineer should keep several cautions in mind when using standard specifications. First, they are designed to cover a wide variety of situations, and consequently they will contain considerable material that will not apply to the specific facility under consideration, and they may lack other material that should be included. Therefore, standard specifications must be appropri-

[23]601 Madison Avenue, Industrial Park, Alexandria, VA 22314.

ately edited and supplemented to embody the engineer's intentions fully and accurately. Second, many standard specifications contain material primarily for non-industrial facilities, and may not reflect the requirements of the specific industrial processes.

MASTERSPEC, issued by American Institute of Architects (AIA),[24] permits the engineer to issue a full-length specification in standardized format. SPECTEXT II, which is an abridged computer program with similar capabilities, is issued by CSI. CEGS and NFGS are the U.S. Army Corps of Engineers and the U.S. Naval Facilities Engineering Command Guide Specifications.

Computer-aided specifications (CAS) have been developed that will automatically create specifications as an output from the CAE-CADD process (see 1.12.4).

1.12.4 Drawings

Designers will usually be given preliminary architectural drawings as a first step. These drawings permit the designers to arrive at the preliminary scope of the work, roughly estimate the requirements, and determine in a preliminary way the location of equipment and the methods and types of lighting. In this stage of the design, such items as primary and secondary distribution systems and major items of equipment will be decided. The early requirements for types of machinery to be installed will be determined. If a typical plant of the type to be built or modernized exists, it would be well for the engineer to visit such a facility and to study its plans, cost, construction, and operational history.

Early in the design period, the designer should emphasize the need for room to hang conduits and cable trays, crawl spaces, structural reinforcements for equipment, and special floor loadings; and for clearances around substations, switchgear, transformers, busways, cable trays, panelboards, switchboards, and other items that may be required. It is much more difficult to obtain such special requirements once the design has been committed. The need for installing, removing, and relocating machinery must also be considered.

The one-line diagrams should then be prepared in conformity with the utility's service requirements. Based on these, the utility will develop a *service layout*. Checking is an essential part of the design process. The checker looks for design deficiencies in the set of plans. The designer can help the checker by having on hand reference and catalog information detailing the equipment he has selected. The degree of checking is a matter of design policy.

Computer-aided engineering (CAE) and computer-aided design and drafting (CADD) systems are tools by which the engineer/designer can perform automatic checking of interferences and clearances with other trades. The development of these computer programs has progressed to the level of automatically performing load-flow analysis, fault analysis, and motor-starting analysis from direct entry of the electrical technical data of the components and equipment.

[24]1735 New York Avenue, NW, Washington, DC 20006.

1.12.5 Manufacturer's or shop drawings

After the design has been completed and contracts are awarded, contractors, manufacturers and other suppliers will submit drawings for review or information. It is important to review and comment upon these drawings and return them as quickly as possible; otherwise, the supplier and/or contractor may claim that the work was delayed by the engineer's review process. Unless the drawings contain serious errors and/or omissions, it is usually a good practice not to reject them but to stamp the drawings with terminology such as "revise as noted" and mark them to show errors, required changes, and corrections. The supplier can then make appropriate changes and proceed with the work without waiting to resubmit the drawings for approval.

If the shop drawings contain major errors or discrepancies, however, they should be rejected with a requirement that they be resubmitted to reflect appropriate changes that are required on the basis of notes and comments of the engineer.

Unless otherwise directed, communication with contractors and suppliers is always through the construction (often inspection) authority. In returning corrected shop drawings, remember that the contract for supplying the equipment is usually with the general contractor and that the official chain of communication is through him or her. Sometimes direct communication with a subcontractor or a manufacturer may be permitted; however, the content of such communication should always be confirmed in writing with the general contractor. Recent lawsuits have resulted in placing the responsibility for shop drawing correctness (in those cases and possibly future cases) upon the design engineer, leaving no doubt that checking is an important job.

1.13 Estimating

A preliminary estimate is usually requested. Sometimes the nature of a preliminary estimate makes it nothing more than a good guess. Enough information is usually available, however, to perform the estimate on a square foot, per process machine, per production area, by the horsepower or number of motors, or on a similar basis for a comparable facility.

A second estimate is often provided after the project has been clearly defined but before any drawings have been prepared. The electrical designer can determine from sketches and architectural layouts the type of lighting fixtures as well as many items of heavy equipment that are to be used. Lighting fixtures, as well as most items of heavy equipment, can be priced directly from the catalogs, using appropriate discounts.

The most accurate estimate is made when drawings have been completed and bids are about to be received or the contract negotiated. The estimating procedure of the designer in this case is similar to that of the contractor's estimator. It involves first the takeoffs, that is, counting the number of receptacles, lighting fixtures, lengths of wire and conduit, determining the number and types of equipment, and then applying unit costs for labor, materials, overhead, and profit.

The use of standard estimating sheets is a big help. Various forms are available from the National Electrical Contractors' Association (NECA).[25] For preliminary estimates, there are a number of general estimating books that give unit cost figures (often per square foot) and other general costs, such as the following three titles: *Building Construction Cost Data; Mechanical Cost Data;* and *Electrical Cost Data*.[26] Several computer programs permit streamlining and standardizing engineering estimating.

Chapter 16 illustrates the detailed procedures for making estimates for industrial facilities.

Extra work ("extras") refers to work performed by the contractor that has to be added to the contract because of unforeseen conditions or changes in the scope of work. The contractor is not usually faced with competition in making these changes; therefore, extra work is expected to be more costly than the same work would be if included in the original contract. Extra cost on any project can be minimized by giving greater attention to design details in the original planning stage. On rehabilitation or modification work, extras are more difficult to avoid; however, with careful field investigation, extras can be held to a minimum.

1.14 Contracts

Contracts for construction may be awarded on either a lump-sum or a unit-price basis, or on a cost-plus (time-and-material) basis. A lump sum involves pricing the entire job as one or several major units of work.

The unit-price basis simply specifies so much per unit of work, for example, so many dollars per foot of 3-inch conduit. The lump-sum contract is usually preferable when the design can be worked out in sufficient detail. The unit-price contract is desirable when it is not possible to determine exactly the quantities of work to be performed and when a contractor, in order to provide a lump-sum contract, might have to overestimate the job to cover items that could not accurately be determined from the drawings.

If the unit-price basis is used, the estimated quantities should be as accurate as possible, otherwise it may be advantageous for the contractor to quote unit prices of certain items as high as possible and reduce other items to a minimum figure. It could be to the contractor's advantage to list those items highest on which payment would be received first or those items that would be most likely to increase in quantity.

The time-and-material basis is valuable for emergency or extra work where it would be impractical to use either of the above two methods. It has the disadvantage of requiring a close audit of manpower and material expenditures of the contractor. Where only a part of the work is not clearly defined, a combination of the three pricing methods might be in order.

[25] 7315 Wisconsin Avenue, Bethesda, MD 20814.

[26] Published by R. Snow Means Co., 100 Construction Plaza Avenue, Kingston, MA.

1.15 Access and loading

It is imperative that the equipment fit into the area specified and that the floor-load rating be adequate for the weight of the equipment. Sizes of door openings, corridors, and elevators for moving of equipment (initially and for maintenance and replacement purposes) must be checked. However, it is easy to forget that equipment has to be moved across floors, and that the floor-load ratings of the access areas for moving the equipment must be adequate for this. If floor strengths are not adequate, provision must be made to reinforce the floor or, if practical, to specify that the load be distributed so that loading will not exceed structural limitations.

It is important to review weights and loadings with the structural engineers. Sometimes it is necessary to provide removable panels, temporarily remove windows, and even to make minor structural changes in order to move large and heavy pieces of equipment or machinery. Provisions also must be made for removal of equipment for replacement purposes. Clearances must be in accordance with code provisions regarding working space. Clearance must also be provided for installation, maintenance, and such items as cable pulling, transformer replacement, maintenance/testing, and switchgear-drawout space. It is often essential to phase items of work in order to avoid conflict with other electrical work or work of other trades.

1.16 Contractor performance

Contractors may be selected on the basis of bid or quoted price or by negotiation. Governmental or corporate policies may mandate selection of the lowest qualified bidder. Where the relative amount of electrical work is large, the contract may be awarded to an electrical contractor. In other instances, the work may be awarded to an electrical subcontractor by the overall general contractor.

The performance of the work will usually be monitored and inspected by representatives of the owner and the engineer-of-record. The work may be subject to the inspection of governmental and other assigned approval agencies, such as insurance underwriters. The designer may communicate with the contractor only to the extent permitted by the agency exercising control over the contract.

It is essential that designers, in attempting to expedite the contract, not place themselves in the position of requesting without proper authorization, or “reading into” the contract, what is not clearly required by the specifications or drawings.

The contract may require the contractor to deliver, at the end of the work, revised contract drawings, known as “as-built” drawings. These show all changes in the work that may have been authorized, or details that were not shown on the original drawings.

1.17 Environmental considerations

In all branches of engineering, an increasing emphasis is being placed on social and environmental concerns. Today's engineer must consider air, water, noise, lighting, and other items that have an environmental impact. The limited availability of energy sources and the steadily increasing cost of electric energy require that energy conservation be addressed.

This issue is becoming more than just a matter of conscience or professional ethics. Laws, codes, rules, and standards issued by legislative bodies, governmental agencies, public service commissions, insurance, and professional organizations (including groups whose primary concern is the protection of the environment and conservation of natural resources) increasingly require an assessment of how the project may affect the environment. Energy conservation is covered in Chapter 14. Environmental studies, which include the effect of noise, vibration, exhaust gasses, lighting, and effluence, must be considered in relationship to the working environment, the general environment, and the public.

Landscape architects can provide pleasing designs of trees and shrubbery to completely conceal outdoor substations and overhead lines may, of course, be replaced by underground systems. Substations situated in residential areas must be carefully located so as not to create a local nuisance. Precast sound barriers can reduce transformer and other electrical equipment noise. Floodlighting and parking-lot lighting must not spill onto adjacent areas where it may provide undesirable glare or lighting levels (see IES Committee Report CP-46-85 [B9]). The engineer should keep up-to-date on developments in the areas of environmental protection and energy conservation. Federal Environmental Protection Agency guidelines and judicial rulings on local environmental litigation are generally covered in the Federal Register and in the periodicals previously listed.

1.18 Technical files

Drawings and other technical files are often kept in file cabinets as originals or copies. A system of filing and reference is essential when many such items are involved. A computerized data base may a valuable method of referencing and locating the proper document. When drawings are produced by computer-graphic systems, such as CADD, magnetic tape may be used for storage. Plotters can be used with computer systems to produce hard copy. Original drawings (often prepared on tracing material) can be stored photographically on film; the drawings can be made available on viewers or enlarger-printers. Microfiche involves placing the microfilm on computer-type cards for handling manually or in data-processing type systems.

1.19 Electronic systems

Electronic systems are a major item in industrial facilities for control purposes, motor control, lighting ballasts, communication systems, data processing, computer applications, industrial process control, data management, and plant (building) management systems. This subclause is concerned primarily with the effects of the power supply, control and power wiring, and interference on these systems; and with some indication of the extent of the use of electronic equipment in industrial facilities.

Industrial processes often require a degree of speed and torque control of motors, which is obtainable through the use of electronic controllers and computer-based control systems (see Chapter 10). Electronic power supplies/controllers are used for supplying power to heat-process systems and to electrochemical processes. The electronic controller has the advantage of being able to tie together the power equipment, the control computers, the sensing equipment, data acquisition and display systems, robotics, and telemetering equipment into an effective package. Subclause 1.3.1 lists the committees, by industry and application, that are involved with and publish extensive technical material in this area.

1.19.1 Power supply disturbances

The power supply to equipment may contain transients and other short-term under- or over-voltages that result primarily from switching operations, faults, motor starting, lightning disturbances, switching of capacitors, electric welding, and operation of heavy manufacturing equipment. The system may also contain a harmonic content as described in 1.19.2 below. These electrical disturbances may be introduced anywhere on an electric system or in the utility supply, even by other utility customers connected to the same circuits. A term frequently applied to describe the absence or presence of these power deficiencies is *power quality.* The IEEE Emerald Book (see 1.3.2) examines in detail the effects of the power supply on equipment performance. It covers methods of diagnosing and correcting performance problems related to the power supply.

1.19.2 Harmonics

Chapter 9 of this book, Chapter 10 of the Brown Book, the Emerald Book, and IEEE Std 519-1992 [B5] all contain discussion of harmonics. Harmonics are integral multiples of the fundamental (line) frequency involving nonlinear loads or control devices, including electromagnetic devices (transformers, lighting ballasts) and solid-state devices (rectifiers, thyristors, phase-controlled switching devices). In the latter grouping are power rectifiers, adjustable-speed electronic controllers, switching-mode power supplies (used in smaller computers), and UPS systems.

Harmonics can cause or increase EMI in sensitive electronic systems, abnormal heating or cables and motors, transformers, and other electromagnetic equipment, excessive capacitor currents, and excessive voltages because of system resonances at harmonic frequencies.

Recently, it has been determined that the harmonic content of multiwire systems having a high proportion of switching-mode power supplies is very high. The neutral conductors of these systems must be sized at greater than full rating, and transformers must be derated or designed for high-harmonic content. A full discussion of harmonics is beyond the scope of this subclause; reference should be made to the previously mentioned publications.

1.19.3 Electromagnetic interference (EMI)

EMI is the impairment of a wanted electromagnetic signal by an electromagnetic disturbance. EMI can enter equipment either by conduction through power, grounding, control, data, or shielding conductors, or by induction from local electromagnetic or electrostatic fields. The most common causes of EMI problems in sensitive equipment, such as computers, communications equipment, and electronic controllers, are poor inherent design of the equipment or power supply, poor grounding, and unsound design of the equipment interfaces.

It can be reduced by the use of effective grounding (both electronic and equipment grounds), shielding, twisted conductors (pairs) and coaxial cables, and effective use of conduit (especially steel conduit) for control and power (where practical) circuits [B3], [B4]. EMI and other power problems can cause control and equipment malfunctions, slowing of computer operations, lack of reliability, and failure of critical systems. These failures can affect product quality and, in some cases, worker safety.

The use of filters, voltage regulators, surge capacitors, surge arresters, isolation transformers (particularly with electrostatic shielding between coils), power conditioners, UPS systems, or motor-generator sets for isolation are all methods of reducing EMI. Fiber-optic cables and electro-optical isolation at interfaces are extremely effective methods of providing isolation between systems.

1.20 Programmable logic controller (PLC)

The PLC is a microprocessor designed for control and telemetering systems. It is programmed to accept “ladder-type” logic, which enables the operator to use relay-type logic, thereby avoiding the need to use the conventional software languages. The equipment can be housed in cases suitable for mounting in exposed locations and on production floors.

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Chapter 2
System planning

2.1 Introduction

The continuity of production in an industrial plant is only as reliable as its electric power distribution system. This chapter outlines procedures and various considerations for system planning and presents a guide to the use of the succeeding chapters.

No standard electric distribution system is adaptable to all industrial plants, because two plants rarely have the same requirements. The specific requirements must be analyzed qualitatively for each plant and the system designed to meet its electrical requirements. Equal and adequate consideration must be given to both the present and future operating and load conditions.

2.2 Definitions

See 2.4.1.3 for definitions related to demand.

2.3 Basic design considerations

The approach to system planning should include several basic considerations that will affect the overall design and operation.

2.3.1 Safety

Safety of life and preservation of property are two of the most important factors to be considered in the design of the electric system. Codes must be followed and recommended practices or standards should be followed in the selection and application of material and equipment.

Equally important is providing equipment that is properly and adequately sized and rated to handle available fault levels in the system in accordance with established fault duty calculation procedures. Adequate safety features should be incorporated into all parts of the system.

Listed below are the electric system operating and design limits that should be considered in order to provide safe working conditions for personnel:

a) Interrupting devices must be able to function safely and properly under the most severe duty to which they may be exposed.
b) Protection must be provided against accidental contact with energized conductors, such as enclosing the conductors, installing protective barriers, or installing the conductors at sufficient height to avoid accidental contact.

c) Isolating switches must not be operated while they are carrying current, unless they are designed to interrupt such current. They should be equipped with safety interlocks and warning signs if load or transformer magnetizing current-load-interrupting and fault-closing capability are not provided.
d) In many instances it is desirable to isolate a power circuit breaker using disconnect switches. In such cases, the circuit breaker must be opened before the disconnect switches. Safety interlocks to ensure this sequence should be used, together with detailed and specific personnel operating instructions.
e) The system should be designed so that maintenance work on circuits and equipment can be accomplished with the particular circuits and equipment de-energized and grounded. System design should provide for locking out circuits or equipment for maintenance, including grounding instructions. A written procedure should be established to provide instructions on tagging or locking out circuits during maintenance, and re-energizing after completion of the maintenance work following disconnection of the grounding equipment.
f) Electric equipment rooms, especially those containing apparatus over 600 V, such as transformers, motor controls, or motors, should be equipped and located to eliminate or minimize the need for access by nonelectrical maintenance or operating personnel. Conveniently located exits should be provided to allow quick exit during an emergency.
g) Electric apparatus located outside special rooms should be provided with protection against mechanical damage due to equipment location, personnel access, and vehicular traffic. The area should be accessible to maintenance and operating personnel for emergency operation of protective devices.
h) Equipment location should be carefully considered. A nonhazardous area should be set aside for electrical equipment, or it may be necessary to locate explosion-proof equipment in the hazardous area. The advantages and disadvantages of not only initial cost but the maintenance cost and the ability to maintain the integrity of the equipment should all be carefully considered.
i) Warning signs should be installed on electric equipment accessible to unqualified personnel, on fences surrounding electric equipment, on doors giving access to electrical rooms, and on conduits or cables above 600 V in areas that include other equipment or pipelines. An electrical single-line diagram should be installed in each electrical switching room.
j) An adequate grounding system must be installed.
k) Emergency lights should be provided where necessary to protect personnel against sudden lighting failure. In facilities, the Life Safety Codes requires that escape routes and exits have emergency lighting. In addition, process control locations and electric switching centers should be equipped with standby lighting.
l) Operating and maintenance personnel should be provided with complete operating and maintenance instructions, including wiring diagrams, equipment ratings, and protective device settings. Spare fuses of the correct ratings should be stocked.

2.3.2 Reliability of plant primary utility supply service

The continuity of service required is dependent on the type of manufacturing or process operation of the plant and the cost of that operation, especially if it is interrupted. Some plants can tolerate interruptions while others require the highest degree of service continuity. The system should always be designed to isolate faults with a minimum disturbance to the system and should have features to give the maximum dependability consistent with the plant requirements and justifiable cost.

The majority of utilities today supply energy to medium and large industrial customers directly at 34.5, 69, 115, 138, 161 and 230 kV using dedicated substations. Small industrial complexes may receive power at voltages as low as 4 kV.

Some industrial plants accept supplies directly from utility area distribution substations at 4.16, 12.5, 13.8 kV, etc. In most instances, the utility substations also serve other customers so that there are usually several distribution lines connected to the same bus as the plant supply line(s), although in some cases dedicated services, including bus(es) and lines, are provided. For the most part, plant personnel feel secure with this type of supply, especially if the supply substation is nearby and if multiple supply lines are provided to meet *firm power* or first contingency requirements. However, these provisions can create a false sense of security, especially when the facts regarding the reliability of distribution lines, the impact of nearby customer faults and system operations on such services, and the impact this has on plant operations are overlooked. For example, when a fault occurs on the supply system near the plant, there is an accompanying voltage sag on all of the plant primary distribution and utilization voltage buses. This lowered voltage persists while the utility relays operate and until the utility breaker trips, at which point the voltage will be reduced to zero on the faulted line and will be restored to near normal on the unfaulted portions of the system. Experience has shown that these short-time voltage sags are often severe enough and persist long enough to cause the solenoid coils of mechanical contactors and relays to open automatically. When this occurs in a plant there will be parts damage, tool breakage, lost production, etc., all of which cause major disruptions in plant operations even though the supply may be lost only temporarily. Furthermore, new customers added to the area distribution supply substation can also reduce the quality and reliability of the service.

Lower voltage distribution services often tend to be older systems that are susceptible to a more frequent rate of system interruption and failure than higher voltage transmission systems. Underground, lower voltage cable systems are especially susceptible, although some underground cable systems have proven to have high reliability. This reliability tends to be very site- and utility-specific. Installation, maintenance, age, and workmanship quality on cable terminations and splices can all significantly affect the reliability of such systems. Statistically, 138 kV lines may have interruption rates of four or five interruptions per hundred miles per year. On the other hand, distribution lines in the 8–23 kV voltage range may have interruption rates of 100 or more interruptions per hundred miles per year. Thus, the probability of damaging voltage sags is at least 20 times as great on distribution lines as on transmission voltage lines. This difference in probabilities is magnified even more when it is realized that the exposure to voltage sag incidents includes many nearby interconnected lines not necessarily dedicated to the plant supply.

Depending upon circumstances, the capacity available for future expansion from area substations may often be limited, even with or without a single contingency situation occurring. Available capacity may be limited by a transformer, switch, circuit breaker, bus, protective device(s) and supplying cable capacity and, therefore, requires careful evaluation for both normal and abnormal operating conditions. In addition, if firm or first contingency capacity is desired, then the availability of duplicate capacity in the transformer(s), protective device(s), and cables must all be taken into account. Expansion of available capacity in such circumstances to meet first contingency needs may present difficulties due to station configuration and the impact on other customers, especially if available user fault levels are changed as a result of the expansion. This aspect requires very careful consideration so capacity constrained conditions do not develop that will later present significant technical and economical difficulties in meeting increased plant loads.

2.3.3 Plant distribution system reliability analysis

One of the questions often raised during the design of the plant power distribution system is how to make a quantitative comparison of the failure rate and the forced downtime in hours per year for different circuit arrangements, including radial, primary-selective, secondary-selective, simple spot network, and secondary-network circuits. This quantitative comparison could be used in trade-off decisions involving the initial cost versus the failure rate and forced downtime per year. The estimated cost of power interruptions at the various distribution points should be considered in deciding which type circuit arrangement to use. The decisions should be based upon total owning cost over the useful life of the equipment rather than the first cost.

In general, electric power systems are designed on a first contingency basis. The incremental cost to provide such services is typically a relatively small cost as compared to the total facility or plant cost. The risk and cost of a long-term interruption due to system failure far outweighs the added incremental cost required to provide first contingency capacity at the time of installation.

2.3.3.1 Reliability data for electrical equipment

In order to calculate the failure rate and the forced downtime per year, it is necessary to have reliability data on the electric utility supply and each piece of electrical equipment used in the power distribution system. One of the best sources for this type of data are the extensive IEEE surveys on the reliability of electrical equipment in industrial plants and commercial buildings. (See IEEE Std 493-1990.[1]) While this data may be quite useful, it represents a limited data base; therefore, it may not be representative of an individual company's experience. In-house data, if available, may be more appropriate in this analysis.

2.3.3.2 Reliability analysis and total owning cost

Statistical analysis methods involving probability of failure may be used to make calculations of the failure rate and the forced downtime for the power distribution system. The methods and formulas used in these calculations are given in IEEE Std 493-1980. This includes the minimum revenue requirements method for calculating the total owning cost over the useful

[1]Information on references can be found in 2.6.

life of the equipment. Data and calculations for determining the cost of power interruptions are also given in IEEE Std 493-1990.

2.3.4 Simplicity of operation

Simplicity of operation is very important in the safe and reliable operation and maintenance of the industrial power system. The operation should be as simple as possible to meet system requirements.

2.3.5 Voltage regulation

Poor voltage regulation is detrimental to the life and operation of electrical equipment. Voltage at the utilization equipment must be maintained within equipment tolerance limits under all load conditions, or equipment must be selected to operate safely and efficiently within the voltage limits. Use load-flow studies and motor-starting calculations to verify voltage regulation.

2.3.6 Maintenance

The distribution system should include provisions for predictive and preventive maintenance requirements in the initial design. Accessibility and availability for inspection and repair with safety are important considerations in selecting equipment. Space should be provided for inspection, adjustment, and repair in clean, well-lighted, and temperature-controlled areas.

2.3.7 Flexibility

Flexibility in an electric system means expandability as well as adaptability to changing requirements during the life of the plant. Consideration of the plant voltages, equipment ratings, space for additional equipment, and capacity for increased load must be given serious study.

2.3.8 First cost

While first costs are important, safety, reliability, voltage regulation, maintenance, and the potential for expansion should also be considered in selecting the best from alternate plans.

2.4 Planning guide for the supply and distribution system

The following procedure will guide the engineer in the design of an electric distribution system for an industrial plant. The system designer should also have or acquire knowledge of the plant's processes in order to select the proper system and its components.

2.4.1 Load definition and forecasting

Load definition entails load surveys, demand and diversity analysis, and load characteristic definition. In addition, load forecasting for future requirements must be considered.

2.4.1.1 Load survey

Obtain a general plant or facility layout, mark it with the known major loads at various locations, and determine the approximate total plant load in kilowatts or kilovoltamperes. Initially the amount of accurate load data may be limited; therefore, some loads, such as lighting and air conditioning, may be estimated from generalized data. The majority of industrial plant loads are a function of the process equipment, and such information will have to be obtained from process and equipment designers. Since their design is often concurrent with power system design, initial information will be subject to change. It is important, therefore, that there be continuing coordination with the other design disciplines. For example, a change from electric powered to absorption refrigeration or a change from electrostatic to high-energy scrubber air-pollution control can change the power requirements for these devices by several orders of magnitude. The power system load estimates will require continual refinement until job completion.

2.4.1.2 Load requirements and characteristics

The following items define the various requirements and characteristics of the loads and must be determined and defined in the planning process:

a) Load development/build-up schedule
   1) Peak load requirements in kilovoltamperes
   2) Temporary/construction power requirements
   3) Timing
b) Load variations in kilovoltamperes expected during low load (non-productive periods), average load, and peak load conditions.
c) Nature of load in terms of its occurrence
   1) Continuous
   2) Intermittent
   3) Cyclical
   4) Special or unusual loads
   5) Combination of above
d) Expected power factor during low load (nonproductive periods), average load, and peak load periods.
e) Expected daily and annual load factor:

$$\text{Daily} \quad \frac{\text{kWh for 24 h/24 h}}{\text{peak kW during the 24 h}} = \frac{\text{avg. kW}}{\text{peak kW}}$$

$$\text{Annual} \quad \frac{\text{kWh for 8670 h/8670 h}}{\text{peak kW during the 8670 h}} = \frac{\text{avg. kW}}{\text{peak kW}}$$

f) Large motor-starting requirements
   1) Horsepower and other nameplate data
   2) Type (synchronous/induction)
   3) System nominal voltage
   4) Starting requirements
   5) Application

g) Special or unusual loads such as
   1) Resistance welding
   2) Arc welding
   3) Induction melting
   4) Induction heating
   5) Heat treating
   6) SCR controlled ovens
   7) Variable speed drives (large press drives)
   8) Large power conversion devices
h) Harmonic-generating loads
   1) Converter/inverter drives
   2) Arc discharge lighting
   3) Arc furnaces
   4) Other
i) Special power quality requirements for sensitive or critical loads
   1) Data processing operations
   2) Special machines
   3) Continuous process loads
   4) Others

2.4.1.3 Demand

The sum of the electrical ratings of each piece of equipment will give a total connected, noncoincident load. Because some equipment operates at less than full load and some intermittently, the resultant demand upon the power source is always less than the total connected load, so appropriate load diversity considerations should be considered in the analysis. In general, equipment diversities range from slightly less than 100% for a continuous process to as low as 2% to 5% for certain types of press and welding operations. The diversity expectation associated with each type of equipment should be used to develop a specific, total, actual expected load. An appropriate diversity should then also be applied to each large grouping of equipment and to the entire load to reflect randomness and physical reality, based on experience.

Standard definitions for these load combinations and their ratios have been devised.

2.4.1.3.1 demand: The electric load at the receiving terminals averaged over a specified interval of time.

Note that demand is expressed in kilowatts, kilovoltamperes, amperes, or other suitable units. The interval of time is generally 15 min, 30 min, or 1 h, based on the particular utility's demand metering interval.

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

2.4.1.3.3 maximum demand: The greatest of all demands that have occurred during a specified period of time such as one-quarter, one-half, or one hour.

Note that for utility billing purposes the period of time is generally one month.

2.4.1.3.4 demand factor: The ratio of the maximum coincident demand of a system, or part of a system, to the total connected load of the system, or part of the system, under consideration. The resultant is always 1 or less and can range from 0.8 to 1 to as low as 0.15 to 0.25 for some plants with very low diversity.

2.4.1.3.5 diversity factor: The ratio of the sum of the individual non-coincident maximum demands of various subdivisions of the system to the maximum demand of the complete system. The diversity factor is always 1 or greater. The (unofficial) term *diversity*, as distinguished from *diversity factor* refers to the percent of time available that a machine, piece of equipment, or facility has its maximum or nominal load or demand (i.e., a 70% diversity means that the device in question operates at its nominal or maximum load level 70% of the time that it is connected and turned on).

2.4.1.3.6 load factor: The ratio of the average load over a designated period of time to the peak load occurring in that period.

Note that although not part of the official definition, the term *load factor* is used by some utilities and others to describe the equivalent number of hours per period the peak or average demand must prevail in order to produce the total energy consumption for the period.

2.4.1.3.7 coincident demand: Any demand that occurs simultaneously with any other demand, also the sum of any set of coincident demands.

Information on these factors for the various loads and groups of loads is useful in designing the system. For example, the sum of the connected loads on a feeder, multiplied by the demand factor of these loads, will give the maximum demand that the feeder must carry. The sum of the individual maximum demands on the circuits associated with a load center or panelboard, divided by the diversity factor of those circuits, will give the maximum demand at the load center and on the circuit supplying it. The sum of the individual maximum demands on the circuits from a transformer, divided by the diversity factor of those circuits, will give the maximum demand on the distribution transformer. The sum of the maximum demand on all distribution transformers, divided by the diversity factor of the transformer loads, will give the maximum demand on their primary feeder. By the use of the proper factors, as outlined, the maximum demands on the various parts of the system from the load circuits to the power source can be estimated. Allowances should also be made for future load expansion in these calculations.

2.4.1.4 Forecasting and planning

Essentially, the load forecasting and planning process involves at least six separate considerations. These are as follows:

a) Impact of nominal load growth over time. Typically, some slight growth in kilowatt demand will be experienced over time. This may be upwards of $^{1}/_{2}$ to 1% per year;

b) Impact of equipment changes due to new equipment installations or modifications that are not part of the product plan, including environmental equipment, new technology applications, or new requirements, such as facility air conditioning or air tempering;
c) New and modified production plans to meet requirements of the future product plan;
d) Additional site development due to new on-site building(s) and added floor space. Typically, a site may be initially developed to a 15–20% building to land ratio, with an allowance for future development of upwards of 30%. Some sites may be constrained for additional development;
e) Impact of gas/oil conversion to electric use for some types of product heating where electric heating may actually be more economical due to inherent process efficiencies;
f) Other types of changes that cannot easily be categorized, such as higher density plant loading, etc.

Every plant should have a current business forecast, for five or six years of production and project requirements, that may be implemented. These, along with longer term projections, should be weighed in terms of their impact upon electric demand. In similar fashion, the prospect of future expanded utilization of the site must be recognized in terms of electric demand. An array of probable plans for capacity can be developed to keep pace with the demands. If the full range of future possibilities is explored both as to size and timing, long-range plans can be developed that can potentially meet demands. While typically forecasted requirements for additional load occur later and are smaller than planned, the process is essential so that constraints, if present, are fully recognized and plans can be developed to resolve them.

Since forecasting offers a degree of certainty, it would be uneconomical to construct or provide capacity that is never used. However, there are opportunities in planning and designing electrical systems for selecting apparatus and arranging these in schemes that minimize the probabilities of early obsolescence due to improper ratings and the need for reconstructing major portions of the system.

2.4.2 Plant distribution systems

Investigate the various types of plant distribution systems and select the system or systems best suited to the requirements of the plant. A variety of basic circuit arrangements is available for industrial plant power distribution. Selection of the best system or combination of systems will depend upon the needs of the manufacturing process. In general, system costs increase with system reliability if component quality is equal. Maximum reliability per unit investment can be achieved by using properly applied and well-designed components.

The first step is the analysis of the manufacturing process to determine its reliability need and potential losses and costs in the event of power interruption. Some plant processes are minimally affected by interruption. Here a simple radial system may be satisfactory. Other plant processes may sustain long-term damage or experience excessive cost by even a brief interruption, therefore, a more complex system with an alternate power source for critical loads may be justified.

Circuit redundancy may be needed in continuous-process industries to allow equipment maintenance. Although the reliability of electric power distribution equipment is high, optimum reliability and safety of operation still requires routine maintenance. A system that cannot be maintained because of the need to serve a continuous process is improperly designed.

Far more can be accomplished by the proper selection of the circuit arrangement than by economizing on equipment details. Cost reductions should never be made at the sacrifice of safety and performance by using inferior apparatus. Reductions should be obtained by using a less expensive distribution system with some sacrifice in reserve capacity and reliability.

2.4.2.1 Simple radial system

(See figure 2-1.) Distribution is at the utilization voltage. A single primary service and distribution transformer supply all the feeders. There is no duplication of equipment. System investment is the lowest of all circuit arrangements.

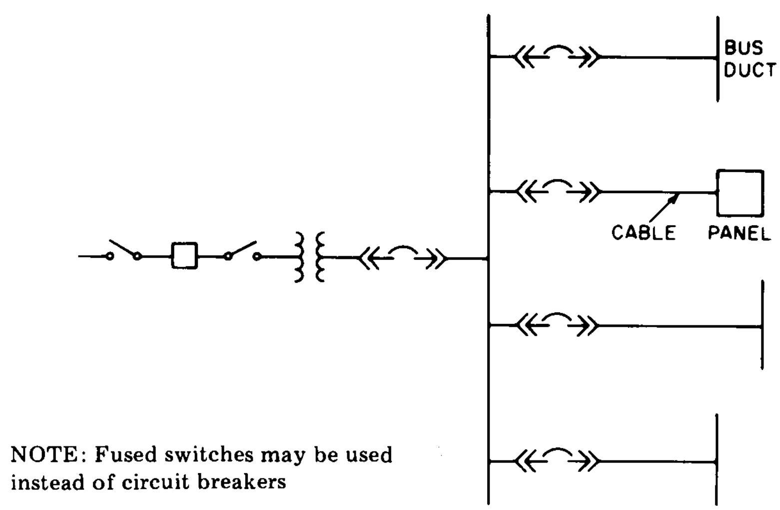


Figure 2-1—Simple radial system

Operation and expansion are simple. When quality components and appropriate ratings are used reliability is high. Loss of a cable, primary supply, or transformer will cut off service. Equipment must be shut down to perform routine maintenance and servicing.

This system is satisfactory for small industrial installations where process allows sufficient down time for adequate maintenance and the plant can be supplied by a single transformer.

2.4.2.2 Expanded radial system

(See figure 2-2.) The advantages of the simple radial system may be applied to larger loads by using an expanded radial primary distribution system to supply a number of unit substations located near the load, which in turn supply the load through radial secondary systems.

The advantages and disadvantages are the same as those described for the simple radial system.

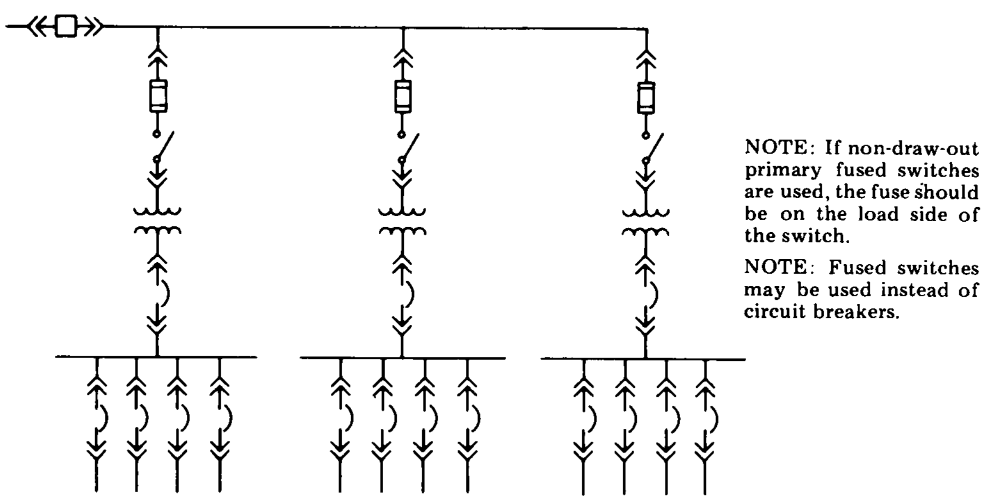


Figure 2-2—Expanded radial system

2.4.2.3 Primary selective system

(See figure 2-3.) Protection against loss of a primary supply can be gained through use of a primary selective system. Each unit substation is connected to two separate primary feeders through switching equipment to provide a normal and an alternate source. Upon failure of the normal source, the distribution transformer is switched to the alternate source. Switching can be either manual or automatic, but there will be an interruption until load is transferred to the alternate source.

If the two sources can be paralleled during switching, some maintenance of primary cable and switching equipment, in certain configurations, may be performed with little or no interruption of service. Cost is somewhat higher than a radial system because of duplication of primary cable and switchgear.

2.4.2.4 Primary loop system

(See figure 2-4.) A primary loop system offers improved reliability and service continuity in comparison to a radial system. In typical loop systems, power is supplied continuously from two sources at the ends of the loop. Such a system, if properly designed and operated, can

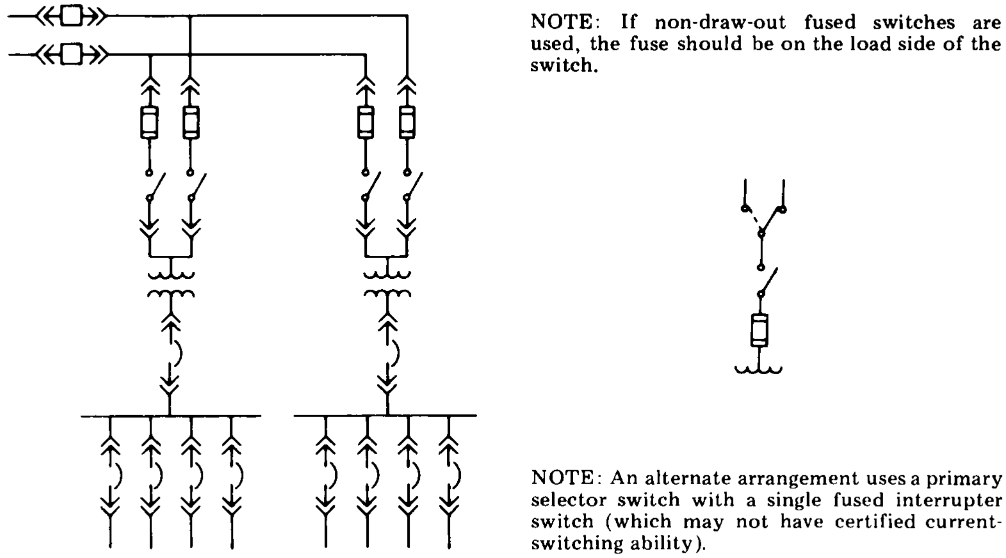


Figure 2-3—Primary selective system

quickly recover from a single cable fault with no continuous loss of power to utilization equipment. It is unlikely that a fault will occur within the area of the closely coupled isolation devices and the bus to the fuse protecting the transformer.

A second important feature of loop systems is that a section of cable may be isolated from the loop for repair or maintenance while other parts of the system are still functioning. However, it is important to analyze the isolation provided with this arrangement.

Since electrical power can flow in both directions in a loop system, it is essential that detailed operating instructions be prepared and followed. These instructions must take into account the fact that the industrial facility may not always be staffed with trained electrical personnel on a 24-hour basis. Additionally, if the two supply points for the loop originate from different buses, the design must consider available short-circuit capacity from both buses, the ability of both buses to supply the total load, and the possibility of a flow of current from one bus to the other bus over the loop.

2.4.2.4.1 Closed-loop operation

To realize optimum service reliability of a primary loop system, the system should be operated with all series switches in figure 2-4 closed (closed-loop mode). When designing a system that is expected to be operated in the closed-loop mode, circuit breakers typically are selected in lieu of fused or nonfused isolation switches.

When the loop switches consist of circuit breakers with interconnected directional overcurrent or pilot wire relays, a cable fault within the loop may be automatically isolated without

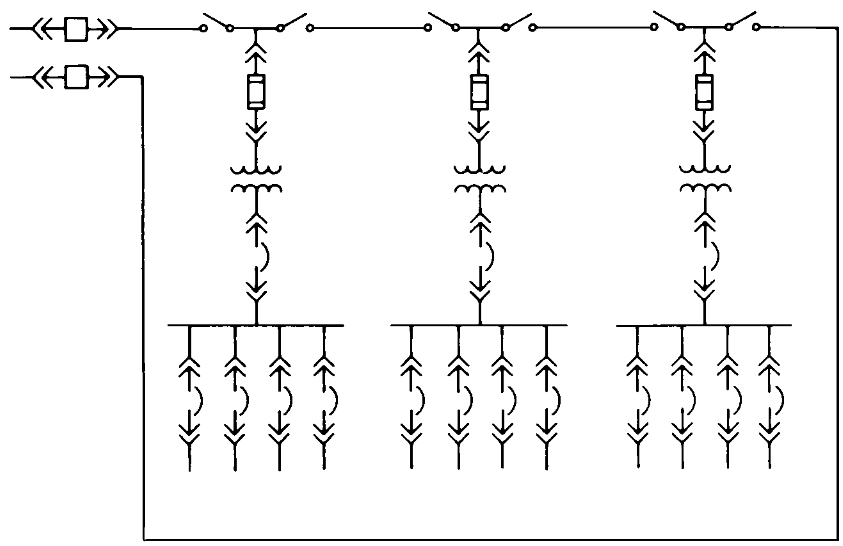


Figure 2-4—Primary loop system

loss of transformer capacity. No loss of power will occur, although the system will experience a voltage dip until the circuit breakers clear the fault. Whenever a section of the loop is faulted, either in the cable of the loop or in the taps from the loop, both circuit breakers feeding that section must trip. If the taps are taken from nonadjacent sections, then the two circuit breakers feeding the portion of the loop between the taps must trip, de-energizing the entire section. When a circuit breaker trips and is not remotely indicated or alarmed, a portion of the loop may unknowingly remain out of service for an extended period of time even though all loads remain energized. To prevent this from happening, an alarm point derived from the overcurrent detection system at both ends of the loop should be installed.

2.4.2.4.2 Open-loop operation

A primary loop system may be operated with one of the series switches in figure 2-4 open. Fused or non-fused isolation switches, or circuit breakers, may be used in this open-loop operation. A disadvantage of open-loop operation is that a cable failure will result in the temporary loss of service to some portion of the system.

2.4.2.4.3 Fault isolation

One method for locating a fault in a loop system is the dangerous practice of isolating a section of the loop and then re-energizing the power source. If the system trips again, another section is isolated and the power is re-applied. Such action is repeated until the fault is isolated. This method of fault location is not recommended. It is unsafe practice and may cause equipment failure as a result of the stress placed on system components and cable insulation. The reclosing of any power protection device into a known fault in order to locate the faulty equipment, or to restore the system power without ascertaining the problem, is not recommended.

2.4.2.4.4 Primary loop system economics

An initial cost saving may be achieved by designing a loop system with isolation switches instead of circuit breakers. The loop system may be designed with non-fused switches for the greatest initial cost savings. However, the selection of non-fused switches for isolating an open loop system provides no overcurrent protection to individual sections of the loop, nor a reduction of the faulted section. Some portion of the loop will lose power whenever any fault occurs.

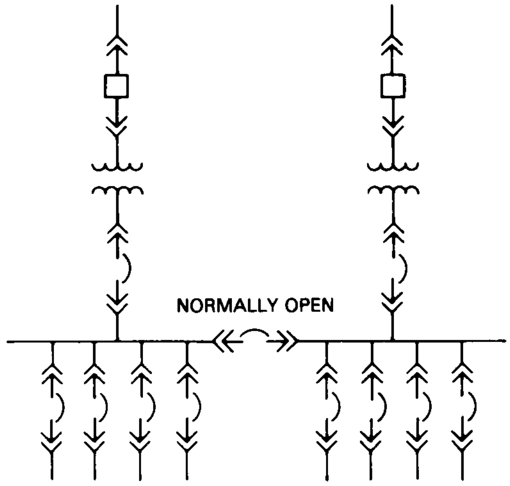
Many times fused isolation switches will be applied in lieu of circuit breakers in a loop system. Since it is not possible to selectively coordinate such a system for faults on a closed loop, the loop should be operated in the open loop mode. The use of fused switches also introduces the potential for single-phasing in the system. Consequences of single-phasing may include motor failure, loss of one-third of the lighting, and partial voltage to an additional one-third of the lighting. Phase failure protection systems are available. If the need for a form of single-phasing protection is established, some of the cost savings of using fused switches over circuit breakers is lost.

One possible disadvantage of the system in figure 2-4 is that there is no disconnecting means ahead of the fuse protecting the transformer. At an additional cost, a disconnect switch would add convenience for the maintenance of the equipment, and if a problem should occur with the transformer it can be isolated without opening the loop. Good safety practice for industrial installations will almost always dictate the inclusion of such a switch-fuse combination or circuit breaker ahead of the transformer.

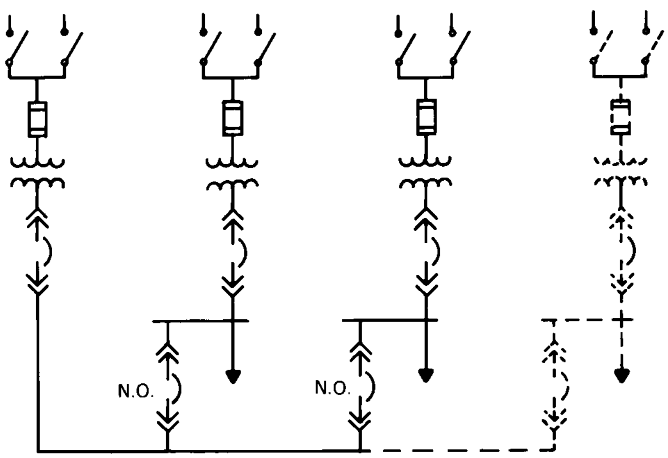
The economics of the variations in design of primary loop systems can be found in Chapter 16.

2.4.2.5 Secondary selective system

[See figure 2-5(a)]. If pairs of substations are connected through a secondary tie circuit breaker, the result is a secondary selective system. If the primary feeder or transformer fails, supply is maintained through the secondary tie circuit breaker. The tie circuit breaker can be operated in a normally opened or a normally closed position. If operated opened, the supply is maintained by a manual or automatic opening of the affected transformer's circuit breaker followed by a closing of the tie circuit breaker. If the tie is operated closed, the supply is maintained by the automatic opening of the affected transformer circuit breaker (by reverse power or reverse current detection); automatic reclosing upon restoration of the faulted circuit is recommended. In case of the normally opened tie circuit breaker, voltage is maintained to the unaffected transformer's circuits. In the case of the normally closed tie, a voltage depression occurs on the bus until the affected transformer's circuit breaker opens.



(a) Secondary selective system



(b) Sparing transformer scheme

Figure 2-5—Typical configurations load center substations

Normally the systems operate as radial systems. Maintenance of primary feeders, transformer, and main secondary disconnecting means is possible with only momentary power interruption, or no interruption if the stations can be operated in parallel during switching, although complete station maintenance will require a shutdown. With the loss of one primary circuit or transformer, the total substation load may be supplied by one transformer. To allow for this condition, one (or a combination) of the following should be considered:

a) Oversizing both transformers so that one transformer can carry the total load;
b) Providing forced-air cooling to the transformer in service for the emergency period;
c) Shedding nonessential load for the emergency period;
d) Using the temporary overload capacity in the transformer and accepting the loss of transformer life.

A distributed secondary selective system has pairs of unit substations in different locations connected by a tie cable and a normally open disconnecting means in each substation. The designer should balance the cost of the additional tie disconnecting means and the tie cable against the cost advantage of putting the unit stations nearer the load center.

The secondary selective system may be combined with the primary selective system to provide a high degree of reliability. This reliability is purchased with additional investment and addition of some operating complexity.

In figure 2-5(a), while adhering to the *firm* capacity concept, the total load allowed to the substation will be equal to or less than the capability of one transformer or one load side overcurrent device, whichever is the most restrictive.

The sparing transformer scheme offers some particular advantages for achieving first contingency capacity in a cost-effective manner in the distribution system. Available transformer capacity is utilized at a higher level than in a simple redundant configuration (where utilization is 50%), and transformers can be readily added to existing substations as the need arises (if physical space and load requirements allow). In the sparing case [figure 2-5 (b)] the first contingency capacity is equal to (*n*-1) transformers or load side overcurrent devices. This scheme has been successfully used in industry, although there may occasionally be some personnel reluctant to accept it since the sparing transformer typically remains essentially unloaded, and the idea of an unloaded unit may seem to represent nonutilization of equipment.

Operations, protection, etc., for configurations shown by figure 2-5(a) and (b) are the same with two exceptions:

a) Automatic transfer initiated by loss of voltage on a low side bus is not applicable in the sparing transformer scheme;
b) Feeder overcurrent device fault duty requirements are almost always greater in the double-end scheme due to the additional motor fault current contribution during the emergency condition when the tie is closed.

2.4.2.6 Secondary spot network

(See figure 2-6.) In this system two or more distribution transformers are each supplied from a separate primary distribution feeder. The secondaries of the transformers are connected in parallel through a special type of device, called a network protector, to a secondary bus. Radial secondary feeders are tapped from the secondary bus to supply utilization equipment.

If a primary feeder fails, or a fault occurs on a primary feeder or distribution transformer, the other transformers start to feed back through the network protector on the faulted circuit. This

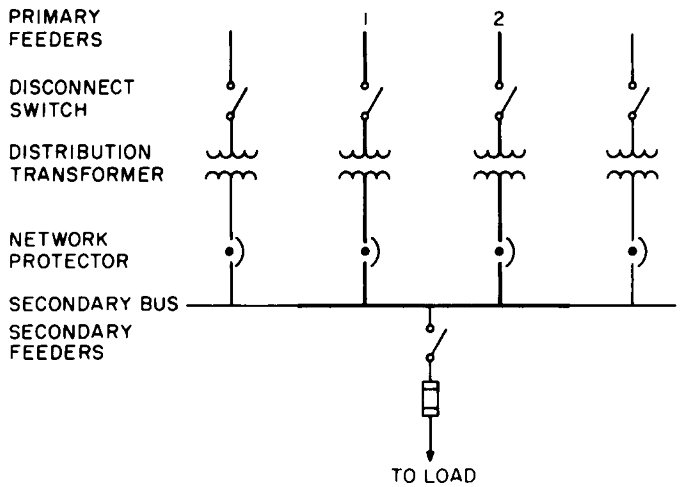


Figure 2-6—Secondary spot network

reverse power causes the network protector to open and disconnect the supply circuit from the secondary bus. The network protector operates so fast that there is a minimal exposure of secondary equipment to the associated voltage drop.

The secondary spot network is the most reliable power supply for large loads. A power interruption can only occur when there is a simultaneous failure of all primary feeders or when a fault occurs on the secondary bus. There are no momentary interruptions caused by the operation of the transfer switches that occur on primary selective, secondary selective, or loop systems. Voltage sags caused by large transient loads are substantially reduced.

Networks are expensive because of the extra cost of the network protector and duplication of transformer capacity. In addition, each transformer connected in parallel increases the short-circuit-current capacity and may increase the duty ratings of the secondary equipment. This scheme is used only in low-voltage applications with a very high load density. Also, it requires a special bus construction to reduce the potential of arcing fault escalation.

The packaged protector used by the utilities and preferred by some industrial users is not in itself adequately protected to meet the National Electrical Code (NEC) (ANSI/NFPA 70-1993) requirements, and also should not be regarded as equivalent to draw-out switchgear from a safety standpoint. Either supplementary protection should be added or, preferably, standard switchgear should be used, suitable for the purpose with proper protective relaying.

2.4.2.7 Ring bus

(See figure 2-7.) The ring bus offers the advantage of automatically isolating a fault and restoring service. Should a fault occur in Source 1, Devices A and D would operate to isolate the fault while Source 2 would feed the loads. A fault anywhere in the ring results in two interrupting devices opening to isolate the fault.

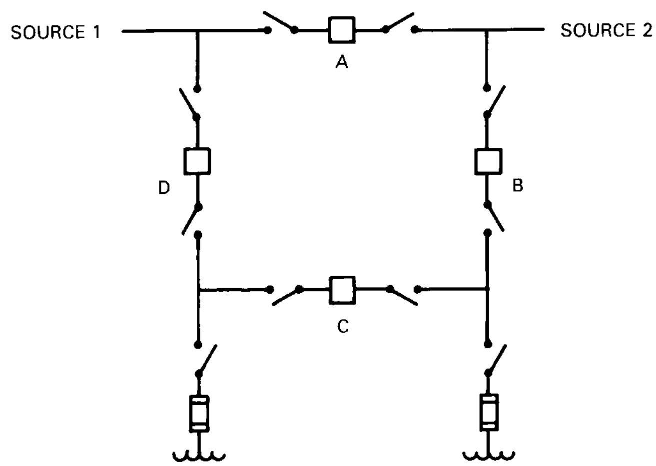


Figure 2-7—Ring bus system

The ring bus scheme is often considered where there are two (2) or more medium voltage (i.e., 4.16, 4.8, or 13.2/13.8 kV) distribution services to the facility and the utmost in flexibility and switching options are desired. Care must be taken that allowable fault duties are not exceeded with closed bus tie breaker operation in this scheme.

Manual isolating switches are installed on each side of the automatic device. This allows maintenance to be performed safely and without interruption of service. This will also allow the system to be expanded without interruption.

2.4.3 Equipment locations

The engineer, in cooperation with process personnel, selects locations for distribution transformers and major utilization voltage switching centers. In general, the closer the transformer to the load center of the area served, the lower the distribution system cost.

2.4.4 Plant utilization voltage

Select the best plant utilization voltage for the various system voltage levels. The most common utilization voltage in United States industrial facilities is 480 V. Other voltage levels depend upon motor rating and size, utility voltage available, total load served, potential expansion requirements, voltage regulation, and cost. Chapter 3 is a guide for correct voltage selection. The system should be capable of providing power to all equipment within published voltage limits under all normal operating conditions and meeting possible future loads. Additional voltage considerations will include flicker restrictions created due to large motor starting and the subsequent voltage drop during starting and restrictions placed on the user by the utility to prevent disturbances to their system when starting the user's large motors. Particular care should be taken when served from utility area distribution substations, since these are typically higher impedance systems having lower fault currents. The starting of large motors or other short-circuit type loads (i.e., welding, arc furnaces, etc.) can result in a short-term voltage sag or fluctuation elsewhere on the feeder.

2.4.5 Primary utility supply service

When it is anticipated that a new service or change in the existing utility supply is required, sufficient time should be allowed in the planning cycle to permit proper negotiations with the utility. The negotiations with the utility should precede the time scheduled for the specification, procurement, manufacture, installation of facilities, and commissioning. The negotiations with the utility should culminate in a contract so that utility engineering, design, and construction may begin in parallel with the customers efforts.

The industrial facility may be required to pay the cost of the change in service or the additional utility facilities.

It should be recognized that utility policy may require a contract for service/facilities before any engineering, right-of-way acquisition, environmental impact statements, or filing of permit applications.

Experience indicates that a utility may require 18 to 24 months to install a new substation or distribution/transmission line. This schedule usually begins after the contract is executed.

Refer to Chapter 15 for additional utility planning and design criteria required to provide an industrial primary supply substation.

At every step, whether for an all-new plant or for an existing plant, plans for the future are absolutely necessary. When this is done properly, subsequent increases in plant load can be accommodated by adding capacity to the initial system instead of necessitating a redesign of the whole primary system. In short, no plant primary supply and distribution system should ever be designed in a manner that will make it difficult or impossible to expand its capacity.

More important than the timing of capital investment is the need to permanently allocate space for installing power supply and distribution apparatus that may be required for the ultimate plant development at the site. Thus, it is clear that an estimate of the ultimate demand is necessary in order to establish the number and nature of future required facilities.

Experience has shown that when insufficient space is allocated for expanding either the high-voltage outdoor substation or the indoor main distribution switchgear, there is a tendency to compromise safety, reliability, and convenience. The latter usually translates into a depreciation of reliability because space for equipment removal or maintenance, or both, is sacrificed. Therefore, it usually becomes necessary to remove additional equipment in order to repair or replace another piece of apparatus that has failed.

Figure 2-8 is presented to illustrate some of the considerations that are a necessary part of planning the power supply. Although the example suggests a totally new plant, similar forward planning is equally necessary at an existing facility before the demand exceeds the firm supply capacity.

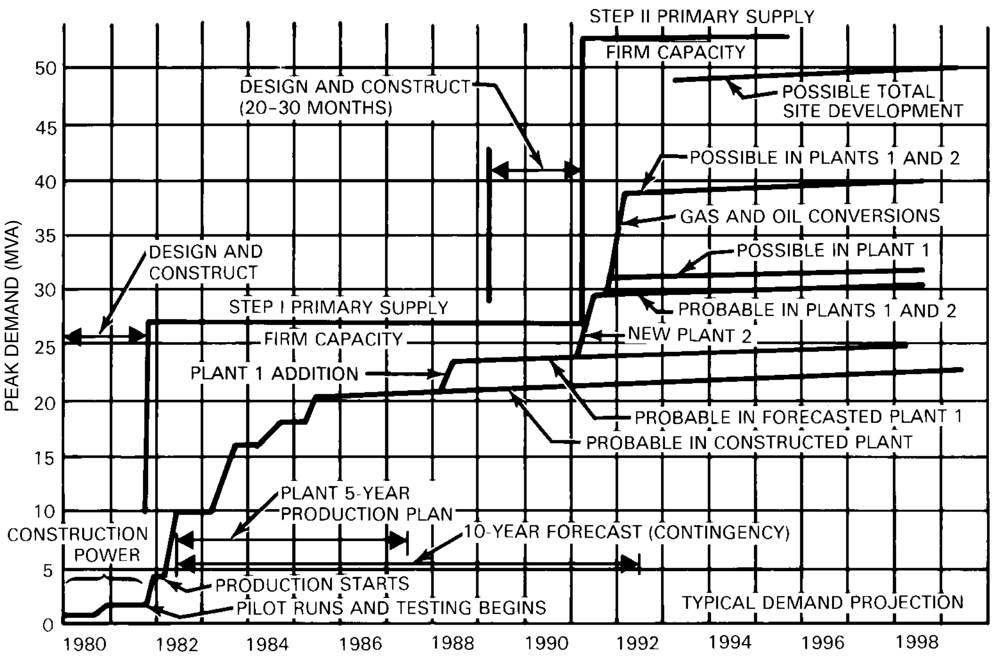


Figure 2-8—Power supply planning considerations

By using various combinations of systems, the engineer can design a system to meet the load requirements. It may be necessary to design a system that can be expanded for future growth. As an example, the engineer can start with a radial system supplied at 13.8 kV from the utility. (See figure 2-1.) As the load at the site grows, the engineer can convert to a double-ended substation, such as is shown in figure 2-5(a). At the time of a major expansion and when the load requires additional power, the engineer can go to a ring bus. (See figure 2-7.) This ring bus, through transformation, can supply an intermediate distribution system at the original utility voltage of 13.8 kV. With proper planning and system selection, the engineer can have enough flexibility to meet any load requirement.

Selecting the number of main distribution buses and the method of interconnecting them depends upon many factors such as the sizes of the immediate and ultimate plant loads, the primary distribution voltage, the availability of suitable supply lines, and other factors relating to the utility system.

Figure 2-9 is presented for the purpose of illustrating a number of main primary substation configurations that can be considered for use. Figure 2-9 demonstrates that there are many ways to develop the main primary distribution configuration while meeting specific requirements or constraints.

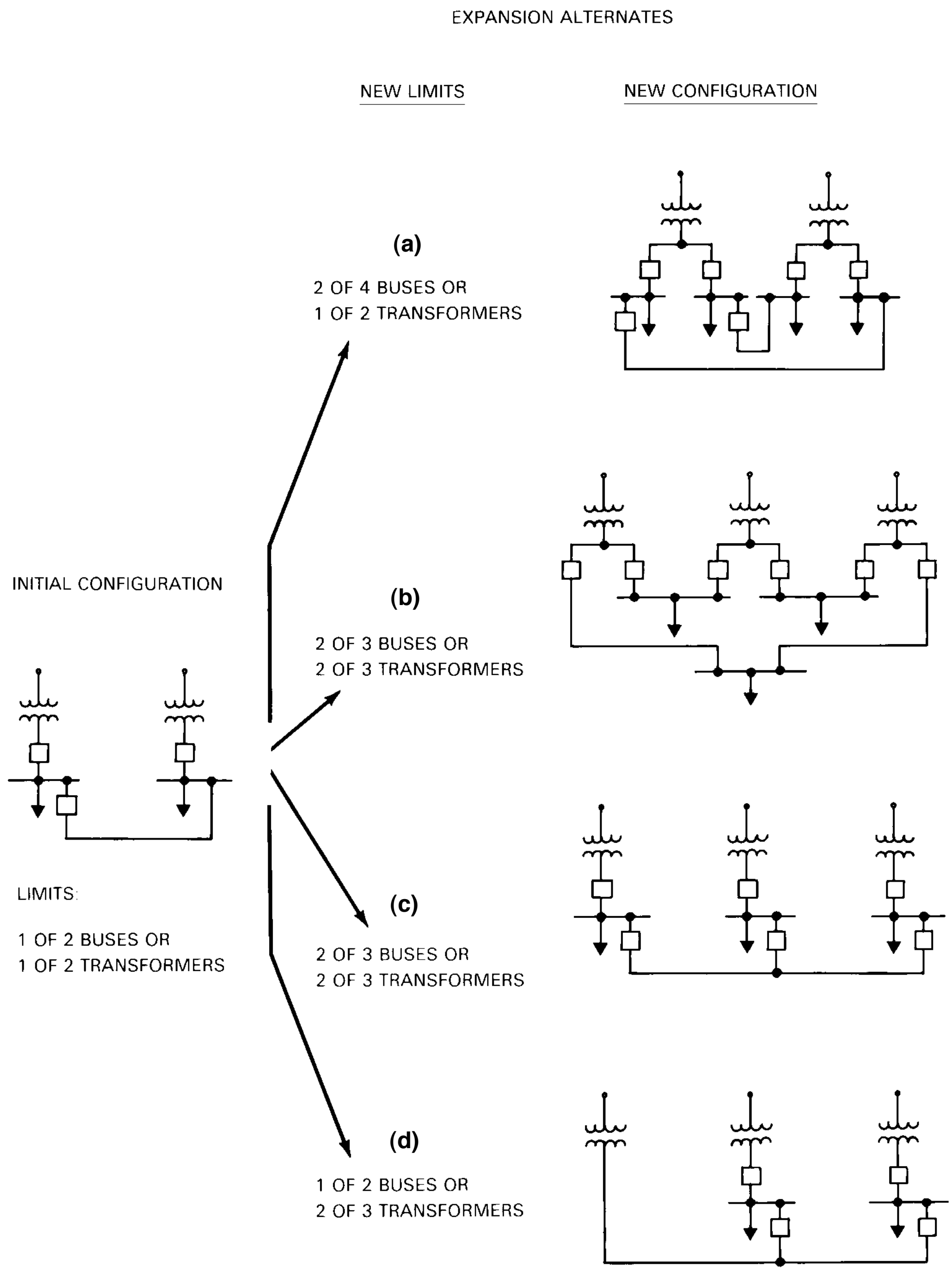


Figure 2-9—Typical main primary distribution arrangements

The two-bus arrangement (figure 2-9), shown as the initial configuration, represents the lowest cost arrangement. To maximize the firm capability of this arrangement requires that the thermal ratings of the supply (transformer), the main circuit breaker, and the switchgear main bus bar be equal. While later discussions will more thoroughly consider specific ratings, precisely matching all of these thermal capacities is extremely difficult and is rarely achieved. Therefore, the usual occurrence is one in which either the supply transformer or the switchgear, the main circuit breaker, or the bus bars are limiting.

Figure 2-9 suggests that the initial sizing of switchgear should be compatible with future expansion. *Future* in this case is intended to reflect the useful life of well-maintained switchgear.

Figure 2-9(a) depicts one method for expanding the system where transformer size is increased and initial switchgear is augmented. This method, when used to increase the useful life of undersized switchgear, may require operation under somewhat restrictive conditions so the circuit breaker short-circuit ratings are not exceeded.

Where a third transformer (supply) is possible and feasible, there are three widely used schemes as shown by figure 2-9(b), (c), and (d). The sparing transformer scheme of figure 2-9(d) is usually the least attractive because switchgear limits are unchanged. Figure 2-9(c) represents the most commonly installed scheme, but this scheme is nearly always capacity-limited by switchgear even when current-limiting reactors are installed in bus tie circuits. Even so, 2-9(c) is usually the preferred configuration because reactive losses are incurred only when the bus loading is unbalanced and during emergency periods. Figure 2-9(b) is more costly than either 2-9(c) or 2-9(d), and its capacity is almost always limited by the transformer rating, particularly when duplex reactors are installed between transformers and main disconnecting devices to limit circuit breaker short-circuit duty.

Substation expansion is also possible by exchanging initially installed transformers for larger units. This is rarely done in instances where the plant owns the supply transformers. However, when transformers are supplied by the utility and when the initial transformers can be utilized by the utility, it is frequently more economical to exchange units than to add a third unit and all of the associated switching apparatus. Usually when a utility exchanges transformers, the customer receives credit for the retired equipment on the basis of replacement cost new less depreciation, although this is also subject to negotiation if there are no clear utility policies. Therefore, it may be financially attractive to begin a supply substation with two 15/20/25 MVA units and later exchange them for two 30/40/50 MVA units. However, in order to be technically feasible, the main plant primary switchgear must be rated to handle the higher load current as well as the higher short-circuit duty due to the larger transformers. The station must originally be designed for such additions, including consideration for needed clearances, structural steel requirements, foundations, and equipment installations and removal spaces.

When expanding an existing plant, determine if all the existing equipment is adequate by checking ratings: voltage, interrupting capacity, short-circuit withstand, momentary capability, switch close and latch, and continuous current. Selective coordination of protective device trip characteristics may require modifications to the existing relaying/fusing to coordinate with the new design and ensure that appropriate margins of safety are maintained.

2.4.6 Generation

Determine whether parallel, standby, or emergency plant generation will be included. Technical and tariff issues must be included in the initial planning so as to prevent having to modify or reconstruct certain parts of the plant supply and distribution system to accommodate generation.

2.4.6.1 Technical issues

The following technical electrical issues must be reviewed during the planning stages:

a) Number of generators and ratings
   1) Generator's output in kilovoltamperes
   2) Generator's voltage
   3) Generator's rated full-load current
   4) Type of generator
   5) Generator's rated power factor
   6) Generator's reactances on generator kilovoltamperes base, including synchronous, transient, and subtransient reactances and time constants to produce generator decrement curves for protective coordination
   7) Generator's transformer requirements, including size/rating in kilovoltamperes, impedance, and base connection
   8) Relaying and protection of generator
b) Metering
c) Voltage regulation
d) Synchronizing
e) Grounding
f) Cost
g) Operation and loading of the generator on a scheduled basis
h) Maintenance requirements
i) Largest motor to be started with generator running
j) Available fault current (three-phase and single-phase to ground) from the generator to the plant system
k) Utility's interconnection and parallel operating conditions including relaying and protective-device requirements

Consideration should be given to the load imposed on the generator when groups of motors are started instead of one large motor. These groups of motors may be arranged for staggered starting so that a smaller generator can be specified.

The complete design must be coordinated with the utility if parallel operation with the utility's system is anticipated. With some utility tariffs, it may be advantageous to utilize plant generation to decrease plant base load or to shave peak load.

2.4.6.2 Rate and financial considerations

The following conditions must be evaluated carefully since the installation of parallel generation will affect the economics of operation and the user's substation design:

a) Utility's charges, including kilowatt and kilovoltampere demand (based on maximum demand), variable or kilowatthour charges, such as fuel (usually in cents/kWh), and other associated costs, such as power-factor metering. These charges are usually determined from an analysis of the approved, applicable, utility rate schedules. The availability of special or incentive rates should also be investigated (i.e., deferred cogeneration, economic development, peak shaving, and interruptible rates);
b) Utility's cogeneration supplemental power, back-up, and maintenance tariffs;
c) Conditions for electric load displacement by the customer and for customer-supplied capacity (including dispatching requirements) and energy delivery to the utility;
d) Customer's load relative to the cogeneration size, especially during peak and minimum (nonproductive) load periods.

Of particular significance are the following:

a) Planned means of connecting the cogenerator to the user's system;
b) Subsequent impact of fault current from the unit on the user's system;
c) Utility's special relaying and protective-device requirements. Particular care should be exercised if automatic recalling on generator operation is considered in order to avoid creating any potential unsafe or dangerous conditions.

2.4.7 Single-line diagram

A complete one-line or single-line diagram, in conjunction with a physical plan of the installation, should present sufficient data to plan and evaluate the electric power system. Figures 4-10 and 5-19 in Chapters 4 and 5 represent single-line diagrams containing some of the information required for system-protection design and fault-current analysis.

The basic function of the single-line diagram is to convey information concerning the power system, including the overall scheme as well as details of each element of the plant supply and distribution system. Symbols commonly used in single-line diagrams are defined in IEEE Std 315-1975.

The following items should be shown on the single-line diagram or other documentation.

2.4.7.1 Utility supply system

a) Utility line supply voltage (34.5/46/115/138/161 kV, etc.);
b) High-voltage protective devices and switches, including circuit switchers, motor-operated air break switches, nonload break switches, etc. The nominal operating mode of all such devices should be indicated (i.e., NO/NC for normally open/normally closed, respectively), together with the nominal continuous-current ratings and interrupting or momentary closing and latching short-circuit current ratings;

c) Maximum and minimum three-phase and phase-to-ground available short-circuit duty (megavoltamperes and symmetrical current), and system equivalent impedances (three-phase and single-phase-to-ground, indicating base used—typically 100 MVA);
d) Types of relays, ANSI identification, relay location, and calibration settings for all high-voltage protective devices;
e) Primary supply cables (if used) including size, capacity, shielding, insulation, installation design (duct banks/direct burial, etc.), number of conductors, nominal ampacity (amperes and kilovoltamperes/megavoltamperes) and bases, etc.

2.4.7.2 Primary utility supply transformers

a) Nameplate rating(s) (kilovoltamperes and kilovolts) and temperature rise;
b) Rating in kilovoltamperes for continuous summer duty;
c) High-voltage winding voltage taps and winding connection (delta/wye);
d) Low-voltage winding voltage taps and winding connection (delta/wye);
e) Load tap changer—voltage range and percent steps;
f) In-line voltage regulator (if separate) ratings;
g) Impedance and kilovoltamperes base;
h) Grounding scheme and ohmic value of neutral resistor(s) if used; show connections;
i) Surge arrestors and capacitors (show switching if switched), and connections;
j) Metering of utility supply;
k) Primary protective devices when primary supply is supplied from distribution system. Include ratings (megavoltamperes, amperes), nominal operational mode, and protective devices with coordination settings.

2.4.7.3 Incoming primary: Cable or bus to main switchgear from supply transformers

a) Indicate type (bus, cable, etc.), type of insulation, continuous-current rating (ampacity), physical support, and installation design (underground cable in duct bank, bus, overhead cable in tray, tray size, etc.);
b) Nominal maximum current rating(s) and basis.

2.4.7.4 Main switchgear

a) Manufacturer(s), type, model, current rating, megavoltamperes class, symmetrical interrupting current rating, and asymmetrical momentary/closing-and-latching current rating for main, tie, and feeder devices;
b) Indicate nominal operational mode for all switchgear and disconnecting devices;
c) Ampacity of bus.

2.4.7.5 Primary feeder cables

a) Number of feeders;
b) Cable insulation and type;
c) Installation design (conduit, Interlocked Armored Cable [IAC] in tray, size of tray, number of cables in tray, etc.);
d) Nominal maximum current rating and basis;

e) Cable size and number of cables per phase;
f) Year of installation.

2.4.7.6 Primary distribution system

a) Include primary switching, fusing, other protective devices, transformer connections, ratings, system grounding, nominal loading (kilovoltamperes and amperes), and low-voltage protective-device arrangement for unit substation and load centers. Indicate each protective device's continuous-current rating, symmetrical interrupting current and asymmetrical momentary or closing-and-latching current rating, manufacturer, type, and model identification. Indicate tap settings on all primary transformers;
b) Indicate bus ratings in amperes;
c) Identify major load centers and indicate general electrical configuration;
d) Identify nominal loads in kilovoltamperes and amperes on unit substations, transformers, and load centers;
e) Identify and show all major medium-voltage loads and motors, including associated transformers and all other major, significant and identifiable loads, such as motor loads on motor control centers, large press and other motor or drive loads, dedicated lighting loads, arc furnaces, induction furnaces, special purpose loads, such as data processing and computer applications, welding loads, powerhouse loads, including waste treatment, air compressor loads, etc.

2.4.7.7 Relay and protective device coordination

The relay coordination and protective-device settings should be on separate documentation that forms a part of the single-line diagram. Show for utility medium-voltage supply, primary distribution system, and low-voltage or secondary distribution system.

2.4.7.8 Normal operation mode of switching and isolation devices

Indicate normal operation mode of all switching, isolation, and protective devices.

2.4.7.9 Future space considerations

Primary main switchgear. Indicate space for expansion of primary feeder overcurrent devices in switch house or available cubicles for such expansion.

2.4.7.10 Running (operating) motor loads

An integral part of the single-line diagram is the summary of running motor loads in the plant. This information is important for short-circuit and protective-device coordination.

At a minimum, the following information should be obtained:

a) By size category for each 480 V transformer (less than 50 hp; 50 hp and larger);

b) List individual medium-voltage motors (e.g., 2400 V, 4160 V, 4800 V, 6900 V and 13800 V systems), including horsepower/kilowatt, revolutions per minute, and type (induction, synchronous);
c) Include powerhouse motors (chillers, compressors, etc.);
d) Indicate all solid-state/SCR-controlled variable-speed ac/dc-converter motor drives. (These may not contribute to fault current.)

2.4.7.11 Capacitor banks

Medium- and low-voltage capacitor bank installations should be shown on the single-line diagram together with connections and switching configuration and ratings (voltage, kilovar, etc.).

a) Location and rating of each capacitor bank installed;
b) Switched or permanently connected? If switched, design criteria (if available), and details on control scheme;
c) Capacitors status (connected?/working?).

The actual drawing should be kept as simple as possible. It is a schematic diagram and need not show geographical relationship. Duplication should be avoided.

2.4.8 Short-circuit analysis

Calculate short-circuit currents available at all system components. Chapter 4 provides a detailed guide to making these calculations. A short-circuit evaluation should always be performed if changes are made to the primary utility supply system that may affect available fault current. Such changes can include, but are not limited to, the following:

a) High-voltage conversion or upgrading;
b) Replacement of lower capacity primary transformers with higher capacity or lower impedance transformers;
c) Additional primary service from alternate sources;
d) Operation in a different mode that increases available short-circuit current, such as changing to a closed bus tie operation from a normally open configuration or the installation of a large generator on the primary distribution system.

Additionally, significant changes in motor loads within the facility may affect available fault current.

Normal, emergency, and standby system operating configurations should be included in the analysis.

As a guide, a short-circuit analysis should be performed at least every five to ten years if no major system changes have occurred that dictate a new study.

2.4.9 Protection and protective-device coordination

The protection and protective-device coordination evaluation should always be performed in conjunction with a short-circuit evaluation. This should be performed whenever there are major changes made to the utility primary electric supply that can affect available fault current or other major system changes that can affect system operation and coordination. Using the data presented in Chapter 5, design the required protective systems. System-protection design must be an integral part of the total system design and not be superimposed on a system later.

Coordination of critical loads, such as uninterruptible power supplies (UPS) with their fast-acting overcurrent devices to protect electronic devices, should be included in the analysis.

2.4.10 Communications

Any plan for the protection of a plant must include a reliable communication system, such as a self-contained system of telephones, alarms, etc., which may include modern radio and television equipment, or by a joint system tied into the existing communication services.

Fire and smoke alarm circuits, whether self-contained or connected to municipal alarm systems, should be installed to minimize the effect of faults and changes in buildings or plant operations. Circuits should be arranged to provide easy means of testing and to isolate portions of the system without interfering with the remainder of the system.

Security guard circuits, including television and radio equipment, are used in many plants for the purpose of providing a ready means for the individual security guard to report unusual circumstances to the supervisor without delay. Such systems are frequently combined with public-address paging systems and other alarm methods.

Annunciator systems are available for alerting operations to abnormal situations in critical areas. The operator can dispatch personnel to investigate the malfunction or disorder or take corrective action.

2.4.11 Maintenance

Electric equipment must be selected and installed with attention to adequacy of performance, safety, and reliability. To preserve these features, a maintenance program must be established and tailored to the type of equipment and the details of the particular installation. Some items require daily attention, some weekly, and others can be tested or checked annually or less frequently.

Requirements of a maintenance program should be incorporated in the electrical design to provide working space, easy access for inspection, facilities for sampling and testing, and disconnecting means for protection of the workmen, lighting, and standby power. The maintenance program should have the following objectives.

2.4.11.1 Cleanliness

Dirt and dust accumulation affects the ventilation of equipment and causes excess heat, which reduces the life of the insulation. Dirt and dust also build up on the surfaces of insulators to form paths for leakage that may result in arcing faults. Insulated surfaces should be cleaned regularly to minimize these hazards.

2.4.11.2 Moisture control

Moisture reduces the dielectric strength of many insulating materials. Unnecessary openings should be closed and necessary openings should be baffled or filtered to prevent the entrance of moisture, especially light snow. Also, even though equipment is adequately housed and indoors, condensation from weather changes should be minimized by supplying heat, usually electric, to the enclosure interiors. From 5–7.5 W/ft^2 of external enclosure surface is usually effective when placed at the bottom of each space affected. A small amount of ventilation outdoors is necessary even with heating to avoid condensation damage and insulation failure.

2.4.11.3 Adequate ventilation

Much electric equipment is designed with paths for ventilating air to pass over insulating surfaces to dissipate heat. Filters must be changed, fans inspected, and equipment cleaned often enough to keep such ventilating systems operating properly.

2.4.11.4 Reduced corrosion

Corrosion destroys the integrity of equipment and enclosures. As soon as evidence of corrosion is noted, action should be taken to clean the affected surfaces and inhibit future deterioration.

2.4.11.5 Maintenance of conductors

Conducting surfaces reveal problems caused by overheating, wear, or misalignment of contact surfaces. These conditions should be corrected by tightening bolts, correcting excessive operations, aligning contacts, or whatever action is necessary.

2.4.11.6 Regular inspections

Inspections should be scheduled on a regular basis depending on equipment needs and process requirements. External inspection can often be made and reveal significant information without process shutdown. However, a complete inspection will require a shutdown. Plans for repairs should be based on such inspections so that necessary manpower, tools, and replacement parts will be available as needed during the shutdown.

2.4.11.7 Regular testing

Performance of protective devices depends on the accuracy and repeatability of the sensing devices and the integrity of the control circuits. Periodic tests of such devices as well as of the dielectric strength of insulating systems and the color and acidity of the insulating oils, etc., will reveal deteriorating conditions that cannot be determined by visual inspection. Necessary adjustments or corrections can be made before failure occurs.

2.4.11.8 Adequate records

An organized system of inspection records, maintenance, tests, and repairs provides a basis for trouble-shooting, predicting equipment failures, and selecting future equipment.

2.4.11.9 Codes and standards

Throughout the design, adherence to all applicable national and local laws, codes, and standards is required.

2.5 Power system modernization and evaluation studies/programs

The following circumstances, occurring individually, or in combination, suggest that a power system analysis and evaluation may be required to ensure continued safe and reliable power system operation. These aspects should be continually monitored to ensure that system components and operation are adequately maintained over time.

a) *Production changes*. Major production program may be initiated that could impact the primary electric power system supply and/or distribution system.
b) *Load growth*. Rapid load growth due to production increases. Typically a 10–15% load growth increase projected over a relatively short time period (i.e., 1 to $1^1/_2$ years) is cause for further evaluation.
c) *Modifications to applicable electrical laws and codes*
d) *Primary distribution system and load center substation equipment capacity limits*. Primary supply and/or transformation equipment, primary bus, primary switchgear, primary feeders, or load center substations may be nearing their firm/first contingency capacity or may be already exceeding that capacity and additional equipment or load rebalancing is required. These concerns can occur over time as routine product and process enhancements are incorporated into production operations.
e) *Power factor problems*. The first notice of a power factor problem usually occurs when there is a power factor penalty charge included in the electric utility bill. It should be noted that all utilities do not have a power factor penalty. Symptoms of a power factor problem can include blown capacitor fuses, inoperable capacitor banks, low voltage, overloaded primary feeders, etc.
f) *Harmonic problems*. Symptoms of harmonic problems include blown power factor correction capacitor fuses, a reduction in plant power factor, motor and transformer heating and/or failure, and possibly unexplainable operation malfunctions of process controls, especially timing problems in electronic equipment. Typical causes of harmonic problems include the application of power electronics and other solid-state power control devices for plant processes combined with power factor correction capacitors, creating harmonic resonance situations.
g) *Power quality problems*. Power quality problems may be encountered with the primary utility supply, within the plant primary and/or secondary distribution systems, with particular plant equipment, or with all systems. Frequent voltage sags, surges, transients, interruptions, or other utility system disturbances may affect plant

production operations. Such system disturbances can also be caused by in-plant devices that generate disturbances in their operation. In some cases, equipment may create system disturbances by its operation that in turn may affect its operations. Excessive interruptions or equipment shutdown may then be encountered on the specific pieces of in-plant equipment or systems.

h) *Welding processes*. A new or additional welding process may be installed that causes problems with existing welding operations or process control schemes may be modified resulting in unacceptable operations. Symptoms include low voltage, blown fuses, poor weld quality, component overheating and/or failure.

i) *Deterioration of primary equipment*. Primary equipment can become obsolete over time; outdated due to age or condition; present safety or environmental concerns (i.e., toxic, hazardous, or containment provisions); or equipment can become overdutied, unsafe, inoperable, or approach the end of its useful life. Electrical system component response or performance over time can then be affected, suggesting that equipment be replaced or upgraded to ensure safety and system operating reliability. Conditions can usually be determined by inspection and are often obvious, although a detailed, professional inspection is important to verify the plant's findings.

Power system evaluation programs all involve the identification and resolution of safety related concerns, inadequate facility or equipment capacity concerns, and the implementation of safety improvements to maintain or enhance safety and operating reliability of the plant power system.

These evaluations perform two fundamental, extremely useful functions in the overall process of evaluating and maintaining safe and reliable power system. First, they provide a documented engineering concept or basis for the required system changes needed to resolve a particular problem, situation, or concern. Second, they provide the engineering cost basis for the required changes so that adequate funding can be estimated, supported, sought, and allocated.

The engineering activities associated with this type of evaluation are quite challenging and often are not well understood. Consequently, this type of work is sometimes performed inadequately or incompletely. This problem seems to occur primarily because the engineering task is not necessarily well defined, since defining the work and determining the conditions and the economical yet practical requirements are really the engineering assignment. This type of work requires the application of experience and engineering concepts and not a simple application of known design rules.

2.5.1 Criteria for engineering studies and evaluations

Criteria for these studies should be developed in a conceptual format. The criteria should define the known or identified problems, concerns, or circumstances that are to be addressed in the evaluation of the existing power system. The specific system concept requirements that require identification, evaluation, and resolution should be described, including supply/distribution system concept development, system analysis, system/equipment evaluations, and general schedule requirements for the projects.

Conceptual engineering study work areas may typically include the following types:

a) Evaluation of the adequacy of power system equipment, including the testing and coordination of protective devices
b) Analysis for the expansion/conversion of the medium-voltage primary supply
c) Plant distribution system life-extension and modernization evaluation and alternatives
d) Load-flow analysis
e) Network (including welding system) studies to define available fault current, voltage drops, and load flow
f) Motor-starting studies
g) Short-circuit analysis and protective-device coordination
h) Power-factor improvement programs including evaluation of harmonic resonance concerns and/or need for tuned-filter apparatus
i) Specifications, standards, and guidance development
j) PCB-equipment-replacement programs
k) Switching-transients analysis
l) Harmonic analysis of the power system
m) Reliability analysis
n) Removal and construction work sequence for modernization projects to ensure that the work is feasible during production operations and to establish a cost baseline
o) Cable-ampacity analysis
p) Ground-mat studies

The study criteria should also define the applicable standard specifications that will apply to the work when performed. These specifications should be considered in developing and evaluating alternatives, in performing the study, and when preparing any cost estimates for concept projects.

2.6 References

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

ANSI/NFPA 70-1993, National Electrical Code.[2]

ANSI/NFPA 70B-1990, Recommended Practice for Electrical Equipment Maintenance.

IEEE P277, Recommended Practice for Cement Plant Power Distribution (D1.1, 6/9/88).[3]

IEEE Std 315-1975 (CSA Z99-1975) (Reaff 1989), IEEE Standard Graphic Symbols for Electrical and Electronics Diagrams (ANSI).[4]

[2]NFPA publications are available from Publication Sales, National Fire Protection Agency, 1 Batterymarch Park, P.O. Box 9101, Quincy, MA 02269-9101, USA.

[3]This IEEE authorized standards project is available from the Sales Dept., IEEE Service Center, 445 Hoes Lane, Piscataway, NJ 08855-1331.

[4]IEEE publications are available from the Institute of Electrical and Electronics Engineers, Service Center, 445 Hoes Lane, Piscataway, NJ 08855-1331, USA.

IEEE Std 493-1990, IEEE Recommended Practice for the Design of Reliable Industrial and Commercial Power Systems (IEEE Gold Book) (ANSI).

2.7 Bibliography

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[B3] Heising, C. R., “Examples of Reliability and Availability Analysis of Common Low-Voltage Industrial Power Distribution Systems,” IEEE Industrial and Commercial Power Systems Technical Conference, Los Angeles, May 10–13, 1976.

[B4] Heising, C. R., “Reliability and Availability Comparison of Common Low-Voltage Industrial Power Distribution Systems,” *IEEE Transactions on Industry and General Applications*, vol. IGA-6, pp. 416–424, Sept./Oct. 1970.

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[B8] McFadden, R. H., “Power-System Analysis: What It Can Do for Industrial Plants,” *IEEE Transactions on Industry and General Applications*, vol. IGA-7, pp. 181–188, Mar./Apr. 1971.

[B9] Paten, A. D., “Fundamentals of Power System Reliability Evaluation,” IEEE Industrial and Commercial Power Systems Technical Conference, Los Angeles, May 10–13, 1976.

[B10] Regotti, A. R., and Trasky, J. G., “What to Look for in a Low-Voltage Unit Substation,” *IEEE Transactions on Industry and General Applications*, vol. IGA-5, pp. 710–719, Nov./Dec. 1969.

[B11] Shaw, E. T., *Inspection and Test of Electrical Equipment*. Pittsburgh, PA: Westinghouse Electric Corporation, Electric Service Division, Pub. MB3051, 1967.

[B12] Yuen, M. H., and Knight, R. L., “On-Site Electrical Power Generation and Distribution for Large Oil and Gas Production Complex in Libya,” *IEEE Transactions on Industry and General Applications*, vol. IGA-7, pp. 273–289, Mar./Apr. 1971.

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Chapter 3
Voltage considerations

3.1 General

An understanding of system voltage nomenclature and the preferred voltage ratings of distribution apparatus and utilization equipment is essential to ensure proper voltage identification throughout a power distribution system. The dynamic characteristics of the system need to be recognized and the proper principles of voltage control applied so that satisfactory voltages will be supplied to all utilization equipment under all normal conditions of operation. Consideration should be given for transient and momentary voltage variations to ensure appropriate performance of utilization equipment.

3.1.1 Definitions

The following terms and definitions, quoted from ANSI C84.1-1989,[1] are used to identify the voltages and voltage classes used in electric power distribution.

3.1.1.1 System voltage terms

Note that the nominal system voltage is near the voltage level at which the system normally operates. To allow for operating contingencies, systems generally operate at voltage levels about 5–10% below the maximum system voltage for which system components are designed.

3.1.1.1.1 system voltage: The root-mean-square phase-to-phase voltage of a portion of an ac electric system. Each system voltage pertains to a portion of the system that is bounded by transformers or utilization equipment. (All voltages hereafter are root-mean-square phase-to-phase or phase-to-neutral voltages.)

3.1.1.1.2 nominal system voltage: The voltage by which a portion of the system is designated and to which certain operating characteristics of the system are related. Each nominal system voltage pertains to a portion of the system that is bounded by transformers or utilization equipment.

3.1.1.1.3 maximum system voltage: The highest system voltage that occurs under normal operating conditions, and the highest system voltage for which equipment and other components are designed for satisfactory continuous operation without derating of any kind. In defining maximum system voltage, voltage transients and temporary overvoltages caused by abnormal system conditions, such as faults, load rejection, and the like, are excluded. However, voltage transients and temporary overvoltages may affect equipment operating performance and are considered in equipment application.

[1]Information on references can be found in 3.12.

3.1.1.1.4 service voltage: The voltage at the point where the electric system of the supplier and the electric system of the user are connected.

3.1.1.1.5 utilization voltage: The voltage at the line terminals of utilization equipment.

3.1.1.1.6 nominal utilization voltage: The voltage rating of certain utilization equipment used on the system.

3.1.1.2 System voltage classes

3.1.1.2.1 low voltage: A class of nominal system voltages less than 1000 V.

3.1.1.2.2 medium voltage: A class of nominal system voltages equal to or greater than 1000 V and less than 100 000 V.

3.1.1.2.3 high voltage: A class of nominal system voltages equal from 100 000 V to 230 000 V.

3.1.2 Standard nominal system voltages for the United States

These voltages and their associated tolerance limits are listed in ANSI C84.1-1989 for voltages from 120–230 000 V and in ANSI C92.2-1987 for voltages above 230 kV nominal. Table 3-1, reprinted from ANSI C84.1-1989 and containing information from ANSI C92.9-1987, provides all the standard nominal system voltages and their associated tolerance limits for the United States. Preferred nominal system voltages and voltage ranges are shown in boldface type while other systems in substantial use that are recognized as standard voltages are shown in regular type. Other voltages may be encountered on older systems but they are not recognized as standard voltages. The transformer connections from which these voltages are derived are shown in figure 3-1.

Two sets of tolerance limits are defined: range A, which specifies the limits under most operating conditions, and range B, which allows minor excursions outside the range A limits.

3.1.3 Application of voltage classes

a) Low-voltage class voltages are used to supply utilization equipment.
b) Medium-voltage class voltages are used for subtransmission and primary distribution. Medium voltages often supply distribution transformers which step the medium voltage down to low voltage to supply utilization equipment. Medium voltages may also supply distribution substations that transform the voltage from a higher to a lower voltage in the medium-voltage class. Medium voltages of 13 800 V and below are also used to supply utilization equipment such as large motors (see 3.5.2, table 3-8).
c) High-voltage class voltages are used to transmit large amounts of electric power between transmission substations. Transmission substations located adjacent to generating stations step the generator voltage up to the transmission voltage. Other transmission substations transform the high voltage down to medium voltage for

Table 3-1—Standard nominal system voltages and voltage ranges

(Preferred system voltages in bold-face type)

VOLTAGE CLASS	NOMINAL SYSTEM VOLTAGE (Note a) Two-wire	Three-wire	Four-wire	Nominal Utilization Voltage (Note i) Two-wire Three-wire Four-wire	VOLTAGE RANGE A (Note b) Maximum: Utilization and Service Voltage (Note c)	Minimum: Service Voltage	Minimum: Utilization Voltage	VOLTAGE RANGE B (Note b) Maximum: Utilization and Service Voltage	Minimum: Service Voltage	Minimum: Utilization Voltage
						Single-Phase Systems				
Low Voltage (Note 1)	120			**115**	126	114	110	127	110	106
		120/240		**115/230**	**126/252**	**114/228**	**110/220**	**127/254**	**110/220**	**106/212**
						Three-Phase Systems				
			208Y/120 (Note d)	**200**	**218Y/126**	**197Y/114**	**191Y/110**	**220Y/127**	**191Y/110** (Note 2)	**184Y/106** (Note 2)
			240/120	**230/115**	**252/126**	**228/114**	**220/110**	**254/127**	**220/110**	**212/106**
		240		**230**	252	228	220	254	220	212
			480Y/277	**460**	**504Y/291**	**456Y/263**	**440Y/254**	**508Y/293**	**440Y/254**	**424Y/245**
		480		**460**	**504**	**456**	**440**	**508**	**440**	**424**
		600 (Note e)		**575**	630 (Note e)	570	550	635 (Note e)	550	530
Medium Voltage		2 400			2 520	2 340	2 160	2 540	2 280	2 080
			4 160Y/2 400		4 370/2 520	4 050Y/2 340	3 740Y/2 160	4 400Y/2 540	3 950Y/2 280	3 600/2 080
		4 160			**4 370**	**4 050**	**3 740**	**4 400**	**3 950**	**3 600**
		4 800			5 040	4 680	4 320	5 080	4 560	4 160
		6 900			7 240	6 730	6 210	7 260	6 560	5 940
			8 320Y/4 800		8 730Y/5 040	8 110Y/4 680	(Note f)	8 800Y/5 080	7 900Y/4 560	(Note f)
			12 000Y/6 930		12 600Y/7 270	11 700Y/6 760		12 700Y/7 330	11 400Y/6 580	
			12 470Y/7 200		**13 090Y/7 560**	**12 160Y/7 020**		**13 200Y/7 620**	**11 850Y/6 840**	
			13 200Y/7 620		**13 860Y/8 000**	**12 870Y/7 430**		**13 970Y/8 070**	**12 504Y/7 240**	
			13 800Y/7 970		14 490Y/8 370	13 460Y/7 770		14 520Y/8 380	13 110Y/7 570	
		13 800			**14 490**	**13 460**	**12 420**	**14 520**	**13 110**	**11 880**
			20 780Y/12 000		21 820Y/12 600	20 260Y/11 700	(Note f)	22 000Y/12 700	19 740Y/11 400	(Note f)
			22 860Y/13 200		24 000Y/13 860	22 290Y/12 870		24 200Y/13 970	21 720Y/12 540	
		23 000			24 150	22 430		24 340	21 850	
			24 940Y/14 400		**26 190Y/15 120**	**24 320Y/14 040**		**26 400Y/15 240**	**23 690Y/13 680**	
			34 500Y/19 920		**36 230Y/20 920**	**33 640Y/19 420**		**36 510Y/21 080**	**32 780Y/18 930**	
		34 500			36 230	33 640		36 510	32 780	
					Maximum Voltage (Note g)					
		46 000			48 300					
		69 000			**72 500**					
High Voltage		**115 000**			**121 000**					
		138 000			**145 000**					
		161 000			169 000					
		230 000			**242 000**					
		(Note h)								
Extra-High Voltage		**345 000**			**362 000**					
		500 000			**550 000**					
		765 000			**800 000**					
Ultra-High Voltage		**1 100 000**			**1 200 000**					

NOTES: (1) Minimum utilization voltages for 120-600 volt circuits not supplying lighting loads are as follows.

Nominal System Voltage	Range A	Range B
120	108	104
120/240	**108/216**	**104/208**
(Note 2) **208Y/120**	**187Y/108**	**180Y/104**
240/120	**216/108**	**208/104**
240	216	208
480Y/277	**432Y/249**	**416Y/240**
480	**432**	**416**
600	540	520

(2) Many 220 volt motors were applied on existing 208 volt systems on the assumption that the utilization voltage would not be less than 187 volts. Caution should be exercised in applying the Range B minimum voltages of Table 1 and Note (1) to existing 208 volt systems supplying such motors.

Source: ANSI C84.1-1989

Table 3-1 (Continued)

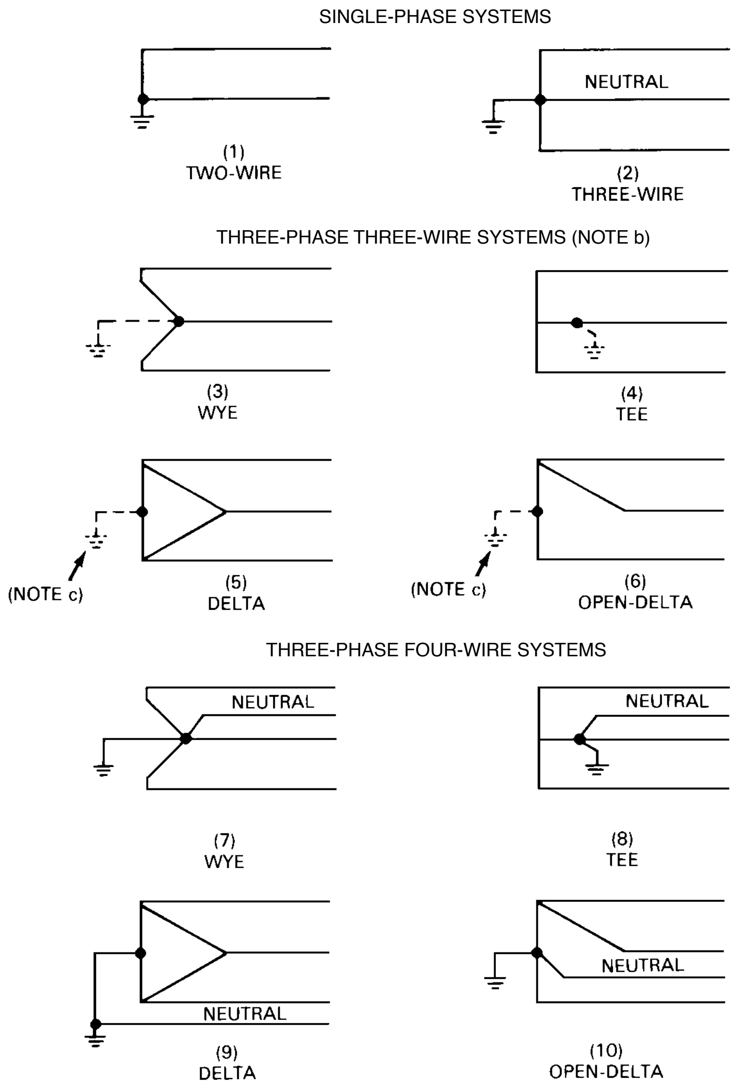
NOTES FOR TABLE 3-1
a—Three-phase, three-wire systems are systems in which only the three-phase conductors are carried out from the source for connection of loads. The source may be derived from any type of three-phase transformer connection, grounded or ungrounded. Three-phase, four-wire systems are systems in which a grounded neutral conductor is also carried out from the source for connection of loads. Four-wire systems in this table are designated by the phase-to-phase voltage, followed by the letter Y (except for the 240/120 V delta system), a slant line, and the phase-to-neutral voltage. Single-phase services and loads may be supplied from either single-phase or three-phase systems. The principal transformer connections that are used to supply single-phase and three-phase systems are illustrated in figure 3-1.
b—The voltage ranges in this table are illustrated in ANSI C84.1-1989, Appendix B.
c—For 120–600 V nominal systems, voltages in this column are maximum service voltages. Maximum utilization voltages would not be expected to exceed 125 V for the nominal system voltage of 120, nor appropriate multiples thereof for other nominal system voltages through 600 V.
d—A modification of this three-phase, four-wire system is available as a 120/208Y-volt service for single-phase, three-wire, open-wye applications.
e—Certain kinds of control and protective equipment presently available have a maximum voltage limit of 600 V; the manufacturer or power supplier, or both, should be consulted to ensure proper application.
f—Utilization equipment does not generally operate directly at these voltages. For equipment supplied through transformers, refer to limits for nominal system voltage of transformer output.
g—For these systems, Range A and Range B limits are not shown because, where they are used as service voltages, the operating voltage level on the user's system is normally adjusted by means of voltage regulation to suit their requirements.
h—Standard voltages are reprinted from ANSI C92.2-1987 for convenience only.
i—Nominal utilization voltages are for low-voltage motors and control. See ANSI C84.1-1989, Appendix C, for other equipment nominal utilization voltages (or equipment nameplate voltage ratings).

subtransmission and primary distribution. Transmission lines also interconnect transmission substations to provide alternate paths for power transmission for higher reliability.

3.1.4 Voltage systems outside of the United States

Voltage systems in other countries generally differ from those in the United States. For example, 415Y/240 V and 380Y/220 V are widely used as utilization voltages even for residential service. Also, the frequency in many countries is 50 Hz instead of 60 Hz, which affects the operation of some equipment such as motors. Motors on 50 Hz systems run approximately 17% slower than in the United States. Plugs and receptacles are generally different, and this helps to prevent utilization equipment from the United States from being connected to the wrong voltage.

Users should check with the equipment manufacturer before attempting to operate equipment on a voltage or frequency for which the equipment is not specifically rated. Equipment rated for use with one voltage and frequency often cannot be used or may not give adequate performance on another voltage or frequency. Some equipment has multiple voltage and/or frequency ratings for application on a variety of systems. If electric equipment made for use on one system must be used on a different system, information on the voltage, frequency, and type of plug required should be obtained. If the difference is only in the voltage, transformers are generally available to convert the available supply voltage to match the equipment voltage.



NOTES

a—The above diagrams show connections of transformer secondary windings to supply the nominal system voltages of table 3-1. Systems of more than 600 V are normally three phase and supplied by connections (3), (5) ungrounded, or (7). Systems of 120–600 V may be either single phase or three phase and all of the connections shown are used to some extent for some systems in this voltage range.

b—Three-phase, three-wire systems may be solidly grounded, impedance grounded, or ungrounded, but are not intended to supply loads connected phase-to-neutral (as the four-wire systems are).

c—In connections (5) and (6), the ground may be connected to the midpoint of one winding as shown (if available), to one phase conductor (*corner* grounded), or omitted entirely (ungrounded).

d—Single-phase services and single-phase loads may be supplied from single-phase systems or from three-phase systems. They are connected phase-to-phase when supplied from three-phase, three-wire systems and either phase-to-phase or phase-to-neutral from three-phase, four-wire systems.

Figure 3-1—Principal transformer connections to supply the system voltages of table 3-1

3.1.5 Voltage standard for Canada

The voltage standard for Canada is CAN3-C235-83. This standard differs from the United States standard in both the list of standard nominal voltages and the tolerance limits.

3.2 Voltage control in electric power systems

Power supply systems and utilization equipment should be designed to be compatible. This requires coordinated efforts and standards that place requirements on voltage ranges supplied by utilities, allowable voltage drops in plant distribution systems, and voltage ranges for utilization equipment. This section outlines these coordinated efforts and standards associated with assuring good operation of the utilization equipment.

3.2.1 Principles of power transmission and distribution in utility systems

A general understanding of the principles of power transmission and distribution in utility systems is necessary since most industrial plants obtain most of their electric power from the local electric utility. Figure 3-2 shows a simplified one-line diagram of a typical utility power generation, transmission, and distribution system.

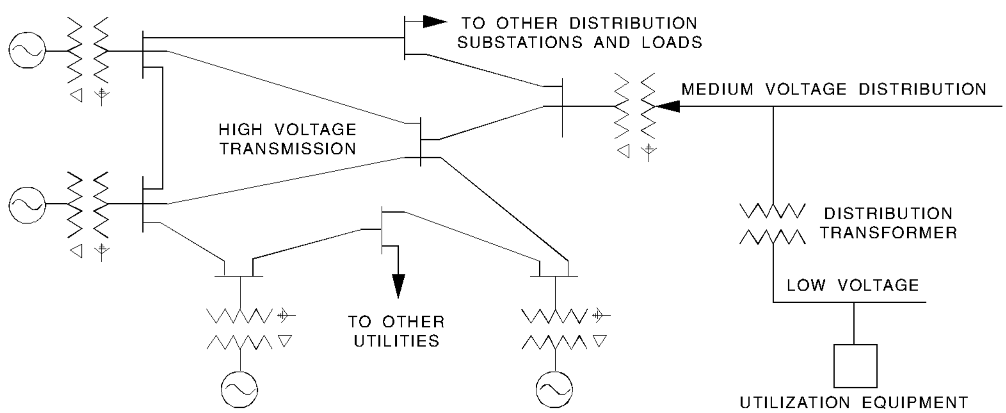


Figure 3-2—Typical utility generation, transmission and distribution system

Most utility generating stations are located near sources of water, often a considerable distance from major load areas. Generated power, except for station requirements, is transformed in a transmission substation located at the generating station to voltage generally 69 000 V or higher for transmission to major load areas. These transmission lines are usually interconnected in large free flowing networks. For example, most transmission lines in the eastern half of the United States are interconnected to form one network. Utilities are constantly adjusting generation to match the load. They adjust generation to regulate the 60 Hz frequency, keeping clocks on time within a few seconds. Transmission lines are generally for bulk energy transfers and are controlled only to keep the lines operating within normal voltage limits and to facilitate power flow. ANSI C84.1-1989 and ANSI C92.2-1987 specify nominal and maximum but no minimum values for systems over 34 500 V.

Transmission line networks supply distribution substations equipped with transformers that step the transmission voltage down to a primary distribution voltage generally in the range from 4160 to 34 500 V with 12 470, 13 200, and 13 800 V in widest use. There is an increasing trend in the electric utility industry to use 23 kV and 34.5 kV for distribution. If the supplying utility offers one of these voltages for primary distribution within a building, competent electricians experienced in making splices and terminations must be secured to obtain a good installation.

Voltage control is applied when necessary for the purpose of supplying satisfactory voltage to the terminals of utilization equipment. Transformers stepping the transmission voltage down to the primary distribution voltage are generally equipped with automatic tap-changing-under-load equipment, which changes the turns ratio of the transformer under load. This regulates the primary distribution voltage within a specific range of values regardless of fluctuations in the transmission voltage or load. Separate step or induction regulators may also be used.

If the load is remote from the substation, the regulator controls are equipped with compensators that raise the voltage as the load increases and lower the voltage as the load decreases to compensate for the voltage drop in the primary distribution system that extends radially from the substation. This effectively regulates the voltage at a point of the primary distribution system some distance from the substation. This is illustrated in figure 3-3. Note that plants close to the substation will receive voltages which, on the average, will be higher than those received by plants at a distance from the distribution substation. See 3.2.8 on the use of distribution transformer taps. Switched or fixed capacitors are also used to improve the voltage on primary feeders.

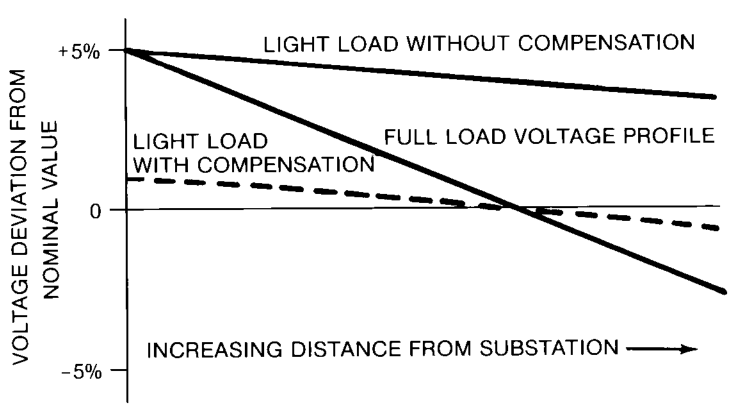


Figure 3-3—Effect of regulator compensation on primary distribution system voltage

The primary distribution system supplies distribution transformers that step the primary distribution voltage down to utilization voltages generally in the range of 120 to 600 V to supply a secondary distribution system to which the utilization equipment is connected. Distribution transformers generally do not have any automatic means for regulating the utilization voltage. Small transformers used to step a higher utilization voltage down to a lower utilization voltage, such as 480 V to 208Y/120 V, are considered part of the secondary distribution system.

The supply voltages available to an industrial plant depend upon whether the plant is connected to the distribution transformer, the primary distribution system, or the transmission system, which in turn depends on the size of the plant load.

Small plants with loads up to several hundred kilovoltamperes and all plants supplied from low-voltage secondary networks are connected to the distribution transformer, and the secondary distribution system consists of the connections from the distribution transformer to the plant service and the plant wiring.

Medium-sized plants with loads of a few thousand kilovoltamperes are connected to the primary distribution system, and the plant provides the portion of the primary distribution system within the plant, the distribution transformers, and the secondary distribution system.

Large plants with loads of more than a few thousand kilovoltamperes are connected to the transmission system, and the plant provides the primary distribution system, the distribution transformers, the secondary distribution system, and it may provide the distribution substation.

Details of the connection between the utility system and the plant system will depend on the policy of the supplying utility. Refer to Chapter 15 for more detailed information about utility interface considerations.

3.2.2 System voltage tolerance limits

ANSI C84.1-1989 specifies the preferred nominal voltages and operating voltage ranges for utilization and distribution equipment operating from 120–34 500 V in the United States. It specifies voltages for two critical points on the distribution system: the point of delivery by the supplying utility and the point of connection to utilization equipment. For transmission voltages over 34 500 V, ANSI C84.1-1989 only specifies the nominal and maximum voltage because these voltages are normally unregulated and only a maximum voltage is required to establish the design insulation level for the line and associated apparatus.

The actual voltage measured at any point on the system will vary depending on the location of the point of measurement and the system load at the time the measurement is made. Fixed voltage changes take place in transformers in accordance with the transformer ratio. Voltage variations occur from the operation of voltage control equipment, changes in voltage drop due to changes in load current, and other reasons. It should be recognized that because of conditions beyond the control of the supplier or user, or both, there will be infrequent and limited periods when sustained voltages outside range B limits will occur.

The tolerance limits for the service voltage provide guidance to the supplying utility for the design and operation of its distribution system. The service voltage is the voltage at the point where the utility conductors connect to the user conductors. It is generally measured at the service switch for services of 600 V and below and at the billing meter voltage (potential) transformers for services over 600 V. The tolerance limits for the voltage at the point of connection of utilization equipment provide guidance to the user for the design and operation of the user distribution system, and to utilization equipment manufacturers for the design of utilization equipment. Electric supply systems are to be designed and operated so that most service voltages fall within the range A limits. User systems are to be designed and operated so that, when the service voltages are within range A, the utilization voltages are within range A. Utilization equipment is to be designed and rated to give fully satisfactory performance within the range A limits for utilization voltages.

Range B allows limited excursions of voltage outside the range A limits that necessarily result from practical design and operating conditions. When voltages are outside range A and inside range B, the corrective action should be taken within a reasonable time to restore service voltages to range A limits. Insofar as practicable, utilization equipment may be expected to give acceptable performance at voltages outside range A but within range B. When voltages occur outside the limits of range B, prompt corrective action should be taken. Responsibility for corrective action depends upon where the voltage is out of range A compared to the limits specified for each location identified in ANSI C84.1-1989.

3.2.3 Development of the voltage tolerance limits for ANSI C84.1-1989

The voltage tolerance limits in ANSI C84.1-1989 are based on NEMA MG 1-1993, which established the voltage tolerance limits of the standard induction motor at ±10% of nameplate ratings of 230 V and 460 V. Since motors represent the major component of utilization equipment, they were given primary consideration in the establishment of the voltage standard.

The best way to show the voltages in an electric power distribution system is in terms of a 120 V base. This cancels the transformation ratios between systems so that the actual voltages vary solely on the basis of the voltage drops in the system. Any voltage may be converted to a 120 V base by dividing the actual voltage by the ratio of transformation to the 120 V base. For example, the ratio of transformation for the 480 V system is 480/120 or 4, so 460 V in a 480 V system would be 460/4 or 115 V on a 120 V base.

The tolerance limits of the 460 V motor in terms of the 120 V base become 115 V plus 10%, or 126.5 V, and 115 V minus 10%, or 103.5 V. The problem is to decide how this tolerance range of 23 V should be divided between the primary distribution system, the distribution transformer, and the secondary distribution system, which make up the regulated distribution system. The solution adopted by ANSI Accredited Committee C84 is shown in table 3-2.

The Range B tolerance limits raised the standard motor tolerance on the 120 V base 0.5 V to 127 V maximum and 104 V minimum to eliminate the fractional volt. These values became the tolerance limits for range B in the standard. An allowance of 13 V was allotted for the voltage drop in the primary distribution system. Deducting this voltage drop from 127 V establishes a minimum of 114 V for utility services supplied from the primary distribution

Table 3-2—Standard voltage profile for low-voltage regulated power distribution system, 120 V base

	Range A (V)	Range B (V)
Maximum allowable voltage	126 (125*)	127
Voltage drop allowance for primary distribution line	9	13
Minimum primary service voltage	117	114
Voltage drop allowance for distribution transformer	3	4
Minimum secondary service voltage	114	110
Voltage drop allowance for plant wiring	6 (4†)	6 (4†)
Minimum utilization voltage	108 (110†)	104 (106†)

*For utilization voltage of 120–600 V.
†For building wiring circuits supplying lighting equipment.

system. An allowance of 4 V was provided for the voltage drop in the distribution transformer and the connections to the plant wiring. Deducting this voltage drop from the minimum primary distribution voltage of 114 V provides a minimum of 110 V for utility secondary services from 120–600 V. An allowance of 6 V, or 5%, for the voltage drop in the plant wiring, as provided in ANSI/NFPA 70-1993 (the National Electrical Code [NEC]) Articles 210-19(a) (FPN No. 4) and 215-2(b) (FPN No. 2), provides the minimum utilization voltage of 104 V.

The range A limits for the standard were established by reducing the maximum tolerance limits from 127 V to 126 V and increasing the minimum tolerance limits from 104 V to 108 V. The spread band of 18 V was then allotted as follows: 9 V for the voltage drop in the primary distribution system to provide a minimum primary service voltage of 117 V; 3 V for the voltage drop in the distribution transformer and secondary connections to provide a minimum secondary service voltage of 114 V; and 6 V for the voltage drop in the plant low-voltage wiring to provide a minimum utilization voltage of 108 V.

Four additional modifications were made in this basic plan to establish ANSI C84.1-1989. The maximum utilization voltage in range A was reduced from 126 V to 125 V for low-voltage systems in the range from 120 to 600 V because there should be sufficient load on the distribution system to provide at least 1 V drop on the 120 V base under most operating conditions. This maximum voltage of 125 V is also a practical limit for lighting equipment because the life of the 120 V incandescent lamp is reduced by 42% when operated at 125 V (see 3.5.4, table 3-9). The voltage drop allowance of 6 V on the 120 V base for the drop in the plant wiring was reduced to 4 V for circuits supplying lighting equipment. This raised the minimum voltage limit for utilization equipment to 106 V in range B and 110 V in range A because the minimum limits for motors of 104 V in range B and 108 V in range A were considered too low for satisfactory operation of lighting equipment. The utilization voltages for the 6900 V and 13 800 V systems in range B were adjusted to coincide with the tolerance limits of ±10% of the nameplate rating of the 6600 V and 13 200 V motors used on these respective systems.

To convert the 120 V base voltage to equivalent voltages in other systems, the voltage on the 120 V base is multiplied by the ratio of the transformer that would be used to connect the other system to a 120 V system. In general, distribution transformers for systems below 15 000 V have nameplate ratings that are the same as the standard system nominal voltages; so the ratio of the standard nominal voltages may be used to make the conversion. However, for primary distribution voltages over 15 000 V, the primary nameplate rating of distribution transformers is not the same as the standard system nominal voltages. Also, most distribution transformers are equipped with taps that can be used to change the ratio of transformation. So if the primary distribution voltage is over 15 000 V, or taps have been used to change the transformer ratio, then the actual transformer ratio must be used to convert the base voltage to another system.

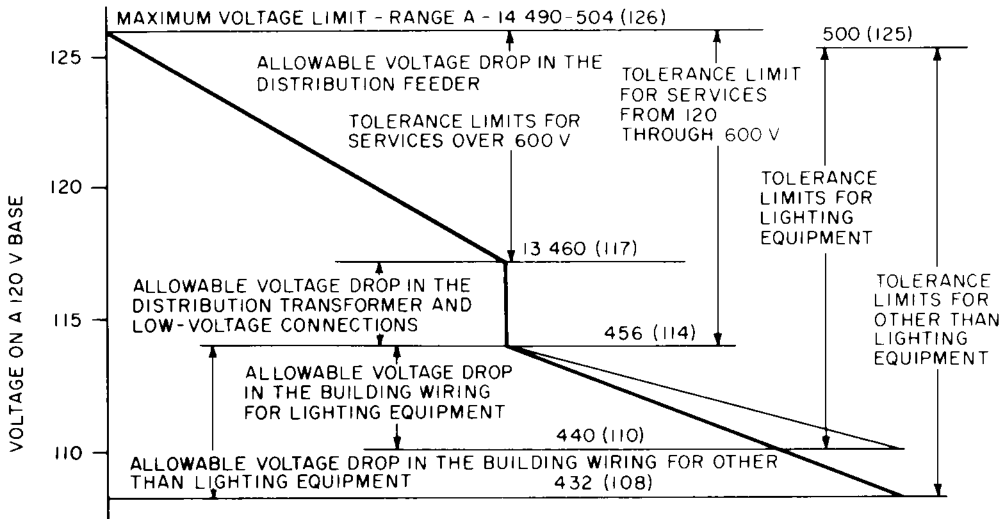
For example, the maximum tolerance limit of 127 V on the 120 V base for the service voltage in range B is equivalent, on the 4160 V system, to $4160 \div 120 \cdot 127 = 4400$ V to the nearest 10 V. However, if the 4160-120 V transformer is set on the $+2\frac{1}{2}\%$ tap, the voltage ratio would be $4160 + (4160 \cdot 0.025) = 4160 + 104 = 4264$ to 120. The voltage on the primary system equivalent to 127 V on the secondary system would be $4264 \div 120 \cdot 127 = 35.53 \cdot 127 = 4510$ V to the nearest 10 V. If the maximum primary distribution voltage of 4400 V is applied to the 4264-120 V transformer, the secondary voltage would be $4400 \div 4260 \cdot 120 = 124$ V.

3.2.4 Voltage profile limits for a regulated distribution system

Figure 3-4 shows the voltage profile of a regulated power distribution system using the limits of range A in table 3-1. Assuming a nominal primary distribution voltage of 13 800 V, range A in table 3-1 shows that this voltage should be maintained by the supplying utility between a maximum of 126 V and a minimum of 117 V on a 120 V base. Since the base multiplier for converting from the 120 V system to the 13 800 V system is 13 800/120 or 115, the actual voltage limits for the 13 800 V system are $115 \cdot 126$ or 14 490 V maximum and $115 \cdot 117$ or 13 460 V minimum.

If a distribution transformer with a ratio of 13 800 to 480 V is connected to the 13 800 V distribution feeder, range A of table 3-1 requires that the nominal 480 V secondary service be maintained by the supplying utility between a maximum of 126 V and a minimum of 114 V on the 120 V base. Since the base multiplier for the 480 V system is 480/120 or 4, the actual values are $4 \cdot 126$ or 504 V maximum and $4 \cdot 114$ or 456 V minimum.

Range A of table 3-1 as modified for utilization equipment of 120–600 V provides for a maximum utilization voltage of 125 V and a minimum of 110 V for lighting equipment and 108 V for other than lighting equipment on the 120 V base. Using the base multiplier of 4 for the 480 V system, the maximum utilization voltage would be $4 \cdot 125$ V or 500 V and the minimum for other than lighting equipment would be $4 \cdot 108$ V or 432 V. For lighting equipment



NOTE: Limits provided by ANSI C84.1-1989; see table 3-1.

Figure 3-4—Range A voltage profile limits

connected phase to neutral, the maximum voltage would be 500 V divided by the square root of 3 or 288 V and the minimum voltage would be $4 \cdot 110$ V or 440 V divided by the square root of 3 or 254 V.

3.2.5 System voltage nomenclature

The nominal system voltages in table 3-1 are designated in the same way as on the nameplate of the transformer for the winding or windings supplying the system.

a) *Single-Phase Systems*

120 Indicates a single-phase, two-wire system in which the nominal voltage between the two wires is 120 V.

120/240 Indicates a single-phase, three-wire system in which the nominal voltage between the two phase conductors is 240 V, and from each phase conductor to the neutral it is 120 V.

b) *Three-Phase Systems*

240/120 Indicates a three-phase, four-wire system supplied from a delta connected transformer. The midtap of one winding is connected to a neutral. The three-phase conductors provide a nominal 240 V three-phase system, and the neutral and the two adjacent phase conductors provide a nominal 120/240 V single-phase system.

480 Indicates a three-phase, three-wire system in which the number designates the nominal voltage between phases.

480Y/277 Indicates a three-phase, four-wire system from a wye-connected transformer in which the first number indicates the nominal phase-to-phase voltage and the second number indicates the nominal phase-to-neutral voltage.

NOTES

1—All single-phase systems and all three-phase, four-wire systems are suitable for the connection of phase-to-neutral load.

2—See Chapter 7 for methods of system grounding.

3—Figure 3-5 gives an overview of voltage relationships for 480 V three-phase systems and 120/240 V single- and three-phase systems.

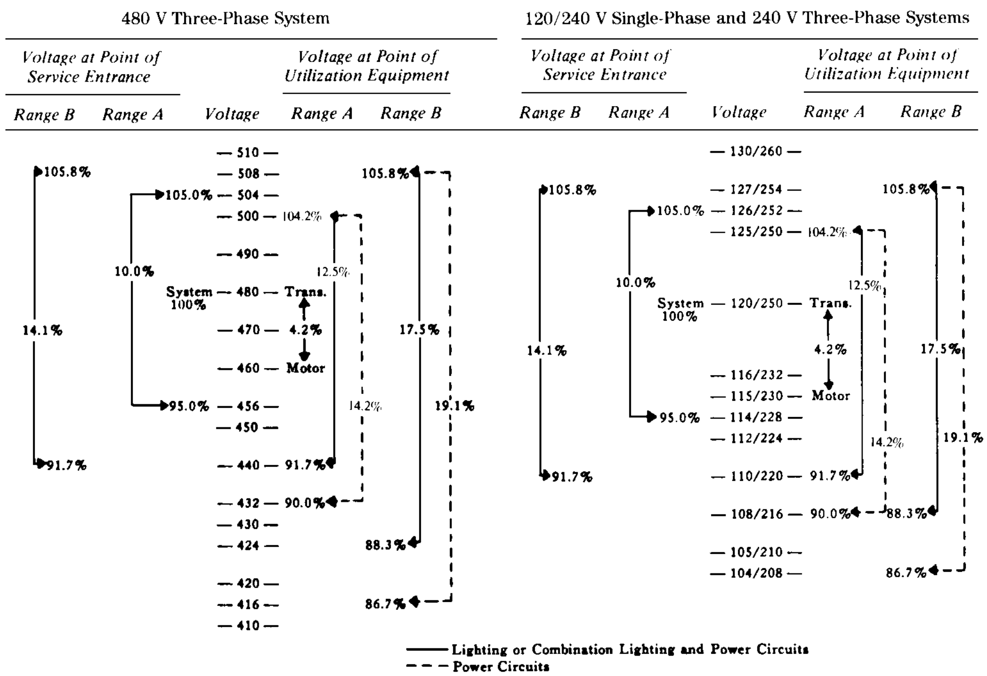


Figure 3-5—Voltage relationships based on voltage ranges in ANSI C84.1-1989

3.2.6 Nonstandard nominal system voltages

Since ANSI C84.1-1989 lists only the standard nominal system voltages in common use in the United States, system voltages will frequently be encountered that differ from the standard list. A few of these may be so widely different as to constitute separate systems in too limited use to be considered standard. However, in most cases the nominal system voltages will differ by only a few percent as shown in table 3-3. A closer examination of the table shows that these differences are due mainly to the fact that some voltages are multiples of 110 V, others are multiples of 115 V, some are multiples of 120 V, and a few are multiples of 125 V.

The reasons for these differences go back to the original development of electric power distribution systems. The first utilization voltage was 100 V. However, the supply voltage had to be raised to 110 V in order to compensate for the voltage drop in the distribution system. This led to overvoltage on equipment connected close to the supply, so the utilization equipment

Table 3-3—Nominal system voltages

Standard nominal system voltages	Associated nonstandard nominal system voltages
Low voltages	
120	110, 115, 125
120/240	110/220, 115/230, 125/250
208Y/120	216Y/125
240/120	
240	230, 250
480Y/277	460Y/265
480	440
600	550, 575
Medium voltages	
2400	2200, 2300
4160Y/2400	
4160	4000
4800	4600
6900	6600, 7200
8320Y/4800	11 000, 11 500
12 000Y/6930	
12 470Y/7200	
13 200Y/7620	
13 200	
13 800Y/7970	14 400
13 800	
20 780Y/12 000	
22 860Y/13 200	
23 000	
24 940Y/14 400	
34 500Y/19 920	
34 500	33 000
46 000	44 000
69 000	66 000
High voltages	
115 000	110 000, 120 000
138 000	132 000
161 000	154 000
230 000	220 000
Extra-high voltages	
345 000	
500 000	
765 000	

rating was also raised to 110 V. As generator sizes increased and distribution and transmission systems developed, an effort to keep transformer ratios in round numbers led to a series of utilization voltages of 110, 220, 440, and 550 V, a series of primary distribution voltages of 2200, 4400, 6600, and 13 200 V, and a series of transmission voltages of 22 000, 33 000, 44 000, 66 000, 110 000, 132 000, and 220 000 V.

As a result of the effort to maintain the supply voltage slightly above the utilization voltage, the supply voltages were raised again to multiples of 115 V, which resulted in a new series of utilization voltages of 115, 230, 460, and 575 V, a new series of primary distribution voltages of 2300, 4600, 6900, and 13 800 V, and a new series of transmission voltages of 23 000, 34 500, 46 000, 69 000, 115 000, 138 000, and 230 000 V.

As a result of continued problems with the operation of voltage-sensitive lighting equipment and voltage-insensitive motors on the same system, and the development of the 208Y/120 V network system, the supply voltages were raised again to multiples of 120 V. This resulted in a new series of utilization voltages of 120, 208Y/120, 240, 480, and 600 V, and a new series of primary distribution voltages of 2400, 4160Y/2400, 4800, 12 000, and 12 470Y/7200 V. However, most of the existing primary distribution voltages continued in use and no 120 V multiple voltages developed at the transmission level.

3.2.7 Standard nominal system voltages in the United States

The nominal system voltages listed in the left-hand column of table 3-3 are designated as standard nominal system voltages in the United States by ANSI C84.1-1989. In addition, those shown in boldface type in table 3-1 are designated as preferred standards to provide a long-range plan for reducing the multiplicity of voltages.

In the case of utilization voltages of 600 V and below, the associated nominal system voltages in the right-hand column are obsolete and should not be used. Where possible, manufacturers are encouraged to design utilization equipment to provide acceptable performance within the utilization voltage tolerance limits specified in the standard. Some numbers listed in the right-hand column are used in equipment ratings, but these should not be confused with the numbers designating the nominal system voltage on which the equipment is designed to operate.

In the case of primary distribution voltages, the numbers in the right-hand column may designate an older system in which the voltage tolerance limits are maintained at a different level than the standard nominal system voltage, and special consideration should be given to the distribution transformer ratios, taps, and tap settings.

3.2.8 Use of distribution transformer taps to shift utilization voltage spread band

Power and distribution transformers often have four taps on the primary winding in 2½% steps. These taps are generally +5%, +2½%, nominal, –2½%, and –5%. These taps allow users to change the transformer ratio and raise or lower the secondary voltage to provide a closer fit to the tolerance limits of the utilization equipment. There are three situations requiring the use of taps:

a) Taps are required when the primary voltage has a nominal value that is slightly different from the transformer primary nameplate rating. For example, if a 13 200–480 V transformer is connected to a nominal 13 800 V system, the nominal secondary voltage would be (13 800/13 200) · 480 = 502 V. However, if the 13 800 V system were connected to the +5% tap of the 13 200–480 V transformer at 13 860 V, the nominal secondary voltage would be (13 800/13 860) · 480 = 478, which is practically the same as would be obtained from a transformer having the proper ratio of 13 800–480 V.

b) Taps are required when the primary voltage spread is in the upper or lower portion of the tolerance limits provided in ANSI C84.1-1989. For example, a 13 200–480 V transformer is connected to a 13 200 V primary distribution system close to the substation where the primary voltage spread band stays in the upper half of the tolerance zone for range A, or 13 200–13 860 V. This would result in a nominal secondary voltage under no-load conditions of 480 to 504 V. By setting the transformer on the +2 1/2% tap at 13 530 V, the no-load secondary voltage would be lowered 2 1/2% to a range of 468–491 V.

c) Taps are required to adjust the utilization voltage spread band to provide a closer fit to the tolerance limits of the utilization equipment. For example, table 3-4 shows the shift in the utilization voltage spread band for the +2 1/2% and 5% taps as compared to the utilization voltage tolerance limits for range A of ANSI C84.1-1989 for the 480 V system. Table 3-5 shows the voltage tolerance limits of standard 460 V and 440 V three-phase induction motors. Table 3-6 shows the tolerance limits for standard 277 V and 265 V fluorescent lamp ballasts. A study of these three tables shows that a tap setting of nominal will provide the best fit with the tolerance limits of the 460 V motor and the 277 V ballast, but a setting on the +5% tap will provide the best fit for the 440 V motor and the 265 V ballast. For buildings having appreciable numbers of both ratings of motors and ballasts, a setting on the +2 1/2% tap may provide the best compromise.

Table 3-4—Tolerance limits for lighting circuits from table 3-1, range A, in volts

Nominal system voltage (volts)	Transformer tap	Minimum utilization voltage (volts)	Maximum utilization voltage (volts)
480Y/277	Nominal	440Y/254	500Y/288
468Y/270	+ 2 1/2%	429Y/248	488Y/281
456Y/263	+ 5%	418Y/241	475Y/274

Table 3-5—Tolerance limits for low-voltage three-phase motors, in volts

Motor rating (volts)	–10%	+10%
460	414	506
440	396	484

Table 3-6—Tolerance limits for low-voltage standard fluorescent lamp ballasts, in volts

Ballast rating (volts)	Minimum –10%	Maximum +10%
277	254	289
120	110	125

Note that these examples assume that the tolerance limits of the supply and utilization voltages are within the tolerance limits specified in ANSI C84.1-1989. This may not be true, so the actual voltages should be recorded over a time period that provides voltage readings during the night and over weekends when maximum voltages often occur. These actual voltages can then be used to calculate voltage profiles similar to figure 3-4 to check the proposed transformer ratios and tap settings. If transformer taps are used to compensate for voltage drop, the voltage profile should be calculated for light-load periods to check for possible overvoltage situations.

Where a plant has not yet been built, the supplying utility should be requested to provide the expected spread band for the supply voltage, preferably supported by a seven-day graphic chart from the nearest available location. If the plant furnishes the distribution transformers, recommendations should also be obtained from the supplying utility on the transformer ratios, taps, and tap settings. With this information, a voltage profile can be prepared to check the expected voltage spread at the utilization equipment.

Where the supplying utility offers a voltage over 600 V that differs from the standard nominal voltages listed in ANSI C84.1-1989, the supplying utility should be asked to furnish the expected tolerance limits of the supply voltage, preferably supported by seven or more days of voltage recordings from a nearby location. The supplying utility should also be asked for the recommended distribution transformer ratio and tap settings to obtain a satisfactory utilization voltage range. With this information, a voltage profile for the supply voltage and utilization voltage limits can be constructed for comparison with the tolerance limits of utilization equipment. If the supply voltage offered by the utility is one of the associated nominal system voltages listed in table 1-1, the taps on a standard distribution transformer will generally be sufficient to adjust the distribution transformer ratio to provide a satisfactory utilization voltage range.

Taps are on the primary side of transformers. Therefore, raising the tap setting to +2½% increases the transformer ratio by 2½% and lowers the secondary voltage spread band by 2½% minus the voltage drop in the transformer. Taps only serve to move the secondary voltage spread band up or down in the steps of the taps. They cannot correct for excessive spread from the supply voltage or from excessive drop in the plant wiring system. If the voltage spread band at the utilization equipment falls outside the satisfactory operating range of the equipment, then action must be taken to improve voltage conditions by other means (see 3.7).

In general, transformers should be selected with the same primary nameplate voltage rating as the nominal voltage of the primary supply system, and the same secondary voltage rating as the nominal voltage of the secondary system. Taps should be provided at +2½% and +5% and at –2½% and –5% to allow for adjustment in either direction.

3.3 Voltage selection

3.3.1 Selection of low-voltage utilization voltages

The preferred utilization voltage for industrial plants is 480Y/277 V. Three-phase power and other 480 V loads are connected directly to the system at 480 V, and gaseous discharge lighting is connected phase-to-neutral at 277 V. Small dry-type transformers rated 480–208Y/120 V are used to provide 120 V, single-phase, for convenience outlets, and 208 V, single-phase and three-phase, for small tools and other machinery. Where requirements are limited to 120 or 240 V, single-phase, 480–120/240 V single-phase transformers may be used. However, single-phase transformers should be connected in sequence to the individual phases in order to keep the load on each phase balanced (see 3.8).

For small industrial plants supplied at utilization voltage by a single distribution transformer, the choice of voltages is limited to those the utility will supply. However, most utilities will supply most of the standard nominal voltages listed in ANSI C84.1-1989 with the exception of 600 V, although all voltages supplied may not be available at every location. The built-up downtown areas of most large cities are supplied from secondary networks. Originally only 208Y/120 V was available, but most utilities now provide spot networks at 480Y/277 V for large installations.

3.3.2 Utility service supplied from a medium-voltage primary distribution line

Industrial plants too large for utilization voltage supply from one distribution transformer, normally furnished by the utility and located outdoors, generally require a tap from the primary distribution line. The plant constructs a primary distribution system from this tap to supply distribution transformers, which are generally dry-type with solid cast or resin-encapsulated windings, less flammable liquid, or nonflammable fluid suitable for indoor installation. Generally these distribution transformers are combined with primary and secondary switching and protective equipment to become unit substations. They are designated as primary unit substations when the secondary voltage is over 1000 V and secondary unit substations when the secondary voltage is 1000 V and below. Primary distribution may also be used to supply large industrial plants or plants involving more than one building. In this case, the primary distribution line may be run overhead or underground and may supply distribution transformers located outside the building or unit substations inside the building.

Original primary distribution voltages were limited to the range from 2400 to 14 400 V, but the increase in load densities in recent years has forced many utilities to limit expansion of primary distribution voltages below 15 000 V and to begin converting transmission voltages in the range from 15 000 to 50 000 V (sometimes called subtransmission voltages) to primary distribution. ANSI C84.1-1989 provides tolerance limits for primary supply voltages up through 34 500 V. IEEE Std C57.12.20-1988 lists overhead distribution transformers for primary voltages up through 69 000 V.

In case an industrial plant, supplied at utilization voltage from a single primary distribution transformer, contemplates an expansion that cannot be supplied from the existing transformer, a changeover to primary distribution will be required, unless a separate supply to the new addition is permitted by the local electrical code enforcing authority and the higher cost resulting from separate bills from the utility is acceptable. In any case, the proposed expansion needs to be discussed with the supplying utility to determine whether the expansion can be supplied from the existing primary distribution system or whether the entire load can be transferred to another system. Any utility charges and the plant costs associated with the changes need to be clearly established.

In general, primary distribution voltages between 15 000 and 25 000 V can be brought into a plant and handled like the lower voltages. Primary distribution voltages from 25 000–35 000 V will require at least a preliminary economic study to determine whether they can be brought into the plant or transformed to a lower primary distribution voltage. Voltages above 35 000 V will require transformation to a lower voltage.

In most cases, plants with loads of less than 10 000 kVA will find that 4160 V is the most economical plant primary distribution voltage, and plants with loads over 20 000 kVA will find 13 800 V the most economical considering only the cost of the plant wiring and transformers. If the utility supplies a voltage in the range from 12 000–15 000 V, a transformation down to 4160 V at plant expense cannot normally be justified. For loads of 10 000–20 000 kVA, an economic study including consideration of the costs of future expansion needs to be made to determine the most economical primary distribution voltage.

Where overhead lines are permissible on plant property, an overhead primary distribution system may be built around the outside of the building or to separate buildings to supply utility-type outdoor equipment and transformers. This system is especially economical at voltages over 15 000 V.

Care must be taken to be sure the transformer types and installation methods are compatible with National Electrical Code (NEC) (ANSI/NFPA 70-1993) requirements, fire insurance rules, and environmental considerations. A number of transformer types are available up to 40 000 V. Appropriate installation methods can be made to satisfy insurers and code-enforcing authorities.

Utility primary distribution systems are almost always solidly grounded wye systems, and the neutral is often carried throughout. This grounding method and other factors must be adapted to the plant distribution system if the utility distribution voltage supplies the plant without transformers and without grounding methods specifically dedicated to that plant.

3.3.3 Utility service supplied from medium-voltage or high-voltage transmission lines

Voltages on transmission lines used to supply large industrial plants range from 23 000 to 230 000 V. There is an overlap with primary distribution system voltages in the range from 23 000 to 69 000 V, with voltages of 34 500 V and below tending to fall into the category of regulated primary distribution voltages and voltages above 34 500 V tending to fall into the category of unregulated transmission lines. The transmission voltage will be limited to those voltages the utility has available in the area. A substation is required to step the transmission voltage down to a primary distribution voltage to supply the distribution transformers in the plant.

3.3.3.1 Substation is supplied by the industrial plant

Most utilities have a low rate for service from unregulated transmission lines which requires the plant to provide the substation. This permits the plant designer to select the primary distribution voltage but requires the plant personnel to assume the operation and maintenance of the substation. The substation designer should obtain from the supplying utility the voltage spread on the transmission line, and recommendations on the substation transformer ratio, tap provisions, and tap setting, and whether regulation should be provided.

With this information, a voltage profile similar to figure 3-4 is obtained using the actual values for the spread band of the transmission line and the estimated maximum values for the voltage drops in the substation transformer, primary distribution system, distribution transformers, and secondary distribution system to obtain the voltage spread at the utilization equipment. If this voltage spread is not within satisfactory limits, then regulators are required in the substation, preferably by equipping the substation transformer or transformers with tap changing under load.

For plants supplied at 13 800 V, the distribution transformers or secondary unit substations should have a ratio of 13 800–480Y/277 V with two ±2½% taps. Where medium-sized motors in the 200 hp or larger range are used, a distribution transformer stepping down to 4160 V or 2400 V may be more economical than supplying these motors from the 480 V system.

For plants supplied at 4160 V, the distribution transformers or secondary unit substations should have a ratio of 4160–480Y/277 V with two ±2½% taps. Medium-sized motors of a few hundred horsepower may economically be connected directly to the 4160 V system, preferably from a separate primary distribution circuit.

3.3.3.2 Distribution substation is supplied by the utility

Most utilities have a rate for power purchased at the primary distribution voltage that is higher than the rate for service at transmission voltage because the utility provides the substation. The choice of the primary distribution voltage is limited to those supplied by the particular utility, but the utility will be responsible for keeping the limits specified for service voltages in ANSI C84.1-1989. The utility should be requested to provide recommendations for the ratio of the distribution transformers or secondary unit substations, provisions for taps, and the tap settings. With this information, a voltage profile similar to figure 3-4 can be constructed using the estimated maximum values for the voltage drops in the primary distribution system, the transformers, and the secondary distribution system to make sure that the utilization voltages fall within satisfactory limits.

3.4 Voltage ratings for low-voltage utilization equipment

Utilization equipment is defined as electric equipment that uses electric power by converting it into some other form of energy such as light, heat, or mechanical motion. Every item of utilization equipment is required to have, among other things, a nameplate listing the nominal supply voltage for which the equipment is designed. With one major exception, most utilization equipment carries a nameplate rating that is the same as the voltage system on which it is to be used; that is, equipment to be used on 120 V systems is rated 120 V (except for a few small appliances rated 117 or 118 V), for 208 V systems, 208 V, and so on. The major exception is motors and equipment containing motors. These are also about the only utilization equipment used on systems over 600 V. Single-phase motors for use on 120 V systems have been rated 115 V for many years. Single-phase motors for use on 208 V single-phase systems are rated 200 V and for use on 240 V single-phase systems are rated 230 V.

Prior to the late 1960s, low-voltage three-phase motors were rated 220 V for use on both 208 and 240 V systems, 440 V for use on 480 V systems, and 550 V for use on 600 V systems. The reason was that most three-phase motors were used in large industrial plants where relatively long circuits resulted in voltages considerably below nominal at the ends of the circuits. Also, utility supply systems had limited capacity and low voltages were common during heavy-load periods. As a result, the average voltage applied to three-phase motors approximated the 220, 440, and 550 V nameplate ratings.

In recent years, supplying electric utilities have made extensive changes to higher distribution voltages. Increased load density has resulted in shorter primary distribution systems. Distribution transformers have been moved inside buildings to be closer to the load. Lower impedance wiring systems have been used in the secondary distribution system. Capacitors have been used to improve power factors. All of these changes have contributed to reducing the voltage drop in the distribution system which raised the voltage applied to utilization equipment. By the mid-1960s, surveys indicated that the average voltage supplied to 440 V motors on 480 V systems was 460 V, and there were increasing numbers of complaints of overvoltages as high as 500 V during light-load periods.

At about the same time, the Motor and Generator Committee of the National Electrical Manufacturers Association (NEMA) decided that the improvements in motor design and insulation systems would allow a reduction of two frame sizes for standard induction motors rated 600 V and below. However, the motor voltage tolerance would be limited to ±10% of the nameplate rating. As a result, the nameplate voltage rating of the new motor designated as the T-frame motor was raised from the 220/440 V rating of the U-frame motor to 230/460 V. Subsequently, a motor rated 200 V for use on 208 V systems was added to the program. Table 3-7 shows the nameplate voltage ratings of standard induction motors, as specified in NEMA MG 1-1978.

Table 3-7—Nameplate voltage ratings of standard induction motors

Nominal system voltage	Nameplate voltage
Single-phase motors	
120	115
240	230
Three-phase motors	
208	200
240	230
480	460
600	575
2400	2300
4160	4000
4800	4600
6900	6600
13 800	13 200

The question has been raised why the confusion between equipment ratings and system nominal voltage cannot be eliminated by making the nameplate rating of utilization equipment the same as the nominal voltage of the system on which the equipment is to be used. However, manufacturers say that the performance guarantee for utilization equipment is based on the nameplate rating and not the system nominal voltage. For utilization equipment such as motors where the performance peaks in the middle of the tolerance range of the equipment, better performance can be obtained over the tolerance range specified in ANSI C84.1-1989 by selecting a nameplate rating closer to the middle of this tolerance range.

3.5 Effect of voltage variations on low-voltage and medium-voltage utilization equipment

3.5.1 General effects

When the voltage at the terminals of utilization equipment deviates from the value on the nameplate of the equipment, the performance and the operating life of the equipment are affected. The effect may be minor or serious depending on the characteristics of the equipment and the amount of the voltage deviation from the nameplate rating. Generally, performance conforms to the utilization voltage limits specified in ANSI C84.1-1989, but it may vary for specific items of voltage-sensitive equipment. In addition, closer voltage control may be required for precise operations.

3.5.2 Induction motors

The variation in characteristics as a function of the applied voltage is given in table 3-8. Motor voltages below nameplate rating result in reduced starting torque and increased full-load temperature rise. Motor voltages above nameplate rating result in increased torque, increased starting current, and decreased power factor. The increased starting torque will increase the accelerating forces on couplings and driven equipment. Increased starting current causes greater voltage drop in the supply circuit and increases the voltage dip on lamps and other equipment. In general, voltages slightly above nameplate rating have less detrimental effect on motor performance than voltages slightly below nameplate rating.

Table 3-8—General effect of voltage variations on induction-motor characteristics

Characteristic	Proportional to	Voltage variation	
		90% of nameplate	110% of nameplate
Starting and maximum running torque	Voltage squared	–19%	+21%
Percent slip	$(1/\text{voltage})^2$	+23%	–19%
Full load speed	Synchronous speed—slip	–0.2 to –1.0%	+0.2 to 1.0%
Starting current	Voltage	–10%	+10%
Full load current	Varies with design	+5 to +10%	–5 to –10%
No load current	Varies with design	–10 to –30%	+10 to +30%
Temperature rise	Varies with design	+10 to +15%	–10 to –15%
Full load efficiency	Varies with design	–1 to –3%	+1 to +3%
Full load power factor	Varies with design	+3 to +7%	–2 to –7%
Magnetic noise	Varies with design	Slight decrease	Slight increase

3.5.3 Synchronous motors

Synchronous motors are affected in the same manner as induction motors, except that the speed remains constant (unless the frequency changes) and the maximum or pull-out torque varies directly with the voltage if the field voltage remains constant, as in the case where the field is supplied by a generator on the same shaft with the motor. If the field voltage varies with the line voltage as in the case of a static rectifier source, then the maximum or pull-out torque varies as the square of the voltage.

3.5.4 Incandescent lamps

The light output and life of incandescent filament lamps are critically affected by the impressed voltage. The variation of life and light output with voltage is given in table 3-9. The figures for 125 V and 130 V lamps are also included because these ratings are useful in signs and other locations where long life is more important than light output.

Table 3-9—Effect of voltage variations on incandescent lamps

Applied voltage (volts)	Lamp Rating					
	120 V		125 V		130 V	
	% life	% light	% life	% light	% life	% light
105	575	64	880	55	—	—
110	310	74	525	65	880	57
115	175	87	295	76	500	66
120	100	100	170	88	280	76
125	58	118	100	100	165	88
130	34	132	59	113	100	100

3.5.5 Fluorescent lamps

Light output for magnetic ballasts varies approximately in direct proportion to the applied voltage. Thus a 1% increase in applied voltage will increase the light output by 1% and, conversely, a decrease of 1% in the applied voltage will reduce the light output by 1%. Light output for electronic ballasts may be more or less dependent on input voltage. Consult with the manufacturer for the information specific to a particular ballast. The life of fluorescent lamps is affected less by voltage variation than that of incandescent lamps.

The voltage-sensitive component of the fluorescent fixture is the ballast. It is a small reactor, transformer, electronic circuit, or combination that supplies the starting and operating voltages to the lamp and limits the lamp current to design values. These ballasts may overheat when subjected to above-normal voltage and operating temperature, and ballasts with integral thermal protection may be required. See NEC, Article 410.

3.5.6 High-intensity discharge (HID) lamps (mercury, sodium, and metal halide)

Mercury lamps using a typical reactor ballast will have a 12% change in light output for a 5% change in terminal voltage. HID lamps may extinguish when the terminal voltage drops below 75% of rated voltage. A constant wattage autotransformer ballast will produce a ±5% change in lamp wattage for mercury or a ±10% change in wattage for metal halide, when the line voltage varies ±10%.

Approximate warm-up and restrike times for HID lamps are as follows:

Light source	Warm-up	Re-strike
Mercury vapor	5 to 7 min	3 to 6 min
Metal halide	2 to 5 min	10 to 20 min
High-pressure sodium	3 to 4 min	0.5 to 1 min
Low-pressure sodium	7 to 10 min	1.2 s to 5 min

The lamp life is related inversely to the number of starts so that, if low-voltage conditions require repeated starting, lamp life will be reduced. Excessively high voltage raises the arc temperature, which could damage the glass enclosure if the temperature approaches the glass softening point. See the manufacturers' catalogs for detailed information.

3.5.7 Infrared heating processes

Although the filaments in the lamps used in these installations are of the resistance type, the energy output does not vary with the square of the voltage because the resistance varies at the same time. The energy output varies slightly less than the square of the voltage. Voltage variations can produce unwanted changes in the process heat available unless thermostatic control or other regulating means is used.

3.5.8 Resistance heating devices

The energy input and, therefore, the heat output of resistance heaters varies approximately as the square of the impressed voltage. Thus a 10% drop in voltage will cause a drop of approximately 19% in heat output. This, however, holds true only for an operating range over which the resistance remains essentially constant.

3.5.9 Electron tubes

Electron tubes are rarely specified in new equipment except for special applications. The current-carrying ability or emission of all electron tubes is affected seriously by voltage deviation from nameplate rating. The cathode life curve indicates that the life is reduced by half for each 5% increase in cathode voltage. This is due to the reduced life of the heater element and to the higher rate of evaporation of the active material from the surface of the cathode. It is extremely important that the cathode voltage be kept near rating on electron tubes for satisfactory service. In many cases this will necessitate a regulated power source. This may be located at or within the equipment, and often consists of a regulating transformer having constant output voltage or current.

3.5.10 Capacitors

The reactive power output of capacitors varies with the square of the impressed voltage. A drop of 10% in the supply voltage, therefore, reduces the reactive power output by 19%, and where the user has made a sizable investment in capacitors for power factor improvement, the user loses the benefit of almost 20% of this investment.

3.5.11 Solenoid-operated devices

The pull of ac solenoids varies approximately as the square of the voltage. In general, solenoids are designed to operate satisfactorily on 10% overvoltage and 15% undervoltage.

3.5.12 Solid-state equipment

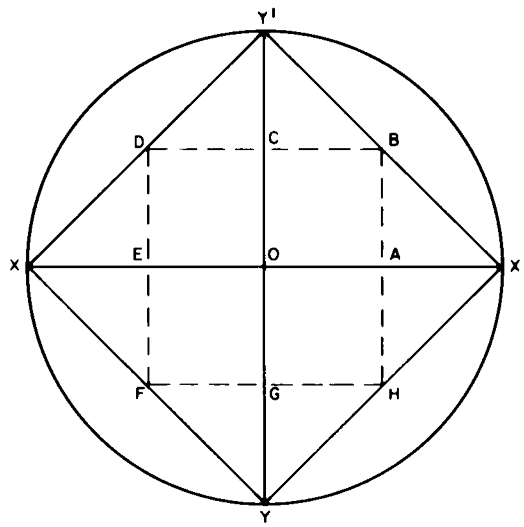
Thyristors, transistors, and other solid-state devices have no thermionic heaters. Thus they are not nearly as sensitive to long-time voltage variations as the electron tube components they are largely replacing. Internal voltage regulators are frequently provided for sensitive equipment such that it is independent of supply system regulation. This equipment as well as power solid-state equipment is, however, generally limited regarding peak reverse voltage, since it can be adversely affected by abnormal voltages of even microsecond duration. An individual study of the maximum voltage of the equipment, including surge characteristics, is necessary to determine the effect of maximum system voltage or whether abnormally low voltage will result in malfunction.

3.6 Voltage drop considerations in locating the low-voltage secondary distribution system power source

One of the major factors in the design of the secondary distribution system is the location of the power source as close as possible to the center of the load. This applies in every case, from a service drop from a distribution transformer on the street to a distribution transformer located outside the building or a secondary unit substation located inside the building. Frequently building esthetics or available space require the secondary distribution system power supply to be installed in a corner of a building without regard to what this adds to the cost of the building wiring to keep the voltage drop within satisfactory limits.

Figure 3-6 shows that if a power supply is located in the center of a horizontal floor area at point 0, the area that can be supplied from circuits run radially from point 0 with specified circuit constants, and voltage drop would be the area enclosed by the circle of radius 0-X. However, conduit systems are run in rectangular coordinates so, with this restriction, the area that can be supplied is reduced to the square X-Y-X'-Y' when the conduit system is run parallel to the axes X-X' and Y-Y'. But the limits of the square are not parallel to the conduit system. Thus, to fit the conduit system into a square building with walls parallel to the conduit system, the area must be reduced to F-H-B-D.

If the supply point is moved to the center of one side of the building, which is a frequent situation when the transformer is placed outside the building, the area that can be served with the



Source: [B11]

Figure 3-6—Effect of secondary distribution system power source location on area that can be supplied under specified voltage drop limits

specified voltage drop and specified circuit constants is E-A-B-D. If the supply station is moved to a corner of the building—a frequent location for buildings supplied from the rear or from the street—the area is reduced to O-A-B-C.

Every effort should be made to place the secondary distribution system supply point as close as possible to the center of the load area. Note that this study is based on a horizontal wiring system and any vertical components must be deducted to establish the limits of the horizontal area that can be supplied.

Using an average value of 30 ft/V drop for a fully loaded conductor, which is a good average figure for the conductor sizes normally used for feeders, the distances in figure 3-6 for 5% and 2½% voltage drops are shown in table 3-10. For a distributed load, the distances will be approximately twice the values shown.

3.7 Improvement of voltage conditions

Poor equipment performance, overheating, nuisance tripping of overcurrent protective devices, and excessive burnouts are signs of unsatisfactory voltage. Abnormally low voltage occurs at the end of long circuits. Abnormally high voltage occurs at the beginning of circuits close to the source of supply, especially under lightly loaded conditions such as at night and over weekends.

Table 3-10—Areas that can be supplied for specific voltage drops and voltages at various secondary distribution system power source locations

Nominal system voltage (volts)	Distance (feet)			
	5% voltage drop		$2^1/_2$% voltage drop	
	0-X	0-A	0-X	0-A
120/240	360	180	180	90
208	312	156	156	78
240	360	180	180	90
480	720	360	360	180

In cases of abnormally low voltage, the first step is to make a load survey to measure the current taken by the affected equipment, the current in the circuit supplying the equipment, and the current being supplied by the supply source under peak-load conditions to make sure that the abnormally low voltage is not due to overloaded equipment. If the abnormally low voltage is due to overload, then corrective action is required to relieve the overloaded equipment.

If overload is ruled out or if the utilization voltage is excessively high, a voltage survey should be made, preferably by using graphic voltmeters, to determine the voltage spread at the utilization equipment under all load conditions and the voltage spread at the utility supply. This survey can be compared with ANSI C84.1-1989 to determine if the unsatisfactory voltage is caused by the plant distribution system or the utility supply. If the utility supply exceeds the tolerance limits specified in ANSI C84.1-1989, the utility should be notified. If the industrial plant is supplied at a transmission voltage and furnishes the distribution substation, the operation of the voltage regulators should be checked.

If excessively low voltage is caused by excessive voltage drop in the plant wiring (over 5%), then plant wiring changes are required to reduce the voltage drop. If the load power factor is low, capacitors may be installed to improve the power factor and reduce the voltage drop. Where the excessively low voltage affects a large area, the best solution may be conversion to primary distribution if the building is supplied from a single distribution transformer, or to install an additional distribution transformer in the center of the affected area if the plant has primary distribution. Plants wired at 208Y/120 or 240 V may be changed over economically to 480Y/277 V if an appreciable portion of the wiring system is rated 600 V and motors are dual rated 220:440 V or 230:460 V.

3.8 Phase-voltage unbalance in three-phase systems

3.8.1 Causes of phase-voltage unbalance

Most utilities use four-wire grounded-wye primary distribution systems so that single-phase distribution transformers can be connected phase-to-neutral to supply single-phase loads, such as residences and street lights. Variations in single-phase loading cause the currents in the three-phase conductors to be different, producing different voltage drops and causing the phase voltages to become unbalanced. Normally the maximum phase-voltage unbalance will occur at the end of the primary distribution system, but the actual amount will depend on how well the single-phase loads are balanced between the phases on the system.

Perfect balance can never be maintained because the loads are continually changing, causing the phase-voltage unbalance to vary continually. Blown fuses on three-phase capacitor banks will also unbalance the load and cause phase-voltage unbalance.

Industrial plants make extensive use of 480Y/277 V utilization voltage to supply lighting loads connected phase-to-neutral. Proper balancing of single-phase loads among the three phases on both branch circuits and feeders is necessary to keep the load unbalance and the corresponding phase-voltage unbalance within reasonable limits.

3.8.2 Measurement of phase-voltage unbalance

The simplest method of expressing the phase-voltage unbalance is to measure the voltages in each of the three phases:

The amount of voltage unbalance is better expressed in symmetrical components as the negative sequence component of the voltage:

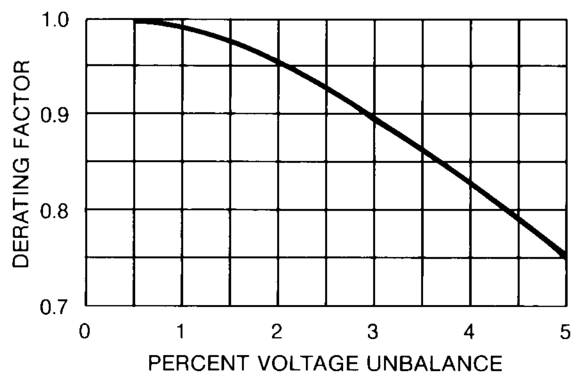
$$\text{percent unbalance} = \frac{\text{maximum deviation from average}}{\text{average}} \cdot 100$$

$$\text{voltage unbalance factor} = \frac{\text{negative-sequence voltage}}{\text{positive-sequence voltage}}$$

3.8.3 Effect of phase-voltage unbalance

When unbalanced phase voltages are applied to three-phase motors, the phase-voltage unbalance causes additional negative-sequence currents to circulate in the motor, increasing the heat losses primarily in the rotor. The most severe condition occurs when one phase is opened and the motor runs on single-phase power. Figure 3-7 shows the recommended derating for motors as a function of percent phase-voltage unbalance. Linders, 1971 [B7],[2] provides a more comprehensive review of the effects of unbalance on motors.

[2]The numbers in brackets preceded by the letter B correspond to those of the bibliography in 3.13.



Source: NEMA MG 1-1993.

Figure 3-7—Derating factor for motors operating with phase voltage unbalance

Although there will generally be an increase in the motor load current when the phase voltages are unbalanced, the increase is insufficient to indicate the actual temperature rise that occurs because NEMA current-responsive thermal or magnetic overload devices only provide a trip characteristic that correlates with the motor thermal damage due to normal overload current (positive-sequence) and not negative-sequence current.

All motors are sensitive to phase-voltage unbalance, but hermetic compressor motors used in air conditioners are most susceptible to this condition. These motors operate with higher current densities in the windings because of the added cooling effect of the refrigerant. Thus the same percent increase in the heat loss due to circulating currents, caused by phase-voltage unbalance, will have a greater effect on the hermetic compressor motor than it will on a standard air-cooled motor.

Since the windings in hermetic compressor motors are inaccessible, they are normally protected by thermally operated switches embedded in the windings, set to open and disconnect the motor when the winding temperature exceeds the set value. The motor cannot be restarted until the winding has cooled down to the point at which the thermal switch will reclose.

When a motor trips out, the first step in determining the cause is to check the running current after it has been restarted to make sure that the motor is not overloaded. The next step is to measure the three-phase voltages to determine the amount of phase-voltage unbalance. Figure 3-7 indicates that where the phase-voltage unbalance exceeds 2%, the motor is likely to become overheated if it is operating close to full load.

Some electronic equipment, such as computers, may also be affected by phase-voltage unbalance of more than 2 or 2½%. The equipment manufacturer can supply the necessary information.

In general, single-phase loads should not be connected to three-phase circuits supplying equipment sensitive to phase-voltage unbalance. A separate circuit should be used to supply this equipment.

3.9 Voltage sags and flicker

The previous discussion has covered the relatively slow changes in voltage associated with steady-state voltage spreads and tolerance limits. However, sudden voltage changes should be given special consideration.

Lighting equipment output is sensitive to applied voltage, and people are sensitive to sudden illumination changes. A voltage change of 0.25 to 0.5% will cause a noticeable reduction in the light output of an incandescent lamp and a less noticeable reduction in the light output of HID lighting equipment. Intermittent equipment operation such as welders, motor starting, and arc furnaces can affect the voltage supplied to lighting equipment so much that people complain about flickering lights.

Motor starting and short circuits on nearby lines can cause lamp flicker and even large momentary voltage sags that disrupt sensitive utilization equipment. Arc furnaces and welders can cause voltage flicker that occurs several times a second. This produces a stroboscopic effect and can be particularly irritating to people.

Care should be taken to design systems that will not irritate people with flickering lights and that will not disrupt important industrial and commercial processes.

3.9.1 Motor starting voltage sags

Motors have a high initial inrush current when turned on and impose a heavy load at a low power factor for a very short time. This sudden increase in the current flowing to the load causes a momentary increase in the voltage drop along the distribution system, and a corresponding reduction in the voltage at the utilization equipment.

In general, the starting current of a standard motor averages about 5 times the full-load running current. The approximate values for all ac motors over ½ hp are indicated by a code letter on the nameplate of the motor. The values indicated by these code letters are given in NEMA MG 1-1978 and also in Article 430 of the NEC.

A motor requires about 1 kVA for each motor horsepower in normal operation, so the starting current of the average motor will be about 5 kVA for each motor horsepower. When the motor rating in horsepower approaches 5% of the secondary unit substation transformer capacity in kilovoltamperes, the motor starting apparent power approaches 25% of the transformer capacity which, with a transformer impedance voltage of 6–7%, will result in a noticeable voltage sag on the order of 1%.

In addition, a similar voltage sag will occur in the wiring between the secondary unit substation and the motor when starting a motor with a full-load current which is on the order of 5% of the rated current of the circuit. This will result in a full-load voltage drop on the order of 4 or 5%. However, the voltage drop is distributed along the circuit so that maximum sag occurs only when the motor and the affected equipment are located at the far end of the circuit. As the motor is moved from the far end to the beginning of the circuit, the voltage drop in the circuit approaches zero. As the affected equipment is moved from the far end to the beginning of the circuit, the voltage dip remains constant up to the point of connection of the motor and then decreases to zero as the equipment connection approaches the beginning of the circuit.

The total voltage sag is the sum of the sag in the secondary unit substation transformer and the secondary circuit. In the case of very large motors of several hundred to a few thousand horsepower, the impedance of the supply system should be considered.

Special consideration should always be given when starting larger motors to minimize the voltage sag so as not to affect the operation of other utilization equipment on the system supplying the motor. Large motors (see table 3-11) may be supplied at medium voltage such as 2400, 4160, 6900, or 13 200 V from a separate transformer to eliminate the voltage dip on the low-voltage system. However, consideration should be given to the fact that the maintenance electricians may not be qualified to maintain medium-voltage equipment. A contract with a qualified electrical firm may be required for maintenance. Standard voltages and preferred horsepower limits for polyphase induction motors are shown in table 3-11.

Table 3-11—Standard voltages and preferred horsepower limits for polyphase induction motors

Motor nameplate voltage	Preferred horsepower limits
	Low-voltage motors
115	No minimum—15 hp maximum
230	No minimum—200 hp maximum
460 and 575	1 hp minimum—1000 hp maximum
	Medium-voltage motors
2300	50 hp minimum—6000 hp maximum
4000	100 hp minimum—7500 hp maximum
4500	250 hp minimum—no maximum
6000	400 hp minimum—no maximum
13 200	1500 hp minimum—no maximum

Source: Based on [B9], table 18-5.

3.9.2 Flicker limits

Where loads are turned on and off rapidly as in the case of resistance welders, or fluctuate rapidly as in the case of arc furnaces, the rapid fluctuations in the light output of incandescent lamps, and to a lesser extent, gaseous discharge lamps, is called flicker. If utilization equipment involving rapidly fluctuating loads is on the order of 10% of the capacity of the secondary unit substation transformer and the secondary circuit, accurate calculations should be made using the actual load currents and system impedances to determine the effect on lighting equipment.

Individuals vary widely in their susceptibility to light flicker. Tests indicate that some individuals are irritated by a flicker that is barely noticeable to others. Studies show that sensitivity depends on how much the illumination changes (magnitude), how often it occurs (frequency), and the type of work activity undertaken. The problem is further compounded by the fact that fluorescent and other lighting systems have different response characteristics to voltage changes. For example, incandescent illumination changes more than fluorescent, but fluorescent illumination changes faster than incandescent. Sudden voltage changes from one cycle to the next are more noticeable than gradual changes over several cycles. Illumination flicker can be especially objectionable if it occurs often and is cyclical.

Figure 3-8 [B6] shows acceptable voltage flicker limits for incandescent lights used by a large number of utilities. Two curves show how the acceptable voltage flicker magnitude depends on the frequency of occurrence. The lower curve shows a borderline where people begin to detect flicker. The upper curve is the borderline where some people will find the flicker objectionable. At 10 per hour, people begin to detect incandescent lamp flicker for voltage fluctuations larger than 1% and begin to object when the magnitude exceeds 3%.

In using this curve, the purpose for which the lighting is provided needs to be considered. For example, lighting used for close work such as drafting requires flicker limits approaching the borderline of visibility curve. For general area lighting such as storage areas, the flicker limits may approach the borderline of the irritation curve. Note that the effect of voltage flicker depends on the frequency of occurrence. An occasional dip, even though quite large, is rarely objectionable.

When objectionable flicker occurs, either the load causing the flicker should be reduced or eliminated, or the capacity of the supply system increased to reduce the voltage drop caused by the fluctuating load. In large plants, flicker-producing equipment should be segregated on separate transformers and feeders so as not to disturb flicker-sensitive equipment.

Objectionable flicker in the supply voltage from the utility should be reported to the utility for correction. Flexibility in approach and effective communications between the customer and the utility can be invaluable in resolving potential flicker problems.

3.9.3 Fault clearing voltage sags

Solid-state controllers such as adjustable speed drives, microprocessor controllers, sensors, and other equipment are often sensitive to momentary voltage sags associated with remote

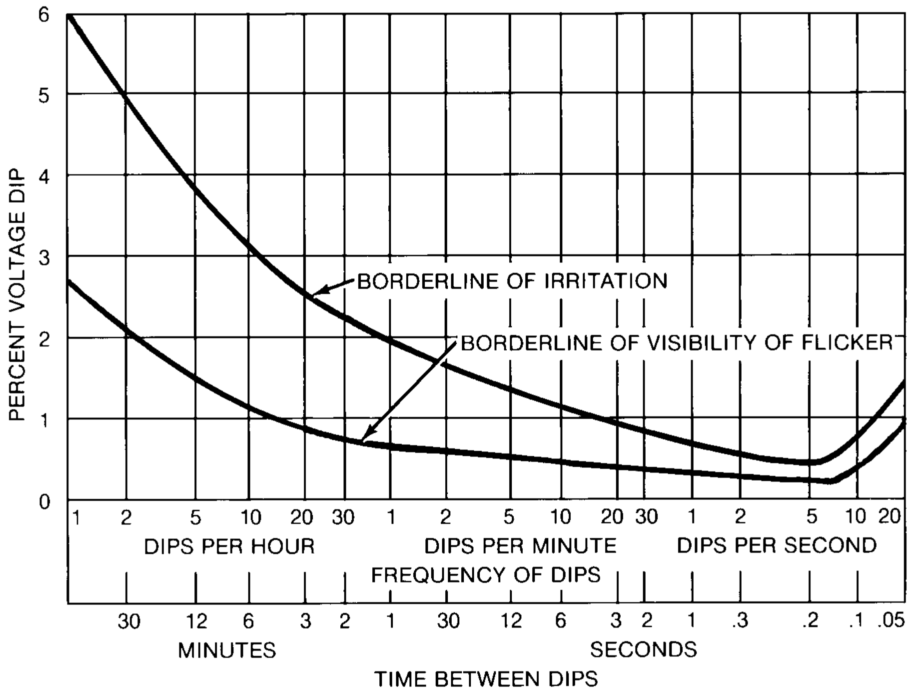


Figure 3-8—Range of observable and objectionable voltage flicker versus time

electrical short circuits. A short circuit on adjacent plant feeders, a nearby utility distribution line, or even a transmission line many miles from the sensitive load can cause a noticeable sag in voltage while short-circuit current is flowing. The voltage sag continues until the circuit breaker or other fault clearing equipment interrupts the short-circuit current. Consideration should be given to include capabilities to ride through these voltage sags for processes where sudden, unplanned shutdowns have a significant cost.

The magnitude of the voltage sag depends on the electrical location of the short circuit relative to the load. Single- and two-phase short circuits are more likely and cause different sag voltages on each phase. Generally, short circuits on only a few miles of line can cause deep voltage sags for any one site. However, there are often many miles where short circuits can cause shallow sags at the same site. This phenomena makes shallow sags many times more likely than deep sags. Figure 3-9 shows relative probabilities of occurrence compared to the lowest phase voltage when sags occur. For example, equipment that turns off at 90% of nominal voltage may experience 3.1 times more voltage sag problems than equipment that tolerates sags to 80% of nominal.

The duration of voltage sags depends upon the time required to detect and interrupt the short-circuit current. Typical minimum interruption time for medium- and high-voltage circuit breakers are 3–5 cycles at 60 Hz while older breakers may be rated for 8 cycles. Some sags

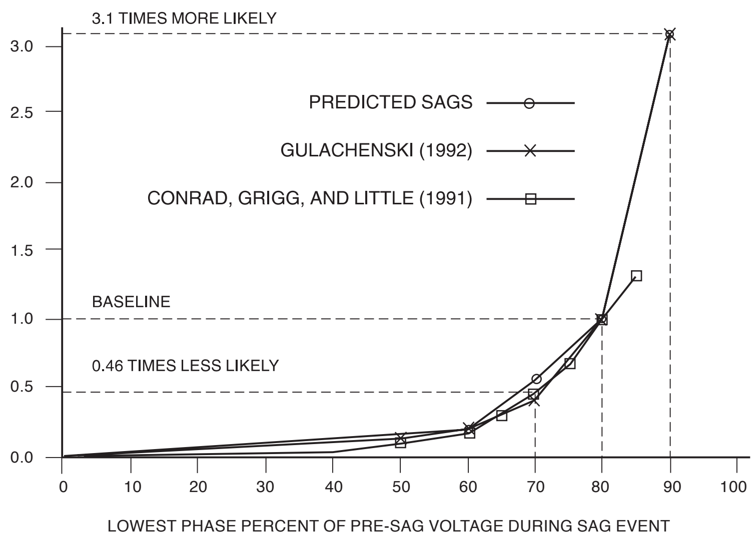


Figure 3-9—Voltage sag probabilities

last even longer because of required time delay for overcurrent coordination. Figure 3-10 shows the probability density of voltage sag duration. The three curves show that half to three quarters of the measured voltage sags had a duration less than 0.2 s.

Equipment sensitivity to voltage sags generally involves a combination of voltage magnitude and duration. Both should be considered when specifying equipment performance capabilities during voltage sags.

3.10 Harmonics

Voltage and current on the ideal ac power system have pure single frequency sine wave shapes. Real power systems have some distortion because an increasing number of loads require current that is not a pure sine wave. Single- and three-phase rectifiers, adjustable speed drives, arc furnaces, computers, and fluorescent lights are good examples.

Fourier analysis shows the waveform distortion contains higher frequency components that are integer multiples of the fundamental frequency. For a 60 Hz power system, the second harmonic would be $2 \cdot 60$ or 120 Hz and the third harmonic would be $3 \cdot 60$ or 180 Hz. These higher frequency components distort the voltage by interacting with the system impedance. Capacitor failure, premature transformer failure, neutral overloads, excessive motor heating, relay misoperation, and other problems are possible when harmonics are not properly controlled.

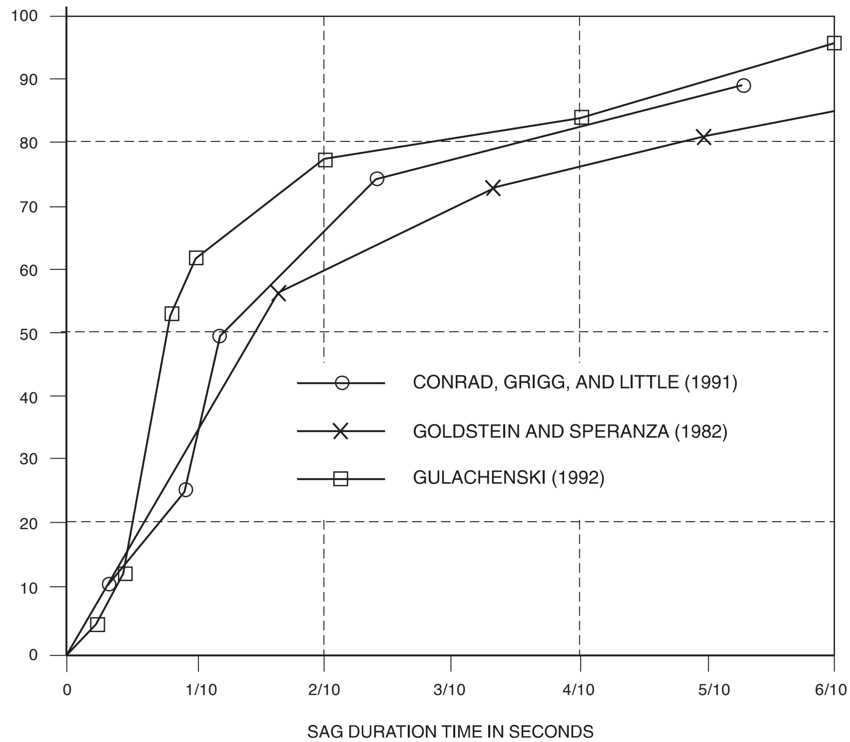


Figure 3-10—Voltage sag duration

IEEE Std 519-1992 is a recommended practice for control of harmonics in power systems. It recommends limits for supply voltage distortion and limits for allowable harmonic current demands. Chapter 9 of this book also contains more detailed information on harmonics.

3.11 Calculation of voltage drops

Building wiring designers must have a working knowledge of voltage drop calculations, not only to meet NEC requirements, but also to ensure that the voltage applied to utilization equipment is maintained within proper limits. The phasor relationships between voltage and current and resistance and reactance require a working knowledge of trigonometry, especially for making exact voltage drop computations. Fortunately, most voltage drop calculations are based on assumed limiting conditions, and approximate formulas are adequate. Also, many voltage drop computer programs are available that offer speed and accuracy.

3.11.1 General mathematical formulas

The phasor relationships between the voltage at the beginning of a circuit, the voltage drop in the circuit, and the voltage at the end of the circuit are shown in figure 3-11.

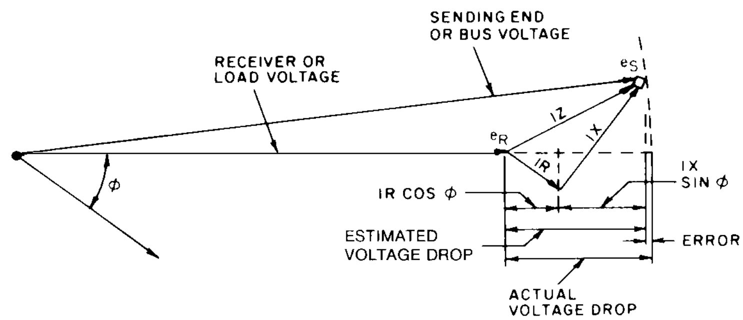


Figure 3-11—Phasor diagram of voltage relations for voltage-drop calculations

The approximate formula for the voltage drop is

$$V = IR\cos\phi + IX\sin\phi$$

where

V	is the voltage drop in circuit, line to neutral
I	is the current flowing in conductor
R	is the line resistance for one conductor, in ohms
X	is the line reactance for one conductor, in ohms
ϕ	is the angle whose cosine is the load power factor
$\cos\phi$	is the load power factor, in decimals
$\sin\phi$	is the load reactive factor, in decimals

The voltage drop V obtained from this formula is the voltage drop in one conductor, one way, commonly called the line-to-neutral voltage drop. The reason for using the line-to-neutral voltage is to permit the line-to-line voltage to be computed by multiplying by the following constants:

Voltage system	Multiply by
Single-phase	2
Three-phase	1.732

In using this formula, the line current I is generally the maximum or assumed load current-carrying capacity of the conductor.

The resistance *R* is the ac resistance of the particular conductor used and of the particular type of raceway in which it is installed as obtained from the manufacturer. It depends on the size of the conductor measured in American Wire Gauge (AWG) for smaller conductors and in thousands of circular mils (kcmil) for larger conductors, the type of conductor (copper or aluminum), the temperature of the conductor (normally 75 ˚C for average loading and 90 ˚C for maximum loading), and whether the conductor is installed in magnetic (steel) or nonmagnetic (aluminum or nonmetallic) raceway. The resistance opposes the flow of current and causes the heating of the conductor.

The reactance *X* is obtained from the manufacturer. It depends on the size and material of the conductor, whether the raceway is magnetic or nonmagnetic, and on the spacing between the conductors of the circuit. The spacing is fixed for multiconductor cable but may vary with single-conductor cables so that an average value is required. Reactance occurs because the alternating current flowing in the conductor causes a magnetic field to build up and collapse around each conductor in synchronism with the alternating current. This magnetic field, as it builds up and falls radially, cuts across the conductor itself and the other conductors of the circuit, causing a voltage to be induced in each in the same way that current flowing in the primary of a transformer induces a voltage in the secondary of the transformer. Since the induced voltage is proportional to the rate of change of the magnetic field, which is maximum when the current passes through zero, the induced voltage will be a maximum when the current passes through zero, or, in vector terminology, lags the current wave by 90 degrees.

ϕ is the angle between the load voltage and the load current and is obtained by finding the power factor expressed as a decimal (1 or less) in the cosine section of a trigonometric table or by using a scientific calculator.

Cos ϕ is the power factor of the load expressed in decimals and may be used directly in the computation of $IR \cos \phi$.

Sin ϕ is obtained by finding the angle ϕ in a trigonometric table of sines or by using a calculator. By convention, sin ϕ is positive for lagging power factor loads and negative for leading power factor loads.

$IR \cos \phi$ is the resistance component of the voltage drop and $IX \sin \phi$ is the reactive component of the voltage drop.

For exact calculations, the following formula may be used:

$$\text{actual voltage drop} = e_S + IR\cos\phi + IX\sin\phi - \sqrt{e_S^2 - (IX\cos\phi - IR\sin\phi)^2}$$

where the symbols correspond to those in figure 3-11.

3.11.2 Cable voltage drop

Voltage drop tables and charts are sufficiently accurate to determine the approximate voltage drop for most problems. Table 3-12 contains four sections giving the three-phase line-to-line voltage drop for 10 000 circuit ampere-feet (A-ft) for copper and aluminum conductors in both magnetic and nonmagnetic conduit. The figures are for single-conductor cables operating at 60 ˚C. However, the figures are reasonably accurate up to a conductor temperature of 75 ˚C and for multiple-conductor cable. Although the length of cable runs over 600 V is generally too short to produce a significant voltage drop, table 3-12 may be used to obtain approximate values. For borderline cases, the exact values obtained from the manufacturer for the particular cable should be used. The resistance is the same for the same wire size, regardless of the voltage, but the thickness of the insulation is increased at the higher voltages, which increases the conductor spacing resulting in increased reactance causing increasing errors at the lower power factors. For the same reason, table 3-12 cannot be used for open-wire or other installations such as trays where there is appreciable spacing between the individual phase conductors.

In using table 3-12, the normal procedure is as follows: Find the voltage drop for 10 000 A-ft and multiply this value by the ratio of the actual number of ampere-feet to 10 000. Note that the distance in feet is the distance from the source to the load.

Example 1. 500 kcmil copper conductor in steel (magnetic) conduit; circuit length 200 ft; load 300 A at 80% power factor. What is the voltage drop?

Using Section 1 of table 3-12, the intersection between 500 kcmil and 80% power factor gives a voltage drop of 0.85 V for 10 000 A-ft.

200 ft · 300 A = 60 000 circuit A-ft
(60 000/10 000) · 0.85 = 6 · 0.85 = 5.1 V drop
voltage drop, phase-to-neutral = 0.577 · 5.1
= 2.9 V

Example 2. AWG No. 12 aluminum conductor in aluminum (nonmagnetic) conduit; circuit length 200 ft; load 10 A at 70% power factor. What is the voltage drop?

Using Section 4 of table 3-12, the intersection between AWG No. 12 aluminum conductor and 0.70 power factor is 37 V for 10 000 A-ft.

200 ft · 10 A = 200 circuit A-ft
voltage drop = (2000/10 000) · 37
= 7.4 V

Example 3. Determine the wire size in Example 2 to limit the voltage drop to 3 V. The voltage drop in 10 000 A-ft would be as follows:

(10 000/2000) · 3 = 15 V

Using Section 4 of table 3-12, move along the 0.70 power factor line to find the voltage drop not greater than 15 V. AWG No. 8 aluminum has a voltage drop of 15 V for 10 000 A-ft, so it is the smallest aluminum conductor in aluminum conduit that could be used to carry 10 A for 200 ft with a voltage drop of not more than 3 V, line-to-line.

Table 3-12—Three-phase line-to-line voltage drop for 600 V single-conductor cable per 10 000 A-ft (60 °C conductor temperature, 60 Hz)

Load power factor lagging	Wire size (AWG or kcmil) 1000	900	800	750	700	600	500	400	350	300	250	4/0	3/0	2/0	1/0	1	2	4	6	8*	10*	12*	14*
Section 1: Copper conductors in magnetic conduit																							
1.00	0.28	0.31	0.34	0.35	0.37	0.42	0.50	0.60	0.68	0.78	0.92	1.1	1.4	1.7	2.1	2.6	3.4	5.3	8.4	13	21	33	53
0.95	0.50	0.52	0.55	0.57	0.59	0.64	0.71	0.81	0.88	1.0	1.1	1.3	1.5	1.9	2.3	2.8	3.5	5.3	8.2	13	20	32	50
0.90	0.57	0.59	0.62	0.64	0.66	0.71	0.78	0.88	0.95	1.1	1.2	1.3	1.6	1.9	2.3	2.8	3.4	5.2	8.0	12	19	30	48
0.80	0.66	0.68	0.71	0.73	0.74	0.80	0.85	0.95	1.0	1.1	1.2	1.4	1.6	1.9	2.3	2.6	3.2	4.8	7.3	11	17	27	43
0.70	0.71	0.73	0.76	0.78	0.80	0.83	0.88	0.97	1.0	1.1	1.2	1.3	1.5	1.8	2.1	2.5	3.0	4.4	6.6	9.9	15	24	38
Section 2: Copper conductors in nonmagnetic conduit																							
1.00	0.23	0.26	0.28	0.29	0.33	0.38	0.45	0.55	0.62	0.73	0.88	1.0	1.3	1.6	2.1	2.6	3.3	5.3	8.4	13	21	33	53
0.95	0.40	0.43	0.45	0.47	0.50	0.54	0.62	0.71	0.80	0.92	1.0	1.1	1.5	1.8	2.2	2.7	3.4	5.3	8.2	13	20	32	50
0.90	0.47	0.48	0.52	0.54	0.55	0.59	0.68	0.76	0.85	0.95	1.1	1.1	1.5	1.8	2.2	2.7	3.3	5.1	7.9	12	19	30	48
0.80	0.54	0.55	0.57	0.59	0.62	0.66	0.73	0.81	0.88	0.97	1.1	1.1	1.4	1.7	2.1	2.5	3.1	4.7	7.2	11	17	27	43
0.70	0.57	0.59	0.62	0.64	0.66	0.69	0.74	0.83	0.88	0.97	1.1	1.1	1.4	1.6	2.0	2.4	2.8	4.3	6.4	9.7	15	24	38
Section 3: Aluminum conductors in magnetic conduit																							
1.00	0.42	0.45	0.49	0.52	0.55	0.63	0.74	0.91	1.0	1.2	1.4	1.7	2.1	2.6	3.3	4.2	5.2	8.4	13	21	33	52	–
0.95	0.62	0.65	0.70	0.73	0.76	0.83	0.94	1.1	1.2	1.4	1.6	1.8	2.3	2.7	3.4	4.2	5.3	8.2	13	20	32	50	–
0.90	0.69	0.72	0.76	0.79	0.82	0.88	0.99	1.2	1.3	1.4	1.6	1.9	2.3	2.7	3.4	4.1	5.1	7.9	12	19	30	48	–
0.80	0.76	0.80	0.83	0.85	0.88	0.95	1.0	1.2	1.3	1.4	1.6	1.8	2.2	2.6	3.2	3.9	4.7	7.3	11	17	27	43	–
0.70	0.80	0.83	0.87	0.89	0.92	0.98	1.1	1.2	1.3	1.4	1.6	1.7	2.1	2.4	2.9	3.6	4.3	6.5	10	15	24	37	–
Section 4: Aluminum conductors in nonmagnetic conduit																							
1.00	0.36	0.39	0.44	0.47	0.51	0.59	0.70	0.88	1.0	1.2	1.4	1.7	2.1	2.6	3.3	4.2	5.2	8.4	13	21	33	52	–
0.95	0.52	0.56	0.60	0.63	0.67	0.74	0.85	1.0	1.1	1.3	1.5	1.8	2.2	2.7	3.4	4.2	5.2	8.2	13	20	32	50	–
0.90	0.57	0.61	0.65	0.68	0.71	0.79	0.89	1.1	1.2	1.3	1.5	1.8	2.2	2.6	3.3	4.1	5.0	7.9	12	19	30	48	–
0.80	0.63	0.66	0.71	0.73	0.76	0.83	0.92	1.1	1.2	1.3	1.5	1.7	2.1	2.5	3.1	3.8	4.6	7.2	11	17	27	42	–
0.70	0.66	0.69	0.73	0.75	0.78	0.83	0.92	1.1	1.1	1.3	1.4	1.6	1.7	2.3	2.8	3.4	4.2	6.4	9.9	15	24	37	–

*Solid conductor. Other conductors are stranded.

To convert voltage drop to	Multiply by
Single-phase, three-wire, line-to-line	1.15
Single-phase, three-wire, line-to-neutral	0.577
Three-phase, line-to-neutral	0.577

3.11.3 Busway voltage drop

See Chapter 13 for busway voltage drop tables and related information.

3.11.4 Transformer voltage drop

Voltage-drop curves in figures 3-12 and 3-13 may be used to determine the approximate voltage drop in single-phase and three-phase, 60 Hz, liquid-filled, self-cooled, and dry-type transformers. The voltage drop through a single-phase transformer is found by entering the chart at a kilovoltampere rating three times that of the single-phase transformer. Figure 3-12 covers transformers in the following ranges:

a) *Single-Phase*
250–500 kVA, 8.6–15 kV insulation classes
833–1250 kVA, 5–25 kV insulation classes

b) *Three-Phase*
225–750 kVA, 8.6–15 kV insulation classes
1000–10 000 kVA, 5–25 kV insulation classes

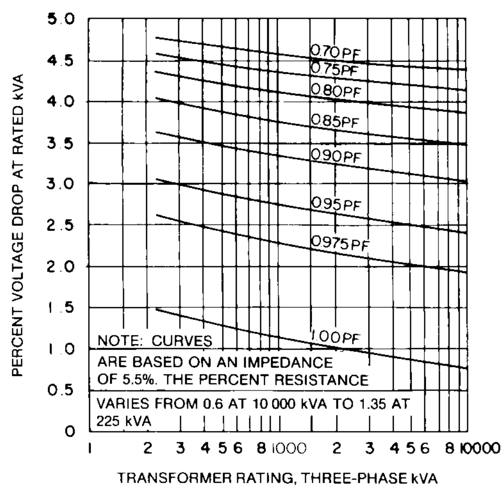


Figure 3-12—Approximate voltage drop curves for three-phase transformers, 225–10 000 kVA, 5–25 kV

An example of the use of the chart is given in the following:

Example. Find the voltage drop in a 2000 kVA three-phase 60 Hz transformer rated 4160-480 V. The load is 1500 kVA at 0.85 power factor.

Solution. Enter the chart on the horizontal scale at 2000 kVA, extend a line vertically to its intersection with the 0.85 power factor curve. Extend a line horizontally from this point to the

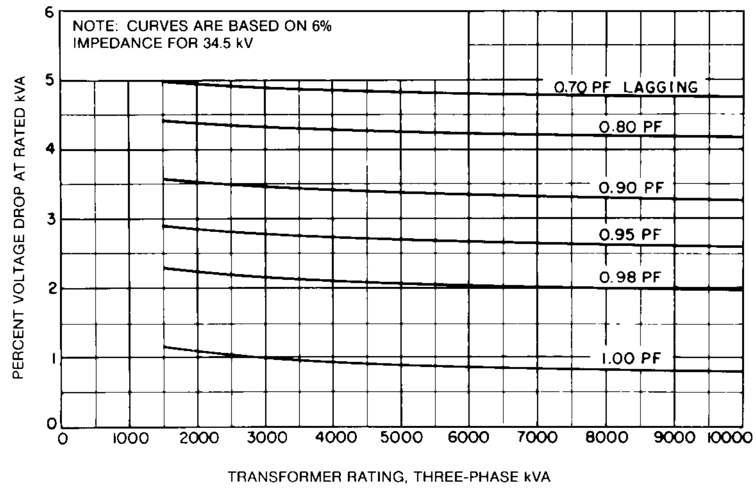


Figure 3-13—Approximate voltage drop curves for three-phase transformers, 1500–10 000 kVA, 34.5 kV

left to its intersection with the vertical scale. This point on the vertical scale gives the percent voltage drop for rated load. Multiply this value by the ratio of actual load to rated load:

$$\text{percent drop at rated load} = 3.67$$

$$\text{percent drop at 1500 kVA} = 3.67 \cdot \frac{1500}{2000}$$

$$= 2.75$$

$$\text{actual voltage drop} = 2.75\% \cdot 480$$
$$= 13.2 \text{ V}$$

Figure 3-13 applies to the 34.5 kV insulation class power transformer in ratings from 1500–10 000 kVA. These curves can be used to determine the voltage drop for transformers in the 46 and 69 kV insulation classes by using appropriate multipliers at all power factors except unity.

To correct for 46 kV, multiply the percent voltage drop obtained from the chart by 1.065, and for 69 kV, multiply by 1.15.

3.11.5 Motor-starting voltage drop

It is characteristic of ac motors that the current they draw on starting is much higher than their normal running current. Synchronous and squirrel-cage induction motors started on full voltage may draw a current as high as seven or eight times their full-load running current. This sudden increase in the current drawn from the power system may result in excessive drop in voltage unless it is considered in the design of the system. The motor-starting load in kilovoltamperes, imposed on the power supply system, and the available motor torque are greatly affected by the method of starting used.

Table 3-13 gives a comparison of several common reduced voltage starting methods. Starting currents for autotransformers include excitation current for the autotransformer. All voltages, currents, and starting torques assume 100% of motor nameplate voltage applied to the starter with no voltage drop in the supply system. Actual motor starting torques vary with the ratio of actual to nameplate voltage squared. Users should be aware that reduced voltage starting methods are often used because full voltage starts cause unacceptable voltage drop. Reduced voltage starting methods cause some voltage drop and starting torques will be less than table 3-13 if the voltage to the starter drops below motor nameplate rating.

Table 3-13—Comparison of motor starting methods

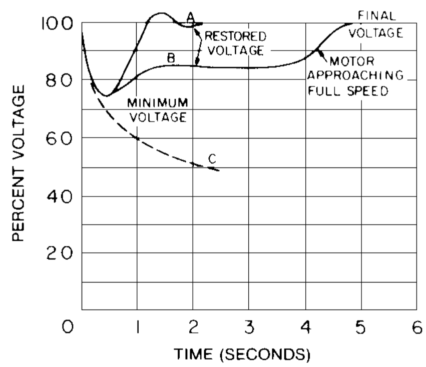
Type of starter (settings given are the more common for each type)	Motor terminal voltage (percent line voltage)	Starting torque (percent full-voltage starting torque)	Line-current (percent full-voltage starting current)
Full-voltage starter	100	100	100
Autotransformer			
80% tap	80	64	67
65% tap	65	42	45
50% tap	50	25	28
Resistor starter, single step (adjusted for motor voltage to be 80% of line voltage)	80	64	80
Reactor			
50% tap	50	25	50
45% tap	45	20	45
37.5% tap	37.5	14	37.5
Part-winding starter (low-speed motors only)			
75% winding	100	75	75
50% winding	100	50	50

NOTE—See 3.11.5 for more information.

In addition to methods listed in table 3-13, users should consider solid-state soft-start motor controllers and/or adjustable speed drives.

3.11.6 Effect of motor starting on generators

Figure 3-14 shows the behavior of the voltage of a generator when an induction motor is started. Starting a synchronous motor has a similar effect up to the time of pull-in torque. The case used for this illustration utilizes a full-voltage starting device, and the full-voltage motor starting load in kilovoltamperes is about 100% of the generator rating. It is assumed for curves A and B that the generator is provided with an automatic voltage regulator.



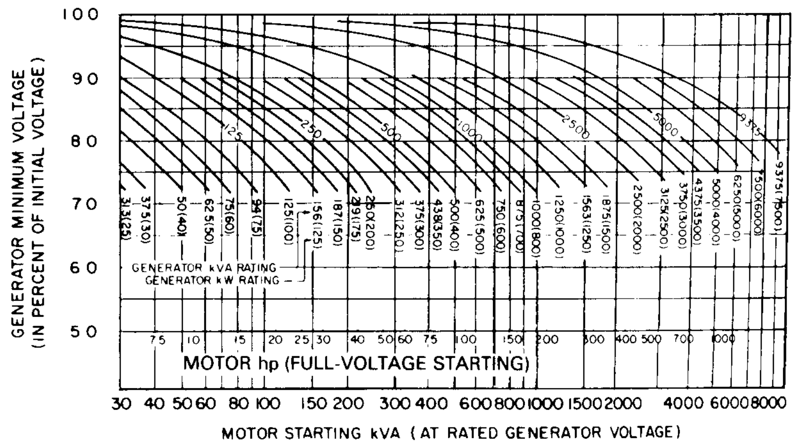
Motor-starting kVA = 100% of generator rating
A — No initial load on generator
B — 50% initial load on generator
C — No regulator

Figure 3-14—Typical generator voltage behavior due to full-voltage starting of a motor

The minimum voltage of the generator as shown in figure 3-14 is an important quantity because it is a determining factor affecting undervoltage devices and contactors connected to the system and the stalling of motors running on the system. The curves of figure 3-15 can be used for estimating the minimum voltage occurring at the terminals of a generator supplying power to a motor being started.

3.11.7 Effect of motor starting on distribution system

Frequently in the case of purchased power, there are transformers and cables between the starting motor and the generator. Most of the drop in this case is within the distribution equipment. When all the voltage drop is in this equipment, the voltage falls immediately (because it is not influenced by a regulator as in the generator case) and does not recover until the motor approaches full speed. Since the transformer is usually the largest single impedance in the distribution system, it takes almost the total drop. Figure 3-16 has been plotted in terms of motor starting load in kilovoltamperes that would be drawn if rated transformer secondary voltage were maintained.



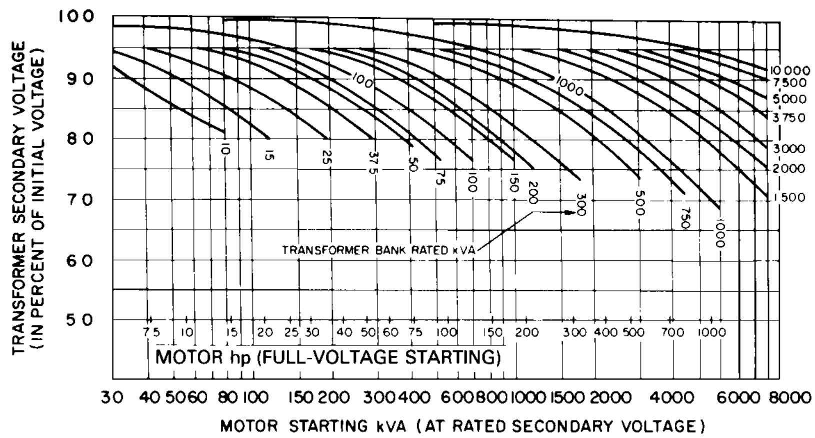
NOTES: (1) The scale of motor horsepower is based on the starting current being equal to approximately 5.5 times normal.

(2) If there is no initial load, the voltage regulator will restore voltage to 100% after dip to values given by curves.

(3) Initial load, if any, is assumed to be of constant-current type.

(4) Generator characteristics are assumed as follows: (a) Generators rated 1000 kVA or less: Performance factor k = 10; transient reactance X_d' = 25%; synchronous reactance X_d = 120%. (b) Generators rated above 1000 kVA: Characteristics for 3600 r/min turbine generators.

Figure 3-15—Minimum generator voltage due to full-voltage starting of a motor



NOTES: (1) The scale of motor horsepower is based on the starting current being equal to approximately 5.5 times normal.

(2) Short-circuit capacity of primary supply is assumed to be as follows:

Transformer bank load (kVA)	Primary short-circuit capacity (kVA)
0-300	25 000
500-1000	50 000
1500-3000	100 000
3760-10 000	250 000

(3) Transformer impedances are assumed to be as follows:

Transformer bank load (kVA)	Primary bank impedance (percent)
10-50	3.0
75-150	4.0
200-500	5.0
750-2000	5.5
3000-10 000	6.0

(4) Representative values of primary system voltage drop, expressed as a fraction of total drop, for the assumed conditions, are as follows:

Transformer bank load (kVA)	System drop / Total drop
100	0.09
1000	0.25
10 000	0.44

Figure 3-16—Approximate voltage drop in a transformer due to full-voltage starting of a motor

3.12 References

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

ANSI C57.12.20-1988, American National Standard Requirements for Overhead-Type Distribution Transformers 67 000 Volts and Below, 500 kVA and Smaller.[3]

ANSI C84.1-1989, American National Standard Voltage Ratings for Electric Power Systems and Equipment (60 Hz).

ANSI C92.2-1987, American National Standard Preferred Voltage Ratings for Alternating-Current Electrical Systems and Equipment Operating at Voltages above 230 Kilovolts Nominal for Power Systems.

ANSI/NFPA 70-1993, National Electric Code.[4]

CAN3-C235-83, Preferred Voltage Levels for AC Systems, 0 to 50 000 V (Canadian Standards Association).[5]

IEEE Std 100-1992, The New IEEE Standard Dictionary of Electrical and Electronics Terms (ANSI).

IEEE Std 142-1991, IEEE Recommended Practice for Grounding of Industrial and Commercial Power Systems (IEEE Green Book) (ANSI).

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

IEEE Std 446-1987, IEEE Recommended Practice for Emergency and Standby Power Systems for Industrial and Commercial Applications (IEEE Orange Book) (ANSI).

IEEE Std 519-1992, IEEE Recommended Practices and Requirements for Harmonic Control in Electric Power Systems.

IEEE Std 1100-1992, IEEE Recommended Practice for Powering and Grounding Sensitive Electronic Equipment (IEEE Emerald Book).

NEMA MG 1-1993, Motors and Generators.[6]

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[3]ANSI publications are available from the Sales Department, American National Standards Institute, 11 West 42nd Street, 13th Floor, New York, NY 10036, USA.

[4]NFPA publications are available from Publication Sales, National Fire Protection Association, 1 Batterymarch Park, P.O. Box 9101, Quincy, MA 02269-9101, USA.

[5]CSA publications are available from the Canadian Standards Association (Standards Sales), 178 Rexdale Blvd., Rexdale, Ontario, Canada M9W 1R3.

[6]NEMA publications can be obtained from the Sales Department, American National Standards Institute, or from the National Electrical Manufacturers Association, 2101 L Street, NW, Washington, DC 20037.

3.13 Bibliography

[B1] Arnold, R. E., "NEMA Suggested Standards for Future Design of AC Integral Horsepower Motors," *IEEE Transactions on Industry and General Applications*, vol. IGA-6, pp. 110–114, Mar./Apr. 1970.

[B2] Brereton, D. S., and Michael, D. T., "Developing a New Voltage Standard for Industrial and Commercial Power Systems," *Proceedings of the American Power Conference*, vol. 30, pp. 733–751, 1968.

[B3] Brereton, D. S., and Michael, D. T., "Significance of Proposed Changes in AC System Voltage Nomenclature for Industrial and Commercial Power Systems: I—Low-Voltage Systems," *IEEE Transactions on Industry and General Applications*, vol. IGA-3, pp. 504–513, Nov./Dec. 1967.

[B4] Brereton, D. S., and Michael, D. T., "Significance of Proposed Changes in AC System Voltage Nomenclature for Industrial and Commercial Power Systems: II—Medium-Voltage Systems," *IEEE Transactions on Industry and General Applications*, vol. IGA-3, pp. 514–520, Nov./Dec. 1967.

[B5] Conrad, L., Grigg, C., and Little, K., "Predicting and Preventing Problems Associated with Remote Fault Clearing Voltage Dips," *IEEE Transactions on Industry Applications*, vol. 27, no. 1, pp. 167–172, Jan./Feb. 1991.

[B6] *Electric Utility Engineering Reference Book, vol. 3: Distribution Systems*. Trafford, PA: Westinghouse Electric Corporation, 1965.

[B7] Goldstein, M., and Speranza, P., "The Quality of U.S. Commercial AC Power," IEEE paper CH1818-4/82/000-00028, 1982.

[B8] Gulachenski, E., "New England Electric's Power Quality Research Study," *Proceedings of the Second International Conference on Power Quality*, Palo Alto, California: Electric Power Research Institute, pp. F-11:1-10, 1992.

[B9] IEEE Distribution Subcommittee Working Group of Voltage Flicker, "Flicker Limitations of Electric Utilities," 1985.

[B10] Linders, J. R., "Effects of Power Supply Variations on AC Motor Characteristics," Conference Record, 6th Annual Meeting of the IEEE Industry and General Applications Group, IEEE 71 C1-IGA, pp. 1055–1068, 1971.

[B11] Michael, D. T., "Proposed Design Standard for the Voltage Drop in Building Wiring for "Low-Voltage Systems," *IEEE Transactions on Industry and General Applications*, vol. IGA-4, pp. 30–32, Jan./Feb. 1968.

[B12] *Standard Handbook for Electrical Engineers*, 10 Ed., Table 18-5. New York: McGraw-Hill.

Chapter 4
Short-circuit current calculations

4.1 Introduction

Even the best designed electric systems occasionally experience short circuits resulting in abnormally high currents. Overcurrent protective devices, such as circuit breakers and fuses, should isolate faults at a given location safely with minimal circuit and equipment damage and minimal disruption of the plant's operation. Other parts of the system, such as cables, busways, and disconnecting switches, shall be able to withstand the mechanical and thermal stresses resulting from maximum flow of short-circuit current through them. The magnitudes of short-circuit currents are usually estimated by calculation, and equipment is selected using the calculation results.

The current flow during a short circuit at any point in a system is limited by the impedance of circuits and equipment from the source or sources to the point of fault. It is not directly related to the size of the load on the system. However, additions to the system that increase its capacity to handle a growing load, such as more or larger incoming transformers from a utility, while not affecting the normal load at some existing locations in the system, may drastically increase the short-circuit currents at those locations. Whether an existing system is expanded or a new system is installed, available short-circuit currents should be determined for proper application of overcurrent protective devices.

Calculated maximum short-circuit currents are nearly always required. In some cases, the minimum sustained values are also needed to check the sensitivity requirements of the current-responsive protective devices.

This chapter has three purposes:

a) To present some fundamental considerations of short-circuit current calculations;
b) To illustrate some commonly used methods of making these calculations with typical examples;
c) To furnish typical data that can be used in making short-circuit current calculations.

The size and complexity of many modern industrial systems may make longhand short-circuit current calculations impractically time-consuming. Computers are generally used for major short-circuit studies. Whether or not computers are available, a knowledge of the nature of short-circuit currents and calculating procedures is essential to conduct such studies.

4.2 Sources of fault current

Fundamental frequency currents that flow during a short circuit come from rotating electric machinery. (Charged power capacitors can also produce extremely high transient short-circuit discharge currents, but they are of natural frequency much higher than power frequency and usually of such short duration that the calculated power frequency short-circuit duty current is not significantly increased by adding the capacitor discharge. Discharge currents are calculated as described for RLC circuits in many electrical engineering texts and an appropriate RLC circuit can be based on power system data.) Rotating machinery in industrial plant short-circuit calculations may be analyzed in five categories:

a) Synchronous generators
b) Synchronous motors and condensers
c) Induction machines
d) Electric utility systems
e) Adjustable speed ac induction or dc motors with solid-state ac power supply equipments

The fault current from each rotating machinery source is limited by the impedance of the machine and the impedance between the machine and the short circuit. Fault currents generally are not dependent upon the pre-fault loading of the machine. The impedance of a rotating machine is not a simple value but is complex and variable with time.

4.2.1 Synchronous generators

If a short circuit is applied to the terminals of a synchronous generator, the short-circuit current starts out at a high value and decays to a steady-state value some time after the inception of the short circuit. Since a synchronous generator continues to be driven by its prime mover and to have its field externally excited, the steady-state value of short-circuit current will persist unless interrupted by some switching means. An equivalent circuit consisting of a constant driving voltage in series with an impedance that varies with time (figure 4-1) is used to represent this characteristic. The varying impedance consists primarily of reactance.

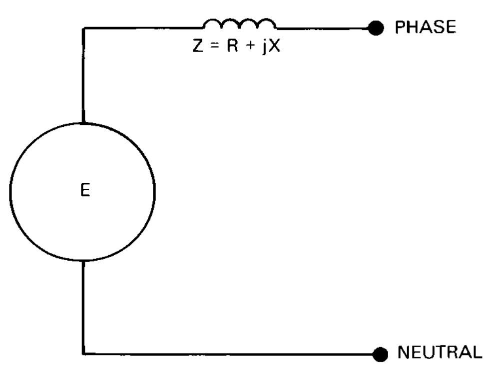


Figure 4-1—Equivalent circuit for generators and motors E = (driving voltage, X varies with time)

For purposes of short-circuit current calculations, industry standards have established three specific names for values of this variable reactance, called subtransient reactance, transient reactance, and synchronous reactance.

X_d'' = subtransient reactance; determines current during first cycle after fault occurs. In about 0.1 s reactance increases to

X_d' = transient reactance; assumed to determine current after several cycles at 60 Hz. In about 0.5 to 2 s reactance increases to

X_d = synchronous reactance; this is the value that determines the current flow after a steady-state condition is reached.

Because most short-circuit interrupting devices, such as circuit breakers and fuses, operate well before steady-state conditions are reached, generator synchronous reactance is seldom used in calculating fault currents for application of these devices.

Synchronous generator data available from some manufacturers includes two values for direct axis subtransient reactance—for example, subtransient reactances X_{dv}'' (at rated voltage, saturated, smaller) and X_{di}'' (at rated current, unsaturated, larger). Because a short-circuited generator may be saturated, and for conservatism, the X_{dv}'' value is used for short-circuit current calculations.

4.2.2 Synchronous motors and condensers

Synchronous motors supply current to a fault much as synchronous generators do. When a fault causes system voltage to drop, the synchronous motor receives less power from the system for rotating its load. At the same time, the internal voltage causes current to flow to the system fault. The inertia of the motor and its load acts as a prime mover and, with field excitation maintained, the motor acts as a generator to supply fault current. This fault current diminishes as the magnetic field in the machine decays.

The generator equivalent circuit is used for synchronous motors. Again, a constant driving voltage and the same three reactances, X_d'', X_d', and X_d, are used to establish values of current at three points in time.

Synchronous condensers are treated in the same manner as synchronous motors.

4.2.3 Induction machines

A squirrel-cage induction motor will contribute current to a power system short circuit. This is generated by inertia driving the motor in the presence of a field flux produced by induction from the stator rather than from a dc field winding. Since this flux decays on loss of source voltage caused by a fault at the motor terminals, the current contribution of an induction motor to a terminal fault reduces and disappears completely after a few cycles. Because field excitation is not maintained, there is no steady-state value of fault current as for synchronous machines.

Again, the same equivalent circuit is used, but the values of transient and synchronous reactance approach infinity. As a consequence, induction motors are assigned only a subtransient value of reactance X_d''. This value varies upward from the locked rotor reactance to account for the decay of the motor current contribution to the short circuit.

For short-circuit current calculations, an induction generator can be treated the same as an induction motor. Wound-rotor induction motors normally operating with their rotor rings short-circuited will contribute short-circuit current in the same manner as a squirrel-cage induction motor. Occasionally, large wound-rotor motors operated with some external resistance maintained in their rotor circuits may have sufficiently low short-circuit time constants that their short-circuit current contribution is not significant and may be neglected. A specific investigation should be made to determine whether to neglect the contribution from a wound-rotor motor.

4.2.4 Electric utility systems

The remote generators of an electric utility system are a source of short-circuit current often delivered through a supply transformer. The generator-equivalent circuit can be used to represent the utility system. The utility generators are usually remote from the industrial plant. The current contributed to a short circuit in the remote plant appears to be merely a small increase in load current to the very large central station generators, and this current contribution tends to remain constant. Therefore, the electric utility system is usually represented at the plant by a single valued equivalent impedance referred to the point of connection.

4.2.5 Adjustable speed ac induction or dc motors with solid-state ac power supply equipments

Some adjustable speed ac induction or dc motors, speed controlled by adjusting the frequency or dc voltage of solid-state ac power supply equipments, can, under certain conditions, contribute current from the motors to a short circuit on the incoming ac electric power system. The design of the power supply equipment determines whether a current can or cannot be “backfed” from the motors. When it can, the power supply operating mode at the time of the power system short circuit usually determines the magnitude and duration of the backfed current. For some motors, the duration is limited by power supply equipment protective functions to less than one cycle of ac power frequency. The adjustable frequency or dc voltage power supply manufacturer should be consulted for information on whether adjustable speed ac induction or dc motors can contribute backfeed current to ac power system short circuits, and if so, under what operating conditions and how much.

4.3 Fundamentals of short-circuit current calculations

Ohm’s law, $I = E/Z$, is the basic relationship used in determining I, the short-circuit current, where E is the driving voltage of the source, and Z is the impedance from the source to the short circuit including the impedance of the source.

Most industrial systems have multiple sources supplying current to a short circuit since each motor can contribute. One step in short-circuit current calculation is the simplification of the multiple-source system to the condition where the basic relationship applies.

4.3.1 Purpose of calculations

System and equipment complexity and the lack of accurate parameters make precise calculations of short-circuit currents exceedingly difficult, but extreme precision is unnecessary. The calculations described provide reasonable accuracy for the maximum and minimum limits of short-circuit currents. These satisfy the usual reasons for making calculations.

The maximum calculated short-circuit current values are used for selecting interrupting devices of adequate short-circuit rating, to check the ability of components of the system to withstand mechanical and thermal stresses, and to determine the time-current coordination of protective relays. The minimum values are used to establish the required sensitivity of protective relays. Minimum short-circuit values are sometimes estimated as fractions of the maximum values. If so, it is only necessary to calculate the maximum values of short-circuit current.

For calculating the maximum short-circuit current, the industrial electric power system should have the largest expected number of connected rotating machines (usually with the system at full future load).

4.3.2 Type of short circuit

In an industrial system, the three-phase short circuit is frequently the only one considered, since this type of short circuit generally results in maximum short-circuit current.

Line-to-line short-circuit currents are approximately 87% of three-phase short-circuit currents. Line-to-ground short-circuit currents can range in utility systems from a few percent to possibly 125% of the three-phase value. In industrial systems, line-to-ground short-circuit currents higher than three phase are rare except when bolted short circuits are near the wye windings with a solidly grounded neutral of either generators or two winding, delta-wye, core-type transformers.

Assuming a three-phase short-circuit condition also simplifies calculations. The system, including the short circuit, remains symmetrical about the neutral point, whether or not the neutral point is grounded and regardless of wye or delta transformer connections. The balanced three-phase short-circuit current can be calculated using a single-phase equivalent circuit that has only line-to-neutral voltage and impedance.

In calculating the maximum short-circuit current, it is assumed that the short-circuit connection has zero impedance (is “bolted”) with no current-limiting effect due to the short circuit itself. It should be recognized, however, that actual short circuits often involve arcing, and variable arc impedance can reduce low-voltage short-circuit current magnitudes appreciably.

In low-voltage systems, the minimum values of short-circuit current are sometimes calculated from known effects of arcing. Analytical studies indicate that the sustained arcing short-circuit currents, in per unit of bolted fault values, may be typically as low as

a) 0.89 at 480 V and 0.12 at 208 V for three-phase arcing
b) 0.74 at 480 V and 0.02 at 208 V for line-to-line single-phase arcing
c) 0.38 at 277 V and 0.01 at 120 V for line-to-neutral single-phase arcing

4.3.3 Basic equivalent circuit

The basic equation finds the current of a simple circuit having one voltage source and one impedance. In the basic equation, the voltage E represents a single overall system driving voltage, which replaces the array of individual unequal generated voltages acting within separate rotating machines. This voltage is equal to the prefault voltage at the point of short-circuit connection. The impedance Z is a network reduction of the impedances representing all significant elements of the power system connected to the short-circuit point including source internal impedances.

This equivalent circuit of the power system is a valid circuit transformation in accordance with Thevenin's theorem. It permits a determination of short-circuit current corresponding to the values of system impedances used.

Ordinarily, the prefault voltage is taken as the system nominal voltage at the point of short circuit because this is close to the maximum operating voltage under fully loaded system conditions, and therefore the short-circuit currents will approach maximum. Higher than nominal voltage might be used in an unusual case when full load system voltage is observed to be above nominal.

The single-phase representation of a three-phase balanced system uses per-phase impedances and the line-to-neutral system driving voltage. Line-to-neutral voltage is line-to-line voltage divided by $\sqrt{3}$.

Calculations may use impedances in ohms and voltages in volts, or both in per unit. Per unit calculations simplify short-circuit studies for industrial systems that involve voltages of several levels. When using the per unit system, the driving voltage is equal to 1.0 per unit if voltage bases are equal to system nominal voltages.

The major elements of impedance must always be included in a short-circuit current calculation. These are impedances of transformers, busways, cables, conductors, and rotating machines. There are other circuit impedances, such as those associated with circuit breakers, wound or bar-type current transformers, bus structures, and bus connections, that are usually small enough to be neglected in medium- or high-voltage-system short-circuit calculations, because the accuracy of the calculation is not generally affected. Omitting them provides slightly more conservative (higher) short-circuit currents. However, in low-voltage systems, and particularly at 208 V, there are cases where impedance of these elements is appreciable and inclusion can significantly reduce the calculated short-circuit current.

Also, the usual practice is to disregard the presence of static loads (such as lighting and electric heating) in the network, despite the fact that their associated impedance is actually connected in shunt with other network branches. This approach is considered valid since usually the relatively high power factor static load impedances are large and approximately 90° out-of-phase compared to the impedances of the other highly reactive parallel branches of the network.

In ac circuits, the impedance *Z* is the vector sum of resistance *R* and reactance *X*. It is always acceptable to calculate short-circuit currents using vector impedances in the equivalent circuit. For most short-circuit current magnitude calculations at medium or high voltage, and for a few at low voltage, when the reactances are much larger than the resistances, it is sufficiently accurate, conservative, and simpler to ignore resistances and use reactances only.

For many low-voltage calculations, however, resistances should not be ignored because the calculated currents would be overconservative.

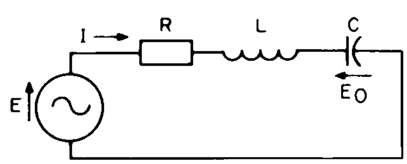
Resistances are definitely needed for calculations of *X*/*R* ratios when applying high- and medium-voltage circuit breakers, but they are analyzed in a network separate from the reactance network.

4.4 Restraints of simplified calculations

The short-circuit calculations described in this chapter are a simple *E*/*Z* evaluation of extensive electric power system networks. Before describing the step-by-step procedures in making these calculations, it is appropriate to review some of the restraints imposed by the simplification.

4.4.1 Impedance elements

When an ac electric power circuit contains resistance *R,* inductance *L,* and capacitance *C,* such as the series connection shown in figure 4-2, the expression relating current to voltage includes the terms shown in figure 4-2. A textbook determination of the current magnitude requires the solution of a differential equation.



$$E = L\frac{dI}{dt} + RI + \frac{\int I\,dt}{C} + E_0$$
$$= L\frac{d^2Q}{dt^2} + R\frac{dQ}{dt} + \frac{Q}{C} + E_0$$

Figure 4-2—Series RLC circuit

If two important restraints are applied to this series circuit, the following simple equation using vector impedances ($XL = \omega L$ and $XC = 1/\omega C$) is valid:

$$E = I\left[R + j\left(\omega L - \frac{1}{\omega C}\right)\right]$$

These restraints are that, first, the electric driving force be a sine wave and, second, the impedance coefficients *R, L,* and *C* be constants. Unfortunately, in short-circuit calculations these restraints may be invalidated. A major reason for this is switching transients.

4.4.2 Switching transients

The vector impedance analysis recognizes only the steady-state sine wave electrical quantities and does not include the effects of abrupt switching. Fortunately, the effects of switching transients can be analyzed separately and added. (An independent solution can be obtained from a solution of the formal differential equations.)

In the case of only resistance *R* (figure 4-3), the closure of switch *SW* causes the current to immediately assume the value that would exist in the steady state. No transient adder is needed.

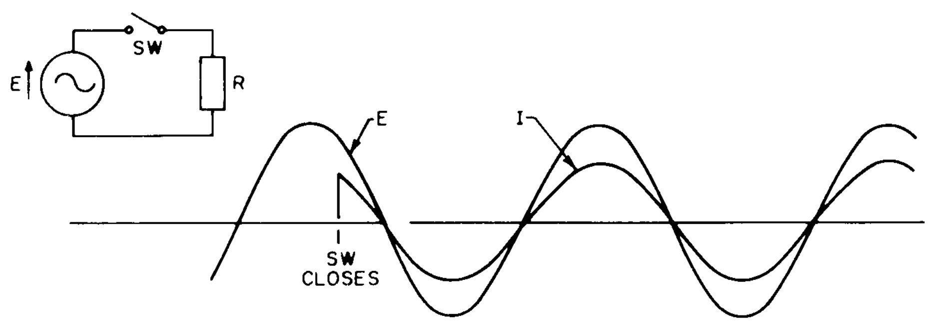


Figure 4-3—Switching Transient R

In the case of all inductance *L* (figure 4-4), an understanding of the switching transient can best be acquired using the following expression:

$$E = L\frac{dI}{dt}, \frac{dI}{dt} = \frac{E}{L}$$

This expression tells us that the application of a driving voltage to an inductance will create a time rate of change in the current magnitude. The slope of the current-time curve in the inductance will be equal to the quantity *E*/*L*.

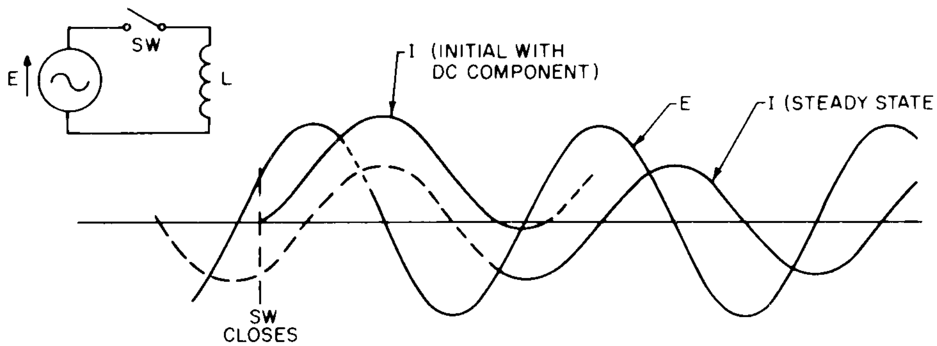


Figure 4-4—Switching transient L

The steady-state current curve is displayed at the right hand side of the graph of figure 4-4. It lags the voltage wave by 90° and is rising at the maximum rate in the positive direction when the voltage is at the maximum positive value. It holds at a fixed value when the driving voltage is zero. This curve is projected back to the time of circuit switching (dashed curve). Note that at the instant the switch is closed, the steady-state current would have been at a negative value of about 90% of crest value. Since the switch was previously open, the true circuit current must be zero. After closing the switch, the current wave will display the same slope as the steady-state wave. This is the solid line current curve beginning at the instant of switch closing. Note that the difference between this curve and the steady state is a positive dc component of the same magnitude that the steady-state wave would have had at the instant of switch closing, in the negative direction. Thus the switching transient takes the form of a dc component whose value may be anything between zero and the steady-state crest value, depending on the angle of switch closing.

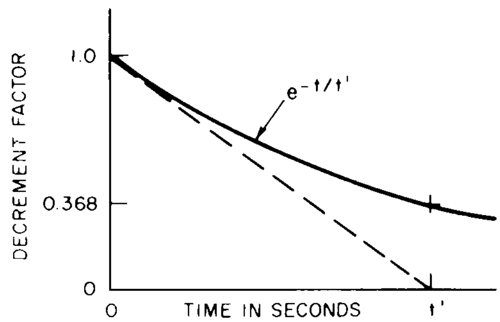
If the circuit contained no resistance, the current would continue forever in the displaced form. The presence of resistance causes the dc component to be dissipated exponentially. The complete expression for the current would take the following form:

$$I = \frac{E}{j\omega L}\sin(\omega t) + I_{dc}e^{(-Rt)/L}$$

The presence of dc components may introduce unique problems in selective coordination between some types of overcurrent devices. It is particularly important to bear in mind that these transitory currents are not disclosed by the vector impedance circuit solution, but must be introduced artificially by the analyst or by the guide rules followed.

4.4.3 Decrement factor

The value at any time of a decaying quantity, expressed in per unit of its initial magnitude, is the decrement factor for that time. Refer to figure 4-5 for decrement factors of an exponential decay.



$e^{-Rt/L} = e^{-t/t'}$
$t' = L/R$ (TIME CONSTANT)

Figure 4-5—Decrement factor

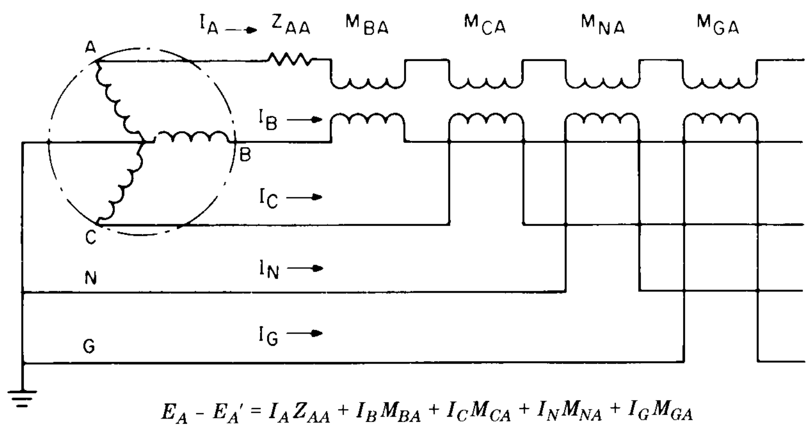
The significance of the decrement factor can be better understood if the exponential is expressed in terms of the time constant. If, as indicated in figure 4-5, the exponent is expressed as $-t/t'$ with the time variable t in the numerator and the rest combined as a single constant t' (called the time constant) in the denominator, the transitory quantity begins its decay at a rate that would cause it to vanish in one time constant. The exponential character of the decay results in a remnant of 36.8% remaining after an elapsed time equal to one time constant. Any value of the transitory term selected at, say, time t will be reduced to 0.368 of that value after a subsequent elapsed time equal to one time constant. A transitory quantity of magnitude 1.0 at time zero would be reduced to a value of 0.368 after an elapsed time equal to one time constant, to a value of 0.135 after an elapsed time equal to two time constants, and to a value of 0.05 after an elapsed time equal to three time constants.

4.4.4 Multiple switching transients

The analyst usually assumes that the switching transient will occur only once during one excursion of short-circuit current flow. An examination of representative oscillograms of short-circuit currents will often display repeated instances of momentary current interruptions. At times, an entire half cycle of current will be missing. In other cases, especially in low-voltage circuits, there may be a whole series of chops and jumps in the current pattern. A switching interrupter, especially when switching a capacitive circuit, may be observed to restrike two or perhaps three times before final interruption. The restrike generally occurs when the voltage across the switching contacts is high. It is entirely possible that switching transients, both simple dc and ac transitory oscillations, may be reinserted in the circuit current a number of times during a single incident of short-circuit current flow and interruption. The analyst should remain mindful of possible trouble.

4.4.5 Practical impedance network synthesis

One approach to an adequate procedure for computing the phase A current of a three-phase system is indicated in figure 4-6. For each physical conducting circuit, the voltage drop is represented as the sum of the self-impedance drops in the circuit and the complete array of mutually coupled voltage drops caused by current flow in other coupled circuits. The procedure is complex even in those instances where the current in both the neutral and ground conductors is zero.



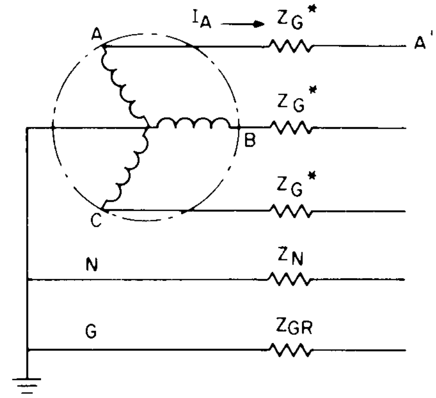
$$E_A - E_A' = I_A Z_{AA} + I_B M_{BA} + I_C M_{CA} + I_N M_{NA} + I_G M_{GA}$$

Figure 4-6—Three-phase, four-wire circuit, unbalanced loading

The simplified analytical approach to this problem assumes balanced symmetrical loading of a symmetrical polyphase system. With a symmetrical system operating with a symmetrical loading, the effects of all mutual couplings are similarly balanced. What is happening in phase A in the way of self- and mutually coupled voltages is also taking place in phase B with exactly the same pattern, except displaced 120°, and it is also taking place in phase C with the same pattern, except displaced another 120°. The key to the simplification is the fact that the ratio of the total voltage drop in one phase circuit to the current in that phase circuit is the same in all three phases of the system. Thus it appears that each phase possesses a firm impedance value common with the other phases. This unique impedance quantity is identified as the single phase line-to-neutral impedance value. Any one line-to-neutral single phase segment of the system may be sliced out for the analysis, since all are operating with the same load pattern.

The impedance diagram of the simplified concept appears in figure 4-7. The need to deal with mutual coupling has vanished. Since each phase circuit presents identically the same information, it is common to show only a single phase segment of the system in a one line diagram as illustrated simply by figure 4-1. The expressions below the sketch in figure 4-7 contain some unfamiliar terms. Their meaning will be discussed in succeeding paragraphs.

One restraint associated with this simple analytical method is that all phases of the system share symmetrical loading. While a three-phase short circuit would satisfy this restraint, some short-circuit problems that must be solved are not balanced. For these unbalanced short-circuit problems, the concept of symmetrical components is used for solution. This concept discloses that any conceivable condition of unbalanced loading can be correctly synthesized by the use of appropriate magnitudes and phasing of several systems of symmetrical loading. In a three-phase system, with a normal phase separation of 120°, there are just three



Impedance identity for each symmetrical pattern:

Positive sequence	Z_{G1}
Negative sequence	Z_{G2}
Zero sequence	$Z_{G0} + 3Z_{GR}$ *

* Based on zero current in conductor N.

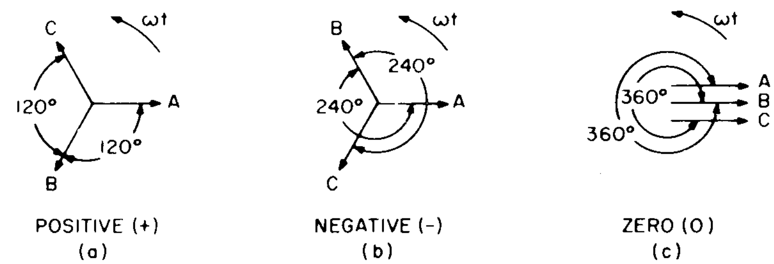
$$E_A - E_A' = I_{A1}\, Z_{G1} + I_{A2}\, Z_{G2} + I_{A0}\, (Z_{G0} + 3Z_{GR})$$

Figure 4-7—Three-phase, four-wire circuit, balanced symmetrical loading

possible symmetrical loading patterns. These can be quickly identified with the aid of figure 4-8. Loadings of the three-phase windings A, B, and C must follow each other in sequence, separated by some multiple of 120°. In figure 4-8(a) they follow each other with a 120° separation, in figure 4-8(b) with a 240° separation, and in figure 4-8(c) with a 360° separation. Note that separation angles of any other multiples of 120° will duplicate one of the three already shown. These loading patterns satisfy the restraints demanded by the analytical method to be used.

Note that figure 4-8(a), identified as the positive sequence, represents the normal balanced operating mode. Thus there are only two sequence networks that differ from the normal. Figure 4-8(b), called the negative sequence, identifies a loading pattern very similar to the positive sequence, except that the electrical quantities come up with the opposite sequence. A current of this pattern flowing in a motor stator winding would create a normal speed rotating field, but with backward rotation. The pattern of figure 4-8(c), called the zero sequence, represents the case in which the equal currents in each phase are in phase. Each phase current reaches its maximum in the same direction at the same instant.

It is understandable that machine interwinding mutual coupling and other mutual coupling effects will be different in the different sequence systems. Hence it is likely that the per phase impedance of the negative and zero sequence systems will differ from that of the positive sequence. Currents of zero sequence, being in phase, do not add up to zero at the end terminal as do both the positive and negative sequence currents. They add arithmetically and return to



The individual phase quantities *A*, *B*, and *C* follow each other with an angular spacing of

Positive sequence	120°
Negative sequence	240°
Zero sequence	360°

Figure 4-8—Three-phase symmetrical load patterns applicable to a three-phase system

the source via an additional circuit conductor. The zero-sequence voltage drop of this return conductor is accounted for in the zero-sequence impedance value. With this understanding of the three symmetrical loading patterns, the significance of the notes below the sketch in figure 4-7 becomes clear.

The simplifications in analytical procedures accomplished by the per-phase line-to-neutral balanced system concepts carry with them some important restraints:

a) The electric power system components shall be of symmetrical design pattern.
b) The electric loading imposed on the system shall be balanced and symmetrical.

Wherever these restraints are violated, it is necessary to construct substantially hybrid network interconnections that bridge the zones of unbalanced conditions. In the field of short-circuit current calculations, the necessary hybrid interconnections of the sequence networks to accommodate the various unbalanced fault connections can be found in a variety of published references. It is harder to find the necessary hybrid interconnections to accommodate a lack of symmetry in the circuit geometry, as needed for an open delta transformer bank, an open line conductor, etc.

4.4.6 Other analytical tools

A large number of valid network theorems can be used effectively to simplify certain kinds of problems encountered in short-circuit analysis. These are described and illustrated in many standard texts on ac circuit analysis; see Chapter 8 of IEEE Std C37.13-1990[1]. Of exceptional importance are Thevenin's theorem and the superposition theorem. Thevenin's theorem allows an extensive complex single-phase network to be reduced to a single driving voltage in series with a single impedance, referred to the particular bus under study. The superposition

[1]Information on references can be found in 4.9.

theorem allows the local effect of a remote voltage change in one source machine to be evaluated by impressing the magnitude of the voltage change, at its point of origin, on the complete impedance network; the current reading in an individual circuit branch is treated as an adder to the prior current magnitude in that branch. These analytical tools, like the others, have specific restraints that must be observed to obtain valid results.

4.4.7 Respecting the imposed restraints

Throughout this discussion, emphasis has been placed on the importance of respecting the restraints imposed by the analytical procedure in order to obtain valid results. Mention has been made of numerous instances in short-circuit analysis where it is necessary to artificially introduce appropriate corrections when analytical restraints have been violated. One remaining area associated with short-circuit analysis involves variable impedance coefficients. When an arc becomes a series component of the circuit impedance, the *R* it represents is not constant. If it is 100 Ω at a current of 1 A, it might be 0.1 Ω at a current of 1000 A. During each half-cycle of current flow, the arc resistance might traverse this range. It is difficult to determine a proper value to insert in the 60 Hz network. Correctly setting this value of *R* does not compensate for the violation of the restraint that demands that *R* be a constant. The variation in *R* lessens the impedance to high-magnitude current, which results in a wave shape of current that is much more peaked than a sine wave. The current now contains harmonic terms. Since they result from a violation of analytical restraints, they will not appear in the calculated results. Their character and magnitude can be determined by other means and the result artificially introduced into the solution for short-circuit current. A similar type of nonlinearity may be encountered in electromagnetic elements in which iron plays a part in setting the value of *L*. If the ferric parts are subject to large excursions of magnetic density, the value of *L* may be found to drop substantially when the flux density is driven into the saturation region. As with variable *R,* the effect of this restraint violation will result in the appearance of harmonic components in the true circuit current.

4.4.8 Conclusions

The purpose of this review of fundamentals is to obtain a better understanding of the basic complexities involved in ac system short-circuit current calculations. In dealing with the day-to-day practical problems, the analyst should adopt the following goals:

a) Select the optimum location and type of fault to satisfy the purpose of the calculation.
b) Establish the simplest electric circuit model of the problem that will both accomplish this purpose and minimize the complexity of the solution.
c) Recognize the presence of system conditions that violate the restraints imposed by the analytical methods in use.
d) Artificially inject corrections in computed results to compensate if these conditions are large enough to be significant.

Some conclusions of the preceding section apply to the simplified procedures of this chapter. A balanced three-phase fault has been assumed and a simple equivalent circuit has been described. The current *E*/*Z* calculated with the equivalent circuit is an alternating symmetrical rms current, because *E* is the rms voltage. Within specific constraints to be discussed, this symmetrical current may be directly compared with equipment ratings, capabilities, or performance characteristics that are expressed as symmetrical rms currents.

The preceding analysis of inductive circuit switching transients indicates that simplified procedures should recognize and account for asymmetry as a system condition. The correction to compensate for asymmetry considers the asymmetrical short-circuit current wave to be composed of two components. One is the ac symmetrical component *E*/*Z*. The other is a dc component initially of maximum possible magnitude, equal to the peak of the initial ac symmetrical component, or, alternatively, of the magnitude corresponding to the highest peak (crest), assuming that the fault occurs at the point on the voltage wave where it creates this condition. At any instant after the fault occurs, the total current is equal to the sum of the ac and dc components (figure 4-9).

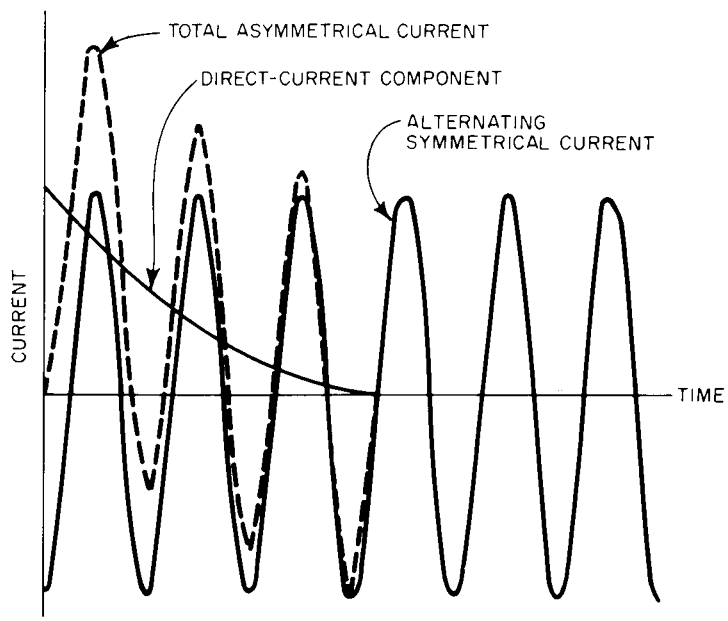


Figure 4-9—Typical system fault current

Since resistance is always present in an actual system, the dc component decays to zero as the stored energy it represents is expended in I^2R loss. The decay is assumed to be an exponential, and its time constant is assumed to be proportional to the ratio of reactance to resistance (*X*/*R* ratio) of the system from source to fault. As the dc component decays, the current gradually changes from asymmetrical to symmetrical (figure 4-9).

Asymmetry is accounted for in simplified calculating procedures by applying multiplying factors to the alternating symmetrical current. A multiplying factor is selected that obtains a resulting estimate of the total (asymmetrical) rms current or the peak (crest) current, as appropriate for comparison with equipment ratings, capabilities, or performance characteristics that are expressed as total (asymmetrical) rms currents or peak (crest) currents.

The alternating symmetrical current may also decay with time, as indicated in the discussion of sources of short-circuit current. Changing the impedance representing the machine properly accounts for ac decay of the current to a short circuit at rotating-machine terminals. The same impedance changes are assumed to be applicable when representing rotating machines in extensive power systems.

4.5 Detailed procedure

A significant part of the preparation for a short-circuit current calculation is establishing the impedance of each circuit element and converting impedances to be consistent with each other for combination in series and parallel. Sources of impedance values for circuit elements are nameplates, handbooks, manufacturers' catalogs, tables included in this chapter, and direct contact with the manufacturer.

Two established consistent forms for expressing impedances are ohms and per unit (per unit differs from percent by a factor of 100). Individual equipment impedances are often given in percent, which makes comparisons easy, but percent impedances are rarely used without conversion in system calculations. In this chapter, the per unit form of impedance is used because it is more convenient than the ohmic form when the system contains several voltage levels. Impedances expressed as per unit on a defined base can be combined directly, regardless of how many voltage levels exist from source to fault. To obtain this convenience, the base voltage at each voltage level must be related according to the turns ratios of the interconnecting transformers.

In the per-unit system, there are four base quantities: base apparent power in voltamperes, base voltage, base current, and base impedance. The relationship of base, per unit, and actual quantities is as follows:

$$\text{per-unit quantity (voltage, current, etc.)} = \frac{\text{actual quantity}}{\text{base quantity}}$$

Usually a convenient value is selected for base apparent power in voltamperes, and a base voltage at one level is selected to match the transformer rated voltage at that level. Base voltages at other levels are then established by transformer turns ratios. Base current and base impedance at each level are then obtained by standard relationships. The following formulas apply to three-phase systems, where the base voltage is the line-to-line voltage in volts or kilovolts and the base apparent power is the three-phase apparent power in kilovoltamperes or megavoltamperes:

$$\text{base current (amperes)} = \frac{\text{base kVA (1000)}}{\sqrt{3}\ \text{(base V)}} = \frac{\text{base kVA}}{\sqrt{3}\ \text{(base kV)}}$$

$$= \frac{\text{base MVA } 10^6}{\sqrt{3}\ \text{(base V)}} = \frac{\text{base MVA (1000)}}{\sqrt{3}\ \text{(base kV)}}$$

$$\text{base impedance (ohms)} = \frac{\text{base V}}{\sqrt{3}\ (\text{base A})} = \frac{(\text{base V})^2}{\text{base kVA (1000)}}$$

$$= \frac{(\text{base kV})^2(1000)}{\text{base kVA}} = \frac{(\text{base kV})^2}{\text{base MVA}}$$

Impedances of individual power system elements are usually obtained in forms that require conversion to the related bases for a per-unit calculation. Cable impedances are generally expressed in ohms. Converting to per unit using the indicated relationships leads to the following simplified formulas, where the per-unit impedance is Z_{pu}:

$$Z_{pu} = \frac{\text{actual impedance in ohms ((base MVA)}}{(\text{base kV})^2}$$

$$= \frac{\text{actual impedance in ohms (base kVA)}}{(\text{base kV})^2(1000)}$$

Transformer impedances are in percent of self-cooled transformer ratings in kilovoltamperes and are converted using the following:

$$Z_{pu} = \frac{\text{percent impedance (base kVA)}}{\text{kVA rating (100)}}$$

$$= \frac{\text{percent impedance (10) (base MVA)}}{\text{kVA rating}}$$

Motor reactance may be obtained from tables providing per unit reactances on element ratings in kilovoltamperes and are converted using the following:

$$X_{pu} = \frac{\text{per-unit reactance (base kVA)}}{\text{kVA rating}}$$

The procedure for calculating industrial system short-circuit currents consists of the following steps:

a) Step 1: Prepare system diagrams
b) Step 2: Collect and convert impedance data
c) Step 3: Combine impedances
d) Step 4: Calculate short-circuit current

Each step will be discussed in further detail in the following subclauses.

4.5.1 Step 1: Prepare system diagrams

A one-line diagram of the system should be prepared to show all sources of short-circuit current and all significant circuit elements. Figure 4-10, used for a subsequent example, is a one-line diagram of a hypothetical industrial system.

Impedance information may be entered on the one-line diagram after initial data collection and after conversion. Sometimes it is desirable to prepare a separate diagram showing only the impedances after conversion. If the original circuit is complex and several steps of simplification are required, each may be recorded on additional impedance diagrams as the calculation progresses.

The impedance diagram might show reactances only or it might show both reactances and resistances if a vector calculation is to be made. For calculation of a system *X*/*R* ratio, as described later for high-voltage circuit breaker duties, a resistance diagram showing only the resistances of all circuit elements shall be prepared.

4.5.2 Step 2: Collect and convert impedance data

Impedance data, including both reactance and resistance, should be collected for important elements and converted to per-unit on bases selected for the study. See annex 4A at the end of this chapter for typical values.

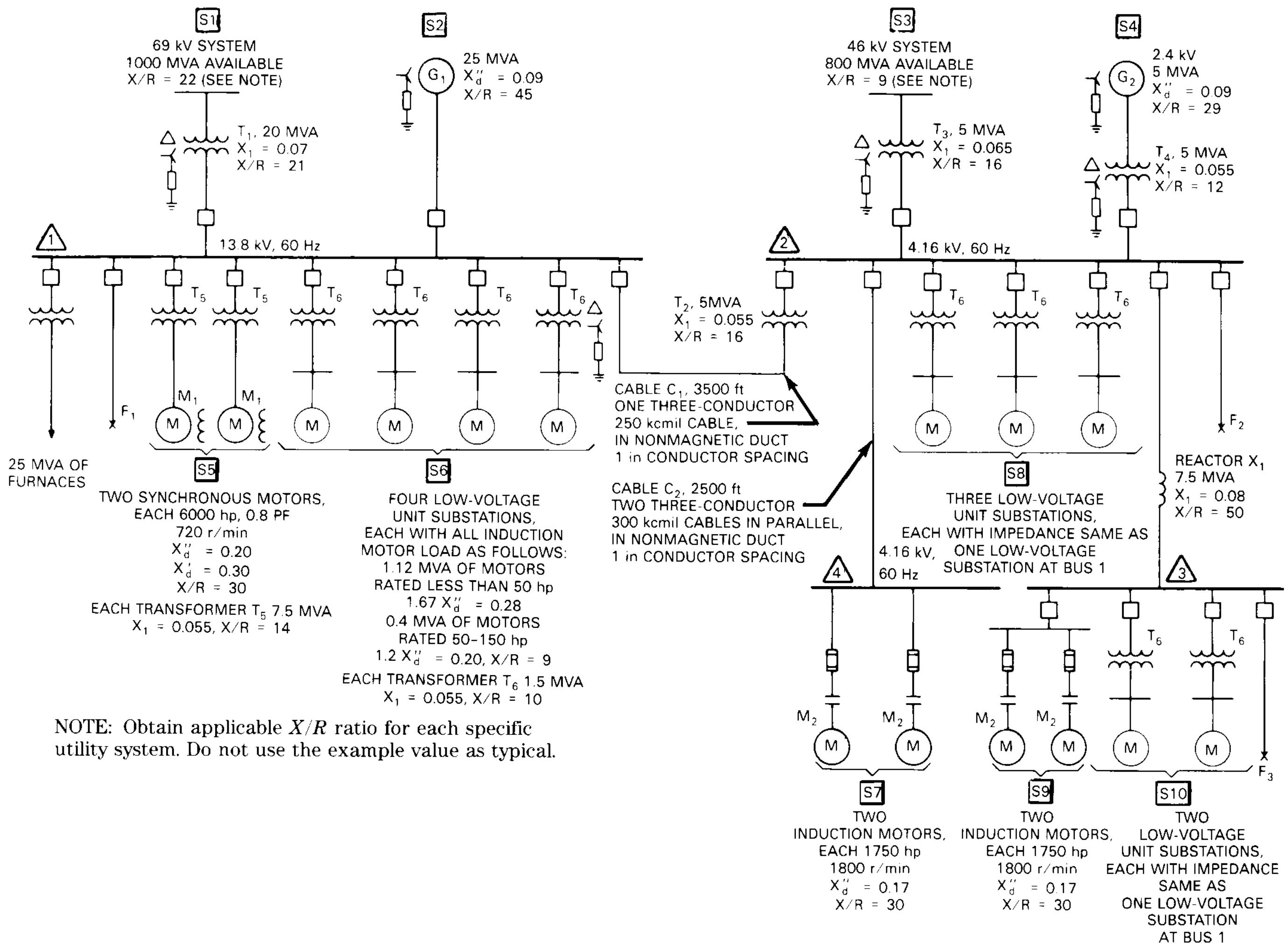
Since resistance is not constant but varies with temperature, consideration should be given to the choice of resistance values for study purposes.

For calculations of maximum short-circuit currents to select electric power system equipment, a fully loaded industrial power system is recommended because it has the largest number of motors connected and contributing to short-circuit current. Consequently, "hot" or rated load resistance values are usually accepted for these calculations. The collected data in annex 4A reflect this acceptance; for example, machine *X*/*R* ratios are at rated load, overhead line resistances are at 50 °C, and cable resistances are at 75 °C and 90 °C.

These "hot" resistance values are also acceptable as conservative impedance data for load flows and similar calculations where probable maximum voltage drops and losses are desired results. This multiple usage provides a simplification of data preparation.

There is a concern that system operations at less than full load could reduce equipment and component temperatures, thus lowering resistances and increasing maximum short-circuit currents calculated using impedances. This does not happen in most cases for industrial systems because the reduction in connected motors, at the reduced load and thus in motor contribution to the calculated short-circuit current, more than offsets the possible increase due to reduced resistance and increased *X*/*R* ratio.

In addition, for industrial systems where relatively high values of short-circuit current are expected, the short-circuit point reactance is generally much larger than the resistance and,



NOTE: Obtain applicable X/R ratio for each specific utility system. Do not use the example value as typical.

Figure 4-10—One-line diagram of industrial system example

due to the quadrature relationship of X and R, a possibly justifiable reduction in "hot" resistance values usually makes no significant difference in fault point impedance.

The effect of reduced resistance at reduced temperature should be examined in particular cases not covered by the general procedures of this chapter. For example, the calculation of the short-circuit current of an individual generator just being energized, before it takes load, should use ambient temperature resistance and X/R ratios for a conservative result. For industrial plant office buildings, and for other facilities with largely non-motor loads, full load might be applied without delay at start-up and calculations should account for pre-start-up temperatures of components and their resistances. For a low-voltage short circuit at the end of a feeder from a substation to a non-motor load, where the resistance of the feeder circuit is significant in determining short-circuit current magnitude, it may be appropriate to assume a no-load feeder conductor temperature and resistance to calculate a maximum current.

4.5.3 Step 3: Combine impedances

The third step is to combine reactances or vector impedances, and resistances where applicable, to the point of fault into a single equivalent impedance, reactance, or resistance. The equivalent impedance of separate impedances in series is the sum of the separate impedances. The equivalent impedance of separate impedances in parallel is the reciprocal of the sum of the reciprocals of the separate impedances. Three impedances forming a wye or delta configuration can be converted by the following formulas for further reduction (figure 4-11).

a) Wye to delta [figure 4-11(a)]:

$$A = \frac{b \cdot c}{a} + b + c$$

$$B = \frac{a \cdot c}{b} + a + c$$

$$C = \frac{a \cdot b}{c} + a + b$$

b) Delta to wye [figure 4-11(b)]:

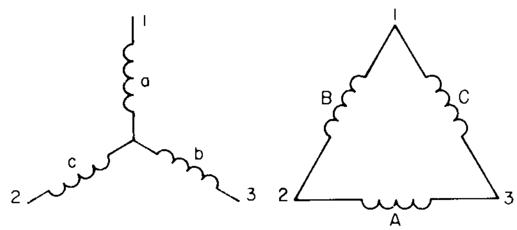
$$a = \frac{B \cdot C}{A + B + C}$$

$$b = \frac{A \cdot C}{A + B + C}$$

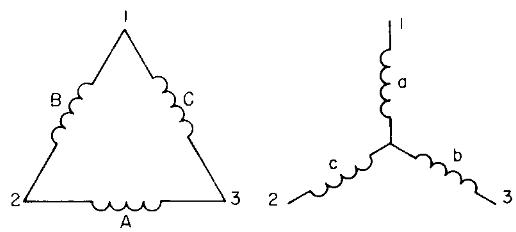
$$c = \frac{A \cdot B}{A + B + C}$$

4.5.4 Step 4: Calculate short-circuit current

The final step is to calculate the short-circuit current. Calculation details are influenced by the system nominal voltage or voltages and the results desired.



a) Wye to delta



b) Delta to wye

Figure 4-11—Wye and delta configurations

It should be noted that nominal system voltages according to ANSI C84.1-1989 are as follows:

a) Low voltage—less than 1000 V
b) Medium voltage—equal to or greater than 1000 V and less than 100 000 V
c) High voltage—equal to or greater than 100 000 V and equal to or less than 230 000 V

IEEE high-voltage circuit breaker standards, IEEE Std C37.010-1979 and IEEE Std C37.5-1979, define high-voltage circuit breakers as those rated above 1000 V, so these standards cover calculating short-circuit currents for circuit breaker applications in both medium- and high-voltage systems. The results of these calculations are also usable when applying medium- and high-voltage fuses.

This chapter examines three basic networks of selected impedances used for the results most commonly desired:

a) First-cycle duties for fuses and circuit breakers
b) Contact-parting (interrupting) duties for medium- and high-voltage circuit breakers
c) Short-circuit currents at operating times for time-delayed relaying devices

The three networks have the same basic elements except for the impedances of rotating machines. These depend on the purpose of the study. Where interrupting equipment applications are the purpose of the calculation, the differing impedances are based on standard application guides.

4.5.4.1 First-cycle duties for fuses and circuit breakers

For calculations of short-circuit duties to be compared with the interrupting ratings of low-, medium-, or high-voltage fuses or of only low-voltage circuit breakers (according to ANSI C97.1-1972, IEEE Std C37.13-1981, IEEE Std C37.41-1981, NEMA AB 1-1975, and NEMA SG 3-1981), unmodified or modified subtransient impedances are used to represent all rotating machines in the equivalent network.

Low-voltage duties. The standards for interrupting equipment allow a modified subtransient reactance for a group of low-voltage induction and synchronous motors fed from a low-voltage substation. If the total of motor horsepower ratings at 480 or 600 V is approximately equal to (or less than) the transformer self-cooled rating in kilovoltamperes, a reactance of 0.25 per unit based on the transformer self-cooled rating may be used as a single impedance to represent the group of motors.

Medium- and high-voltage short-circuit duties calculated with these impedances are used when applying medium- or high-voltage fuses and when finding medium- or high-voltage system available short-circuit duties for use as factors in subsequent low-voltage calculations.

M*edium- and high-voltage duties*. For calculations of short-circuit duties to be compared with only medium- or high-voltage circuit breaker closing and latching capabilities according to IEEE Std C37.010-1979 (post-1964 rating basis) or momentary ratings according to the withdrawn standard, IEEE Std C37.5-1979 (pre-1964 rating basis), multiplying factors shown in the first cycle column of Table 4-1 are applied to rotating machine reactances (or impedances). For motors, this approximates the ac decay during the first cycle of motor short-circuit current contribution.

The preceding description indicates that the different treatments of induction motors might uneconomically necessitate two first-cycle calculations for comprehensive industrial system short-circuit studies covering both low and high (including medium) voltages, if procedures of applicable standards are followed without interpretation. The high- (including medium-) voltage circuit breaker application procedure described in IEEE Std C37.010-1979 and IEEE Std C37.5-1979 defines three induction motor size groups, recommends omitting the group of motors each less than 50 hp, and applies multiplying factors of 1.2 or 1.0 to subtransient impedances of motors in the groups of larger and larger sizes. The low-voltage circuit breaker application guide, IEEE Std C37.13-1981, recommends subtransient impedances (typically 0.16 to 0.20 per unit) for all motors and allows estimates of typical symmetrical first-cycle contributions from connected low-voltage motors to substation bus short circuits at 4 times rated current (the equivalent of 0.25 per unit impedance).

The *4 times rated current* short-circuit contribution estimate is determined approximately in the low-voltage circuit breaker application guide, IEEE Std C37.13-1981, by assuming a typical connected group having 75% induction motors at 3.6 times rated current and 25% synchronous motors at 4.8 times rated. Other typical group assumptions could be made; for

Table 4-1—Rotating-machine reactance (or impedance) multipliers

Type of rotating machine	First-cycle network	Interrupting network
All turbine generators; all hydrogenerators with amortisseur windings; all condensers	1.0 X_d''	1.0 X_d''
Hydrogenerators without amortisseur windings	0.75 X_d'	0.75 X_d'
All synchronous motors	1.0 X_d''	1.5 X_d''
Induction motors		
Above 1000 hp at 1800 r/min or less	1.0 X_d''	1.5 X_d''
Above 250 hp at 3600 r/min	1.0 X_d''	1.5 X_d''
All others, 50 hp and above	1.2 X_d''	3.0 X_d''
All smaller than 50 hp	neglect	neglect

Source: Based on IEEE Std C37.010-1979 and IEEE Std C37.5-1979.

example, many groups now have larger size low-voltage induction motors instead of synchronous motors, but these larger motors also have higher and longer lasting short-circuit current contributions. Accordingly, a *4 times rated current* approximation continues to be accepted practice when the load is all induction motors of unspecified sizes.

Combination first-cycle network. To simplify comprehensive industrial system calculations, a single combination first-cycle network is recommended to replace the two different networks just described. It is based on the following interpretation of IEEE Std C37.010-1979, IEEE Std C37.5-1979, and IEEE Std C37.13-1990. Because the initial symmetrical rms magnitude of the current contributed to a terminal short circuit might be 6 times rated for a typical induction motor, using a *4.8 times rated current* first-cycle estimate for the large low-voltage induction motors (described as *all others, 50 hp and above* in Table 4-1) is effectively the same as multiplying subtransient impedance by approximately 1.2. For this motor group, there is reasonable correspondence of low- and high-voltage procedures. For smaller induction motors (*all smaller than 50 hp* in Table 4-1) a conservative estimate is the *3.6 times rated current* (equivalent of 0.28 per unit impedance) first-cycle assumption of low-voltage standards, and this is effectively the same as multiplying subtransient impedance by 1.67.

With this interpretation as a basis, the following induction motor treatment is recommended to obtain a single-combination first-cycle short-circuit calculation for multivoltage industrial systems:

a) Include connected motors, each less than 50 hp, using either a 1.67 multiplying factor for subtransient impedances, if available, or an estimated first-cycle impedance of 0.28 based on motor rating.

b) Include larger motors using the impedance multiplying factors of Table 4-1. Most low-voltage motors 50 hp and larger are in the 1.2 times subtransient reactance group. An appropriate estimate for this group is first-cycle impedance of 0.20 per unit based on motor rating.

The last two lines of Table 4-1 are replaced by Table 4-2 for the recommended combination network.

The single-combination first-cycle network adds conservatism to both low- and high-voltage standard calculations. It increases calculated first-cycle short-circuit currents at high voltage by the contributions from small induction motors and at low voltage, when many motors are 50 hp or larger, by the increased contribution of larger low-voltage induction motors.

Table 4-2—Combined network rotating machine reactance (or impedance) multipliers
(changes to table 4-1 for comprehensive multivoltage system calculations)

Type of rotating machine	First-cycle network	Interrupting network
Induction motors		
All others, 50 hp and above	$1.2\ X_d''$ *	$3.0\ X_d''$ †
All smaller than 50 hp	$1.67\ X_d''$ ‡	neglect

*Or estimate the first-cycle network $X = 0.20$ per unit based on motor rating.
†Or estimate the interrupting network $X = 0.50$ per unit based on motor rating.
‡Or estimate the first-cycle network $X = 0.28$ per unit based on motor rating.

Once the first-cycle network has been established and its impedances are converted and reduced to a single equivalent per-unit impedance Z_{pu} (or reactance X_{pu}) for each fault point of interest, the symmetrical short-circuit current duty is calculated by dividing the per-unit prefault operating voltage E_{pu} by Z_{pu} (or X_{pu}) and multiplying by base current:

$$I_{\text{sc sym}} = \frac{E_{pu}}{Z_{pu}} \cdot I_{\text{base}}$$

where $I_{\text{sc sym}}$ is a three-phase symmetrical first cycle bolted short-circuit (zero impedance at the short-circuit point) rms current.

The calculated short-circuit current results for low-voltage buses are now directly applicable for comparison with low-voltage circuit breakers, fuses, and other equipment short-circuit ratings or capabilities expressed as symmetrical rms currents. For low-voltage circuit breakers, ratings incorporate an asymmetrical capability as necessary for a circuit *X*/*R* ratio of 6.6 or less (short-circuit power factor of 15% or greater). A typical system served by a transformer rated 1000 or 1500 kVA will usually have a short-circuit *X*/*R* ratio within these limits. For larger or multitransformer systems, it is advisable to check the *X*/*R* ratio; if it is greater than 6.6, the circuit breaker or fuse application should be based on asymmetrical current limitations (see IEEE Std C37.13-1990).

When the equipment rating or capability is expressed as a first-cycle total (asymmetrical) rms current, or first-cycle crest current, the calculated symmetrical short-circuit current duty is multiplied by a corresponding multiplying factor found in the applicable standard to obtain the appropriate first-cycle total (asymmetrical) rms current duty, or first-cycle crest current duty, for comparison.

Closing and latching capabilities of high-voltage circuit breakers preferred before 1987 (or momentary ratings of older units) are total (asymmetrical) rms currents. The appropriate calculated first-cycle duty for comparison is obtained using the 1.6 multiplier specified in IEEE Std C37.010-1979 and IEEE Std C37.5-1979 and the fault point reactance X_{pu} (or impedance Z_{pu}) obtained by network reduction:

$$I_{\text{sc tot}} = 1.6 \cdot \frac{E_{pu}}{X_{pu}} \cdot I_{\text{base}}$$

where $I_{\text{sc tot}}$ is the maximum total (asymmetrical) rms magnitude of the current with highest asymmetry during the first cycle of a three-phase bolted (zero impedance at the short-circuit point) short circuit.

Closing and latching capabilities of high-voltage circuit breakers preferred after 1987 are crest currents. The appropriate calculated first-cycle duty for comparison is obtained using the 2.7 multiplier specified in IEEE Std C37.010-1979 and the fault point reactance X_{pu} (or impedance Z_{pu} obtained by network reduction:

$$I_{\text{sc crest}} = 2.7 \cdot \frac{E_{pu}}{X_{pu}} \cdot I_{\text{base}}$$

where $I_{\text{sc crest}}$ is the maximum possible crest for one of the currents during the first cycle of a three-phase bolted (zero impedance at the short-circuit point) short circuit.

4.5.4.2 Contact-parting (interrupting) duties for high-voltage (above 1 kV, including medium-voltage) circuit breakers

First considered are the duties for comparison with interrupting ratings of older circuit breakers rated on the pre-1964 total rms current rating basis. The procedures of IEEE Std C37.5-1979 apply.

The multiplying factors for reactances of rotating machines in the network are obtained from the "Interrupting network" columns of tables 4-1 and 4-2.

For these interrupting duty calculations, the resistance (*R*) network is also necessary. In the resistance network, each rotating machine resistance value must be multiplied by the factor from table 4-1 that was used to modify the corresponding rotating machine reactance.

At the point of short circuit, reduce the reactance network to a single equivalent reactance X_{pu} and reduce the resistance network to a single equivalent resistance R_{pu}. Determine the X/R ratio by dividing X_{pu} by R_{pu}; determine E_{pu}, the prefault operating voltage; and determine E/X by dividing E_{pu} by X_{pu}.

Select the multiplying factor for E/X correction from the curves of figures 4-12 and 4-13. To use the curves, it is necessary to know the circuit breaker contact parting time as well as the proximity of generators to the point of short circuit (local or remote). Local generator multiplying factors apply only when generators that are predominant contributors to short-circuit currents are located in close electrical proximity to the fault as defined in the caption of figure 4-12 (and figure 4-14).

Minimum contact parting times are usually used and are defined in table 4-3.

Multiply E_{pu}/X_{pu} by the multiplying factor and the base current:

$$\text{multiplying factor} \cdot \frac{E_{pu}}{X_{pu}} \cdot I_{base}$$

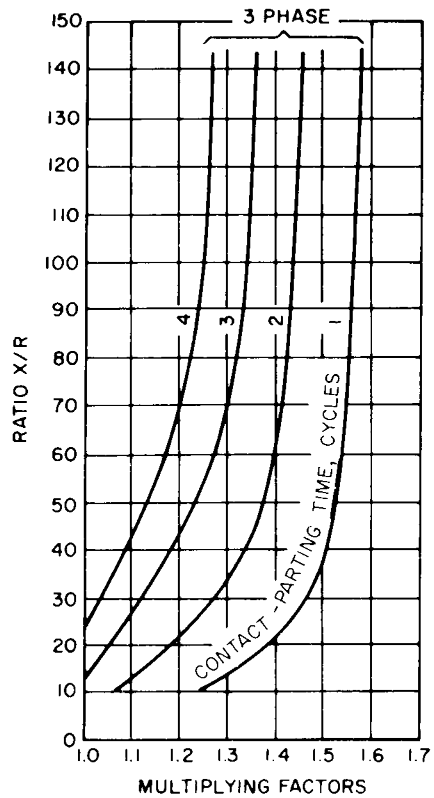
This is the three-phase, contact-parting time, bolted (zero impedance at the short-circuit point), *calculated, total (asymmetrical), rms short-circuit-current interrupting duty* to be compared with the circuit-breaker interrupting capability. For older circuit breakers with total three-phase interrupting ratings in MVA, the short-circuit-current capability in kA is found by dividing the rating in MVA by $\sqrt{3}$ and by the operating voltage in kV when the voltage is between the rated maximum and minimum limits.

$$\text{asymmetrical interrupting capability in kA} = \frac{\text{interrupting rating in MVA}}{\sqrt{3} \cdot \text{operating voltage in kV}}$$

The minimum-limit voltage calculation applies for lower voltages.

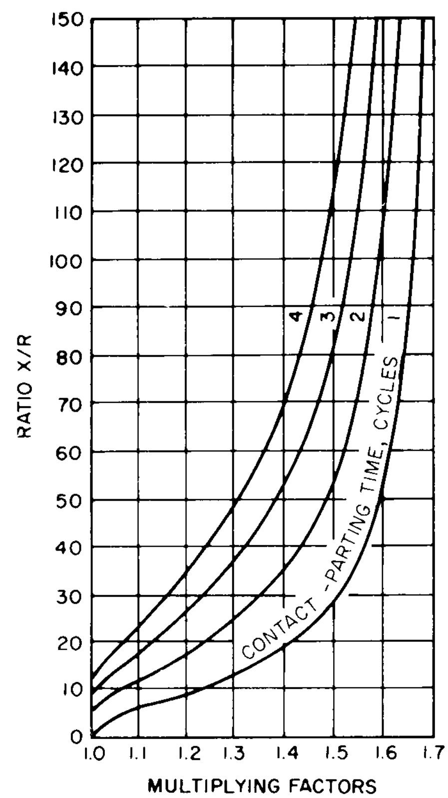
Next, consider the duties for comparison with the short-circuit (interrupting) capabilities of circuit breakers rated on the post-1964 symmetrical rms current basis. Procedures specified in IEEE Std C37.010-1979 apply to calculating duties for these circuit breakers.

E/X and the X/R ratio for a given fault point are as already calculated.



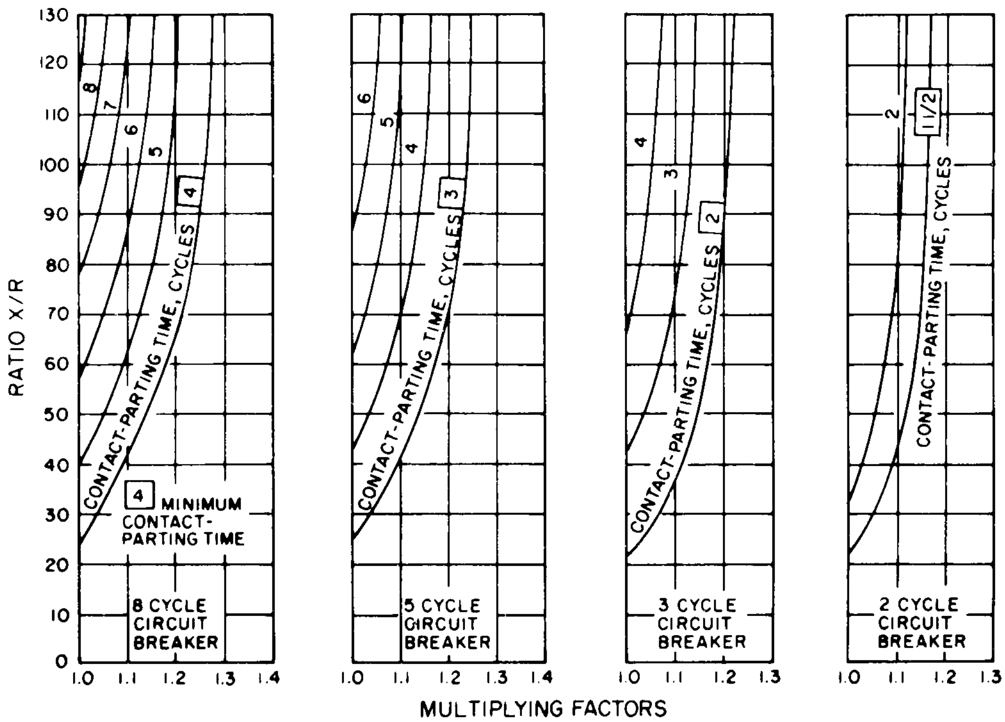
NOTE: Fed predominantly from generators through no more than one transformation or with external reactance in series that is less than 1.5 times generator subtransient reactance (IEEE Std C37.5-1979).

Figure 4-12—Multiplying factors (total current rating basis) for three-phase faults (local)



NOTE: Fed predominantly through two or more transformations or with external reactance in series equal to or above 1.5 times generator subtransient reactance (IEEE Std C37.5-1979).

Figure 4-13—Multiplying factors (total current rating basis) for three-phase and line-to-ground faults (remote)



NOTE: Through no more than one transformation or with external reactance in series that is less than 1.5 times generator subtransient reactance (IEEE Std C37.010-1979).

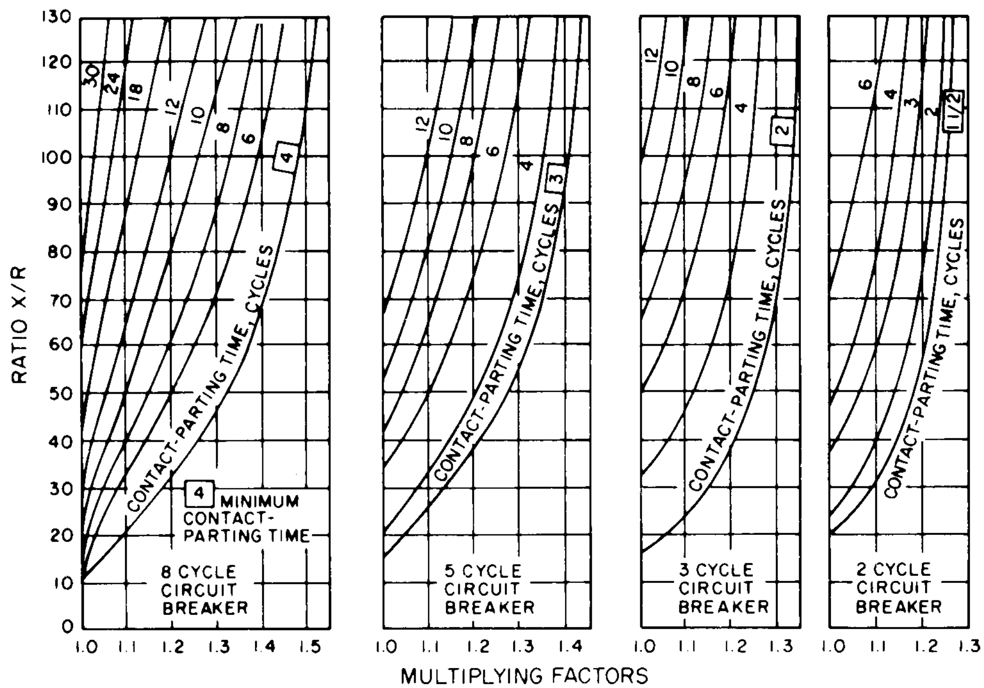
Figure 4-14—Multiplying factors for three-phase faults fed predominantly from generators (local)

Table 4-3—Definition of minimum contact-parting time for ac high-voltage circuit breakers

Rated interrupting time, cycles at 60 Hz	Minimum contact-parting time, cycles at 60 Hz
8	4
5	3
3	2
2	1.5

Source: Based on IEEE Std C37.010-1979 and IEEE Std C37.5-1979.

Select the multiplying factor for *E*/*X* correction from the curves of figures 4-14 and 4-15. To use the curves, it is necessary to know the circuit breaker's contact parting time as well as the proximity of generators to the fault point (local or remote), as before.



NOTE: Through two or more transformations or with external reactance in series that is equal to or above 1.5 times generator subtransient reactance (IEEE Std C37.010-1979).

Figure 4-15—Multiplying factors for three-phase and line-to-ground faults fed predominantly from generators (remote)

Multiply E_{pu}/X_{pu} by the multiplying factor and the base current:

$$\text{multiplying factor} \cdot \frac{E_{pu}}{X_{pu}} \cdot I_{base}$$

The result is the *calculated rms short-circuit-current interrupting duty* to be compared with the symmetrical current interrupting capability (based on rating) of a circuit breaker. (Note that the *calculated interrupting duty* is truly symmetrical only if the multiplying factor for *E*/*X* is 1.0.) The symmetrical current-interrupting capability of the circuit breaker is calculated as follows:

$$\text{symmetrical interrupting capability} = \frac{(\text{rated } I_{sc})(\text{rated maximum} E)}{\text{operating} E}$$

This calculated current shall not exceed the maximum symmetrical current-interrupting capability listed for the circuit breaker.

The calculating procedures described for first-cycle and interrupting networks are different in several respects from procedures detailed in earlier editions of this publication that were based on standards now superseded. The differences are intended to account more accurately for contributions to high-voltage interrupting duty from large induction motors, for the exponential decay of the dc component of short-circuit current, and for the ac decay of contributions from nearby generators.

4.5.4.3 Short-circuit currents for time-delayed relaying devices

For the application of instantaneous relays, the value of the first-cycle short-circuit current determined by the first-cycle network should be used. For an application of time delay relays beyond six cycles, the equivalent system network representation will include only generators and passive elements, such as transformers and cables between the generators and the point of short circuit. The generators are represented by transient impedance or a larger impedance related to the magnitude of decaying generator short-circuit current at the specified calculation time. All motor contributions are omitted. Only the generators that contribute short-circuit current through the relay under consideration to the short-circuit point are considered for the relay application. The dc component will have decayed to near zero and is not considered. The short-circuit symmetrical rms current is E_{pu}/X_{pu}, where X_{pu} is derived from the equivalent reactance network consisting of generators and passive equipment (cables, transformers, etc.) in the short-circuit current paths protected by the relays.

4.6 Example of short-circuit current calculation for a power system with several voltage levels

4.6.1 General discussion

The three-phase 60 Hz power system used for this example is shown in figure 4-10. For purposes of the example, buses are numbered 1 through 4 with numbers shown in triangles, and rotating machine sources of short-circuit currents are numbered S1 through S10 with numbers shown in squares. Groups of similar rotating machines are treated as single sources, each with a rating equal to the sum of the ratings in the group and the characteristics of the typical machine in the group.

The purpose of the example is to calculate short-circuit duties for comparison with ratings or capabilities of circuit breakers applied at buses 1, 2, and 3. Separate, three-phase, bolted, short circuits are assumed at F_1, F_2, and F_3, one at a time. When F_1 is the short circuit where current is being calculated, bus 1 is called the *fault bus*.

All fault buses are at primary distribution voltages of 13.8 or 4.16 kV. Interrupting-duty calculations for their circuit breakers are based on IEEE Std C37.010-1979 and IEEE Std C37.5-1979, which cover applications of high-voltage circuit breakers (over 1000 V, including medium voltage). First-cycle duties are calculated with the previously described single-combination network also satisfying requirements for low-voltage circuit breaker applications in IEEE Std C37.13-1981 and for low- and high-voltage fuses.

Note that the connected motor load assumed for the low-voltage unit substations of this example is lower than that observed for many actual substations. Experience has shown that the rated kVA summation for connected motors often greatly exceeds substation transformer kVA. This is a factor to be considered in studies intended to account for future growth.

4.6.2 Utility system data

In-plant generators operating in parallel with utility system ties are the main sources both at bus 1 and at bus 2. The representation of remote utility generators for plant short-circuit calculations is often based on the utility available short-circuit current, or short-circuit apparent power in MVA, delivered by the utility at a specified voltage from all sources outside the plant not including contributions from in-plant sources. This utility short-circuit contribution should be the highest applicable magnitude, probably future rather than present for conservative equipment selection, and should also specify the *X*/*R* ratio. These data are converted to an equivalent impedance. Obtaining corresponding equivalent impedance data directly from the utility is equally useful.

4.6.3 Per-unit calculations and base quantities

This example uses per-unit quantities for calculations. The base for all per-unit power quantities throughout the system is 10 MVA (any other value could have been selected). Voltage bases are different for different system voltage levels, but it is necessary for all of them to be related by the turns ratios of interconnecting transformers, as specified in kV at each numbered bus in figure 4-10. Any actual quantity is the per-unit magnitude of that quantity multiplied by the applicable base. For example, 1.1 per-unit voltage at bus 1 is actually 1.1 times the 13.8 kV base voltage at bus 1 = 15.18 kV. Per-unit system bases and actual quantities have identical physical relationships. For example, in three-phase systems the relationship shown in the following equation applies both to actual quantities and to bases of per-unit quantities:

$$\text{total MVA} = \sqrt{3}(E_{\text{L-L}} \text{ in kV})(I_{\text{line}} \text{ in kA})$$

Other useful base quantities for this example, derived using the 10 MVA base and the base voltages of figure 4-10 in the equations of 4.5, are listed as follows:

Base line-to-line voltage $E_{\text{L-L}}$

	13.8 kV	**4.16 kV**
Base line current (kA)	0.4184	1.388
Base line-to-neutral impedance (Ω)	19.04	1.73

This example calculates at each fault point a balanced per-unit three-phase short-circuit current duty using one of three identical per-unit line-to-neutral positive-sequence circuits, energized by per-unit line-to-neutral voltage. Only line-to-line base voltages are listed. For balanced three-phase circuits, line-to-line voltages in per unit of these bases are identical to line-to-neutral voltages in per unit of their corresponding line-to-neutral base voltages.

4.6.4 Impedances represented by reactances

The usual calculation of short-circuit duties at voltages over 1000 V involves circuits in which resistance is small with respect to reactance, so manual computations are simplified by omitting resistances from the circuit. The slight error introduced makes the solution conservative. This example employs this simplification by using only the reactances of elements when finding the magnitudes of short-circuit duties. However, element resistance data are necessary to determine *X*/*R* ratios as described later in this example.

4.6.5 Equivalent circuit variations based on time and standards

Calculations of high-voltage circuit breaker short-circuit current duties may make use of several equivalent circuits for the power system, depending on the time after short-circuit inception when duties are calculated and on the procedure described in the standard used as a basis.

The circuit used for calculating first-cycle short-circuit current duties uses subtransient reactance, sometimes modified as shown in tables 4-1 and 4-2, for all rotating machine sources of short-circuit current. Synchronous machines and large induction motors (over 250 hp at 3600 r/min or 1000 hp at 0–1800 r/min) are represented with unmodified subtransient reactance. Medium induction motors (all other induction motors 50 hp and above) have subtransient reactance multiplied by 1.2 (or first-cycle *X* is estimated at 0.20 per unit). Small induction motors (less than 50 hp each) have subtransient reactance multiplied by 1.67 (or first-cycle X is estimated at 0.28 per unit).

The circuit used for calculating short-circuit (interrupting) duties, at circuit-breaker minimum-contact parting times of 1.5 to 4 cycles after the short-circuit starts, retains synchronous generator subtransient reactance unchanged. It also represents synchronous motors and large induction motors with subtransient reactance multiplied by 1.5, as well as medium induction motors with subtransient reactance multiplied by 3.0 (or interrupting *X* is estimated at 0.50 per unit); it neglects induction motors with less than 50 hp.

Passive element reactances are the same in all equivalent circuits.

Resistances are necessary to find fault point *X*/*R* ratios used in short-circuit (interrupting) duty calculations based on IEEE Std C37.010-1979 and IEEE Std C37.5-1979. The fault point *X*/*R* ratio is the fault point *X* divided by the fault point *R*. A fault point *X* is found by reducing the reactance circuit described in preceding paragraphs to a single equivalent *X* at the fault point. A fault point *R* is found by reducing a related resistance-only circuit. This is derived from the reactance circuit by substituting the resistance in place of the reactance of each element, obtaining the resistance value by dividing the element reactance by the element

X/R ratio. For motors whose subtransient reactance is increased by a multiplying factor, the same factor must be applied to the resistance in order to preserve the X/R ratio for the motor.

The X/R data for power system elements of this example, shown in figure 4-10, are medium typical data obtained in most cases from tables and graphs that are included in the applicable standards and are reproduced in annex 4A at the end of this chapter.

The approximately 30-cycle network often is a minimum source representation intended to investigate whether minimum short-circuit currents are sufficient to operate current actuated relays. Minimum source circuits might apply at night or when production lines are down for any reason. Some of the source circuit breakers may be open and all motor circuits may be off. In-plant generators are represented with transient reactance or a larger reactance related to the magnitude of decaying generator short-circuit current at the desired calculation time, for this example assumed at 1.5 times subtransient reactance in the absence of better information.

4.6.6 Impedance data and conversions to per unit

Reactances of passive elements, obtained from figure 4-10, are listed in table 4-4, along with the conversion of each reactance to per unit on the 10 MVA base.

Table 4-4—Passive element reactances in per unit, 10 MVA base

Transformer T_1,	$X = 0.07\ (10/20) = 0.035$ per unit
Transformer T_2,	$X = 0.055\ (10/5) = 0.110$ per unit
Transformer T_3,	$X = 0.065\ (10/5) = 0.130$ per unit
Transformer T_4,	$X = 0.055\ (10/5) = 0.110$ per unit
Transformer T_5,	$X = 0.055\ (10/7.5) = 0.0734$ per unit
Transformer T_6,	$X = 0.055\ (10/1.5) = 0.367$ per unit
Reactor X_1,	$X = 0.08\ (10/7.5) = 0.107$ per unit
Cable C_1, from tables 4A-3 and 4A-6 for 250 kcmil at 1 in spacing, $X = 0.0922–0.0571 = 0.0351\ \Omega/1000$ ft (There are no reactance corrections as this is three-conductor cable in nonmagnetic duct.)	
For 3500 ft of cable, the conversion to per unit on a 10 MVA 13.8 kV base is $X = (3500/1000)\ (0.0351/19.04) = 0.0064$ per unit	
Cable C_2, 300 kcmil at 1 in spacing, $X = 0.0902–0.0571 = 0.0331\ \Omega/1000$ ft	
For 2500 ft of two cables in parallel at 4.16 kV, $X = (2500/1000)\ (1/2)\ (0.0331/1.73) = 0.0239$ per unit	

Most of the data given in figure 4-10 are per unit, based on the equipment nameplate rating. Any original percent impedance data is divided by 100 to obtain a per-unit impedance for figure 4-10. Conversions are changes of MVA base: multiplication by the ratio of the new MVA base (10 MVA for the example) to the old MVA base (rated MVA). When the equipment's rated voltage is not the same as the base voltage, it is also necessary to make voltage base conversions using the square of the ratio of rated voltage to example base voltage as the multiplier (see 4.5). This is not illustrated in this example.

Physical descriptions of cables are used to establish their reactances in ohms based on data in tables 4A-3 and 4A-6. Dividing an impedance in ohms by the base impedance in ohms converts it to per unit.

4.6.7 Subtransient reactances of rotating machines, and reactances for the circuit to calculate first-cycle short-circuit current duties

Subtransient reactances of rotating machine sources of short-circuit current modified for the combination first-cycle network based on interpretation of reference low- and high-voltage standards—IEEE Std C37.010-1979, IEEE Std C37.5-1979, and IEEE Std C37.13-1990—are listed in table 4-5 together with conversions to per unit on the study base.

Table 4-5—Subtransient reactances of rotating machines, modified for first-cycle (momentary) duty calculations in per unit, 10 MVA base

69 kV system, Generator 1,	X = 1.0 (10/1000) = 0.01 per unit X_d''= 0.09 (10/25) = 0.036 per unit
46 kV system, Generator 2,	X = 1.0 (10/800) = 0.0125 per unit X_d''= 0.09 (10/5) = 0.18 per unit
Large synchronous motor M_1, using the assumption that the horsepower rating of an 0.8 power factor machine is its kVA rating,	X_d''= 0.20 (10/6) = 0.333 per unit, each motor
Large induction motor M_2, using the assumption that hp = kVA,	X_d''= 0.17 (10/1.75) = 0.971 per unit
Low-voltage motor group, 0.4 MVA, from 50 to 150 hp,	first-cycle X = 1.2 X_d'' = 0.20 (10/0.4) = 5.0 per unit
Low-voltage motor group, 1.12 MVA, less than 50 hp each,	first-cycle X = 1.67 X_d'' = 0.28 (10/1.12) = 2.5 per unit

The reactance representing the rotating machines of a utility system is found by observing that the available short-circuit apparent power (MVA) is 1.0 per unit of a base equal to itself, and that 1.0 per-unit short-circuit apparent power (MVA) corresponds to 1.0 per-unit reactance (X) at 1.0 per-unit voltage (V), then converting this reactance to the study base.

The circuit development and impedance simplifications are described subsequently.

4.6.8 Reactances and resistances for the circuit to calculate short-circuit (interrupting) current duties

Reactances, and resistances derived from them as described previously, are detailed in table 4-6.

Table 4-6—X/R ratios and resistances for ac high-voltage circuit breaker contact-parting time (interrupting) short-circuit duties

Transformer T_1,	X/R = 21,	R = 0.035/21 = 0.001 667 per unit
Transformer T_2,	X/R = 16,	R = 0.110/16 = 0.006 88 per unit
Transformer T_3,	X/R = 16,	R = 0.130/16 = 0.008 12 per unit
Transformer T_4,	X/R = 12,	R = 0.11/12 = 0.009 16 per unit
Transformer T_5,	X/R = 14,	R = 0.0734/14 = 0.005 24 per unit
Transformer T_6,	X/R = 10,	R = 0.0367/10 = 0.003 67 per unit
Reactor X_1,	X/R = 50,	R = 0.107/50 = 0.002 14 per unit
Cable C_1, ac resistance at 50 °C from table 4A-3 is 0.0487 Ω/1000 ft, correction for 75 °C = 1.087 For 3500 ft of cable converted to per unit on a 10 MVA 13.8 kV base, R = (3500/1000) (1.087) (0.0487/19.04) = 0.009 72 per unit		
Cable C_2, ac resistance from table 4A-3 is 0.0407 Ω/1000 ft For 2500 ft of two cables in parallel on a 10 MVA 4.16 kV base at 75 °C, R = (2500/1000) (1.087/2) (0.0407/1.73) = 0.0320 per unit		
69 kV system, Generator 1,	X/R = 22, X/R = 45,	R = 0.01/22 = 0.000 445 per unit R = 0.036/45 = 0.0008 per unit
46 kV system, Generator 2,	X/R = 9, X/R = 29,	R = 0.0125/9 = 0.001 389 per unit R = 0.18/29 = 0.0062 per unit
Large synchronous motor M_1, using $X = 1.5\,X_d'' = 1.5\,(0.333) = 0.5$ per unit, X/R = 30, R = 0.5/30 = 0.016 67 per unit		
Large induction motor M_2, using $X = 1.5\,X_d'' = 1.5\,(0.971) = 1.457$ per unit, X/R = 30, R = 1.457/30 = 0.048 57 per unit		
Low-voltage motor group 50–150 hp, using $X = 3.0\,X_d'' = (3/1.2)\,(5.0) = 12.5$ per unit, X/R = 9, R = 12.5/9 = 1.389 per unit		
Low-voltage motor group below 50 hp is omitted		

NOTE—See tables 4-4 and 4-5 for reactances of passive elements, utility systems, and generators.

4.6.9 Reactances for the circuit to calculate approximately 30-cycle minimum short-circuit currents

Minimum generation for this problem (defined by system operators) occurs with Generator 1 down, the 46 kV utility system connection open, and all motors disconnected. Reactance details are given in table 4-7.

Table 4-7—Reactances for approximately 30-cycle short-circuit currents

Utility system S_1 reactance is unchanged
Generator 2, S_4 is represented with reactance larger than subtransient, assumed at $1.5\ X_d'' = 1.5 \cdot 0.18 = 0.27$ per unit
All other sources, S_2, S_3, S_5–S_{10}, are disconnected

4.6.10 Circuit and calculation of first-cycle short-circuit current duties

The circuit used for calculating the symmetrical alternating currents of the first-cycle short-circuit duties based on a combination of current circuit breaker and fuse standards is shown in figure 4-16(a). Source circuits S_5 through S_{10} have been simplified using the series and parallel combinations indicated in table 4-8, based on the per-unit element impedances obtained directly from table 4-4 and table 4-5. The identities of buses and sources are retained in figure 4-16(a), even after the individual element impedances from figure 4-10 lose identification when reactances are combined.

Table 4-8—Reactances for figure 4-16(a)

S_5 to bus 1, two circuits in parallel, each with M_1 motor X_d'' and T_5 transformer X, $X_d'' = (1/2)\ (0.3333 + 0.0734) = 0.2034$ per unit
S_6 to bus 1 (after combining all the motors of one substation for an equivalent low-voltage motor X_d'' $= 2.5\ (5)/(2.5 + 5) = 1.667$, four circuits in parallel, each with an equivalent motor X_d'' in series with a T_6 transformer, $X_d'' = (1/4)\ (1.667 + 0.367) = (1/4)\ (2.034) = 0.5085$ per unit
S_7 to bus 4, two M_2 induction motors, $X_d'' = (1/2)\ (0.971) = 0.4855$ per unit
S_8 to bus 2, three circuits, each as for the S_6 to bus 1 calculation, $X_d'' = (1/3)\ (2.034) = 0.678$ per unit
S_9 to bus 3, two M_2 induction motors, $X_d'' = (1/2)\ (0.971) = 0.4855$ per unit
S_{10} to bus 3, two circuits, each as for the S_6 to bus 1 calculation, $X_d'' = (1/2)\ (2.034) = 1.017$ per unit

The connection of an ac source, the voltage magnitude of which is the prefault voltage at the fault bus, between the dotted common connection and the fault at the fault bus causes the flow of per-unit alternating short-circuit current that is being calculated.

The reactances of figure 4-16(a) are further simplified as shown in Fig 4-16(b), without losing track of the three fault locations. The reactance simplifications are summarized in table 4-9. The table contains columns of reactances and reciprocals. Arrows are used to indicate the calculation of a reciprocal. Sums of reciprocals are used to combine reactances in parallel. A dashed line in the reactance column indicates that reactances above the line have been combined in parallel.

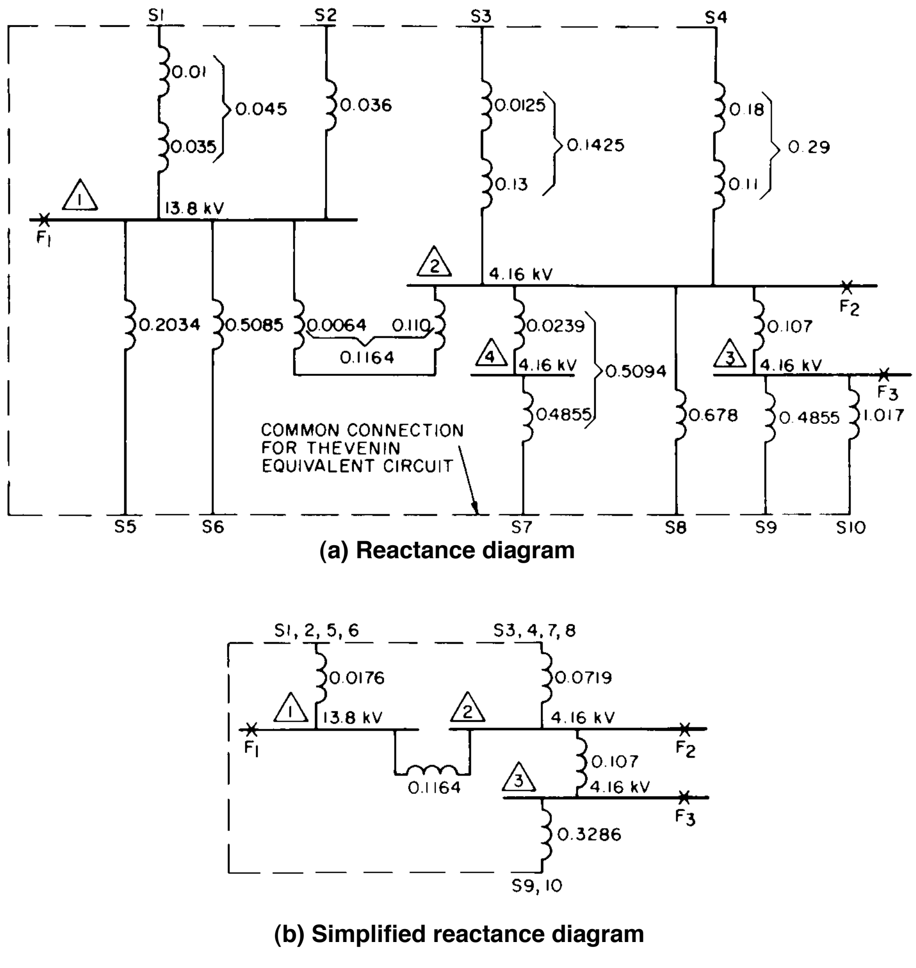


Figure 4-16—Circuits of power system reactances for calculation of first-cycle (momentary) short-circuit current duties for fuses and low-voltage circuit breakers

The final simplification of reactances to obtain one fault point *X* for each fault location is detailed in table 4-10. The results for the specified fault buses are the last entries in the reactance columns.

Table 4-9—Reactance combinations for figure 4-16(a)

S_1, S_2, S_5, S_6			S_3, S_4, S_7, S_8			S_9, S_{10}		
X		1/*X*	*X*		1/*X*	*X*		1/*X*
0.045	→	22.22	0.1425	→	7.02	0.4855	→	2.060
0.036	→	27.78	0.29	→	3.45	1.017	→	0.983
						– – – –		———
0.2034	→	4.91	0.5094	→	1.96			
						0.3286	←	3.043
0.5085	→	1.97	0.678	→	1.47			
– – – –		———	– – – –		———			
0.0176	←	56.88	0.0719	←	13.90			

Table 4-10—Reactance combinations for fault-point X at each fault bus of figure 4-16(b)

Fault at F_1			Fault at F_2			Fault at F_3		
X		1/*X*	*X*		1/*X*	*X*		1/*X*
0.3286			0.0176			0.1340	→	7.46
0.107			0.1164			0.0719	→	13.90
———			———			– – – –		———
0.4356	→	2.30	0.1340	→	7.46	0.0468	←	21.36
0.0719	→	13.90	0.107					
						0.107		
– – – –		———						
			0.3286			———		
0.0617	←	16.20						
			———			0.1538	→	6.502
0.1164			0.4356	→	2.30	0.3286	→	3.043
———						– – – –		———
			0.0719	→	13.90			
0.1781	→	5.62				0.1048	←	9.545
			– – – –		———			
0.0176	→	56.82						
			0.0423	←	23.66			
– – – –		———						
0.016	←	62.44						

Alternating short-circuit currents are calculated from the circuit reactance reductions *X* with a prefault voltage *E* of 1.0 per unit, and alternating rms current is, of course, *E*/*X* per unit. Multiplying by base current converts to real units. The resulting symmetrical (alternating only) first-cycle short-circuit rms currents are as follows:

at F_1, I_{sym} = (1.0/0.016) (0.4184) = 26.15 kA
at F_2, I_{sym} = (1.0/0.0423) (1.388) = 32.81 kA
at F_3, I_{sym} = (1.0/0.1048) (1.388) = 13.25 kA

Note that these currents may be useful as primary available symmetrical short-circuit current data for calculations of short-circuit duties at low-voltage buses of future unit substations connected to these medium-voltage buses.

Total (asymmetrical) rms short-circuit current duties for comparison with ac high-voltage (over 1000 V, including medium-voltage) circuit breaker closing and latching capabilities preferred before 1987 (or momentary ratings for the pre-1964 rating basis) are found using a

1.6 multiplying factor according to IEEE Std C37.010-1979 and IEEE Std C37.5-1979. These first-cycle short-circuit total (asymmetrical) rms currents are as follows:

at F_1, I_{tot} = 1.6 (26.15) = 41.8 kA
at F_2, I_{tot} = 1.6 (32.81) = 52.5 kA
at F_3, I_{tot} = 1.6 (13.25) = 21.2 kA

Crest short-circuit current duties for comparison with ac high-voltage (over 1000 V, including medium-voltage) circuit breaker closing and latching capabilities preferred in 1987 and after are found using a 2.7 multiplying factor according to IEEE Std C37.010-1979. These first-cycle short-circuit crest currents are as follows:

at F_1, I_{crest} = 2.7(26.15) = 70.6 kA
at F_2, I_{crest} = 2.7(32.81) = 88.6 kA
at F_3, I_{crest} = 2.7(13.25) = 35.8 kA

Asymmetrical short-circuit duties are necessary for comparison with total rms current ratings of ac high-voltage (and medium-voltage) fuses, such as those in the fused motor control equipment connected to buses 3 and 4. These are found using multiplying factors from IEEE Std C37.41-1981. The applicable standard for the circuit of figure 4-16 suggests a general case multiplying factor of 1.55, but a special case multiplier of 1.2 may be substituted if the voltage is less than 15 kV and if the *X*/*R* ratio is less than 4. The circuit of this example will not have *X*/*R* ratios as low as 4. The first-cycle short-circuit asymmetrical (total) rms currents for fuse applications are as follows:

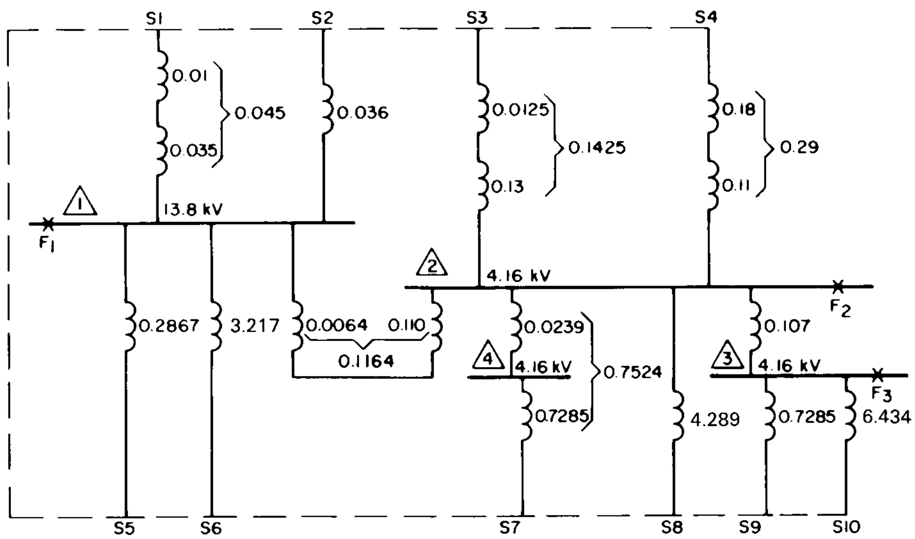
at F_1, I_{tot} = 1.55(26.15) = 40.73 kA
at F_2, I_{tot} = 1.55(32.81) = 50.86 kA
at F_3, I_{tot} = 1.55(13.25) = 20.54 kA

4.6.11 Circuit and calculation of contact parting time (interrupting) short-circuit current duties for high-voltage circuit breakers

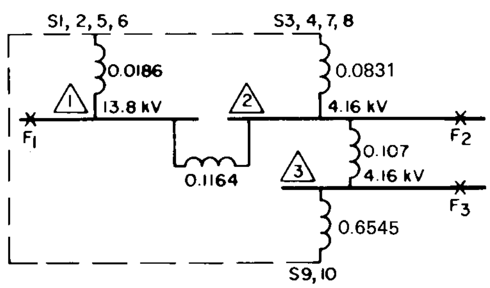
In addition to a circuit of power system reactances for calculating alternating currents ($I_{pu} = E/X$), a resistance-only circuit is needed to establish fault point *X*/*R* ratios. Duties are calculated by applying multiplying factors to *E*/*X*. The multiplying factors depend on the fault-point *X*/*R* and also on other factors defined subsequently.

The circuits used for calculating *X, E*/*X,* and fault point *R* are shown in figures 4-17(a) and 4-18(a), respectively. The rotating-machine reactances for the circuit of figure 4-17(a), if changed from subtransient, are shown in table 4-6. Table 4-11 details how these changes affect the table 4-8 simplifications of source circuits S_5 through S_{10}. Table 4-11 also includes resistance simplifications of source circuits for figure 4-18(a).

Figures 4-17(b) and 4-18(b) show the last steps of reactance and resistance simplifications, respectively, before the several fault location identities are lost. Tables 4-12 and 4-13 detail the reactance and resistance simplifications starting from figures 4-17(a) and 4-18(a), respectively. The final simplifications of reactances and resistances to obtain one fault point *X* and one fault point *R* for each fault location are detailed in tables 4-14 and 4-15, respectively.



(a) Reactance diagram



(b) Simplified reactance diagram

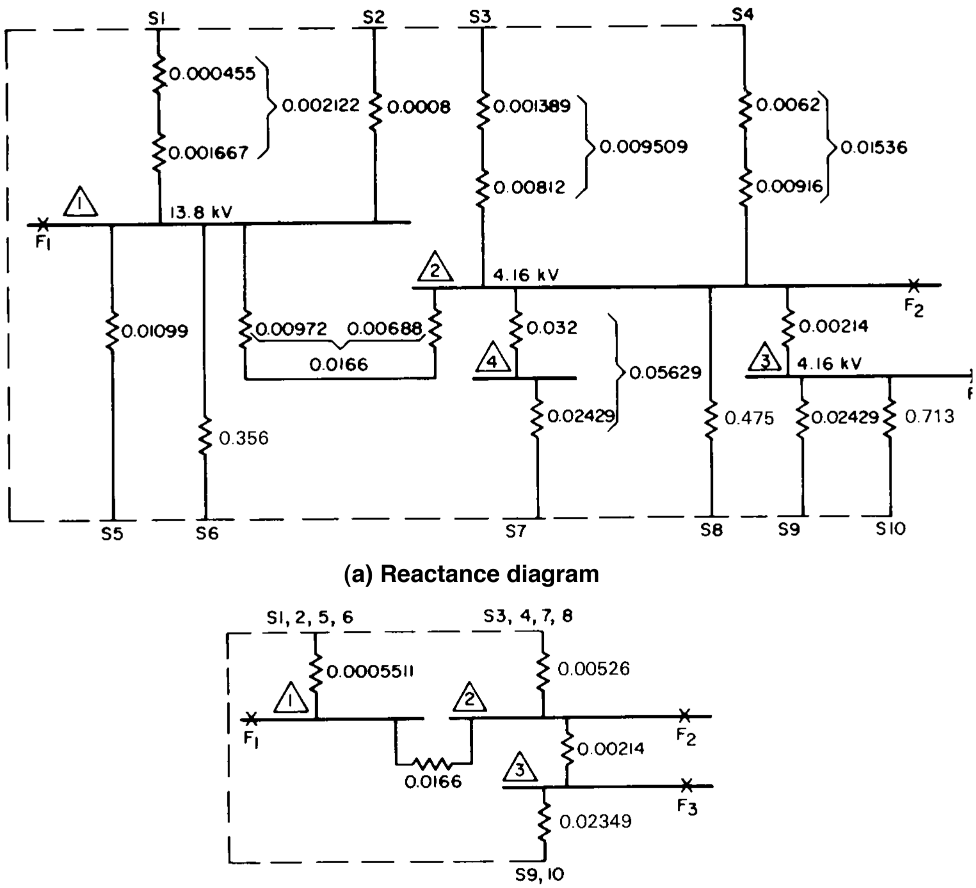
Figure 4-17—Circuits of power system reactances for calculation of E/X and fault-point X for contact-parting-time (interrupting) short-circuit current duties for high-voltage circuit breakers

Values of per-unit E/X for each fault bus are readily obtained from table 4-14 when $E = 1.0$ (as for this example); they are the final entries in the $1/X$ columns, opposite the fault point X entries. Values converted to actual currents are as follows:

at F_1, $E/X = 59.03(0.4184) = 24.70$ kA
at F_2, $E/X = 20.75(1.388) = 28.80$ kA
at F_3, $E/X = 7.841(1.388) = 10.88$ kA

Values of X/R for each fault bus are obtained from the fault point X and R entries of tables 4-14 and 4-15 as follows:

at F_1, $X/R = 0.0169/0.000537 = 31.47$
at F_2, $X/R = 0.0482/0.00348 = 13.85$
at F_3, $X/R = 0.1275/0.00488 = 26.13$



(a) Reactance diagram

(b) Simplified reactance diagram

Figure 4-18—Circuits of power system resistance for calculation of fault-point R for contact-parting-time (interrupting) short-circuit current duties for high-voltage circuit breakers

The reference standards contain graphs of multiplying factors that determine calculated short-circuit current duties when applied to *E*/*X* values. The proper graph is selected with the following information:

a) Three-phase or single-phase short-circuit current (three-phase for this example)
b) Rating basis of the circuit breaker being applied (present symmetrical current short-circuit ratings or previous total current short-circuit ratings)
c) Rated interrupting time of the circuit breaker being applied
d) Fault point *X*/*R* ratio
e) Proximity of generators

Table 4-11—Reactances for figure 4-17(a) and resistances for figure 4-18(a)

S_5 to bus 1, two circuits in parallel, each with 1.5 X_d'' of synchronous Motor M_1 and transformer T_5, X = (1/2) (0.5 + 0.0734) = 0.2867 per unit R = (1/2) (0.016 67 + 0.005 31) = (1/2) (0.021 98) = 0.010 99 per unit
S_6 to bus 1, four circuits in parallel, motor group and transformer T_6, X = (1/4) (12.5 + 0.367) = (1/4) (12.867) = 3.217 per unit R = (1/4) (1.389 + 0.0367) = (1/4) (1.4257) = 0.356 per unit
S_7 to bus 4, two motors M_2, X = (1/2) (1.457) = 0.7285 per unit R = (1/2) (0.048 57) = 0.024 29 per unit
S_8 to bus 2, three circuits, each as for the S_6 to bus 1 calculation, X = (1/3) (12.867) = 4.289 per unit R = (1/3) (1.4257) = 0.475 per unit
S_9 to bus 3, two motors M_2, X = (1/2) (1.457) = 0.7285 per unit R = (1/2) (0.048 57) = 0.024 29 per unit
S_{10} to bus 3, two circuits, each as for the S_6 to bus 1 calculation, X = (1/2) (12.867) = 6.434 per unit R = (1/2) (1.4257) = 0.713 per unit

Table 4-12—Reactance combinations for figure 4-17(a)

S_1, S_2, S_5, S_6			S_3, S_4, S_7, S_8			S_9, S_{10}		
X		**1/*X***	***X***		**1/*X***	***X***		**1/*X***
0.045	→	22.22	0.1425	→	7.018	0.7285	→	1.373
0.036	→	27.78	0.29	→	3.448	6.434	→	0.155
0.2867	→	3.49	0.7524	→	1.329	– – – –		———
3.217	→	0.31	4.289	→	0.233	0.6545	←	1.528
– – – –		———	– – – –		———			
0.0186	←	53.80	0.0831	←	12.028			

Table 4-13—Resistance combinations for figure 4-18(a)

S_1, S_2, S_5, S_6			S_3, S_4, S_7, S_8			S_9, S_{10}		
R		**1/*R***	***R***		**1/*R***	***R***		**1/*R***
0.002 122	→	471.3	0.009 509	→	105.2	0.024 29	→	41.17
0.000 8	→	1250.0	0.015 36	→	65.10	0.713	→	1.403
0.010 99	→	90.99	0.056 29	→	17.77	– – – –		———
0.356	→	2.81	4.475	→	2.11	0.023 49	←	42.57
– – – –		———	– – – –		———			
0.000 551 1	←	1815	0.005 26	←	190.3			

Table 4-14—Reactance combinations for fault-point X at each fault bus of figure 4-17(b)

Fault at F_1			**Fault at F_2**			**Fault at F_3**		
X		**1/*X***	***X***		**1/*X***	***X***		**1/*X***
0.6545			0.0186			0.135	→	7.407
0.107			0.1164			0.0831	→	12.03
———			———			– – – –		--------
0.7615	→	1.313	0.135	→	7.407	0.0514	←	19.44
0.0831	→	12.03	0.7615	→	1.313	0.107		
– – – –		--------	0.0831	→	12.03	———		
0.0750	←	13.34	———		———	0.1584	→	6.313
0.1164			0.0482	←	20.75	0.6545	→	1.528
———						– – – –		———
0.1914	→	5.225				0.1275	←	7.841
0.0186	→	53.80						
– – – –		———						
0.0169	←	59.03						

Table 4-15—Reactance combinations for fault-point R at each fault bus of figure 4-18(b)

Fault at F_1			**Fault at F_2**			**Fault at F_3**		
R		**1/*R***	***R***		**1/*R***	***R***		**1/*R***
0.023 49			0.000 551 1			0.017 15	→	58.31
0.002 14			0.016 6			0.005 26	→	190.3
———			———			– – – – –		---------
0.025 63	→	39.02	0.017 15	→	58.31	0.004 02	←	248.6
0.005 26	→	190.3	0.005 26	→	190.3	0.002 14		
– – – –		--------	0.025 63	→	39.02	———		
0.004 36	←	229.32	– – – – – –		———	0.006 16	→	162.3
0.016 6			0.003 48	←	287.6	0.023 49	→	42.57
———						– – – – –		———
0.020 96	→	47.71				0.004 88	←	204.9
0.000 551 1	→	1815						
– – – –		———						
0.000 537	←	1863						

The proximity of generators determines the choice between graphs (a) for faults fed predominantly from generators through not more than one transformation or with external impedance in series that is less than 1.5 times generator X_d'' (local in this example) and (b) for faults fed predominantly through two or more transformers or with external impedance in series that is equal to or exceeds 1.5 times generator X_d'' (remote in this example). The local and remote multiplying factor graphs of IEEE Std C37.010-1979 and IEEE Std C37.5-1979 are given in figures 4-12 to 4-15. The local multiplying factors are smaller because they include the effects of generator ac (symmetrical current) decay. Remote multiplying factors are based on no decay of the remote generator ac (symmetrical current) up to circuit breaker contact parting time. Utility contributions are considered to be from remote generators in most industrial system duty calculations.

For many systems having only remote sources and no in-plant generators, it is clear that the remote multiplying factor is the only choice. For the few systems that have in-plant generator primary power sources, both multiplying factors may be necessary, as explained subsequently.

In this example, short-circuit duties are calculated for (SYM) symmetrical current short-circuit rated (present basis) circuit breakers with 5-cycle rated interrupting times (SYM 5) and (TOT) total-current short-circuit rated (previous basis) circuit breakers with 8-cycle and 5-cycle rated interrupting times (TOT 8 and TOT 5).

Multiplying factors obtained from both the local and remote graphs of figures 4-12 to 4-15 are shown in table 4-16 for the other conditions previously established in this example.

Table 4-16—Three-phase short-circuit current multiplying factors for E/X for example conditions

Fault location	Fault-point *X*/*R* ratio	Circuit breaker type	Multiplying factor	
			Local	Remote
F_1	31.47	TOT 8 TOT 5 SYM 5	1.05 1.14 1.03	1.19 1.27 1.15
F_2	13.85	TOT 8 TOT 5 SYM 5	1.0* 1.01 1.0*	1.0* 1.06 1.0*
F_3	26.13	TOT 8 TOT 5 SYM 5	1.02 1.10 1.00	1.14 1.21 1.10

*IEEE Std C37.010-1979 and IEEE Std C37.5-1979 indicate that a 1.0 multiplying factor applies without further checking when X/R = 15 or less for SYM circuit breakers of all rated interrupting times and for TOT 8 circuit breakers.

In this example, with each of two main buses connected to both a utility (remote) source and an in-plant generator (local for nearby faults) source, it is not immediately apparent which multiplying factor applies. One technique that perhaps provides an extra margin of conservatism is to use only the larger remote multiplying factors as described in the next paragraphs. An alternative and also conservative procedure that interpolates between multiplying factors requires additional calculations (see 4.6.13).

The calculated interrupting duty short-circuit rms currents for three-phase faults at bus 1, using remote multiplying factors, are as follows:

for SYM 5 circuit breakers, 1.15(24.70) = 28.41 kA-S
for TOT 8 circuit breakers, 1.19(24.70) = 29.39 kA-T
for TOT 5 circuit breakers, 1.27(24.70) = 31.37 kA-T

The kA-T designation denotes an rms current duty in kiloamperes to be compared with the total current short-circuit (interrupting) capability of a total-rated circuit breaker. This is a total (asymmetrical) rms current duty.

The kA-S designation denotes an rms current duty in kiloamperes to be compared with the symmetrical-current short-circuit (interrupting) capability of a symmetrical-rated circuit breaker. This is a symmetrical rms current duty only if the multiplying factor for E/X is 1.0; otherwise, it is neither symmetrical nor asymmetrical, but partway in between.

The F_2 fault calculation for a TOT 5 circuit breaker is not detailed in this example. SYM 5 and TOT 8 duties at bus 2 are already available, since 1.0 multiplying factors apply, as follows:

for SYM 5 circuit breakers, 1.0(28.80) = 28.80 kA-S
for TOT 8 circuit breakers, 1.0(28.80) = 28.80 kA-T

The calculated short-circuit (interrupting) duty rms currents for three-phase faults at bus 3, using remote multiplying factors, are as follows:

for SYM 5 circuit breakers, 1.10(10.88) = 11.97 kA-S
for TOT 8 circuit breakers, 1.14(10.88) = 12.40 kA-T
for TOT 5 circuit breakers, 1.21(10.88) = 13.16 kA-T

4.6.12 Circuit-breaker short-circuit capabilities compared with calculated remote multiplying-factor short-circuit current duties

Short-circuit ratings, or capabilities derived from them, for circuit breakers that might be applied in the example system are listed in table 4-17. The headings of the table also show in parentheses the type of calculated short-circuit duties to be compared with listed equipment capabilities or ratings. The capabilities derived from symmetrical short-circuit ratings using a ratio of rated maximum voltage to operating voltage are computed using the example operating voltages listed in the table.

Circuit breakers for bus 1 application, both SYM 5 and TOT 8 types, having short-circuit ratings or capabilities equal to or greater than the corresponding calculated duties at bus 1, are listed in table 4-18 with the calculated duties for comparison. Circuit breakers for bus 2 and 3 applications are listed in tables 4-19 and 4-20, respectively, with short-circuit ratings or capabilities and calculated duties.

Table 4-17—AC high-voltage circuit-breaker short-circuit ratings or capabilities, in kiloamperes

		TOT 8 8-cycle total-rated circuit breakers		SYM 5 5-cycle symmetrical-rated circuit breakers		
Circuit breaker nominal size identification	Example maximum system operating voltage (kV)	Momentary rating (first-cycle total rms current)	Interrupting rating (total rms current at 4-cycle contact-parting time)	Closing and latching capability before 1987 (first-cycle total rms current)	Closing and latching capability 1987 and after (first-cycle crest current)	Short-circuit capability (symmetrical rms current at 3-cycle contact-parting time)
4.16–75	4.16	20	10.5	19	32	10.1
4.16–250	4.16	60	35	58	97	33.2
4.16–350	4.16	80	48.6	78	132	46.9
13.8–500	13.8	40	21	37	62	19.6
13.8–750	13.8	60	31.5	58	97	30.4
13.8–1000	13.8	80	42	77	130	40.2

4.6.13 Contact parting time (interrupting) duties for high-voltage circuit breakers using weighted interpolation between multiplying factors

For a system with several sources, including in-plant generators that might be classified local or remote depending on fault location, logical calculations make use of both remote and local multiplying factors in a weighting process. The weighting consists of applying the remote multiplying factor to the part of the E/X symmetrical short-circuit current contributed by remote sources and the local multiplying factor to the remainder of E/X. The application of either a local or a remote multiplying factor to the motor contribution part of E/X is permitted by IEEE Std C37.010-1979 (5.4.1, note 5 of the table). The remote sources' part of E/X includes the contribution of an in-plant generator if it is less than 0.4 times the generator current to a short circuit at its terminals; any larger generator current corresponds to a reactance in series that is less than 1.5 times generator X_d'' and supports the use of a local multiplier for the generator contribution, according to IEEE Std C37.010-1979 and IEEE Std C37.5-1979.

Additional calculations are necessary to find the short-circuit currents contributed by each utility and in-plant generator source to the short-circuit duties being investigated. The magni-

Table 4-18—Calculated bus 1 short-circuit duties compared with ratings or capabilities of ac high-voltage circuit breakers

Type of circuit breaker	TOT 8 (8-cycle total rated)	SYM 5 (5-cycle symmetrical rated)
First-cycle duty, before 1987, total rms current	41.8 kA	41.8 kA
First-cycle duty, 1987 and after, crest current		70.6 kA
Short-circuit (interrupting) duty, rms current	29.4 kA-T	28.4 kA-S
Circuit breaker nominal size	13.8–750	13.8–750
Momentary rms current rating, or closing and latching rms capability, before 1987	60 kA	58 kA
Closing and latching crest capability, 1987 and after		97 kA
Interrupting rating, or short-circuit current capability	31.5 kA	30.4 kA

Table 4-19—Calculated bus 2 short-circuit duties compared with ratings or capabilities of ac high-voltage circuit breakers

Type of circuit breaker	TOT 8 (8-cycle total rated)	SYM 5 (5-cycle symmetrical rated)
First-cycle duty, before 1987, total rms current	52.5 kA	52.5 kA
First-cycle duty, 1987 and after, crest current		88.6 kA
Short-circuit (interrupting) duty, rms current	28.8 kA-T	28.8 kA-S
Circuit breaker nominal size	4.16–250	4.16–250
Momentary rms current rating, or closing and latching rms capability, before 1987	60 kA	58 kA
Closing and latching crest capability, 1987 and after		97 kA
Interrupting rating, or short-circuit current capability	35 kA	33.2 kA

Table 4-20—Calculated bus 3 short-circuit duties compared with ratings or capabilities of ac high-voltage circuit breakers

Type of circuit breaker	TOT 8 (8-cycle total rated)	SYM 5 (5-cycle symmetrical rated)
First-cycle duty, before 1987, total rms current	21.2 kA	21.2 kA
First-cycle duty, 1987 and after, crest current		35.8 kA
Short-circuit (interrupting) duty, rms current	12.4 kA-T	12.0 kA-S
Circuit breaker nominal size	4.16–250	4.16–250
Momentary rms current rating, or closing and latching rms capability, before 1987	60 kA	58 kA
Closing and latching crest capability, 1987 and after		97 kA
Interrupting rating, or short-circuit current capability	35 kA	33.2 kA

tude of an in-plant generator contribution for each short circuit determines whether it is included with utility sources in the remote part of *E/X*.

The additional calculation of currents in the source branches of the equivalent circuit during a short circuit at a specified location is a multistep process not illustrated here (and greatly facilitated by available computer programs). The results of the necessary calculations for this example are given in table 4-21. Also shown are remote or local classifications for the in-plant generators contributing to short circuits at F_1, F_2, and F_3.

The weighted interpolation has significance only for the short circuit at F_1. For the short circuit at F_2, the local and remote multiplying factors are both 1.0 (for SYM 5 and TOT 8 duties) and interpolation has no effect. For the short circuit at F_3, since all sources including in-plant generators are classified as remote, the remote multiplying factor applies.

For the short circuit at F_1, the remote part of E/X = 22.22 + 2.75 + 1.35 = 26.32 per unit, and the remainder of E/X = 59.03 – 26.32 = 32.71 per unit. The calculated short-circuit interrupting-duty rms currents for three-phase short circuits at bus 1 (F_1), using weighted interpolation of multiplying factors, are as follows:

for SYM 5 circuit breakers, 1.15 (26.32) + 1.03 (32.71) = 64.0 per unit or 64.0 (0.4184) = 26.8 kA-S

for TOT 8 circuit breakers, 1.19 (26.32) + 1.05 (32.71) = 65.67 per unit or 65.67 (0.4184) = 27.5 kA-T

Table 4-21—Current contributions of separate sources (generators) to E/X symmetrical short-circuit (interrupting) duties, with sources classified remote or local (currents are in per unit on the 10 MVA base of this example)

Fault contributions and classifications*	Fault at F_1	Fault at F_2	Fault at F_3
Fault point *E/X* symmetrical short-circuit current	59.03	20.75	7.84
S_1–69 kV utility contribution Classification	22.22 remote	3.06 remote	0.99 remote
S_2–25 MVA generator contribution Classification†	27.78 local	3.83 remote	1.24 remote
S_3–48 kV utility contribution Classification	2.75 remote	7.02 remote	2.28 remote
S_4–5 MVA generator contribution Classification‡	1.35 remote	3.45 local	1.12 remote

*Utility is always remote, in-plant generator is remote if contribution is less than 0.4 E/X″
†*E/X*″ (for three-phase short circuit at terminals) = 27.78 per unit
‡*E/X*″ (for three-phase short circuit at terminals) = 5.56 per unit

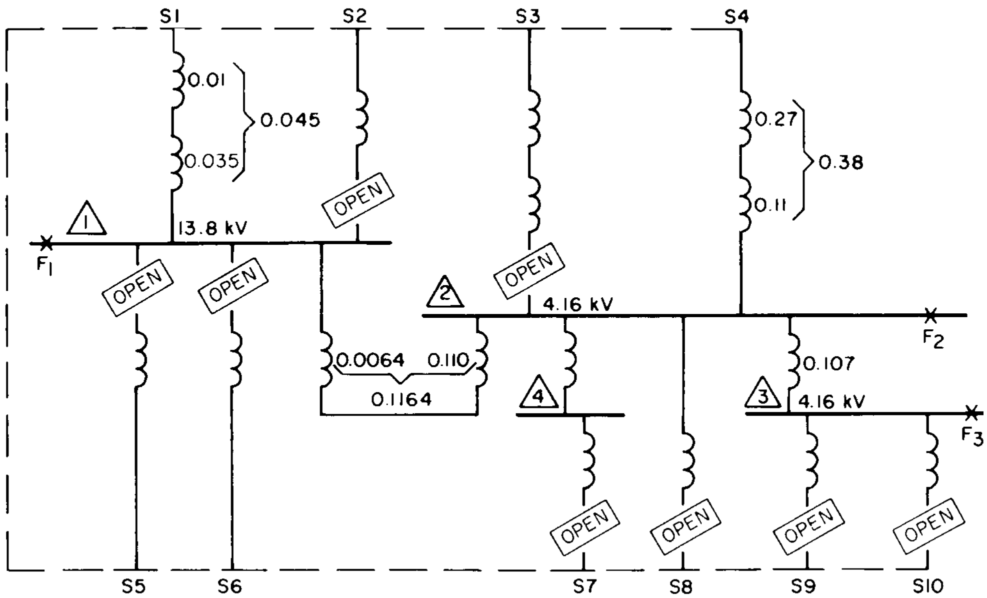
Comparison of these results with previously calculated bus 1 results, table 4-18, shows that the previous use of only remote multiplying factors gives an extra margin of conservatism of 6 or 7% in this example.

4.6.14 Circuit and calculation of approximately 30-cycle minimum short-circuit currents

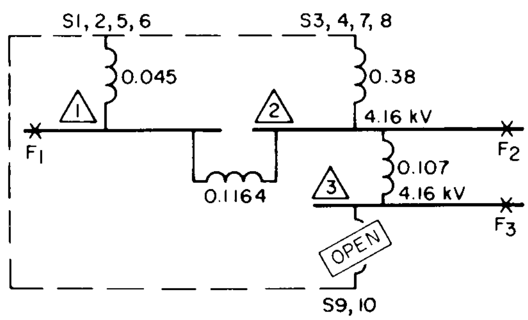
The circuit used is shown in figure 4-19. The rotating-machine reactances are shown in table 4-7. Table 4-22 details the reactance simplifications starting from figure 4-19(b).

A prefault voltage of 1.0 per unit is assumed, *I* is calculated at *E/X* per unit, and the conversion is made to real units. There is no dc component remaining to cause asymmetry. The resulting, symmetrical, approximately 30-cycle, short-circuit currents are as follows:

at F_1, $I = (1.0/0.0413)\ (0.4184) = 10.14$ kA
at F_2, $I = (1.0/0.1133)\ (1.388) = 12.25$ kA
at F_3, $I = (1.0/0.2203)\ (1.388) = 6.30$ kA



(a) Reactance diagram



(b) Simplified reactance diagram

Figure 4-19—Circuits of power system reactances for calculation of approximately 30-cycle minimum short-circuit currents

4.7 Example of short-circuit current calculation for a low-voltage system (under 1000 V)

As in portions of a power system with voltage over 1000 V, calculation of short-circuit currents at various locations in a low-voltage system (voltage under 1000 V) is essential for proper application of circuit breakers, fuses, buses, and cables. All should withstand the thermal and magnetic stresses imposed by the maximum possible short-circuit currents until the currents are interrupted. In addition, circuit breakers and fuses should safely interrupt these maximum short-circuit currents.

Table 4-22—Reactance combinations for fault-point X at each fault bus of figure 4-19(b)

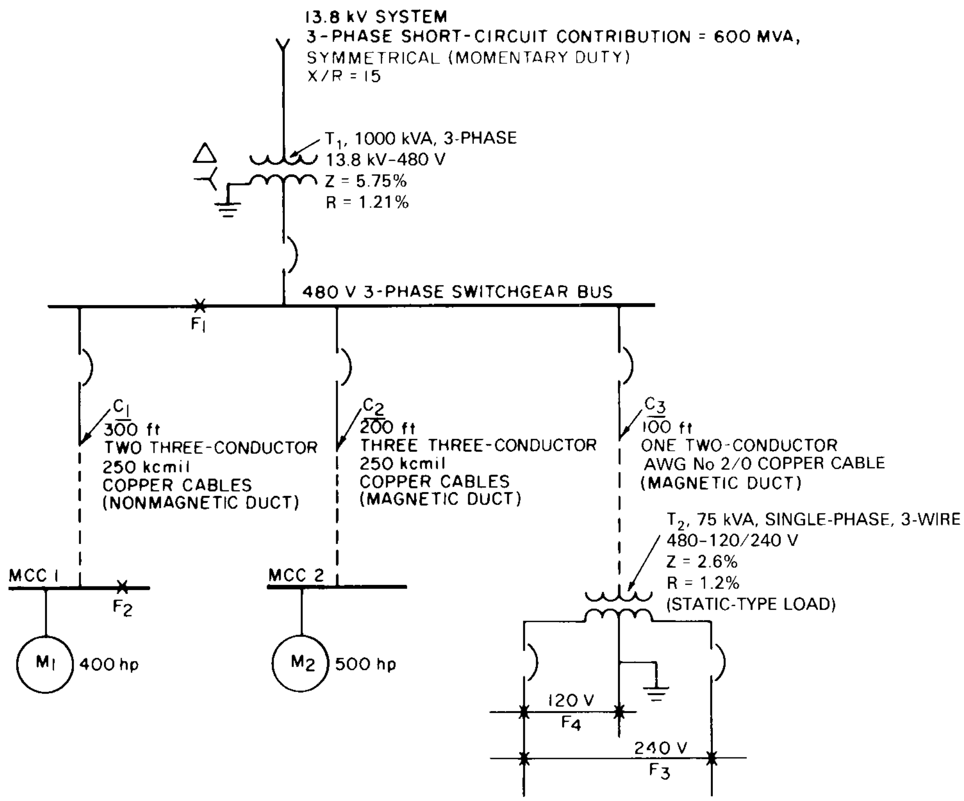
Fault at F_1 X		Fault at F_1 $1/X$	Fault at F_2 X		Fault at F_2 $1/X$	Fault at F_3 X
0.38			0.045			0.1133
0.1164			0.1164			0.107
———			———			———
0.4964	→	2.0145	0.1614	→	6.1958	0.2203
0.045	→	22.2222	0.38	→	2.6316	
– – – –		———	– – – –		———	
0.041 26	←	24.2367	0.1133	←	8.8274	

For the three-phase system, the three-phase short circuit will usually produce the maximum fault current. On a balanced three-phase system, the line-to-line fault current will never exceed 87% of the three-phase value. With a system neutral solidly grounded, the line-to-ground fault current could exceed the three-phase short-circuit current by a small percentage; however, this is apt to occur only when there is little or no motor load and the primary system fault contribution is small.

The calculation of symmetrical short-circuit current duties is normally sufficient for the application of circuit breakers and fuses under 1000 V because they have published symmetrical-current-interrupting ratings. The ratings are based on the first-cycle symmetrical rms current, calculated using results at 1/2 cycle after short-circuit-current inception, and incorporate an asymmetrical capability as necessary for a circuit X/R ratio of 6.6 or less (short-circuit power factor of 15% or greater). A typical system served by a transformer rated 1000 or 1500 kVA will usually have a short-circuit X/R ratio within these limits. For larger or multi-transformer systems, it is advisable to check the X/R ratio; if it is greater than 6.6, the circuit breaker or fuse application should be based on asymmetrical current limitations (see IEEE Std C37.13-1990).

The low-voltage short-circuit current calculation procedure differs very little from that used for finding first-cycle short-circuit duties in higher voltage systems. All connected motor ratings are included as fault contributing sources, and this contribution is based on the subtransient reactance of the machines. The contribution from the primary system should be equivalent to that calculated for its first-cycle short-circuit duty. Due to the quantity and small ratings of motors usually encountered in low-voltage systems, it is customary to use an assumed typical value for their equivalent reactance in the low-voltage short-circuit network. This typical reactance value is 25% (0.25 per unit) based on the individual motor rating or the total rating of a group of motors, both in kilovoltamperes (see 4.5.4).

The example fault calculation presented here is for a 480 V three-phase system, illustrated by the single line diagram of figure 4-20. The system data shown are typical of those required to perform the calculations.



NOTE: The motor horsepower indicated at MCC 1 and 2 represents a lumped total of small induction three-phase machines ranging in size from 10–150 hp.

Figure 4-20—Low-voltage system

Bolted three-phase short circuits F_1 and F_2 are assumed at each of the bus locations, and zero impedance (bolted) line-to-line short circuits F_3 and F_4 are assumed at the 120/240 V single-phase locations. Both resistance and reactance components of the circuit element impedances are used in order to illustrate a more precise procedure and to obtain *X*/*R* ratios.

Resistances are usually significant in low-voltage short-circuit current calculations. Their effect may be evaluated either by a complex impedance reduction or by separate *X* and *R* reductions. The complex reduction leads to the most accurate short-circuit-current magnitude results (but probably nonconservative *X*/*R* ratios). The separate *X* and *R* reductions are simpler, conservative, and have the added benefit that they give the best approximation for the *X*/*R* ratio at the fault point. They are illustrated by this example:

4.7.1 Step 1: Convert all element impedances to per-unit values on a common base

The assumed base power is 1000 kVA and the base voltage is E_b = 480 V:

$$\text{base current} I_b = \frac{\text{kVA (1000)}}{\sqrt{3} \cdot E_b}$$

$$= \frac{1000 \cdot 1000}{\sqrt{3} \cdot 480}$$

$$= 1202.8 \text{ A}$$

$$\text{base impedance} Z_b = \frac{E_b / \sqrt{3}}{I_b}$$

$$= \frac{480 / \sqrt{3}}{1202.8} = 0.2304 \ \Omega$$

a) *13.8 kV source impedance*. The short-circuit-current contribution from the 13.8 kV system will usually be expressed as a symmetrical rms current (in kA) or apparent power (in MVA), giving a specific *X/R* ratio. This three-phase short-circuit duty should be the maximum possible available at the primary terminals of the transformer and equivalent to the first-cycle symmetrical short-circuit duty. For this example, the 13.8 kV available short-circuit duty is 600 MVA or 25 102 A symmetrical rms at an *X/R* ratio of 15. The equivalent R_s and X_s impedance Z_s can be obtained as follows:

$$Z_s = \frac{\text{base kVA}}{\text{short-circuit kVA}} = \frac{1000}{600\ 000} = 0.00166 \text{ per unit}$$

Since $Z_s = \sqrt{(R_s)^2 + (X_s)^2}$ and X_s/R_s = 15, the value of $R_s = Z_s / \sqrt{1 + (15)^2}$ = 0.00011 per unit, and the value of $X_s = 15/R_s = 0.00165$ per unit.

b) *1000 kVA transformer impedance*. The transformer manufacturer provides the information that the impedance is 5.75% on the self-cooled base rating of 1000 kVA, and the resistance is 1.21% (R_{T1}). Reactance $X = \sqrt{Z^2 - R^2} = 5.62\%\ (X_{T1})$. The per-unit values are as follows:

$$R_{T1} = \frac{\text{base kVA}}{\text{transformer kVA}} \cdot \frac{\%R_{T1}}{100} = \frac{1000}{1000} \cdot \frac{1.21}{100} = 0.0121 \text{ per unit}$$

$$X_{T1} = \frac{\text{base kVA}}{\text{transformer kVA}} \cdot \frac{\%X_{T1}}{100} = \frac{1000}{1000} \cdot \frac{5.62}{100} = 0.0562 \text{ per unit}$$

c) *Cable* C_1 (300 ft of two 250 kcmil three-conductor copper cables in nonmagnetic duct). From published tables, the ac resistance R_{C1} is 0.0541 Ω per conductor per 1000 ft, and the reactance X_{C1} is 0.0330 Ω per conductor per 1000 ft.

For 300 ft of two paralleled conductors,

$$R_{C1} = \frac{0.0541 \cdot 300}{2 \cdot 1000} = 0.00812\ \Omega$$

$$X_{C1} = \frac{0.0330 \cdot 300}{2 \cdot 1000} = 0.00495\ \Omega$$

Converting impedances to per unit,

$$R_{C1} = \frac{\text{actual ohms}}{\text{base ohms}} = \frac{0.00812}{0.2304} = 0.0352 \text{ per unit}$$

$$X_{C1} = \frac{\text{actual ohms}}{\text{base ohms}} = \frac{0.00495}{0.2304} = 0.0215 \text{ per unit}$$

d) *Cable* C_2 (200 ft of three 250 kcmil three-conductor copper cables in magnetic duct). From published tables, the ac resistance R_{C2} is 0.0552 Ω per conductor per 1000 ft, and the reactance X_{C2} is 0.0379 Ω per conductor per 1000 ft.

For 200 ft of three parallel conductors,

$$R_{C2} = \frac{0.0552 \cdot 200}{3 \cdot 1000} = 0.00368\ \Omega$$

$$X_{C2} = \frac{0.0379 \cdot 200}{3 \cdot 1000} \cdot 0.00253\ \Omega$$

Converting impedances to per unit,

$$R_{C2} = \frac{0.00368}{0.2304} = 0.01597 \text{ per unit}$$

$$X_{C2} = \frac{0.00253}{0.2304} = 0.01098 \text{ per unit}$$

e) *Cable* C_3 (100 ft of one AWG No. 2/0 two-conductor copper cable in magnetic duct). From published tables, the ac resistance R_{C3} is 0.102 Ω/1000 ft, and the reactance X_{C3} is 0.0407 Ω/1000 ft.

For 100 ft,

$$R_{C3} = \frac{0.102 \cdot 100}{1000} = 0.0102\ \Omega$$

$$X_{C3} = \frac{0.0407 \cdot 100}{1000} = 0.00407\Omega$$

Converting impedances to per unit,

$$R_{C3} = \frac{0.0102}{0.2304} = 0.0443 \text{ per unit}$$

$$X_{C3} = \frac{0.00407}{0.2304} = 0.01766 \text{ per unit}$$

f) *Motor contribution*. The running motor loads at motor control center 1 and 2 buses total 400 hp and 500 hp, respectively. Typical assumptions made for 480 V small motor groups are that 1 hp = 1 kVA, and the average subtransient reactance is 25%. The resistance is 4.167%, based on a typical *X*/*R* ratio of 6.

Converting impedances to per unit on the 1000 kVA base,

$$R_{M1} = \frac{\text{base kVA} \cdot \%\mathrm{R}_{M1}}{\text{motor kVA} \cdot 100} = \frac{1000 \cdot 4.167}{400 \cdot 100} = 0.1042 \text{ per unit}$$

$$X_{M1} = \frac{\text{base kVA} \cdot \%X_{M1}}{\text{motor kVA} \cdot 100} = \frac{1000 \cdot 25}{400 \cdot 100} = 0.625 \text{ per unit}$$

$$R_{M2} = \frac{1000 \cdot 4.167}{500 \cdot 100} = 0.0833 \text{ per unit}$$

$$X_{M2} = \frac{1000 \cdot 25}{500 \cdot 100} = 0.500 \text{ per unit}$$

4.7.2 Step 2: Draw separate resistance and reactance diagrams applicable for fault locations F_1 and F_2 (figures 4-21 and 4-22)

Since the single-phase 120/240 V system has no short-circuit current contributing sources, it will not be represented in these diagrams.

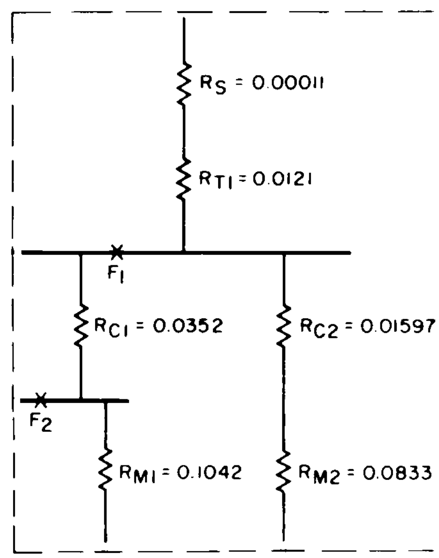


Figure 4-21—Resistance network for faults at F_1 and F_2

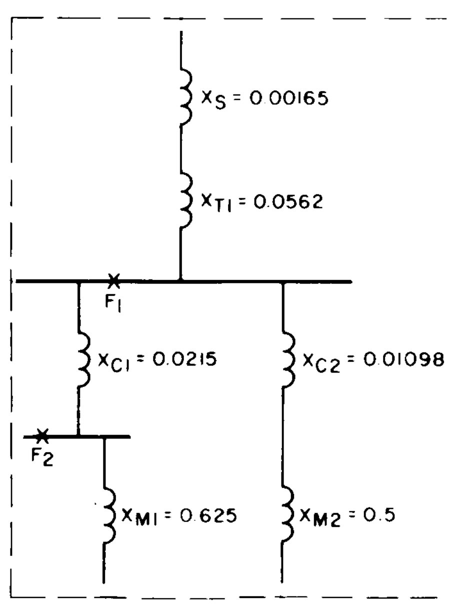


Figure 4-22—Reactance network for faults at F_1 and F_2

4.7.3 Step 3: For each fault location reduce R and X networks to per-unit values and calculate fault current

The reduction of the *R* and *X* networks at short-circuit location F_1 is shown in figures 4-23 and 4-24. The short-circuit current at F_1 is then calculated as follows:

The total impedance *Z* is

$$Z = \sqrt{R^2 + X^2} = \sqrt{(0.010\ 09)^2 + (.048\ 11)^2} = 0.049\ 16 \text{ per unit}$$

The total three-phase symmetrical short-circuit current at F_1 is *(E/Z)* · base current; that is,

$$\frac{\text{base amperes}}{\text{per-unit } Z} = \frac{1202.8}{0.049\ 16} = 24\ 470 \text{ A}$$

and the *X/R* ratio of the system impedance for the short circuit at F_1 is

$$X/R = \frac{0.048\ 11}{0.010\ 09} = 4.77$$

The reduction of the *R* and *X* networks at short-circuit location F_2 is shown in figures 4-25 and 4-26. The short-circuit current at F_2 is then calculated as follows:

The total impedance Z is

$$Z = \sqrt{R_2 + X_2} = \sqrt{(0.0319)^2 + (0.0657)^2} = 0.073 \text{ per unit}$$

The total three-phase symmetrical short-circuit current at F_2 is

$$\frac{\text{base amperes}}{\text{per-unit } Z} = \frac{1202.8}{0.073} = 16\ 480 \text{ A}$$

and the *X/R* ratio of the system impedance for the short circuit at F_2 is

$$X/R = \frac{0.0657}{0.0319} = 2.06$$

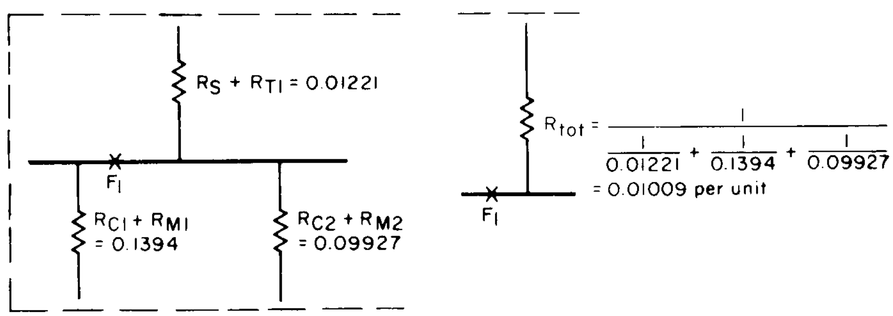


Figure 4-23—Reduction of R network for fault at F_1

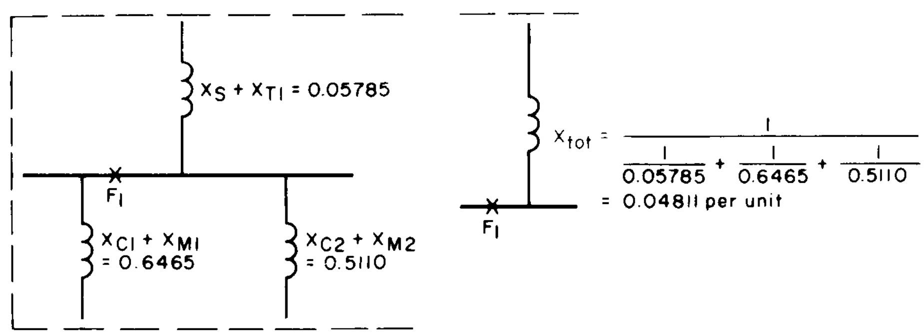


Figure 4-24—Reduction of X network for fault at F_1

4.7.4 Step 4: Draw separate resistance and reactance diagrams applicable for short circuits at the 120/240 V single-phase secondary of the 75 kVA transformer, and calculate fault currents

Per-unit calculations of short-circuit currents at the low-voltage side of a single-phase transformer connected line-to-line to a three-phase system may continue to use the same base, in this example 1000 kVA, but as a single-phase base. Impedances in the primary system connected to the transformer have double the values used for three-phase calculations to account for both outgoing and return paths of single-phase primary currents. This procedure assumes that the positive and negative sequence impedances are equal.

The total system three-phase short-circuit point impedance, as calculated above for a short circuit at F_1, consists of $R_s = 0.0101$ per unit and $X_s = 0.0481$ per unit. Since these are line-to-neutral values, they are doubled to obtain the line-to-line equivalents. Thus R_s becomes 0.0202 per unit and X_s becomes 0.0962 per unit.

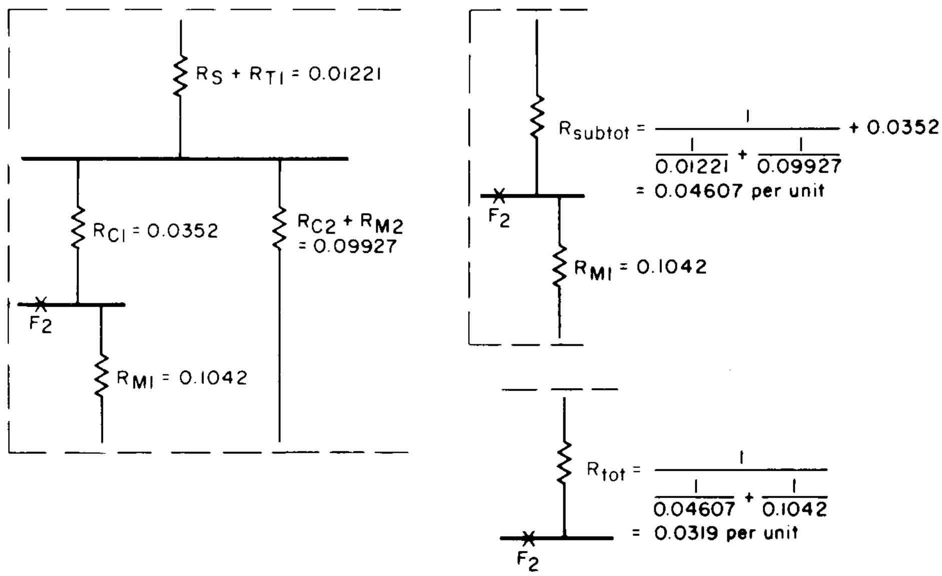


Figure 4-25—Reduction of R network for fault at F_2

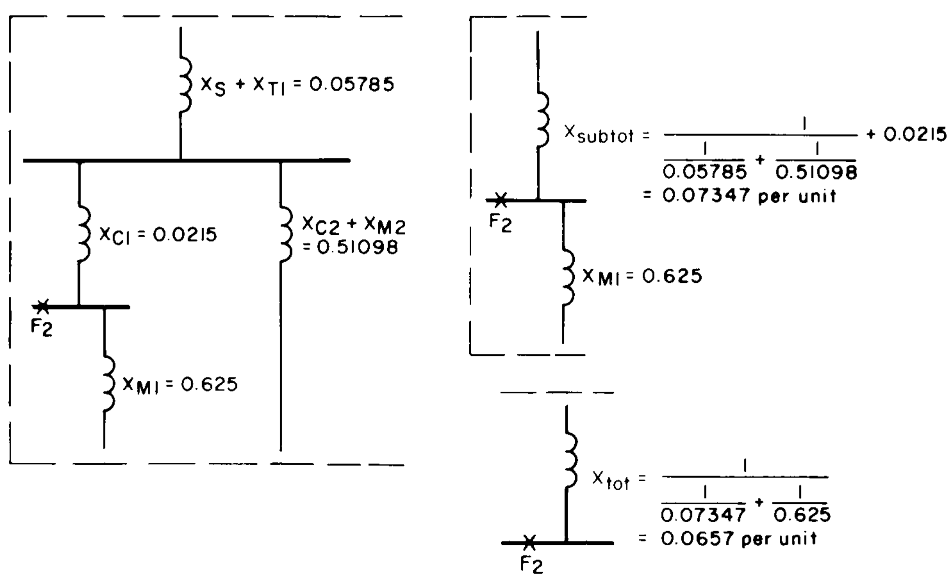


Figure 4-26—Reduction of X network for fault at F_2

The single-phase cable circuit C_3 was determined to have a per-unit line-to-neutral resistance R_{C3} equal to 0.0443 and a per-unit line-to-neutral reactance X_{C3} of 0.017 66. These values must also be doubled for the line-to-line short-circuit calculation, and become 0.0886 and 0.0353 per unit, respectively.

The 75 kVA transformer impedance, from a manufacturer's published tables, is 2.6% on the base rating of 75 kVA, including the full secondary winding. The impedance components are 1.2% resistance R_{T2} and 2.3% reactance X_{T2}.

The per-unit values on the common 1000 kVA base are as follows:

$$R_{T2} = \frac{\text{base kVA}}{\text{transformer kVA}} \cdot \frac{\%R_{T2}}{100} = \frac{1000}{75} \cdot \frac{1.2}{100} = 0.16 \text{ per unit}$$

$$X_{T2} = \frac{\text{base kVA}}{\text{transformer kVA}} \cdot \frac{\%X_{T2}}{100} = \frac{1000}{75} \cdot \frac{2.3}{100} = 0.3067 \text{ per unit}$$

For a line-to-line short circuit at F_3 across the 240 V secondary winding of the 75 kVA transformer, the applicable resistance and reactance diagrams are shown in figures 4-27 and 4-28. The total impedance Z is

$$Z = \sqrt{(0.2688)^2 + (0.4382)^2} = 0.5141 \text{ per unit}$$

the total short-circuit apparent power (in kVA) is

$$\frac{\text{base kVA}}{\text{per-unit } Z} = \frac{1000}{0.5141} = 1945 \text{ kVA}$$

and the total symmetrical rms short-circuit current is

$$\frac{\text{kVA (1000)}}{E_{\text{L-L}}} = \frac{1945 \cdot 1000}{240} = 8104 \text{ A}$$

For a line-to-line short circuit across the 120 V secondary of the 75 kVA transformer, the transformer resistance and reactance values are modified to compensate for the half winding effect. On the same 75 kVA base rating, impedances of one 120 V winding are obtained from those of the 240 V winding using a resistance multiplier of approximately 1.5 and a reactance multiplier of approximately 1.2. These multipliers are typical for a single-phase distribution class transformer. However, for greater accuracy, the transformer manufacturer should be consulted.

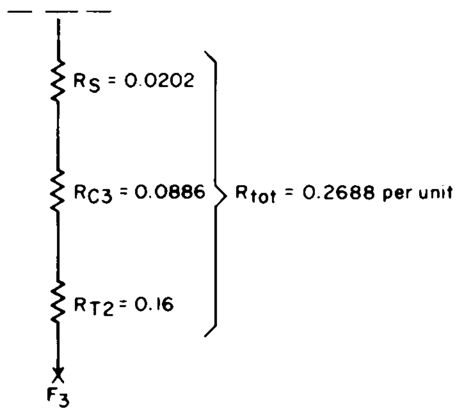


Figure 4-27—Resistance network for fault at F_3

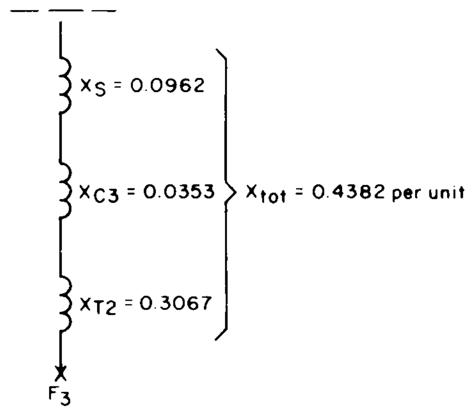


Figure 4-28—Reactance network for fault at F_3

For a short circuit at F_4 the resistance and reactance diagrams are shown in figures 4-29 and 4-30. The total impedance Z is

$$Z = \sqrt{(0.3488)^2 + (0.4995)^2} = 0.6092 \text{ per unit}$$

the total short-circuit apparent power (in kVA) is

$$\frac{\text{base kVA}}{\text{per-unit } Z} = \frac{1000}{0.6092} = 1642 \text{ kVA}$$

and the total symmetrical rms short-circuit current is

$$\frac{\text{kVA (1000)}}{E_{\text{L-L}}} = \frac{1642 \cdot 1000}{120} = 13\,683 \text{ A}$$

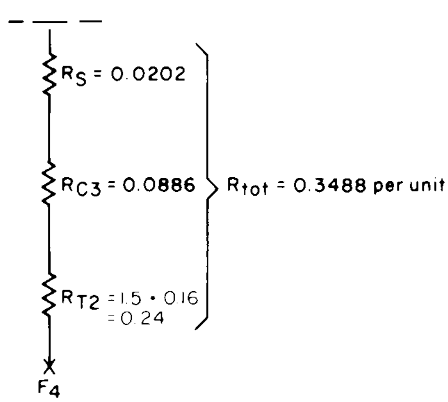


Figure 4-29—Resistance network for fault at F_4

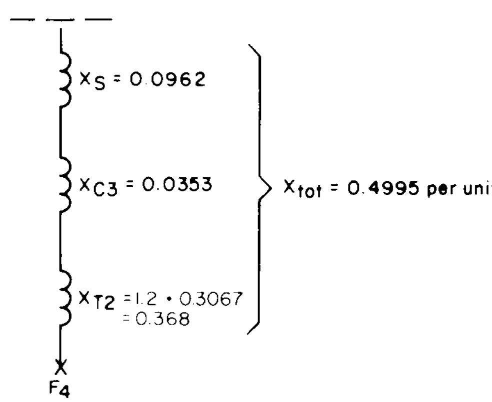


Figure 4-30—Reactance network for fault at F_4

4.8 Calculation of short-circuit currents for dc systems

The calculation of dc short-circuit currents is essential in the design and application of distribution and protective apparatus used in dc systems. A knowledge of mechanical stresses imposed by these fault currents is also important in the installation of cables, buses, and their supports.

As in the application of ac protective devices, the magnitude of the available dc short-circuit current is the prime consideration. Since high-speed or semi-high-speed dc protective devices can interrupt the flow of fault current before the maximum value is reached, it is necessary to consider the rate of rise of the fault current, along with the interruption time, in order to determine the maximum current that will actually be obtained. Lower speed protective devices will generally permit the maximum value to be reached before interruption.

The sources of dc short-circuit currents are the following:

a) Generators
b) Synchronous converters
c) Motors
d) Electronic rectifiers
e) Semiconductor rectifiers
f) Batteries
g) Electrolytic cells

Simplified procedures for the calculation of dc short-circuit currents are not well established; therefore, this chapter can only provide reference to publications containing helpful information (see ANSI C97.1-1972, IEEE Std C37.5-1979, IEEE Std C37.41-1988, NEMA AB 1-1975, and NEMA SG 3-1981).

4.9 References

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

ANSI C84.1-1989, American National Standard Electric Power Systems and Equipment—Voltage Ratings (60 Hz).[2]

ANSI C97.1-1972, American National Standard for Low-Voltage Cartridge Fuses 600 Volts or Less.

IEEE Std C37.010-1979, IEEE Application Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis (ANSI).[3]

[2]ANSI publications are available from the Sales Department, American National Standards Institute, 11 West 42nd Street, 13th Floor, New York, NY 10036, USA.

[3]IEEE publications are available from the Institute of Electrical and Electronics Engineers, Service Center, 445 Hoes Lane, P.O. Box 1331, Piscataway, NJ 08855-1331, USA.

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 (ANSI).[4]

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

IEEE Std C37.41-1988, IEEE Standard Design Tests for High-Voltage Fuses, Distribution Enclosed Single-Pole Air Switches, Fuse Disconnecting Switches, and Accessories (ANSI).

NEMA AB 1-1975, Molded-Case Circuit Breakers.[5]

NEMA SG 3-1981, Low-Voltage Power Circuit Breakers.

4.10 Bibliography

[B1] AIEE Committee Report, "Protection of Electronic Power Converters." *AIEE Transactions*, vol. 69, pp. 813–829, 1950.

[B2] Beeman, D. L., Ed., *Industrial Power Systems Handbook*. New York: McGraw-Hill, 1955, chapter 2.

[B3] Crites, W. R., and Darling, A. G., "Short-Circuit Calculating Procedure for DC Systems with Motors and Generators." *AIEE Transactions (Power Apparatus and Systems)*, pt. III, vol. 73, pp. 816–825, Aug. 1954.

[B4] Dortort, I. K., "Equivalent Machine Constants for Rectifiers." *AIEE Transactions (Communications and Electronics)*, pt. I, vol. 72, pp. 435–438, Sept. 1953.

[B5] Dortort, I. K., "Extended Regulation Curves for Six-Phase Double-Way and Double-Wye Rectifiers." *AIEE Transactions (Communications and Electronics)*, pt. I, vol. 72, pp. 192–202, May 1953.

[B6] *Electrical Transmission and Distribution Reference Book*. East Pittsburgh, PA: Westinghouse Electric Corporation, 1964.

[B7] Greenwood, A., "Basic Transient Analysis for Industrial Power Systems," Conference Record, 1972 IEEE Industrial and Commercial Power Systems and Electric Space Heating Joint Technical Conference, IEEE 72CHO600-7-IA, pp. 13-20.

[B8] Herskind, C. C., Schmidt, A., Jr., and Rettig, C. E., "Rectifier Fault Currents—II," *AIEE Transactions*, vol. 68, pp. 243–252, 1949.

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[4]IEEE Std C37.5-1979 has been withdrawn and is out of print; however, copies can be obtained from the IEEE Standards Department, IEEE Service Center, 445 Hoes Lane, P.O. Box 1331, Piscataway, NJ 08855-1331, USA.

[5]NEMA publications can be obtained from the National Electrical Manufacturers Association, 2101 L Street, NW, Washington, DC 20037, USA.

[B9] Huening, W. C., Jr., Interpretation of New American National Standards for Power Circuit Breaker Applications. *IEEE Transactions on Industry and General Applications*, vol. IGA-5, no. 5, Sept./Oct. 1969.

[B10] Reed, M. B., *Alternating Current Circuit Theory*, 2nd edition. New York: Harper and Brothers, 1956.

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

[B12] Stevenson, W. D., Jr., *Elements of Power System Analysis*. New York: McGraw-Hill, 1982.

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

Annex 4A
Typical impedance data for short-circuit studies

(informative)

The following tables and figures appear in this annex:

The following tables appear in other chapters:

Table 4A-1—Typical reactance values for induction and synchronous machines, in per unit of machine kVA ratings*

	X_d'	X_d''
Turbine generators†		
2 poles	0.09	0.15
4 poles	0.15	0.23
Salient-pole generators with damper windings†		
12 poles or less	0.16	0.33
14 poles or less	0.21	0.33
Synchronous motors		
6 poles	0.15	0.23
8–14 poles	0.20	0.30
16 poles or more	0.28	0.40
Synchronous condensers†	0.24	0.37
Synchronous converters†		
600 V direct current	0.20	—
250 V direct current	0.33	—
Individual large induction motors, usually above 600 V	0.17	—
Smaller motors, usually 600 V and below	See tables 4-1 and 4-2.	

NOTE—Approximate synchronous motor kVA bases can be found from motor horsepower ratings as follows:
0.8 power factor motor—kVA base = hp rating
1.0 power factor motor—kVA base = 0.8 · hp rating

*Use manufacturer's specified values if available.
†X_d' not normally used in short-circuit calculations.

Table 4A-2—Representative conductor spacings for overhead lines

Nominal system voltage (volts)	Equivalent delta spacing (inches)
120	12
240	12
480	18
600	18
2400	30
4160	30
6900	36
13 800	42
23 000	48
34 500	54
69 000	96
115 000	204

NOTE—When the cross section indicates conductors are arranged at points of a triangle with spacings *A*, *B*, and *C* between pairs of conductors, the following formula may be used:

$$\text{equivalent delta spacing} = \sqrt[3]{A \cdot B \cdot C}$$

When the conductors are located in one place and the outside conductors are equally spaced at distance *A* from the middle conductors, the equivalent is 1.26 times the distance *A*:

$$\text{equivalent delta spacing} = \sqrt[3]{A \cdot A \cdot 2A}$$
$$= 1.26A$$

Table 4A-3—Constants of copper conductors for 1 ft symmetrical spacing*

Size of conductor		Resistance R at 50 °C, 60 Hz	Reactance X_A at 1 ft spacing, 60 Hz
(cmil)	(AWG No.)	(Ω/conductor/1000 ft)	(Ω/conductor/1000 ft)
1 000 000		0.0130	0.0758
900 000		0.142	0.0769
800 000		0.0159	0.0782
750 000		0.0168	0.0790
700 000		0.0179	0.0800
600 000		0.0206	0.0818
500 000		0.0246	0.0839
450 000		0.0273	0.0854
400 000		0.0307	0.0867
350 000		0.0348	0.0883
300 000		0.0407	0.0902
250 000		0.0487	0.0922
211 600	4/0	0.0574	0.0953
167 800	3/0	0.0724	0.0981
133 100	2/0	0.0911	0.101
105 500	1/0	0.115	0.103
83 690	1	0.145	0.106
66 370	2	0.181	0.108
52 630	3	0.227	0.111
41 740	4	0.288	0.113
33 100	5	0.362	0.116
26 250	6	0.453	0.121
20 800	7	0.570	0.123
16 510	8	0.720	0.126

NOTE—For a three-phase circuit the total impedance, line to neutral, is $Z = R + j\,(X_A + X_B)$.

*Use spacing factors of X_B of tables 4A-5 and 4A-6 for other spacings.

Table 4A-4—Constants of aluminum cable, steel reinforced (ACSR), for 1 ft symmetrical spacing*

Size of conductor		Resistance R at 50 °C, 60 Hz	Reactance X_A at 1 ft spacing, 60 Hz
(cmil)	(AWG No.)	(Ω/conductor/1000 ft)	(Ω/conductor/1000 ft)
1 590 000		0.0129	0.0679
1 431 000		0.0144	0.0692
1 272 000		0.0161	0.0704
1 192 500		0.0171	0.0712
1 113 000		0.0183	0.0719
954 000		0.0213	0.0738
795 000		0.0243	0.0744
715 500		0.0273	0.0756
636 000		0.0307	0.0768
556 500		0.0352	0.0786
477 000		0.0371	0.0802
397 500		0.0445	0.0824
336 400		0.0526	0.0843
266 800		0.0662	0.0945
	4/0	0.0835	0.1099
	3/0	0.1052	0.1175
	2/0	0.1330	0.1212
	1/0	0.1674	0.1242
	1	0.2120	0.1259
	2	0.2670	0.1215
	3	0.3370	0.1251
	4	0.4240	0.1240
	5	0.5340	0.1259
	6	0.6740	0.1273

NOTE—For a three-phase circuit the total impedance, line to neutral, is $Z = R + j\,(X_A + X_B)$.

*Use spacing factors of X_B from tables 4A-5 and 4A-6 for other spacings.

Table 4A-5—60 Hz reactance spacing factor X_B, in ohms per conductor per 1000 ft

	Separation (inches)											
(ft)	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**
0	—	–0.0571	–0.0412	–0.0319	–0.0252	–0.0201	–0.0159	–0.0124	–0.0093	–0.0066	–0.0042	–0.0020
1	—	0.0018	0.0035	0.0051	0.0061	0.0080	0.0093	0.0106	0.0117	0.0129	0.0139	0.0149
2	0.0159	0.0169	0.0178	0.0186	0.0195	0.0203	0.0211	0.0218	0.0255	0.0232	0.0239	0.0246
3	0.0252	0.0259	0.0265	0.0271	0.0277	0.0282	0.0288	0.0293	0.0299	0.0304	0.0309	0.0314
4	0.0319	0.0323	0.0328	0.0333	0.0337	0.0341	0.0346	0.0350	0.0354	0.0358	0.0362	0.0366
5	0.0370	0.0374	0.0377	0.0381	0.0385	0.0388	0.0392	0.0395	0.0399	0.0402	0.0405	0.0409
6	0.0412	0.0415	0.0418	0.0421	0.0424	0.0427	0.0430	0.0433	0.0436	0.0439	0.0442	0.0445
7	0.0447	0.0450	0.0453	0.0455	0.0458	0.0460	0.0463	0.0466	0.0468	0.0471	0.0473	0.0476
8	0.0478											

Table 4A-6—60 Hz reactance spacing factor X_B, in ohms per conductor per 1000 ft

Separation (quarter inches)				
(inches)	**0**	**1/4**	**2/4**	**3/4**
0	—	—	–0.072 9	–0.063 6
1	–0.0571	–0.051 9	–0.047 7	–0.044 3
2	–0.0412	–0.038 4	–0.035 9	–0.033 9
3	–0.0319	–0.030 1	–0.028 2	–0.026 7
4	–0.0252	–0.023 8	–0.022 5	–0.021 2
5	–0.0201	–0.017 95	–0.017 95	–0.016 84
6	–0.0159	–0.014 94	–0.013 99	–0.013 23
7	–0.0124	–0.011 52	–0.010 78	–0.010 02
8	–0.0093	–0.008 52	–0.007 94	–0.007 19
9	–0.0066	–0.006 05	–0.005 29	–0.004 74
10	–0.0042	—	—	—
11	–0.0020	—	—	—
12	—	—	—	—

Table 4A-7—60 Hz impedance data for three-phase copper cable circuits, in approximate ohms per 1000 ft at 75 °C*

(a) Three single conductors

	In magnetic duct						In nonmagnetic duct					
AWG or kcmil	600 V and 5 kV nonshielded			5 kV shielded and 15 kV			600 V and 5 kV nonshielded			5 kV shielded and 15 kV		
	R	***X***	***Z***	***R***	***X***	***Z***	***R***	***X***	***Z***	***R***	***X***	***Z***
8	0.811	0.0754	0.814	0.811	0.0860	0.816	0.811	0.0603	0.813	0.811	0.0688	0.814
8 (solid)	0.786	0.0754	0.790	0.786	0.0860	0.791	0.786	0.0603	0.788	0.786	0.0688	0.789
6	0.510	0.0685	0.515	0.510	0.0796	0.516	0.510	0.0548	0.513	0.510	0.0636	0.514
6 (solid)	0.496	0.0685	0.501	0.496	0.0796	0.502	0.496	0.0548	0.499	0.496	0.0636	0.500
4	0.321	0.0632	0.327	0.321	0.0742	0.329	0.321	0.0506	0.325	0.321	0.0594	0.326
4 (solid)	0.312	0.0632	0.318	0.312	0.0742	0.321	0.312	0.0506	0.316	0.312	0.0594	0.318
2	0.202	0.0585	0.210	0.202	0.0685	0.214	0.202	0.0467	0.207	0.202	0.0547	0.209
1	0.160	0.0570	0.170	0.160	0.0675	0.174	0.160	0.0456	0.166	0.160	0.0540	0.169
1/0	0.128	0.0540	0.139	0.128	0.0635	0.143	0.127	0.0432	0.134	0.128	0.0507	0.138
2/0	0.102	0.0533	0.115	0.103	0.0630	0.121	0.101	0.0426	0.110	0.102	0.0504	0.114
3/0	0.0805	0.0519	0.0958	0.0814	0.0605	0.101	0.0766	0.0415	0.0871	0.0805	0.0484	0.0939
4/0	0.0640	0.0497	0.0810	0.0650	0.0583	0.0929	0.0633	0.0398	0.0748	0.0640	0.0466	0.0792
250	0.0552	0.0495	0.0742	0.0557	0.570	0.0797	0.0541	0.0396	0.0670	0.0547	0.0456	0.0712
300	0.0464	0.0493	0.0677	0.0473	0.0564	0.0736	0.0451	0.0394	0.0599	0.0460	0.0451	0.0644
350	0.0378	0.0491	0.0617	0.0386	0.0562	0.0681	0.0368	0.0393	0.0536	0.0375	0.0450	0.0586
400	0.0356	0.0490	0.0606	0.0362	0.0548	0.0657	0.0342	0.0392	0.0520	0.0348	0.0438	0.0559
450	0.0322	0.0480	0.0578	0.0328	0.0538	0.0630	0.0304	0.0384	0.0490	0.0312	0.0430	0.0531
500	0.0294	0.0466	0.0551	0.0300	0.0526	0.0505	0.0276	0.0373	0.0464	0.0284	0.0421	0.0508
600	0.0257	0.0463	0.0530	0.0264	0.0516	0.0580	0.0237	0.0371	0.0440	0.0246	0.0412	0.0479
750	0.0216	0.0445	0.0495	0.0223	0.0497	0.0545	0.0194	0.0356	0.0405	0.0203	0.0396	0.0445

NOTE—Resistance based on tinned copper at 60 Hz; 600 V and 5 kV nonshielded cable based on varnished cambric insulation; 5 kV shielded and 15 kV cable based on neoprene insulation.

*Resistance values (R_L) at lower copper temperatures (T_L) are obtained by using the formula $R_L = \frac{R_{75}(234.5 + T_L)}{309.5}$.

Table 4A-7—60 Hz impedance data for three-phase copper cable circuits, in approximate ohms per 1000 ft at 75 °C*

(b) Three-conductor cable

	In magnetic duct and steel interlocked armor						In nonmagnetic duct and aluminum interlocked armor					
AWG or kcmil	600 V and 5 kV nonshielded			5 kV shielded and 15 kV			600 V and 5 kV nonshielded			5 kV shielded and 15 kV		
	R	*X*	*Z*	*R*	*X*	*Z*	*R*	*X*	*Z*	*R*	*X*	*Z*
8	0.811	0.0577	0.813	0.811	0.0658	0.814	0.811	0.0503	0.812	0.811	0.0574	0.813
8 (solid)	0.786	0.0577	0.788	0.786	0.0658	0.789	0.786	0.0503	0.787	0.786	0.0574	0.788
6	0.510	0.0525	0.513	0.510	0.0610	0.514	0.510	0.0457	0.512	0.510	0.0531	0.513
6 (solid)	0.496	0.0525	0.499	0.496	0.0610	0.500	0.496	0.0457	0.498	0.496	0.0531	0.499
4	0.321	0.0483	0.325	0.321	0.0568	0.326	0.321	0.0422	0.324	0.321	0.0495	0.325
4 (solid)	0.312	0.0483	0.316	0.312	0.0508	0.317	0.312	0.0422	0.315	0.312	0.0495	0.316
2	0.202	0.0448	0.207	0.202	0.0524	0.209	0.202	0.0390	0.206	0.202	0.0457	0.207
1	0.160	0.0436	0.166	0.160	0.0516	0.168	0.160	0.0380	0.164	0.160	0.0450	0.166
1/0	0.128	0.0414	0.135	0.128	0.0486	0.137	0.127	0.0360	0.132	0.128	0.0423	0.135
2/0	0.102	0.0407	0.110	0.103	0.0482	0.114	0.101	0.0355	0.107	0.102	0.0420	0.110
3/0	0.0805	0.0397	0.0898	0.0814	0.0463	0.0936	0.0766	0.0346	0.0841	0.0805	0.0403	0.090
4/0	0.0640	0.0381	0.0745	0.0650	0.0446	0.0788	0.0633	0.0332	0.0715	0.0640	0.0389	0.0749
250	0.0552	0.0379	0.0670	0.0557	0.0436	0.0707	0.0541	0.0330	0.0634	0.0547	0.0380	0.0666
300	0.0464	0.0377	0.0598	0.0473	0.0431	0.0640	0.0451	0.0329	0.0559	0.0460	0.0376	0.0596
350	0.0378	0.0373	0.0539	0.0386	0.0427	0.0576	0.0368	0.0328	0.0492	0.0375	0.0375	0.0530
400	0.0356	0.0371	0.0514	0.0362	0.0415	0.0551	0.0342	0.0327	0.0475	0.0348	0.0366	0.0505
450	0.0322	0.0361	0.0484	0.0328	0.0404	0.0520	0.0304	0.0320	0.0441	0.0312	0.0359	0.0476
500	0.0294	0.0349	0.0456	0.0300	0.0394	0.0495	0.0276	0.0311	0.0416	0.0284	0.0351	0.0453
600	0.0257	0.0343	0.0429	0.0264	0.0382	0.0464	0.0237	0.0309	0.0389	0.0246	0.0344	0.0422
750	0.0216	0.0326	0.0391	0.0223	0.0364	0.0427	0.0197	0.0297	0.0355	0.0203	0.0332	0.0389

NOTE—Resistance based on tinned copper at 60 Hz; 600 V and 5 kV nonshielded cable based on varnished cambric insulation; 5 kV shielded and 15 kV cable based on neoprene insulation.

*Resistance values (R_L) at lower copper temperatures (T_L) are obtained by using the formula $R_L = \frac{R_{75}(234.5 + T_L)}{309.5}$.

Table 4A-8—60 Hz impedance data for three-phase aluminum cable circuits, in approximate ohms per 1000 ft at 90 °C*

(a) Three single conductors

	In magnetic duct						In nonmagnetic duct					
AWG or kcmil	600 V and 5 kV nonshielded			5 kV shielded and 15 kV			600 V and 5 kV nonshielded			5 kV shielded and 15 kV		
	R	*X*	*Z*	*R*	*X*	*Z*	*R*	*X*	*Z*	*R*	*X*	*Z*
6	0.847	0.053	0.849	—	—	—	0.847	0.042	0.848	—	—	—
4	0.532	0.050	0.534	0.532	0.068	0.536	0.532	0.040	0.534	0.532	0.054	0.535
2	0.335	0.046	0.338	0.335	0.063	0.341	0.335	0.037	0.337	0.335	0.050	0.339
1	0.265	0.048	0.269	0.265	0.059	0.271	0.265	0.035	0.267	0.265	0.047	0.269
1/0	0.210	0.043	0.214	0.210	0.056	0.217	0.210	0.034	0.213	0.210	0.045	0.215
2/0	0.167	0.041	0.172	0.167	0.055	0.176	0.167	0.033	0.170	0.167	0.044	0.173
3/0	0.133	0.040	0.139	0.132	0.053	0.142	0.133	0.037	0.137	0.132	0.042	0.139
4/0	0.106	0.039	0.113	0.105	0.051	0.117	0.105	0.031	0.109	0.105	0.041	0.113
250	0.0896	0.0384	0.0975	0.0892	0.0495	0.102	0.0894	0.0307	0.0945	0.0891	0.0396	0.0975
300	0.0750	0.0375	0.0839	0.0746	0.0479	0.0887	0.0746	0.0300	0.0804	0.0744	0.0383	0.0837
350	0.0644	0.0369	0.0742	0.0640	0.0468	0.0793	0.0640	0.0245	0.0705	0.0638	0.0374	0.0740
400	0.0568	0.0364	0.0675	0.0563	0.0459	0.0726	0.0563	0.0291	0.0634	0.0560	0.0367	0.0700
500	0.0459	0.0355	0.0580	0.0453	0.0444	0.0634	0.0453	0.0284	0.0535	0.0450	0.0355	0.0573
600	0.0388	0.0359	0.0529	0.0381	0.0431	0.0575	0.0381	0.0287	0.0477	0.0377	0.0345	0.0511
700	0.0338	0.0350	0.0487	0.0332	0.0423	0.0538	0.0330	0.0280	0.0433	0.0326	0.0338	0.0470
750	0.0318	0.0341	0.0466	0.0310	0.0419	0.0521	0.0309	0.0273	0.0412	0.0304	0.0335	0.0452
1000	0.0252	0.0341	0.0424	0.0243	0.0414	0.0480	0.0239	0.0273	0.0363	0.0234	0.0331	0.0405

NOTE—Cross-linked polyethylene insulated cable.

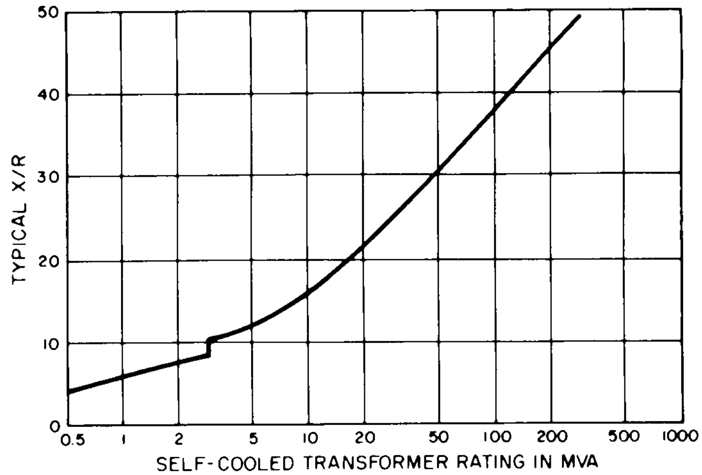
*Resistance values (R_L) at lower aluminum temperatures (T_L) are obtained by using the formula $R_L = \frac{R_{90}(228.1 + T_L)}{318.1}$.

Table 4A-8—60 Hz impedance data for three-phase aluminum cable circuits, in approximate ohms per 1000 ft at 90 °C*
(b) Three-conductor cable

	In magnetic duct						In nonmagnetic duct					
AWG or kcmil	600 V and 5 kV nonshielded			5 kV shielded and 15 kV			600 V and 5 kV nonshielded			5 kV shielded and 15 kV		
	R	***X***	***Z***	***R***	***X***	***Z***	***R***	***X***	***Z***	***R***	***X***	***Z***
6	0.847	0.053	0.849	—	—	—	0.847	0.042	0.848	—	—	—
4	0.532	0.050	0.534	—	—	—	0.532	0.040	0.534	—	—	—
2	0.335	0.046	0.338	0.335	0.056	0.340	0.335	0.037	0.337	0.335	0.045	0.338
1	0.265	0.048	0.269	0.265	0.053	0.270	0.265	0.035	0.267	0.265	0.042	0.268
1/0	0.210	0.043	0.214	0.210	0.050	0.216	0.210	0.034	0.213	0.210	0.040	0.214
2/0	0.167	0.041	0.172	0.167	0.049	0.174	0.167	0.033	0.170	0.167	0.039	0.171
3/0	0.133	0.040	0.139	0.133	0.048	0.141	0.133	0.037	0.137	0.132	0.038	0.138
4/0	0.106	0.039	0.113	0.105	0.045	0.114	0.105	0.031	0.109	0.105	0.036	0.111
250	0.0896	0.0384	0.0975	0.0895	0.0436	0.100	0.0894	0.0307	0.0945	0.0893	0.0349	0.0959
300	0.0750	0.0375	0.0839	0.0748	0.0424	0.0860	0.0746	0.0300	0.0804	0.0745	0.0340	0.0819
350	0.0644	0.0369	0.0742	0.0643	0.0418	0.0767	0.0640	0.0245	0.0705	0.0640	0.0334	0.0722
400	0.0568	0.0364	0.0675	0.0564	0.0411	0.0700	0.0563	0.0291	0.0634	0.0561	0.0329	0.0650
500	0.0459	0.0355	0.0580	0.0457	0.0399	0.0607	0.0453	0.0284	0.0535	0.0452	0.0319	0.0553
600	0.0388	0.0359	0.0529	0.0386	0.0390	0.0549	0.0381	0.0287	0.0477	0.0380	0.0312	0.0492
700	0.0338	0.0350	0.0487	0.0335	0.0381	0.0507	0.0330	0.0280	0.0433	0.0328	0.0305	0.0448
750	0.0318	0.0341	0.0466	0.0315	0.0379	0.0493	0.0309	0.0273	0.0412	0.0307	0.0303	0.0431
1000	0.0252	0.0341	0.0424	0.0248	0.0368	0.0444	0.0239	0.0273	0.0363	0.0237	0.0294	0.0378

NOTE—Cross-linked polyethylene insulated cable.

*Resistance values (R_L) at lower aluminum temperatures (T_L) are obtained by the formula $R_L = \frac{R_{90}(228.1 + T_L)}{318.1}$.



Source: Based on IEEE Std C37.010-1979.

Figure 4A-1—X/R ratio of transformers

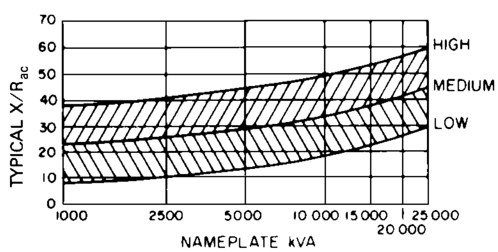


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Figure 4A-2—X/R range for small generators and synchronous motors (solid rotor and salient pole)

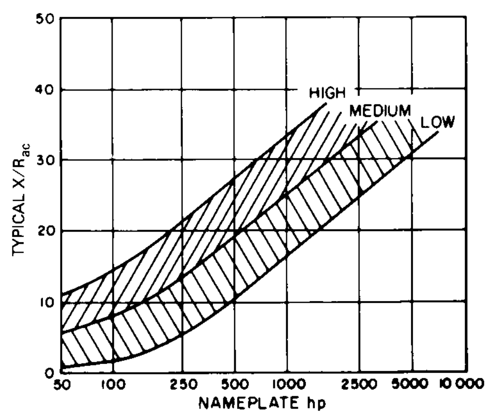

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Figure 4A-3—X/R range for three-phase induction motors