

Electrical Power Transmission System Engineering

Analysis and Design

FOURTH EDITION



Originally authored by
Turan Gönen

Revised and updated by
Yunhe Hou



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Electrical Power Transmission System Engineering

Today, there are various textbooks dealing with a broad range of topics in the power system area of electrical engineering. Some of them are considered to be classics. However, they do not particularly concentrate on topics dealing with electric power transmission. Therefore, **Electrical Power Transmission System Engineering: Analysis and Design**, as a textbook, is unique; it is written specifically for an in-depth study of modern power transmission engineering.

Written in the classic, self-learning style of the original, **Electrical Power Transmission System Engineering: Analysis and Design, Fourth Edition** is updated and features:

- HVDC system operation and control
- Renewable energy (including wind and solar energy)
- Detailed numerical examples and problems
- MATLAB® applications

This book includes a comprehensive and systematic introduction to electric power transmission systems, from basic transmission planning and concepts to various available types of transmission systems. Written particularly for a student or practicing engineer who may want to teach himself or herself, the basic material has been explained carefully, clearly, and in detail with numerous examples, which is also useful for professors. In addition to the detailed basic knowledge of transmission lines, new components enabling modern electronics and renewable penetrated transmission systems are emphasized. The discussion goes beyond the usual analytical and qualitative analysis to cover the overall aspects of transmission system analysis and design.



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*We are all ignorant, just
about different things.*

Mark Twain

*There is so much good in the worst of us,
And so much bad in the best of us,
That it little behooves any of us,
To talk about the rest of us.*

J. M.

*For everything you have missed,
You have gained something else;
And for everything you gain,
You lose something else.*

R. W. Emerson

Dedicated to my late brother, Zaim Suat Gönen, for giving me the motivation



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Preface

The structure of the electric power system is very large and complex. Nevertheless, its main components (or subsystems) can be identified as the generation system, transmission system, and distribution system. These three systems are the basis of the electric power industry. Today, there are various textbooks dealing with a broad range of topics in the power system area of electrical engineering. Some of them are considered to be classics. However, they do not particularly concentrate on the topics dealing with electric power transmission. Therefore, this text is unique; in that, it is written specifically for an in-depth study of modern power transmission engineering.

This book has evolved from the content of courses given by the author at California State University, Sacramento, the University of Missouri at Columbia, the University of Oklahoma, and Florida International University. It has been written for senior-level undergraduate and beginning-level graduate students, as well as practicing engineers in the electric power utility industry. The basic material has been explained carefully, clearly, and in detail with numerous examples. Each new term is clearly defined when it is first introduced. The special features of the book include ample numerical examples and problems designed to apply the information presented in each chapter. An effort has been made to familiarize the reader with the vocabulary and symbols used in the industry.

As a fourth edition of **Electrical Power Transmission System Engineering: Analysis and Design**, the text updates the previous edition by condensing parts of previously published contents and incorporating new technologies in transmission systems. The text is primarily divided into eight chapters, including topics such as transmission system planning; basic concepts, environmental impacts of transmission lines; transmission line parameters and the steady-state performance of transmission lines; AC transmission systems; DC transmission lines; overhead transmission lines and underground transmission and gas-insulated transmission lines; and renewable energy systems, for example, wind and solar energy. As a new edition, this text is particularly featured with knowledge of high-voltage direct-current systems and renewable energy in modern transmission systems.

This edition is accomplished under the valuable contributions of Chee-Wooi Ten with Electrical and Computer Engineering, Michigan Technological University. Acknowledgments also go to Ph.D. students at Dr. Yunhe Hou's group, Department of Electrical and Electronic Engineering, The University of Hong Kong, for their contributions to editing this book.

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Authors

Turan Gönen (deceased) was a professor of Electrical Engineering at California State University, Sacramento (CSUS). He received his BS and MS in Electrical Engineering from Istanbul Technical College (1964 and 1966, respectively) and his PhD in Electrical Engineering from Iowa State University (1975). Dr. Gönen also received an MS in Industrial Engineering (1973) and a PhD co-major in Industrial Engineering (1978) from Iowa State University, as well as an MBA from the University of Oklahoma (1980).

Professor Gönen was the director of the Electrical Power Educational Institute at CSUS. Prior to this, he was a professor of Electrical Engineering and the director of the Energy Systems and Resources Program at the University of Missouri-Columbia. Professor Gönen also held teaching positions at the University of Missouri-Rolla, the University of Oklahoma, Iowa State University, Florida International University, and Ankara Technical College. He taught electrical power engineering for over 40 years.

Professor Gönen had a strong background in the power industry. He worked as a design engineer in numerous companies in both the United States and abroad for eight years. He also served as a consultant for the United Nations Industrial Development Organization, Aramco, Black & Veatch Consultant Engineers, and the public utility industry. Recently, he was a consultant/senior engineer at the San Diego Gas and Electric company. Professor Gönen has written over 100 technical papers as well as four other books: *Modern Power System Analysis*, *Electric Power Distribution System Engineering*, *Electrical Machines*, and *Engineering Economy for Engineering Managers*.

Professor Gönen was a fellow of the Institute of Electrical and Electronics Engineers and a senior member of the Institute of Industrial Engineers. He served on several committees and working groups of the IEEE Power Engineering Society and was a member of numerous honor societies, including Sigma Xi, Phi Kappa Phi, Eta Kappa Nu, and Tau Alpha Pi. Professor Gönen received the Outstanding Teacher Award at CSUS in 1997 and 2009.

Yunhe Hou is an associate professor at the Department of Electrical and Electronic Engineering, The University of Hong Kong, Hong Kong.



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1 Transmission System Planning

It is curious that physical courage should be so common in the world and moral courage so rare.

Mark Twain

1.1 INTRODUCTION

An *electrical power system* can be considered to consist of a *generation system*, a *transmission system*, a *subtransmission system*, and a *distribution system*. In general, the generation and transmission systems are referred to as the *bulk power supply*, and the subtransmission and distribution systems are considered to be the final means to transfer the electric power to the ultimate customer.

In the United States, the alternating current (AC) transmission system was developed from a necessity to transfer large blocks of energy from remote generation facilities to load centers. As the system developed, transmission additions were made to improve reliability, achieve economic generation utilization through interconnections, and strengthen the transmission backbone with higher-voltage overlays. *Bulk power transmission* is made up of a high-voltage network, generally 138–765 kV AC, designed to interconnect power plants and electric utility systems and to transmit power from the plants to major load centers.

Table 1.1 gives the standard transmission voltages up to 700 kV as dictated by ANSI Standard C-84 of the American National Standards Institute (ANSI). In the United States and Canada, 138, 230, 345, 500, and 765 kV are the most common transmission grid voltages. In Europe, voltages of 130, 275, and 400 kV are commonly used for bulk power grid infrastructures.

The *subtransmission* refers to a lower-voltage network, normally 34.5–115 kV, interconnecting bulk power and distribution substations. The voltages that are in the range of 345–765 kV are classified as *extra-high voltages* (EHVs). The EHV systems dictate a very thorough system design. While, on the contrary, high-voltage transmission systems up to 230 kV can be built in relatively simple and well-standardized designs, voltages above 765 kV are considered as *ultra-high voltages* (UHV). Currently, the UHV systems, at 1,000, 1,100, 1,500, and 2,250 kV voltage levels, are in the R&D stages [1].

TABLE 1.1
Standard System Voltages Rating

Nominal (kV)	Maximum (kV)
34.5	36.5
46	48.3
69	72.5
115	121
138	145
161	169
230	242
345	362
500	550
700	765

Figures 1.1 and 1.2 show three-phase double-circuit transmission lines made of steel towers. Figure 1.3 shows the installation of a 345 kV double-circuit transmission tower made of a steel cage. Figure 1.4 shows a transmission line that is being upgraded.



FIGURE 1.1 A three-phase double-circuit transmission line made of steel towers.

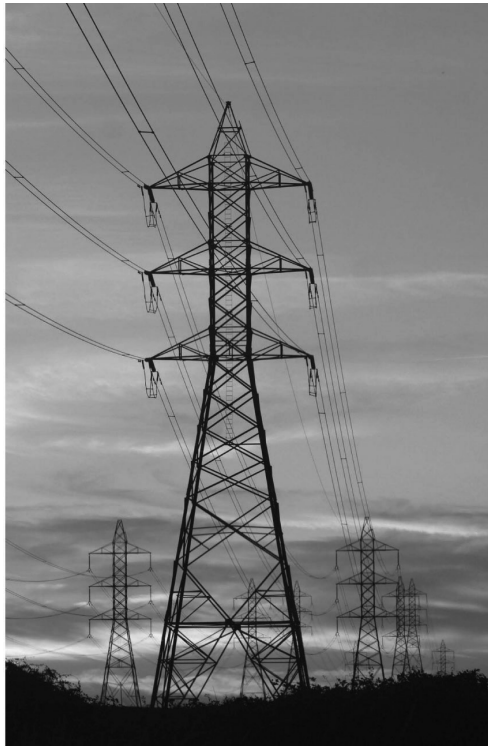


FIGURE 1.2 A three-phase double-circuit transmission line made of steel towers.



FIGURE 1.3 Installation of a 345 kV double-circuit transmission tower made of a steel cage.



FIGURE 1.4 A transmission line is being upgraded.

1.2 AGING TRANSMISSION SYSTEM

In the United States, the transmission network was built primarily in the 1950s or so to reliably serve local demands for power and interconnect neighboring utilities. By and large, it has done these without any significant problems. However, for the past 20 years, the growth of electricity demand has far outpaced the growth in transmission capacity. With limited new transmission capacity available, the loading of existing transmission lines has increased significantly. Since 1980, for example, the country’s electricity use has increased by 75%. Based on recent predictions, the demand will grow by another 30% within the next 10 years.

Nowadays, the transmission grid is also carrying a growing number of wholesale electricity transactions. Just in the last 5 years, the amount of these deals has grown by 300%. At times, this has left the transmission grid facing more requests for transmission than it can handle. This means that generation from distant sources, which can often be more economical, cannot get through. According to Fama [2], after recognizing the growing demand being placed on the transmission grid, today the utility industry is beginning to spend more money on new transmission lines and/or upgrading existing transmission lines. As indicated in Table 1.2, both integrated and stand-alone transmission companies are investing heavily to expand transmission capacity. During 1999–2003, for example, privately owned utilities increased their annual transmission investment by 12% annually, for a total of US \$17 billion. Through the year 2008, preliminary data indicated that utilities invested, or planned to invest, US \$28 billion more. This is a 60% increase over the previous 5 years.

However, even with this new spending, the continually increasing demand for electricity, together with the expanding number of wholesale market transactions, means that more investment will be necessary.

1.3 BENEFITS OF TRANSMISSION

The primary function of transmission is to transmit bulk power from sources of desirable generation to bulk power delivery points. Benefits have traditionally included lower electrical energy costs, access to renewable energy such as wind and hydro, locating power plants away from large population centers, and access to alternative generation sources when primary sources are not available.

In the past, transmission planning and its construction have been done by individual utilities with a focus on local benefits. However, today proponents of nationwide transmission policies now

TABLE 1.2
Actual and Planned Transmission Investment by
Privately Owned Integrated and Stand-Alone
Transmission Companies

	Actual Transmission	Planned Transmission
Year	Investment (in Million US \$)	Investment (in Million US \$)
1999	2,585	—
2000	3,614	—
2001	3,704	—
2002	3,785	—
2003	4,107	—
2004	—	4,567
2005	—	5,678
2006	—	6,041
2007	—	6,141
2008	—	6,111

TABLE 1.3
1980 Regional Transmission Lines in Miles

Region	Voltage (kV)						
	HVAC				HVDC		
	230	345	500	765	250	400/450	800
ECAR	934	9.850	796	1.387	0	0	0
ERCOT	0	4.110	0	0	0	0	0
MAAC	4.400	160	1.263	0	0	0	0
MAIN	258	4.852	0	90	0	0	0
MARCA (United States)	6.477	3.504	138	0	465	436	0
NPCC (United States)	1.557	3.614	5	251	0	0	0
SERC	16.434	2	4.363	0	0	0	0
SPP	3.057	2.843	1.432	0	0	0	0
WSCC (United States)	27.892	5.923	7.551	0	0	0	844
NERC (United States)	61.009	34.858	15.548	1.728	465	436	844

Source: National Electric Reliability Council, *10th Annual Review of Overall Reliability and Adequacy of the North American Bulk Power Systems*, NERC, Princeton, NJ, 1980.

consider the transmission system as an *enabler* of energy policy objectives at even the national level. According to Morrow and Brown [3], this view is reasonable since a well-planned transmission grid has the potential to provide for the following:

1. *Hedge against generation outages*: The transmission system should typically permit access to alternative economic energy sources to replace lost sources.
2. *Efficient bulk power markets*: Bulk power needs should be met by the lowest-cost generation, instead of by higher-cost electricity purchases to prevent violation of transmission loading constraints. (The difference between the actual price of electricity at the point of usage and the lowest price on the grid is called the *congestion cost*.)
3. *Operational flexibility*: The transmission system should permit for the economic scheduling of maintenance outages and for the economic reconfiguration of the grid when unforeseen events take place.
4. *Hedge against fuel price changes*: The transmission system should permit purchases to economically access generation from diversified fuel resources as a hedge against fuel disruptions due to various causes.
5. *Low-cost access to renewable energy*: The transmission system should usually permit developers to build renewable energy sources without the need for expensive transmission upgrades.

The aforementioned benefits are not fully achieved on a regional or national level, since planning has traditionally been focused on providing these benefits at the local level.

1.4 TRANSMISSION PLANNING

Transmission planning is closely related to generation planning. The objectives of transmission planning are to develop year-to-year plans for the transmission system based on existing systems, future load and generation scenarios, right-of-way constraints, cost of construction, line capabilities, and reliability criteria.

In general, transmission lines have two primary objectives: (1) to transmit electrical energy^l from the generators to the load centers within a single utility and (2) to provide paths for electrical energy

to flow between utilities. These latter lines are called *tie lines* and enable the utility companies to operate as a team to gain benefits that would otherwise not be obtainable. Interconnections, or the installation of transmission circuits across utility boundaries, influence both generation and transmission planning of each utility involved.

When power systems are electrically connected by transmission lines, they must operate at the same frequency, that is, the same number of cycles per second, and the pulse of the AC must be coordinated. As a corollary, generator speeds, which determine the frequency, must also be coordinated. The various generators are said to be *stable*.

A sharp or sudden change in loading at a generator will affect the frequency, but if the generator is strongly interconnected with other generators, they will normally help to absorb the effect on the changed loading so that the change in frequency will be negligible and the system stability unaffected. Hence, the installation of an interconnection affects generation planning substantially in terms of the amount of generation capacity required, the reserve generation capacity, and the type of generation capacity required for operation.

Also, interconnections may affect the generation planning through the installation of apparatus owned jointly by neighboring utilities and the planning of generating units with greater capacity than would be otherwise feasible for a single utility without interconnections. Furthermore, interconnection planning affects transmission planning by moving required bulk power deliveries away from or to interconnection substations, that is, bulk power substations, and often the addition of circuits on a given utility's own network [4].

Subtransmission planning includes planning activities for the major supply of bulk stations, subtransmission lines from the stations to distribution substations, and the high-voltage portion of the distribution substations.

Furthermore, distribution planning must take into consideration not only substation siting, sizing, number of feeders to be served, voltage levels, and type and size of the service area but also the coordination of overall subtransmission, and even transmission planning efforts, in order to ensure the most reliable and cost-effective system design [5].

1.5 TRADITIONAL TRANSMISSION SYSTEM PLANNING TECHNIQUES

The purpose of *transmission system planning* is to determine the timing and type of new transmission facilities required in order to provide adequate transmission network capability to cope with the future generating capacity additions and load-flow requirements.

Figure 1.5 shows a functional block diagram of a typical transmission system planning process. This process may be repeated, with diminishing detail, for each year of a long-range (15–20 years) planning horizon. The key objective is to minimize the long-range capital and operating costs involved in providing an adequate level of system reliability, with due consideration of environmental and other relevant issues.

Transmission planning may include not only existing but also new service areas. The starting point of the planning procedure is to develop load forecasts in terms of annual peak demand for the entire system, as well as for each region and each major present and future substation, and then find specific alternatives that satisfy the new load conditions. The system performance is tested under *steady-state* and *contingency* conditions.

The logic diagram for the transmission expansion study is shown in Figure 1.6. The main objective is to identify the potential problems, in terms of unacceptable voltage conditions, overloading of facilities, decreasing reliability, or any failure of the transmission system to meet performance criteria. After this analysis stage, the planner develops *alternative plans* or *scenarios* that not only will prevent the foreseen problems but also will best meet the long-term objectives of system reliability and economy. The effectiveness of the alternative plans is determined by *load-flow*, or *power-flow*, studies under both normal and emergency operations.

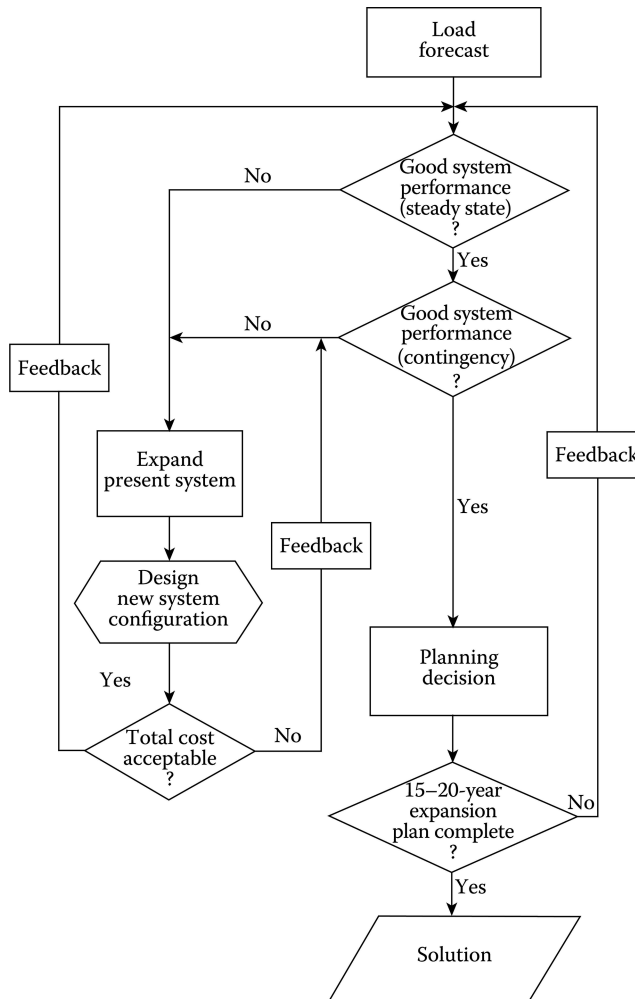


FIGURE 1.5 Block diagram of a typical transmission system planning process.

The load-flow programs now in use by the utilities allow the calculation of currents, voltages, and real and reactive power flows, taking into account the voltage-regulating capability of generators, transformers, synchronous condensers, specified generation schedules, as well as net interchange among interconnected systems, automatically. By changing the location, size, and number of transmission lines, the planner can achieve to design an economical system that meets the operating and design criteria.

After determining the best system configuration from load-flow studies, the planner studies the system behavior under fault conditions. The main objectives of short-circuit studies can be expressed as follows: (1) to determine the current-interrupting capacity of the circuit breaker so that the faulted equipment can be disconnected successfully, therefore clearing the fault from the system and (2) to establish the relay requirements and settings to detect the fault and cause the circuit breaker to operate when the current flowing through it exceeds the maximum allowable current.

The short-circuit studies can also be used to (1) calculate voltages during faulted conditions that affect insulation coordination and lightning arrester applications, (2) design the grounding systems, and (3) determine the electromechanical forces affecting the facilities of the system.

Finally, the planner performs stability studies in order to be sure that the system will remain stable following a severe fault or disturbance. Here, the *stability analysis* is defined as the transient

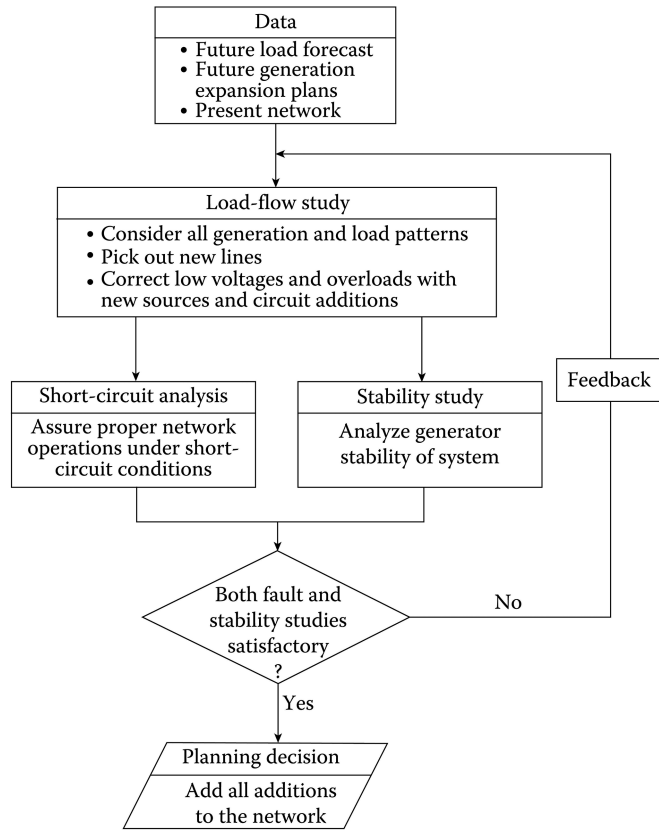


FIGURE 1.6 Logic diagram for the transmission expansion study.

behavior of the power system following a disturbance. It can be classified as transient stability analysis. The *transient stability* is defined as the ability of the system to maintain synchronous operation following a disturbance, usually a fault condition.

Unless the fault condition is cleared rapidly by circuit breakers, the generators, which are connected to each other through a transmission network, will get out with respect to one another, that is, they will *not run in synchronism*.

This situation, in turn, will cause large currents to flow through the network, transferring power from one generator to another in an oscillating way and causing the power system to become *unstable*. Consequently, the protective relays will detect these excessive amounts of currents and activate circuit breakers all over the network to open, causing a complete loss of power supply.

Usually, the first swing of rotor angles is considered to be an adequate indicator of whether or not the power system remains stable. Therefore, the simulation of the first few seconds following a disturbance is sufficient for transient stability. Whereas steady-state stability analysis is defined as long-term fluctuations in system frequency and power transfers resulting in *total blackouts*,² in this case, the system is simulated from a few seconds to several minutes.

There are various computer programs available for the planner to study the transient and steady-state stabilities of the system. In general, a *transient stability program* employs the data, in terms of initial voltages and power flows, provided by a load-flow program as the input and transforms the system to that needed for the transient stability analysis.

Usually, the *critical switching time*, that is, the time during which a faulted system component must be tripped to assure stability, is used as an indicator of *stability margin*. The critical switching

times are calculated for various fault types and locations. The resultant *minimum required clearing time* is compared to the actual relay and circuit breaker operating time.

If the relays and circuit breakers cannot operate rapidly enough to maintain stable operation, the planner may consider a change in the network design or a change in the turbine-generator characteristics or perhaps control apparatus.

1.6 TRANSMISSION ROUTE IDENTIFICATION AND SELECTION

Figure 1.7 shows a typical *transmission route (corridor)* selection procedure. The restricting factors affecting the process are safety, engineering and technology, system planning, institutional, economics, environmental, and aesthetics. Today, the planner selects the appropriate transmission route based on his knowledge of the system, results of the system analysis, and available ROWs.

However, recently, two computer programs, Power and Transthetics, have been developed to aid the planner in transmission route identification and selection [6–8]. The Power computer program can be used to locate not only transmission line corridors but also other types of corridors. In contrast, the Transthetics computer program is specifically designed for electrical utilities for the purpose of identifying and selecting potential transmission line corridors and purchasing the necessary ROWs.

1.7 TRADITIONAL TRANSMISSION SYSTEM EXPANSION PLANNING

In the past, the system planner was mostly used to use tools such as load-flow, stability, and short-circuit programs in analyzing the performance of specific transmission system alternatives. However, some utilities also employed the use of the so-called automatic expansion models to determine the optimum system.

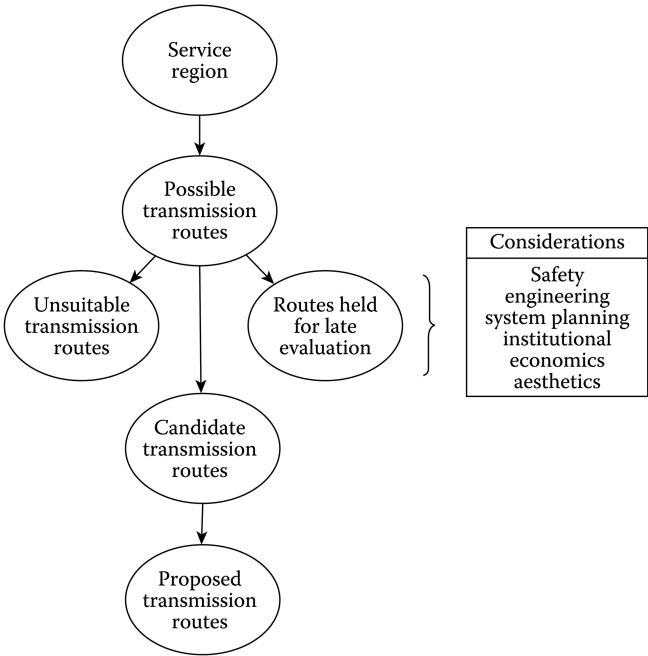


FIGURE 1.7 Transmission route selection procedure.

Here, the optimality claim is in the mathematical sense; that is, the optimum system is the one that minimizes an objective function (performance function) subject to restrictions. In general, the automatic expansion models can be classified into three basic groups:

1. Heuristic models
2. Single-stage optimization models
3. Time-phased optimization models

1.7.1 HEURISTIC MODELS

The primary advantage of the *heuristic models* was interactive planning. The system planner can observe the *expansion process* and direct its direction as it is desired. The characteristics of the heuristic models are (1) simple model and logic, (2) user interaction, and (3) families of *feasible, near-optimal* plans [9].

In contrast, the characteristics of the mathematical programming models are (1) no user interaction, (2) fixed model by program formulation, (3) detailed logic or restriction set definition, and (4) single *global* solution.

The heuristic models can be considered to be custom-made, contrary to mathematical models. Some help to simulate the way a system planner uses analytical tools such as load-flow programs [10] and reliability analysis [11] involving simulations of the planning process through automated design logic. The classical paper by Garver [12] describes a method that unites heuristic logic for circuit selection with optimization techniques. The proposed method is to determine the most direct route transmission network from generation to load without causing any circuit overloads. In the heuristic approach, the best circuit addition or exchange is given to the planner by the computer program automatically at each stage of the synthesis process. The planner may select to accept it or modify it as he desires. Further information on heuristic models is given in Baldwin et al. [13–16].

1.7.2 SINGLE-STAGE OPTIMIZATION MODELS

The *single-stage* or *single-state* (or the so-called *static*) optimization models can be used for determining the *optimum network expansion* from one stage to the next. But *they do not give the timing of the expansion*. Therefore, even though they provide an optimum solution for year-by-year expansion, they may not give the optimum solution for an overall expansion pattern over a time horizon. The mathematical programming techniques used in single-state optimization models include (1) linear programming (LP), (2) integer programming, and (3) gradient search method.

1.7.2.1 Linear Programming

LP is a mathematical technique that can be used to minimize or maximize a given linear function, called the *objective function* in which the variables are subject to linear constraints. The objective function takes the linear form

$$Z = \sum_{i=1}^n c_i x_i \quad (1.1)$$

where Z is the value to be optimized. (In expansion studies, Z is the total cost that is to be minimized.) The x_i represents n unknown quantities, and the c_i are the costs associated with one unit of x_i . The c_i may be positive or negative, whereas the x_i must be defined in a manner as to assume only positive values. The constraints, or restrictions, are limitations on the values that the unknowns may assume and must be a linear combination of the unknowns. The constraints assume the form

$$\sum a_{ji} =, \geq, \leq b_j \quad x_i \geq 0 \quad (1.2)$$

or

$$\begin{aligned} a_{11}x_1 + a_{12}x_2 + \cdots + a_{1n}x_n &=, \geq, \leq b_1 \\ a_{21}x_1 + a_{22}x_2 + \cdots + a_{2n}x_n &=, \geq, \leq b_2 \\ \vdots & \\ a_{m1}x_1 + a_{m2}x_2 + \cdots + a_{mn}x_n &=, \geq, \leq b_m \\ x_1 \geq 0, x_2 \geq 0, \dots, x_n &\geq 0 \end{aligned}$$

where

$$j=1, 2, \dots, m \text{ and } i=1, 2, \dots, n$$

where there are m constraints of which any number may be equalities or inequalities. Also, the number of constraints, m , may be greater than, less than, or equal to the number of unknowns, n . The coefficients of the unknowns, a_{ij} , may be positive, negative, or zero but must be constants. The b_j are also constants, which may be positive, negative, or zero. The constraints define a region of solution feasibility in n -dimensional space. The optimum solution is the point within this space whose x_i values minimize or maximize the objective function Z . In general, the solutions obtained are real and positive.

Here, the power flows are calculated using a *linear loss function network model* that is similar to a transportation model. This model uses Kirchhoff's current law (i.e., at each bus, the sum of all flows in and out must sum to zero) but not Kirchhoff's voltage law to specify flows. Instead, the model uses *guide potentials* to assure that conventional circuits are not overloaded. However, the flow model also uses *overload paths*, in which power can flow if required, to determine where circuit additions are to be added. The network is expanded one circuit at a time to eliminate the path with the largest overload until no overload paths exist. After the completion of the network expansion, the system is usually tested, employing an AC load-flow program. As mentioned, the method is also heuristic partly due to the fact that assigning the guide numbers involves a great deal of judgment [17,18]. A similar method has been suggested by Kaltenbach et al. [19]. However, it treats the problem more rigidly as an optimization problem.

1.7.2.2 Integer Programming

The term *integer programming* refers to the class of LP problems in which some or all of the decision variables are restricted to be integers. For example, in order to formulate the LP given in Equations 1.1 and 1.2 as an integer program, a binary variable can be introduced for each line to denote whether it is selected or not:

$$x_i = 1 \quad \text{if line } i \text{ is selected}$$

$$x_i = 0 \quad \text{if line } i \text{ is not selected}$$

Therefore,

$$\text{minimize } Z = \sum_{i=1}^n c_i x_i \quad (1.3)$$

Subject to

$$\sum_{i=1}^n a_{ji}x_i \leq b_j \quad x_i = 0,1 \quad (1.4)$$

where $j=1, 2, \dots, m$ and $i=1, 2, \dots, n$.

In general, integer programming is *more suitable* for the transmission expansion problem than LP because it takes into account the discrete nature of the problem; that is, a line component is either added or not added to the network. The integer program wherein all variables are restricted to be (0–1) integer valued is called a *pure integer program*. Conversely, if the program restricts some of the variables to be integers while others can take continuous (fractional) values, it is called a *mixed-integer program*.

In 1960, Knight [20,21] applied integer programming to the transmission expansion problem. Adams and Laughton [22] used mixed-integer programming for optimal planning of power networks. Lee et al. [23] and Sjelvgren and Bubenko [24] proposed methods that employ a combination of sensitivity and screening procedures to restrict the search on a limited number of new additions that are most likely to meet all restrictions.

The method proposed by Lee et al. [23] starts with a direct current (DC) load-flow solution to distinguish the overloaded lines as well as to compute the line-flow sensitivities to changes in admittances in all transmission corridors. In order to reduce the dimension of the integer programming problem in terms of the number of variables and therefore the computer time, it employs a screening process to eliminate ineffective corridors.

The resulting problem is then solved by a branch-and-bound technique. It adds capacity only in discrete increments as defined by the optimal capacity cost curves. The process is repeated as many times as necessary until all restrictions are satisfied. Further information on integer programming models is given in Gonen and Foote [25,26].

1.7.2.3 Gradient Search Method

The gradient search method is a nonlinear mathematical programming applicable to the so-called automated transmission system planning. Here, the objective function that is to be minimized is a performance index of the given transmission network.

The method starts with a *DC load-flow solution* for the initial transmission network and future load and generation forecasts. The system performance index is calculated, and the necessary circuit modifications are made using the partial derivatives of the performance index with respect to circuit admittances. Again, a DC load-flow solution is obtained, and the procedure is repeated as many times as necessary until a network state is achieved for which no further decrease in the performance index can be obtained.

The method proposed by Fischl and Puntel [27] applies Tellegen's theorem. The gradient information necessary to update the susceptances associated with effective line additions as aforementioned was implemented. More detailed information can also be found in Fischl and Puntel [28,29].

1.7.3 TIME-PHASED OPTIMIZATION MODELS

The single-stage transmission network expansion models do not take into account the timing of new installations through a given time horizon. Therefore, as Ref. [30] points out, there is a need for a *method of finding a sequence of yearly transmission plans which result in the lowest revenue requirements through time but which may be higher in cost than really needed in any one particular year*.

A *time-phased (through-time, or multistate, or the so-called dynamic)* optimization model can include inflation, interest rates, as well as yearly operating cost in the comparison of various network expansion plans.

Both integer programming and dynamic programming optimization methods have been used to solve the time-phased network expansion models [31]. The *integer programming* has been applied by dividing a given time horizon into numerous annual subperiods. Consequently, the objective function in terms of the present worth of a cost function is minimized in order to determine the capacity, location, and timing of new facilities subject to defined constraints [32].

The dynamic programming [28] has been applied to network expansion problems by developing a set of network configurations for each year (stage). Only those feasible plans (states) that satisfy the defined restrictions are accepted. However, as Garver [30] points out, the dynamic programming method has organized the search so that a minimum number of evaluations were necessary to find the lowest-cost expansion. However, the dynamic programming method by itself cannot introduce new plans (states); it only links given states together in an optimal manner.

Dusonchet and El-Abiad [33] applied discrete dynamic optimization employing a combination of dynamic programming, a random search, and a heuristic stopping criterion. Henault et al. [32] studied the problem in the presence of uncertainty. Mamandur and Berg [34] applied the *k-shortest paths* method to replace dynamic programming for transmission network expansion. The *k-shortest paths* technique [35] is employed to determine the expansion plans with the minimum costs.

1.8 TRADITIONAL CONCERNS FOR TRANSMISSION SYSTEM PLANNING³

In the previous sections, some of the techniques used by the system planning engineers of the utility industry performing transmission system planning have been discussed. Also, the factors affecting the transmission system planning have been reviewed. The purpose of this section is to examine what today's trends are likely to bring for the future of the planning process.

There are several traditional economic factors that will still have significant effects on the transmission system planning of the future. The first factor is inflation, which is fueled by energy shortages, energy source conversion costs, environmental concerns, and large government deficits; it will continue to play a major role.

The second important economic factor will still be the increasing expense of acquiring capital. As long as inflation continues to decrease the real value of the dollar, attempts will be made by the government to reduce the money supply. This, in turn, will increase the competition for attracting the capital necessary for expansions in power systems.

The third factor, which must be considered, is increasing difficulty in increasing customer rates. This rate increase *inertia* also stems in part from inflation as well as from the results of customers being made more sensitive to rate increases by consumer activist groups.

For the economic reasons listed earlier, transmission systems will become more expensive to build, expand, and modify. Thus, it is particularly important that each transmission system design be as cost-effective as possible. This means that the system must be optimal from many points of view over the time period from the first day of operation to the planning time horizon. In addition to the accurate load growth estimates, components must be phased in and out of the system so as to minimize capital expenditure, meet performance goals, and minimize losses.

In the utility industry, the most powerful force shaping the future is that of economics. Therefore, any new innovations are not likely to be adopted for their own sake. These innovations will be adopted only if they reduce the cost of some activity or provide something of economic value that previously had been unavailable for comparable costs. In predicting that certain practices or tools will replace current ones, it is necessary that one judge their acceptance on this basis.

The expected innovations that satisfy these criteria are planning tools implemented on a digital computer that deals with transmission systems in network terms. One might be tempted to conclude that these planning tools would be adequate for industry use throughout the future.

1.8.1 PLANNING TOOLS

Tools to be considered fall into two categories: network design tools and network analysis tools [36]. Analysis tools may become more efficient but are not expected to undergo any major changes, although the environment in which they are used will change significantly. This environment will be discussed in the next section.

Design tools, however, are expected to show the greatest development since better planning could have a significant impact on the utility industry. The results of this development will show the following characteristics:

1. Network design will be optimized with respect to many criteria using programming methods of operations research.
2. Network design will be only one facet of transmission system management directed by human engineers using a computer system designed for such management functions.
3. So-called network editors will be available for designing trial networks; these designs in digital form will be passed to extensive simulation programs that will determine if the proposed network satisfies performance and load growth criteria.

1.8.2 SYSTEMS APPROACH

A collection of computer programs to solve the analysis problems of a designer does not necessarily constitute an efficient problem-solving system nor even does such a collection when the output of one can be used as the input of another.

The systems approach to the design of a useful tool for the designer begins by examining the types of information required and its sources. The view taken is that this information generates decisions and additional information that pass from one stage of the design process to another. At certain points, it is noted that the human engineer must evaluate the information generated and add his inputs. Finally, the results must be displayed for use and stored for later reference.

With this conception of the planning process, the systems approach seeks to automate as much of the process as possible, ensuring in the process that the various transformations of information are made as efficiently as possible.

1.9 NEW TECHNICAL CHALLENGES

With authority over the rates, terms, and conditions of wholesale electric sales and transmission in interstate commerce, the Federal Energy Regulatory Commission plays an important role in stimulating investment in the grid.

Today, the primary technical challenges for the transmission planning are reliability and congestion. Here, reliability relates to unexpected transmission contingencies, including faults, and the ability of the system to respond to these contingencies without interrupting load. Congestion takes place when transmission reliability limitations dictate to use higher-cost generation than would be the case without any reliability constraints.

In the United States, transmission reliability is tracked and managed by the National Electric Reliability Council (NERC) which now serves as the federal electric reliability organization under the jurisdiction of the Federal Energy Regulatory Commission since 2006.

In the past, the main reliability consideration used by the NERC for transmission planning has been known as $N-1$. This concept can be explained as follows. For a system that has N main components, the $N-1$ criterion is satisfied if the system can perform satisfactorily with only $N-1$ components in service. A given $N-1$ analysis consists of a steady-state and a dynamic part.

The purpose of the steady-state analysis is to find out if the transmission system can withstand the loss of any single major piece of apparatus, such as a large transformer or a transmission line, without sacrificing voltage or equipment loading limits. On the other hand, the purpose of the dynamic analysis is to find out if the system can retain synchronism after all potential faults.

Up to now, $N-1$ has served the power industry well. But it has several challenges when applied to transmission planning today. The first one is its *deterministic nature*. That is, $N-1$ treats all contingencies as equal regardless of how likely such contingencies are to take place or the severity of consequences. The second one is the inability of $N-1$, and $N-2$, to take into account for the increased risk associated with a more heavily interconnected system and a more heavily loaded system.

According to Morrow and Brown [3], transmission system planners also face the problem of congestion. The basic congestion planning steps are as follows:

1. Hourly loads for an entire year are assigned to each bulk power delivery point.
2. A power flow is performed for each hour, taking into account scheduled generation and transmission maintenance.
3. If transmission reliability criteria are violated, the necessary corrective actions are taken. For example, generation redispatch is done until the restrictions are removed.
4. The additional energy costs due to these corrective actions are assigned to congestion costs.

In general, there are numerous ways to solve the existing congestion problems. However, it is difficult to combine congestion planning with reliability planning. Hence, a congestion simulation that takes into account for unplanned contingencies is required.

In the past, a transmission planner was mainly concerned with the transmission of bulk power to load centers without violating any local restrictions. Today, a transmission planner has to have a wide-area perspective, be aware of aging infrastructure, have an economic mindset, willing to coordinate extensively, and have the ability for effectively integrating new technologies with traditional methods.

Today, the North American power grid faces many challenges that it was not designed and built for properly handling them. On the one hand, congestion and atypical power flows threaten to overwhelm the transmission grid system of the country, while on the other hand, demand increases for higher reliability and improved security and protection. Because of the fact that modern infrastructure systems are so highly interconnected, a change in conditions at any location can have an immediate impact over a wide area. Hence, the effect of a local disturbance even can be magnified as it propagates through a network. The vulnerability of the US transmission grid to cascading effects has been demonstrated by the wide-area outages of the late 1990s and summer of 2003.

According to Amin and Wollenberg [37], power transmission systems in the United States also suffer from the fact that intelligence is only applied locally by protection systems and by central control through the supervisory control and data acquisition (SCADA) system. In some cases, the central control system is too slow. Also, the protection systems by design are only limited to the protection of specific components.

According to Amin and Wollenberg [37], based on the modern computer and communication technologies, the transmission system planners must think beyond the existing protection systems and the central control systems (i.e., the SCADA/energy management systems (EMS)/independent system operator (ISO) systems) to a fully distributed system that places intelligent devices at each component, substation, and power plant. Such distributed system will finally enable the utility industry to build a *truly smart transmission grid*.

PROBLEMS

Problem 1.1

Please list the differences between the static expansion planning approach and the time-phased expansion planning approach.

Solution:

The static expansion planning approach (also called single-stage or single-state) is used for determining the optimum network expansion schemes for year-by-year expansion. They do not consider the timing of the expansion and do not give the optimum solution for the overall expansion pattern over the whole study horizon.

The time-phased expansion planning approach considers inflation, interest rates, as well as yearly operating cost in comparison to various network expansion plans through a given time horizon. It provides a method of finding a sequence of yearly transmission plans, which result in the lowest revenue requirements through time but which may be higher in cost than really needed in any one particular year.

Problem 1.2

Please state the necessity of $N - 1$ reliability criteria and its limitations.

Solution:

The $N - 1$ criterion is satisfied if the system can perform satisfactorily with only $N - 1$ components in service. A given $N - 1$ analysis consists of a steady-state and a dynamic part.

The purpose of the steady-state analysis is to find out if the transmission system can withstand the loss of any single major piece of apparatus, such as a large transformer or a transmission line, without sacrificing voltage or equipment loading limits. The purpose of the dynamic analysis is to find out if the system can retain synchronism after all potential faults.

Limitations: (1) $N - 1$ treats all contingencies as equal regardless of how likely such contingencies are to take place or the severity of consequences. (2) The $N - 1$ principle fails to take into account for the increased risk associated with a more heavily interconnected system and a more heavily loaded system.

Problem 1.3

Please list the benefits of implementing the transmission system planning at a system level instead of a local utility level.

Solution:

1. Hedge against generation outages by permitting access to alternative economic energy sources to replace lost sources.
2. Efficient bulk power markets.
3. Operational flexibility by permitting for the economic scheduling of maintenance outages and for the economic reconfiguration of the grid when unforeseen events take place.
4. Hedge against fuel price changes by permitting access to generation from diversified fuel resources as a hedge against fuel disruptions due to various causes.
5. Low-cost access to renewable energy since the transmission system usually permits developers to build renewable energy sources without the need for expensive transmission upgrades.

NOTES

- 1 The term *energy* is being increasingly used in the electric power industry to replace the conventional term *power*. Here, they are used interchangeably.
- 2 The Institute of Electrical and Electronics Engineers (IEEE) has redefined *steady-state stability* to include the manifestation formerly included in both *steady-state* and *dynamic stabilities*. The purpose of this change is to bring American practice into agreement with international practice. Therefore, dynamic stability is no longer found in IEEE publications unless the reviewers happened to overlook the old usage.
- 3 This section is based on Gönen [4]. Included with permission from CRC Press.

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2 Transmission Line Structures and Equipment

I would have my ignorance rather than another man's knowledge, because I have so much of it.

Mark Twain

2.1 INTRODUCTION

The function of the overhead (OH) three-phase electric power transmission line is to transmit bulk power to load centers and large industrial users beyond the primary distribution lines. A given transmission system comprises all land, conversion structures, and equipment (such as step-down transformers) at a primary source of supply, including interconnecting transmission lines, switching, and conversion stations, between a generating or receiving point and a load center or wholesale point. It includes all lines and equipment whose main function is to increase, integrate, or tie together power supply sources.

2.2 DECISION PROCESS TO BUILD A TRANSMISSION LINE

The decision to build a transmission line results from system planning studies to determine how best to meet the system requirements. At this stage, the following factors need to be considered and established:

1. Voltage level
2. Conductor type and size
3. Line regulation and voltage control
4. Corona and losses
5. Proper load flow and system stability
6. System protection
7. Grounding
8. Insulation coordination
9. Mechanical design:
 - a. Sag and stress calculations
 - b. Conductor composition
 - c. Conductor spacing
 - d. Insulation and conductor hardware selection
10. Structural design:
 - a. Structure types
 - b. Stress calculations

Once the decision to build a particular transmission line has been reached, after considering all the previously mentioned factors, there is a critical path that needs to be followed in its design.

According to the Electric Power Research Institute (EPRI) [1], the critical path steps in an extra-high voltage (EHV) line design are as follows:

1. Define needs and list alternative system layouts.
2. Acquisition of Right-of-Way (ROW).

- 3. Load flow (i.e., power flow) and stability study.
- 4. Determine overvoltage.
- 5. Set performance criteria and formulate weather conditions.
- 6. Preliminary line design.
- 7. Specification of apparatus.
- 8. Purchase of apparatus.
- 9. Installation of station.
- 10. Economic conductor solution.
- 11. Electrical design of towers.
- 12. Lightning performance design.
- 13. Audible and radio noise (RN) analysis.
- 14. Addressing special design problems.
- 15. Insulation planning.
- 16. Final tower design.
- 17. Optimization of tower locations.
- 18. Line construction.
- 19. Fulfillment of power needs.

Figure 2.1 shows the order of these critical path steps in EHV line design. Further, the levels of various types of line compensation and other system impedances affect load flow, stability, voltage drop, and other transmission system performances. Accordingly, the most accurate transmission line performance computation must take all of these considerations into account and must be performed by using a digital computer program. The obtained results must be reflected in the transmission line design effectively.

The optimum line design is the design that meets all the technical specifications and the other requirements at the lowest cost. The process of finding such a line design with the lowest cost can be accomplished by using a computerized design. The transmission line design engineer can then quickly examine thousands of different combinations of line parameters by using such a computer design program to achieve the best solution. Table 2.1 gives some of the line design characteristics that affect the transmission line cost.

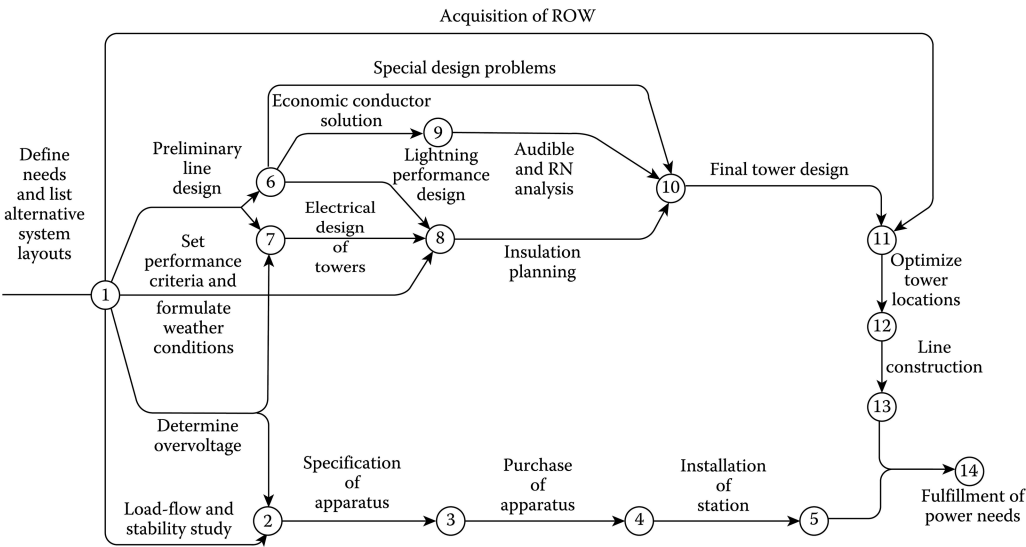


FIGURE 2.1 Critical path steps in an EHV line design. (From Electric Power Research Institute, 1979. Used by permission. © 1979 Electric Power Research Institute.)

TABLE 2.1
Line Design Characteristics Affecting Cost

Line voltage loading (MW)
Number of conductors
Number of circuits
Phase bundle configuration
Phase spacing
Insulation characteristics
Span length range
GWs: diameter, weight
Number, type, and cost of insulator units
Tower type
Wind pressure on conductors
Ice thickness
Unloaded loaded tension
Broken conductors and broken conductors' tension
Allowable conductor temperature

2.3 DESIGN TRADE-OFFS

There are also various design trade-offs that need to be considered in the areas of insulation, corona performance, and the environment. For example, with respect to insulation, a tower with legs of a small cross section inhibits switching-surge flashover in the gap between the conductor and the tower leg. Small tower legs increase tower inductance. Hence, the lightning performance is negatively affected.

In EHV and ultrahigh voltage (UHV) designs, increasing line height or adding auxiliary conductors for field control can reduce the maximum field under the line at the ground level and the field at the edge of the ROW. However, such a design would be expensive and suffer in appearance. Minimizing insulation clearances would decrease line costs but increase corona, especially at UHV. Since the corona effects are small, line compaction is most easily done at 69–110 kV voltage range designs.

In double-circuit line designs, there are trade-offs in the areas of corona and electric field for various phasing arrangements. For example, to improve the corona performance of a line, the tower-top configuration must have the nearby phases in the following order:

A	A
B	B
C	C

However, in such order while conductor surface gradients improve, the ground-level electric field increases. On the other hand, the following phase order is best for ground field and worse for corona performance [1]:

A	C
B	B
C	A

Note that the use of underbuilt auxiliary conductors and circuits with or without applied voltage would separate the relationship between the conductor surface electric field and the ground-level electric field. Also, in a single-circuit horizontal arrangement, the conductor surface gradient and the electric field at the edge of the ROW are affected by phase spacing. Hence, decreasing the phase spacing in a design would help its electric field but would negatively affect its conductor surface gradient. But, the use of a vertical design arrangement would change or tend to decouple this relationship [1].

2.4 TRADITIONAL LINE DESIGN PRACTICE

In the present practice, each support structure (i.e., pole or tower) supports a half-span of conductors and OH lines on either side of the structure. For a given line voltage, the conductors and the overhead ground wires (OHGWs) are arranged to provide, at least, the minimum clearance mandated by the National Electric Safety Code (NESC) in addition to other applicable codes. The resultant configuration is designed to control the following:

1. The separation of energized parts from other energized parts
2. The separation of energized parts from the support structures of other objects (located along the ROW)
3. The separation of energized parts above ground

The NESC divides the United States into three loading zones: heavy, medium, and light. It specifies the minimum load levels that must be employed within each loading zone. Furthermore, the NESC uses the concept of an *overload capacity factor* to take into account uncertainties resulting from the following factors:

1. Likelihood of occurrence of the specified load
2. Grade of construction
3. Dispersion of structure strength
4. Structure function, for example, suspension, dead end, and angle
5. Determination of strength during service life
6. Other line support components, for example, guys and foundations

In general, the following steps are used for the design of a transmission line:

1. A list of loading events is prepared by the utility company that would own the transmission lines. This list includes the following:
 - a. Mandatory regulations from the NESC and other codes
 - b. Possible climatic events that are expected in the loading zone in which the line is located
 - c. Specific contingency loading events such as broken conductors
 - d. Expectations and special requirements

Note that each of these loading events is multiplied by its own overload capacity factor to take care of uncertainties involved to come up with an agenda of final ultimate design loads.

2. A ruling span is determined according to sag/tension requirements of the preselected conductor.
3. A structure type is selected based on past experience or on possible suppliers' recommendations.
4. Ultimate design loads due to the ruling span are applied statistically as components in the longitudinal, transverse, and vertical directions and the structure is deterministically designed.

5. Ground line reactions are calculated and used to design the foundation by using the loads and structure configuration.
6. The ruling span line configuration is adjusted to fit the actual ROW profile.
7. To adjust for variations in actual span lengths and changes in elevation and running angles, the structure/foundation designs are modified.
8. Since the tangent structures are the weakest link in the line, accordingly, hardware, insulators, and other accessory components are selected to be stronger than the structure.

2.4.1 FACTORS AFFECTING STRUCTURE-TYPE SELECTION

According to Pholman [2], there are usually many factors that affect the determination of the structure type to be used in a given OH transmission line design. Some of them are listed as follows:

1. *Public concerns*: In order to take into account the general public, living, working, or coming into proximity to the line, it is customary to have hearings as part of the approval process for a new transmission line. To hold such public meetings that are satisfactory is a prerequisite for the required permit.
2. *Erection technique*: In general, different structure types dictate different erection techniques. For example, a tapered steel pole is probably to be manufactured in a single piece and erected directly on its previously installed foundation in one hoist. Steel lattice towers have hundreds of individual parts that must be bolted together, assembled, and erected onto the four previously installed foundations.
3. *Inspection, assessment, and maintenance*: The structures are inspected by human inspectors who may use diagnostic technologies in addition to their personal inspection techniques. Some of the techniques may involve observations from the ground or fly-by patrol: Climbing, bucket trucks, or the use of helicopters. The necessary line maintenance activities are also needed to be considered.
4. *Possible future upgrade or uprating*: It is difficult to get the necessary ROWs and required permits to build new transmission lines. Because of these considerations, some utilities select structure types for new transmission lines in a manner that would allow easy upgrading and/or uprating, if needed in the future.

2.4.2 IMPROVED DESIGN APPROACHES

Today, there are many techniques to assess the true capability of an OH transmission line that was designed by using the conventional practice of specifying ultimate static loads and designing a structure that would properly support them.

So far, the best technique was developed by Ostendorp [3] and is presently under development by CIGRE Study Committee 22: *Recommendations for Overhead Lines* [4]. This technique is known as “improved design criteria of overhead transmission lines based on reliability concepts.” It is based on the concept that loads and strengths are statistical variables and the combined reliability is computable if the statistical functions of loads and strengths are known. The flow diagram of the methodology of this technique is shown in Figure 2.2. The steps of this recommended methodology for designing transmission line components are as follows:

1. Collect preliminary line design data and available climatic data.
2. Do the following in this step:
 - a. Select the reliability level in terms of the return period of design loads.
 - b. Select the security requirements (failure containment).
 - c. List safety requirements imposed by mandatory regulations and construction and maintenance loads.

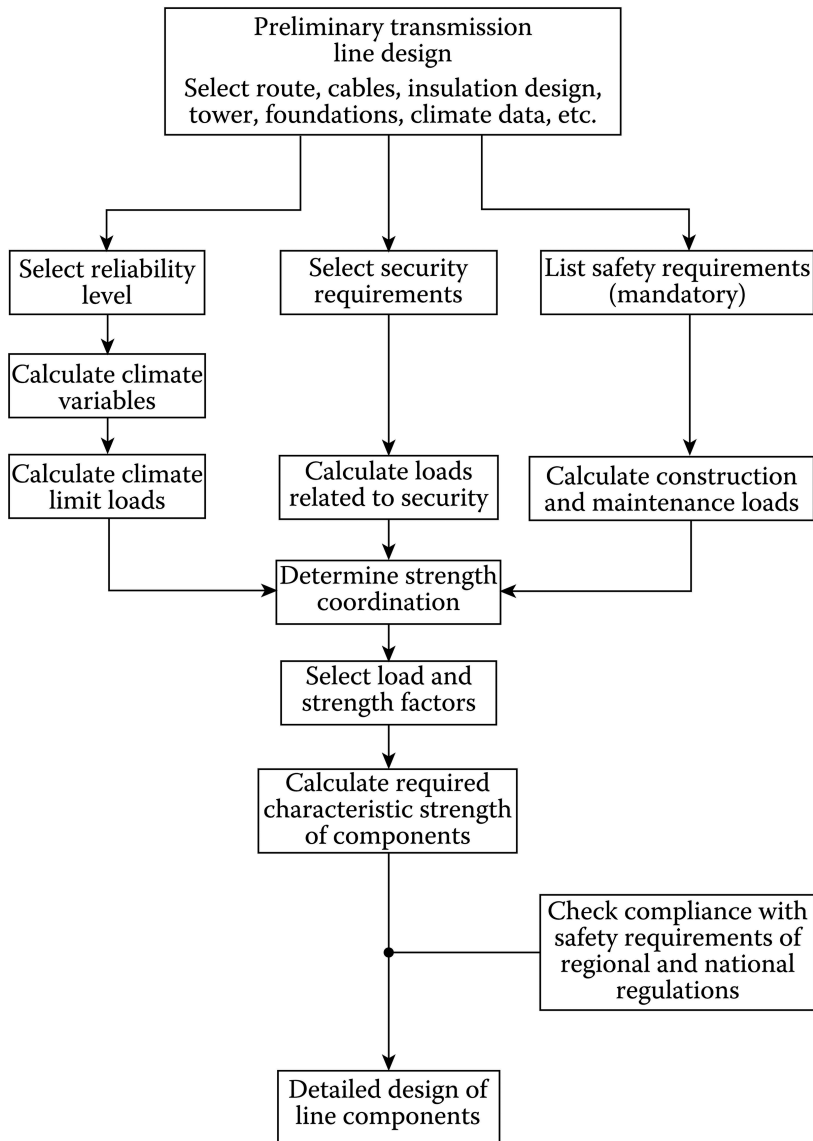


FIGURE 2.2 The methodology involved in developing improved design criteria of OH transmission lines based on reliability concepts.

3. Calculate climatic variables corresponding to the selected return period of design loads.
4. Do the following in this step:
 - a. Calculate climatic limit loadings on components.
 - b. Calculate loads corresponding to security requirements.
 - c. Calculate loads related to safety requirements during construction and maintenance.
 - d. Determine the suitable strength coordination between line components.
5. Select appropriate load and strength equations.
6. Calculate the characteristic strengths required for components.
7. Design line components for the strength requirements.

2.5 TRANSMISSION LINE STRUCTURES

In order to put it into a historical perspective, it should be mentioned that it was in late 1887 when Tesla filed for several patents in the field of polyphase AC systems. Among them was a patent on power transmission. Among polyphase systems, Tesla strongly preferred two-phase configurations. In 1893, George Westinghouse and his Niagara Falls Power Company decided on the adoption of polyphase (two phases) AC. Later in August 1895, the power system went into operation, including a higher-voltage transmission line in Buffalo, New York, about 20 mi away. In 1903, when the next Niagara plant extension took place, the new AC generators were built with three phases, as were all the following plant additions. However, the birth of the first long-distance three-phase power transmission was achieved by Swiss engineers in 1891. This 30 kV transmission line was connected between Lauffen and Frankfurt by means of Tesla's system.

As displayed in Table 1.1, the standard transmission voltages are continuously creeping up historically. In the design of a system, the voltage selected should be the one best suited for the particular service on the basis of economic considerations. The AC transmission system in the United States developed from a necessity to transfer large blocks of energy from remote generation facilities to load centers. As the system grew, transmission additions were made to improve reliability, achieve economic generation utilization through interconnections, and strengthen the transmission backbone with higher-voltage overlays.

Numerous transmission lines with 115–230 kV are used as primary transmission or become underlay to higher-voltage lines. At the end of 1974, about 85% (i.e., 208,000 mi) of transmission lines in service in the United States were in the range of 115–230 kV. Today, it is estimated that this class of transmission lines is about more than half of the total transmission lines of all classes.

In general, the basic structure configuration selected depends on many interrelated factors, including aesthetic considerations, economics, performance criteria, company policies and practice, line profile, ROW restrictions, preferred materials, and construction techniques.

2.5.1 COMPACT TRANSMISSION LINES

For a long time (about 30 years), the transmission lines in the 115–230 kV class saw very little change in design practices than the previous ones. But, in the 1960s, this voltage class saw major changes due to two reasons: (1) the induction of prefabricated steel poles, laminated structures, and armless structures and (2) the increasing difficulties in obtaining new ROWs due to increasing environmental pressures that, in turn, forced the utilities to update the existing 69 kV circuits to 138 kV circuits and 138 kV circuits to 230 kV circuits. This trend has demonstrated the applicability of EHV technology to lower voltage circuits.

Later, the practicality of using vertical postinsulators and 3 ft phase-to-phase spacing on a wood pole line was demonstrated on a 138 kV transmission line at Saratoga, New York, in 1973. Other applications verified that compact 138 kV constructions were feasible in 1974. Figure 2.3 shows typical compact configurations for horizontal unshielded, horizontal shielded, vertical, delta, and vertical delta.

Several provisions of the NESC are directly applicable to 138 kV compact lines, especially in the areas of phase-to-phase spacing and maintenance clearances. Compact lines, due to reduced design margins, dictate more rigorous analysis of insulation and mechanical parameters to ensure adequate reliability than is needed for conventional lines.

2.5.2 CONVENTIONAL TRANSMISSION LINES

Higher-voltage lines with higher loading capabilities continue to experience higher growth rates. As loads grow, 765 kV is a logical voltage for the overlay of 345 kV having a previous underlay of 138 kV. Similarly, 500 kV will continue to find its place as an overlay of 230 and 161 kV. Here, higher

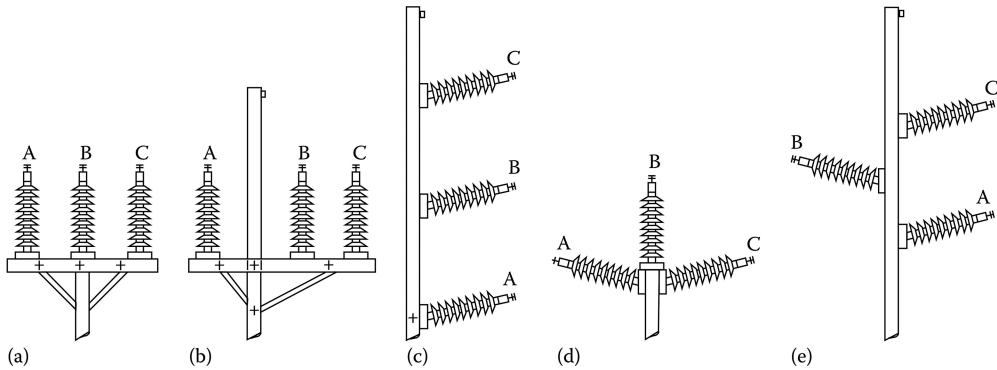


FIGURE 2.3 Typical compact configurations (not to scale): (a) horizontal unshielded, (b) horizontal shielded, (c) vertical, (d) delta, and (e) vertical delta. (From Electric Power Research Institute, *Transmission Line Reference Book: 115–138 kV Compact Line Design*, 2nd edn., EPRI, Palo Alto, CA, 1978. Used by permission. © 1978 Electric Power Research Institute.)

voltages mean higher power transfer capability, as can be observed from the surge impedance loading capabilities of typical EHV transmission lines. Some power systems rate their transmission voltages by the nominal voltages; others may use the maximum voltage. Typically, 345, 500, 700, and 765 kV and their corresponding maximums are classified as EHV. They are used extensively and commercially in the United States and are gaining popularity in other parts of the world. In addition, 380 or 400 kV EHV transmission is used mainly in Europe.

EHV systems require an entirely new concept of system design. Contrarily, voltages of 230 kV and below are relatively simple and well standardized in design and construction practices. EHV dictates complete and thorough reconsideration of all normally standardized design features, such as the necessity for bundled conductors and switching surges that control the insulation, corona, radio interference, lightning protection, line-charging current, clearances, and construction practices.

The 345 kV system established the practice of using bundle conductors, the V-configuration of insulator strings (to restrain conductor swinging), and the use of aluminum in line structures. The first 500 kV transmission line was built in 1964 to tie a mine-mouth power plant in West Virginia to load centers in the eastern part of the state. The main reason for preferring to use 500 kV over the 345 kV voltage level was that upgrading from 230 to 345 kV provided a gain of only 140% increase in the amount of power that can be transmitted in comparison to a 400% gain that can be obtained by using the 500 kV level.

Also in 1964, Hydro-Quebec inaugurated its 735 kV 375-mi line. A line voltage of 765 kV was introduced into service by American Electric Power Co. Inc. (AEP) in 1969. The 1980s witnessed the Bonneville Power Administration's (BPA) 1,100 kV transmission line.

The trend toward higher voltages is basically motivated by the resulting increased line capacity while reducing line losses. The reduction in power losses is substantial. Also, the better use of land is a side benefit as the voltage level increases. For example, for building a transmission line with a capacity of 10,000 MW, a ROW width of 76 m is required for a 500 kV line having a double circuit, whereas the required ROW width for a 1,100 kV line is only 56 m.

The power transmission voltages above 765 kV, generally in the range of 1,100 and 1,500 kV, are known as the UHVs. They are subject to intensive research and development before they can be included in practical line designs and apparatus for commercial service. The problems associated with UHV transmission include audible noise (AN), RN, electrostatic field effects, contamination, and switching overvoltages. However, research into higher-voltage transmission will help utilities to transmit up to six times the electric power possible with the lines in use in the 1970s. But, it is well known that engineering and physical problems become more complex at operating voltages above 765 kV.

2.5.3 DESIGN OF LINE SUPPORT STRUCTURES

After the proper considerations of voltage drop, power loss, thermal overloading, and other considerations, the design of a transmission line has simply become an adaptation of available standard designs to best fit the requirements of a particular job at hand. Otherwise, designing a complete transmission line from scratch is a complex and tedious process.

However, once a good design is developed, it can be used repeatedly or it can be adapted to the situation at hand easily. Using computers and standard line designs, a new line can be designed rather quickly. In general, companies only change a standard structure after much consideration and after the proper testing and production of the necessary materials. In the United States, originally, three engineering companies were responsible for all of the design work for 80% of the transmission lines. Eventually, the best of all available designs was adopted and used in all designs in the country.

Also, conductors, fittings, and hardware were standardized by the IEEE and the National Electrical Manufacturing Association. Towers were standardized by major steel tower manufacturers.

Furthermore, the federal government is also in the electric power business with the Tennessee Valley Authority, BPA, and Bureau of Water Power and the Rural Electrification Association (REA). The use of the design guides prepared by the REA is mandatory for all borrowers of federal funds through the REA program.

Figure 2.4 shows typical pole- and lattice-type structures for 345 kV transmission systems. The construction of OH lines will not be discussed in detail here. Figure 2.5 shows typical wood H-frame-type structures for 345 kV transmission systems. Figure 2.6 shows typical pole- and lattice-type structures for 500 kV transmission systems. Figure 2.7 shows typical pole- and lattice-type structures for 735–800 kV transmission systems. Figure 2.8 shows a typical 230 kV transmission line steel tower with bundled conductors and double circuit.

2.6 SUBTRANSMISSION LINES

The subtransmission system is the part of the electric utility system that delivers power from the bulk power sources, such as large transmission substations. The subtransmission circuits may be made of OH open-wire construction or wood poles with post-type insulators. Steel tubes or concrete towers are also used. The line has a single conductor in each phase. Postinsulators hold the conductor without metal crossarms.

One grounded shield conductor located on the top of the tower provides the necessary shielding for the phase conductors against lightning. The shield conductor is grounded at each tower or pole. Plate or vertical tube electrodes, also known as *ground rods*, are used for grounding. Occasionally, the subtransmission lines are also built using underground cables.

The voltage of these circuits varies from 12.47 to 230 kV, with the majority at 69, 115, and 138 kV voltage levels. There is a continuous trend in the usage of higher voltages as a result of the increasing use of higher primary voltages. Typically, the maximum length of subtransmission lines is in the range of 50–60 mi. In cities, most subtransmission lines are located along streets and alleys.

The subtransmission system designs vary from simple radial systems to a subtransmission network. The major considerations affecting the design are cost and reliability. Figure 2.9 shows a radial subtransmission system. It is a simple system and has a low first cost but also has low service continuity. Because of this, the radial system is not generally used. Instead, an improved form of radial-type subtransmission design is preferred, as shown in Figure 2.10. It allows relatively faster service restoration when a fault occurs on one of the subtransmission circuits.

In general, due to higher service reliability, the subtransmission system is designed as loop circuits or multiple circuits, forming a form of subtransmission grid or network. Figure 2.11 shows a loop-type subtransmission system. In this design, a single circuit originating from a bulk power bus runs through a number of substations and returns to the same bus.

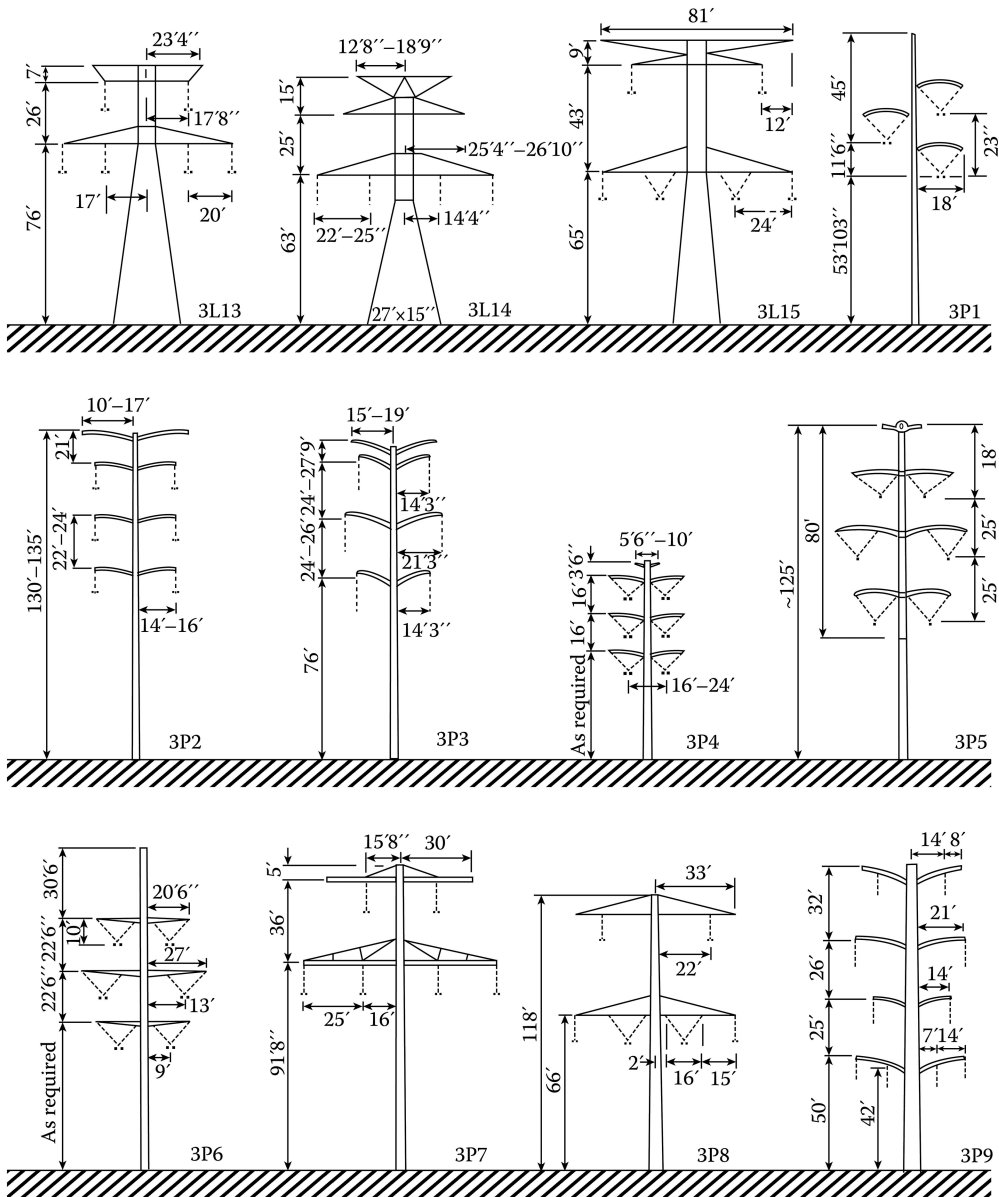


FIGURE 2.4 Typical pole- and lattice-type structures for 345 kV transmission systems. (From Electric Power Research Institute, *Transmission Line Reference Book: 345 kV and Above*, 2nd edn., EPRI, Palo Alto, CA, 1982. Used with permission. © 1979 Electric Power Research Institute.)

Figure 2.12 shows a grid-type subtransmission that has multiple circuits. Here, the distribution substations are interconnected, and the design may have more than one bulk power source. Therefore, it has the greatest service reliability, but it requires costly control of power flow and relaying. It is the most commonly used form of subtransmission.

Occasionally, a subtransmission line has a double circuit, having a wooden pole and post-type insulators. Steel tubes or concrete towers are also used. The line may have a single conductor or bundled conductors in each phase. Postinsulators carry the conductors without metal crossarms. One grounded shield conductor (or OHGW) on the top of the tower shields the phase conductors

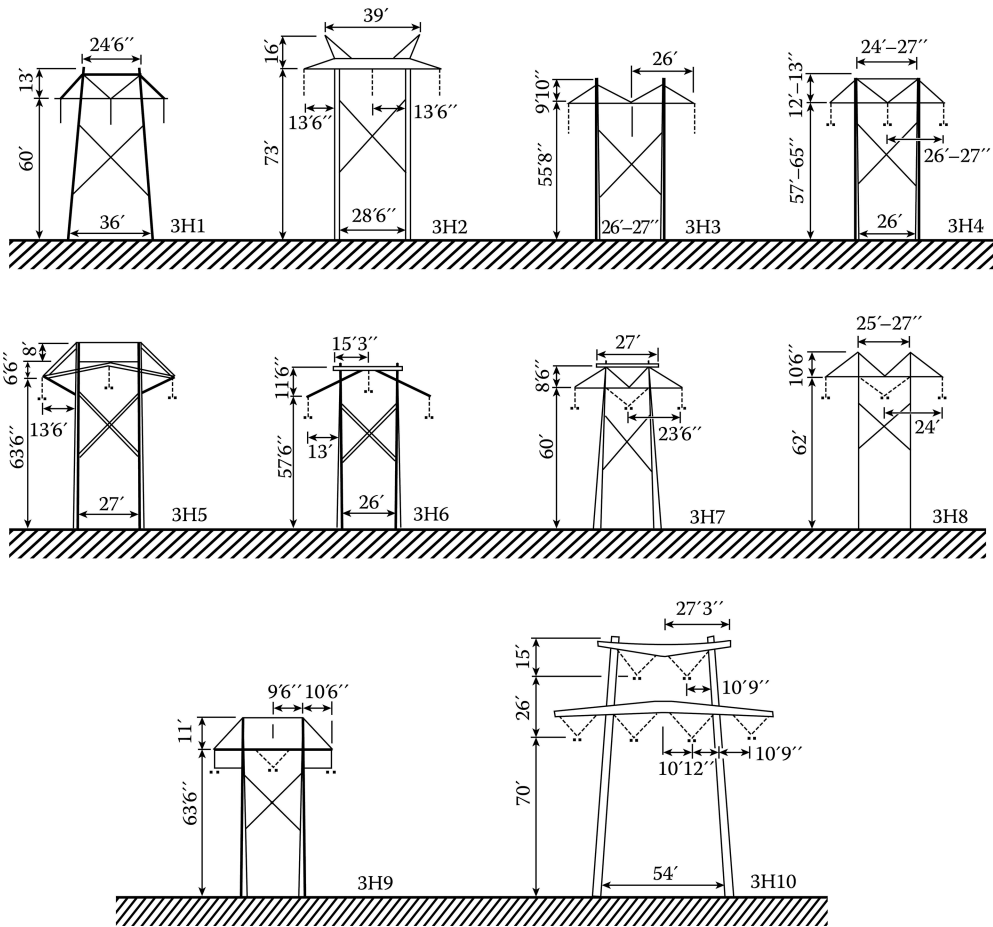


FIGURE 2.5 Typical wood H-frame-type structures for 345 kV transmission systems. (From Electric Power Research Institute, *Transmission Line Reference Book: 345 kV and Above*, 2nd edn., EPRI, Palo Alto, CA, 1982. Used by permission. © 1979 Electric Power Research Institute.)

from lightning. The shield conductor is grounded at each tower. Plate or vertical tube electrodes (ground rod) are used for grounding.

Figure 2.13 shows a 34.5 kV line with a double circuit and wood poles. (It has a newer style pole-top configuration.) Figure 2.14 shows a 34.5 kV line with a single circuit and wood poles. It has a 12.47 kV underbuilt line and 34.5 kV switch. (It has an old-style pole-top configuration.) Figure 2.15 shows a typical 34.5 kV line with a double circuit and wood poles. It has a 4.16 kV underbuilt line and a 34.5 kV switch. Figure 2.16 shows a typical 12.47 kV line with a single circuit and wood pole. It has a newer type of pole-top construction.

2.6.1 SUBTRANSMISSION LINE COSTS

Subtransmission line costs at the end of the line are associated with the substation at which it is terminated. According to the *ABB Guidebook* [3], based on 1994 prices, costs can run from as low as \$50,000 per mile for a 46 kV wooden pole subtransmission line with perhaps 50 MVA capacity (\$1 per kVA-mile) to over \$1,000,000 per mile for a 500 kV double-circuit construction with 2,000 MVA capacity (\$0.5 per kVA-mile).

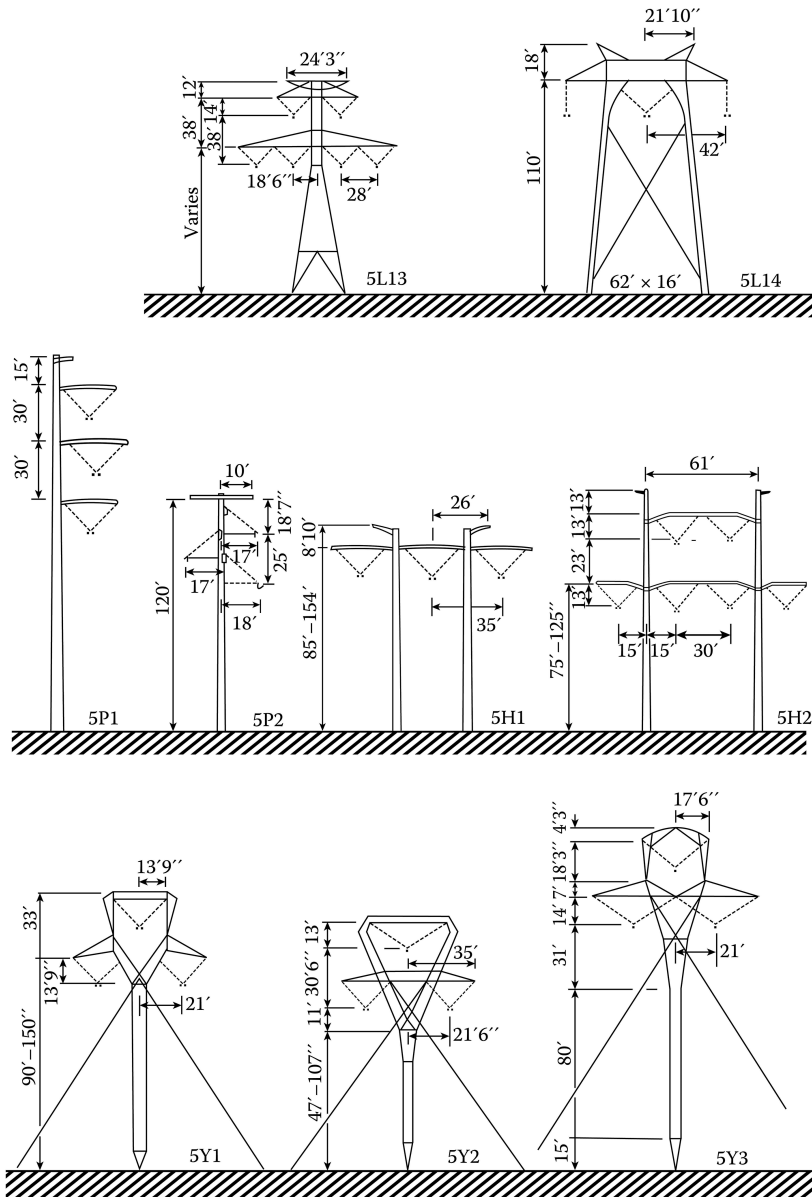


FIGURE 2.6 Typical pole- and lattice-type structures for 500kV transmission systems. (From Electric Power Research Institute, *Transmission Line Reference Book: 345kV and Above*, 2nd edn., EPRI, Palo Alto, CA, 1982. Used by permission. © 1979 Electric Power Research Institute.)

2.7 TRANSMISSION SUBSTATIONS

In general, there are four main types of electric substations in the AC power systems, namely, the following:

1. Switchyard
2. Customer substation
3. Transmission substation
4. Distribution substation

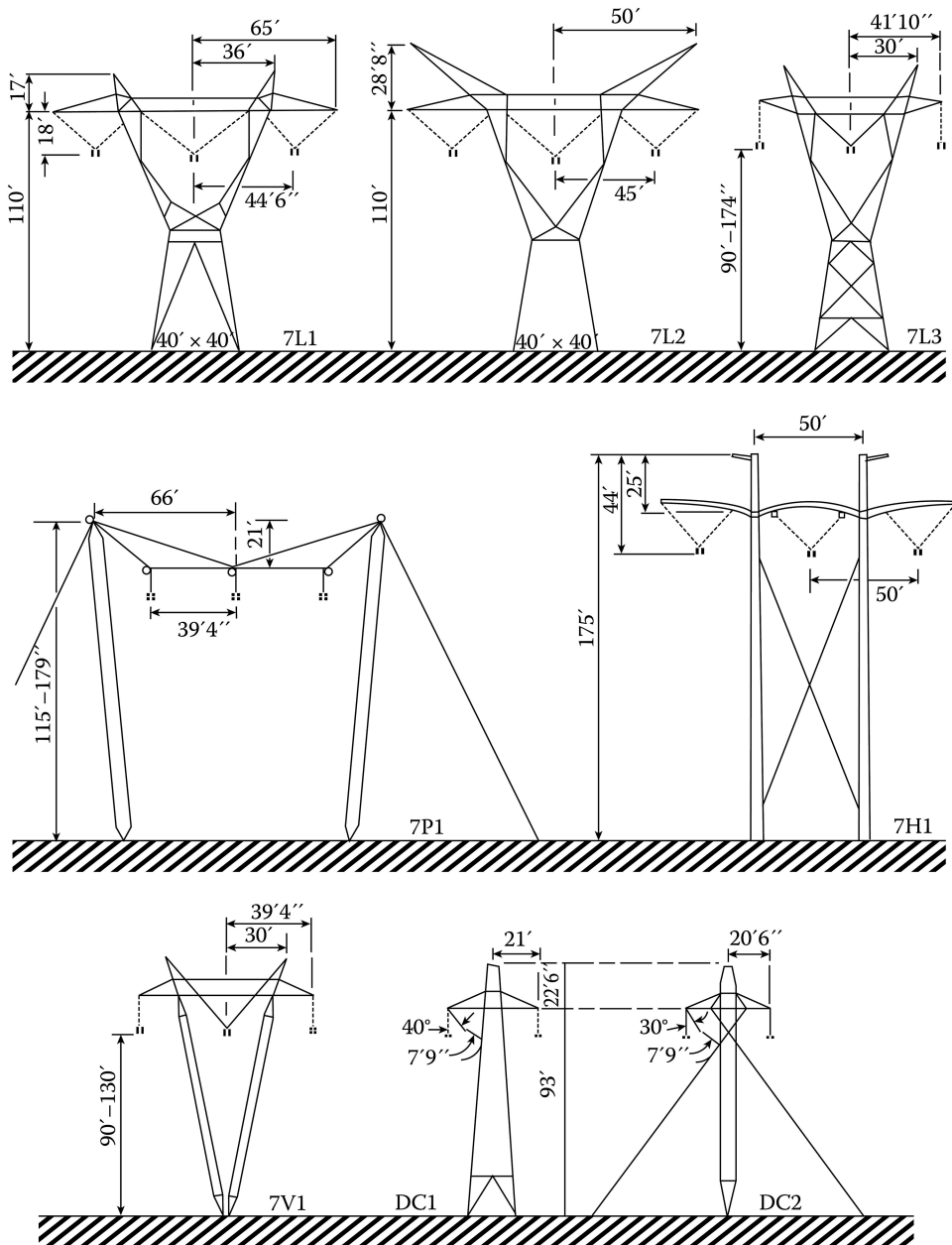


FIGURE 2.7 Typical pole- and lattice-type structures for 735–800 kV transmission systems. (From Electric Power Research Institute, *Transmission Line Reference Book: 345 kV and Above*, 2nd edn., EPRI, Palo Alto, CA, 1982. Used by permission. © 1979 Electric Power Research Institute.)

The switchyard is located at a generating plant (or station). They are used to connect the generators to the transmission grid and also provide off-site power to the plant. Such generator switchyards are usually very large installations covering large areas.

The customer substation functions as the primary source of electric power for one specific industrial/business customer. Its type depends on the customer's requirements. Transmission substations are also known as *bulk power substations*. They are large substations and are located at the ends of the transmission lines emanating from generating switchyards. They provide power to distribution



FIGURE 2.8 A typical 230kV transmission line steel tower with bundled conductors and double circuit.

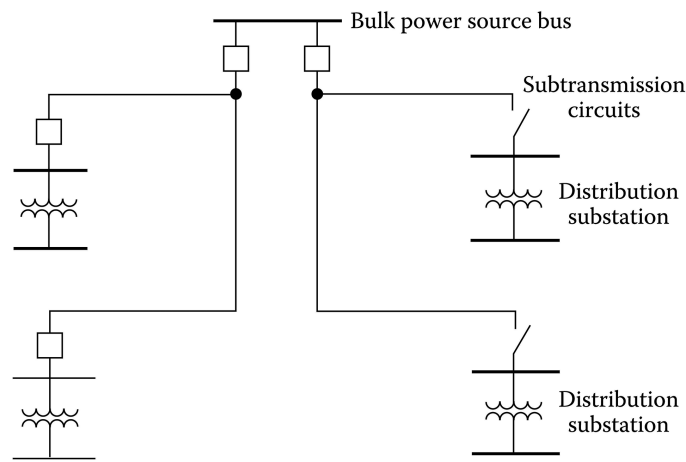
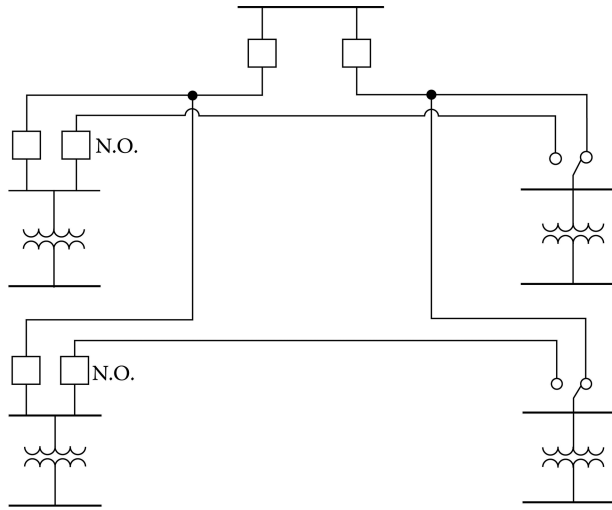


FIGURE 2.9 A radial-type subtransmission. (Courtesy West Power Inc.)



1. *Voltage transformation:* Power transformers are used to raise or lower the voltages as necessary.
2. *Switching functions:* Connecting or disconnecting parts of the system from each other.

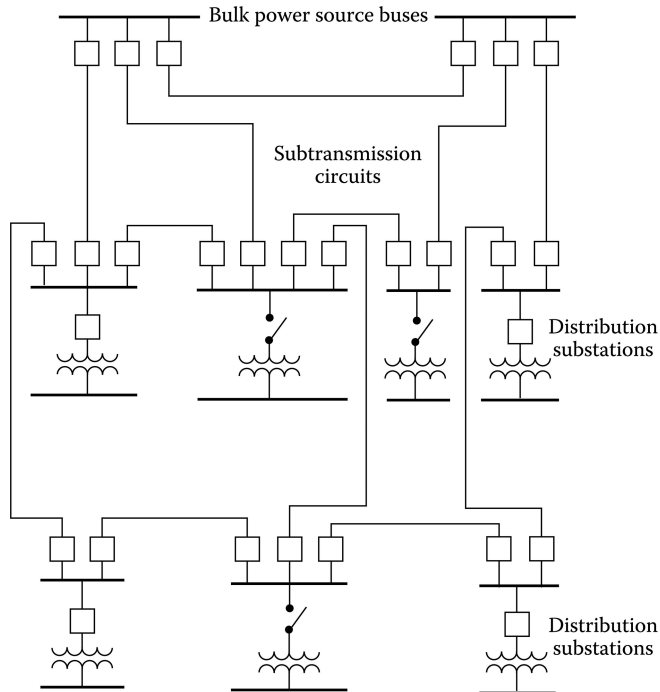


FIGURE 2.12 A grid- or network-type subtransmission.



FIGURE 2.13 A typical 34.5 kV line with a double circuit and wood poles. It has a newer style construction. (Union Electric Company.)

3. *Reactive power compensation:* Shunt capacitors, shunt reactors, synchronous condensers, and static var systems are used to control voltage. Series capacitors are used to reduce line impedance.

Transmission substations serving bulk power sources operate at voltages from usually 69 to 765 kV or more. As an integral part of the transmission system, the substation or switching station functions

as a connection and switching point for transmission lines, subtransmission lines, generating circuits, and step-up and step-down transformers. A transmission substation changes voltages to or from transmission-level voltages and operates Circuit Breakers (CBs) in response to transmission line or substation faults. It also has the following functions: controlling power to an area, housing protective relays and instrument transformers, and housing switching arrangements that allow maintenance of any substation equipment without disrupting the power to any area served by the substation.

Essentially, a transmission substation performs all of the functions of an important distribution substation at much higher voltage and power levels. Most of the apparatus is the same and operates the same as the equipment at a distribution substation, except that it is larger and has some larger capacity functions.

In addition, there are other differences between transmission and distribution substations. For example, spacing between conductors is greater, autotransformers are often used, reactors are sometimes housed, and grounding is more critical in bulk power substations. Figure 2.18 shows a bulk power substation operating at a 138/34.5 kV voltage level. On the other hand, Figure 2.19 shows a distribution substation operating at a 34.5/12.47 kV voltage level. Similarly, Figure 2.20 shows another distribution substation operating at a 34.5/4.16 kV voltage level.



FIGURE 2.14 A 34.5 kV line with a single circuit and wood poles. It also has a 12.47 kV underbuilt line and 34.5 kV switch. It has an old style construction. (Union Electric Company.)



FIGURE 2.15 A typical 34.5kV line with a double circuit and wood poles. It also has a 4.16kV underbuilt line and a 34.5kV switch. (Union Electric Company.)



FIGURE 2.16 A typical 12.47kV line with a single circuit and wood pole. It has a newer type of pole-top construction. (Union Electric Company.)

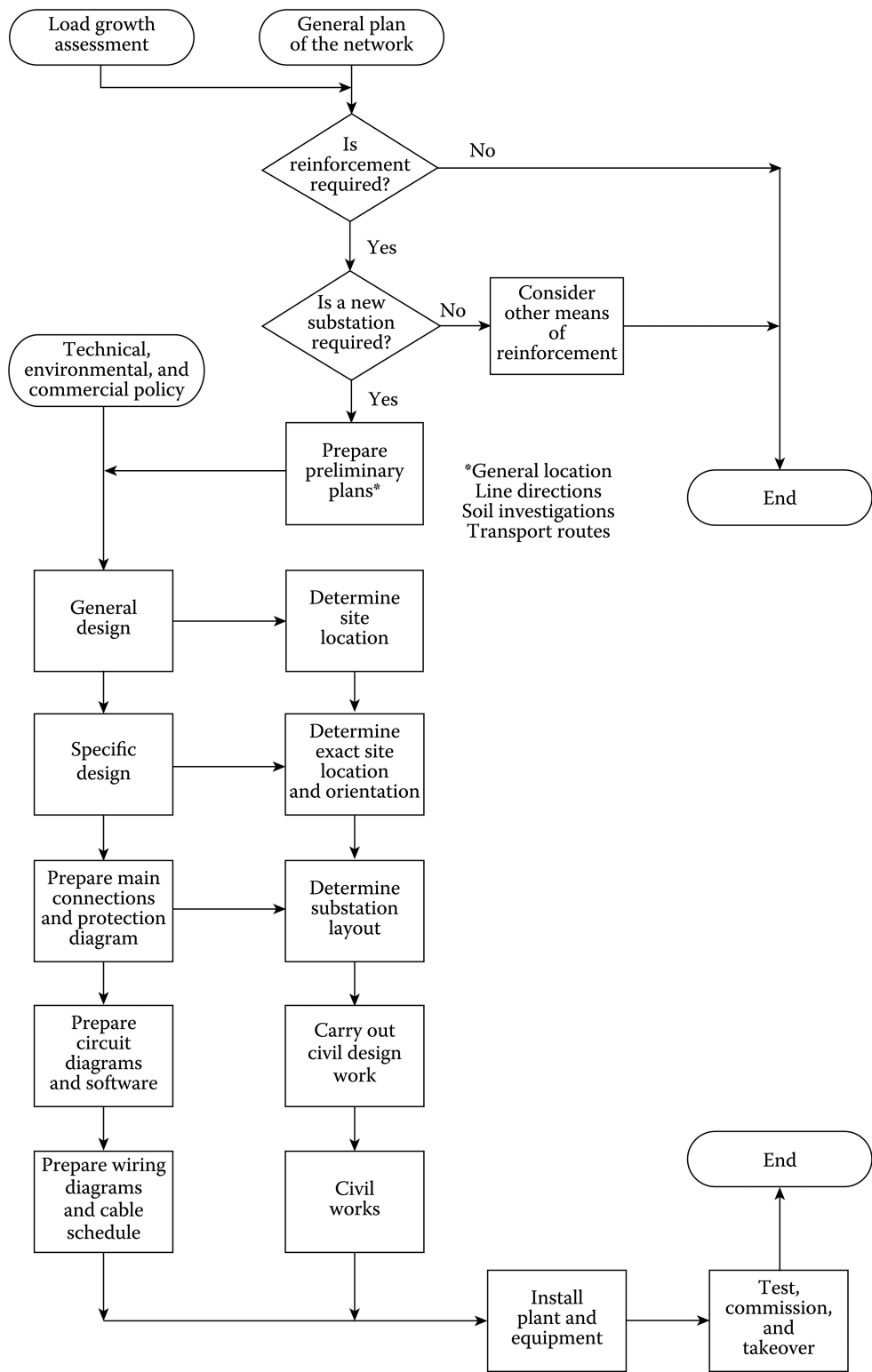


FIGURE 2.17 Establishment of a new substation. (From Burke, J. and Shazizian, M., How a substation happens? in McDonald, J. D. (ed.), *Electric Power Substation Engineering*, CRC Press, Boca Raton, FL, 2007.)



FIGURE 2.18 A bulk power substation operating at a 138/34.5 kV voltage level. (Union Electric Company.)



FIGURE 2.19 A distribution substation operating at a 34.5/12.47 kV voltage level. (Union Electric Company.)

2.7.1 ADDITIONAL SUBSTATION DESIGN CONSIDERATIONS

The design of an High Voltage (HV) substation includes basic station configuration and physical system layout, grounding, transformer selection, CB selection, bus designs, switches, lightning protection, lightning shielding, and protective relaying systems. The essential information that is needed, in determining the selection of a basic substation configuration, includes the following:

1. The estimation of initial and future loads to be served by the substation
2. A careful study of the transmission facilities and operating voltages
3. The study of service reliability requirements
4. Determination of space availability for station facilities and transmission line access



FIGURE 2.20 A distribution substation operating at a 34.5/4.16 kV voltage level. (Union Electric Company.)

In general, the need for improved reliability dictates for additional apparatus that, in turn, requires more space. For a given substation design, the size of the bays depends on the voltages used. For example, they vary from about 24 ft² at 34.5 kV to about 52 ft² at a 138 kV voltage level.

In order to improve the substation reliability, it is usual that more substation area is needed. This, in turn, increases the cost of the substation. The determination of reliability dictates the knowledge of the frequency of each piece of equipment and the cost of the outage. Failure rates for substations vary, depending on the substation size, the degree of contamination, and the definition of what is a failure.

2.7.2 SUBSTATION COMPONENTS

A typical substation may include the following equipment: (1) power transformers, (2) CBs, (3) disconnecting switches, (4) substation buses and insulators, (5) current-limiting reactors, (6) shunt reactors, (7) current transformers, (8) potential transformers, (9) capacitor voltage transformers (VTs), (10) coupling capacitors, (11) series capacitors, (12) shunt capacitors, (13) grounding system, (14) lightning arresters and/or gaps, (15) line traps, (16) protective relays, (17) station batteries, and (18) other apparatus.

2.7.3 BUS AND SWITCHING CONFIGURATIONS

In general, the substation switchyard scheme (or configuration) selected dictates the electrical and physical arrangement of the switching equipment. It is affected by the emphasis put on reliability, economy, safety, and simplicity as warranted by the function and importance of the substation. Additional factors that need to be considered are maintenance, operational flexibility, relay protection cost, and also line connections to the facility. The following are the most commonly used bus schemes:

1. Single-bus scheme
2. Double-bus-double-breaker scheme
3. Main-and-transfer bus scheme
4. Double-bus-single-breaker scheme
5. Ring bus scheme
6. Breaker-and-a half scheme

Figure 2.21a shows a typical single-bus scheme, Figure 2.21b presents a typical double-bus-double-breaker scheme, Figure 2.21c illustrates a typical main-and-transfer bus scheme, Figure 2.22a shows a typical double-bus-single-breaker scheme, Figure 2.22b presents a typical ring bus scheme, and Figure 2.22c illustrates a typical breaker-and-a-half scheme.

Each scheme has some advantages and disadvantages depending upon the economical justification of a specific degree of reliability. Table 2.2 gives a summary of switching schemes' advantages and disadvantages.

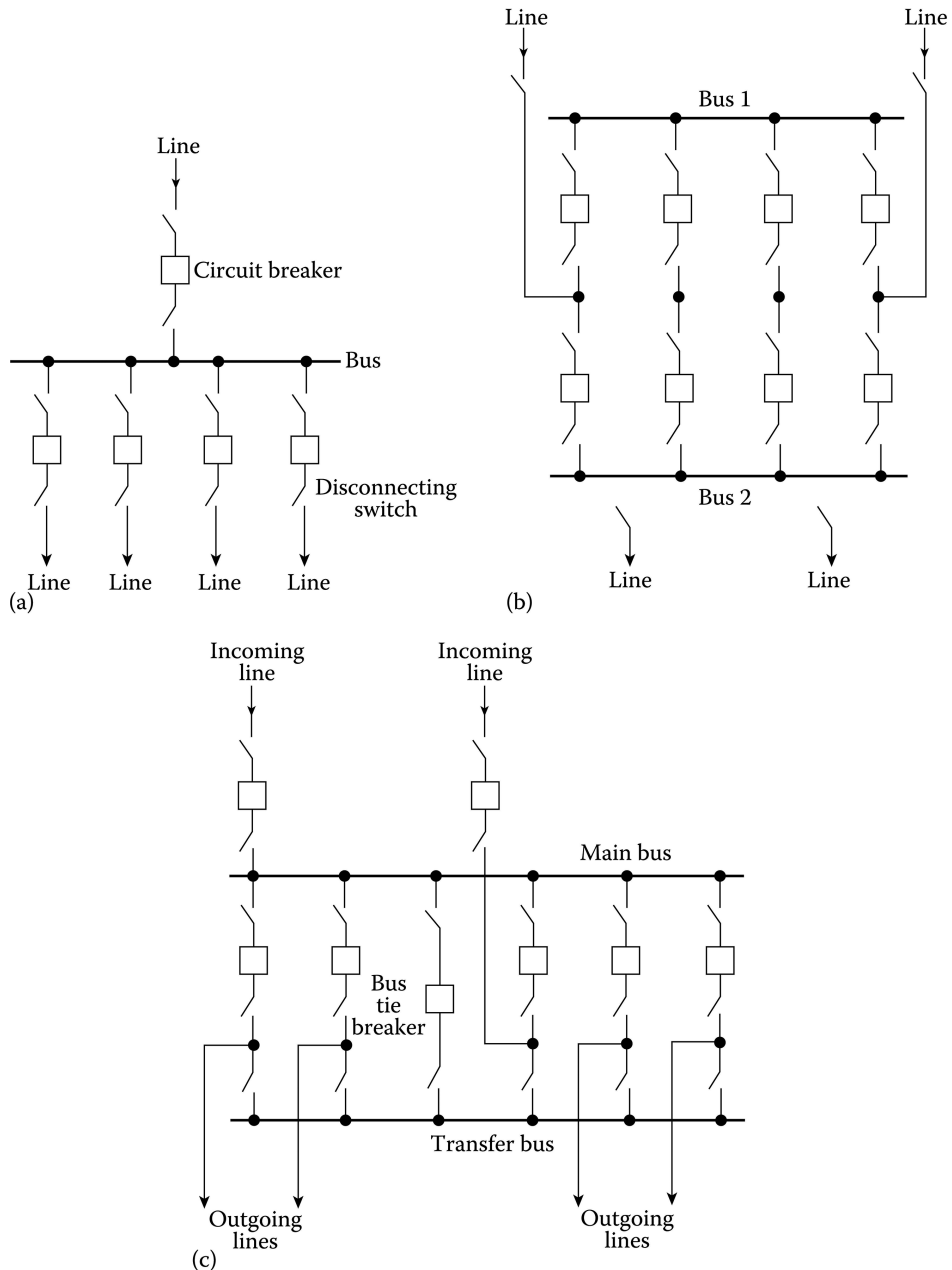


FIGURE 2.21 Most commonly used substation bus schemes: (a) single-bus scheme, (b) double-bus-double-breaker scheme, and (c) main-and-transfer bus scheme.

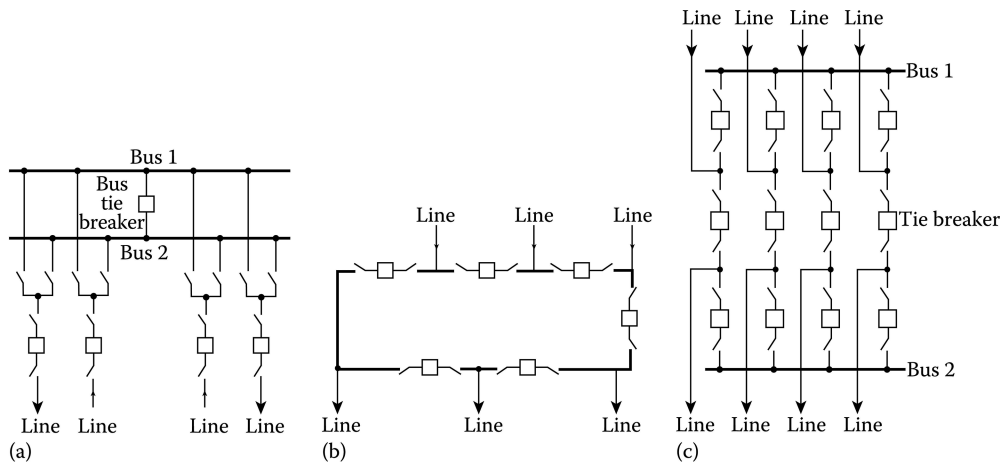


FIGURE 2.22 Most commonly used substation bus schemes: (a) double-bus-single-breaker scheme, (b) ring bus scheme, and (c) breaker-and-a-half scheme.

TABLE 2.2
Summary of Comparison of Switching Schemes

Switching Scheme	Advantages	Disadvantages
1. Single bus	1. Lowest cost	1. Failure of bus or any CB results in shutdown of the entire substation. 2. Difficult to do any maintenance. 3. Bus cannot be extended without completely deenergizing substation. 4. Can be used only where loads can be interrupted or have other supply arrangements.
2. Double bus-double breaker	1. Each circuit has two dedicated breakers. 2. Has flexibility in permitting feeder circuits to be connected to either bus. 3. Any breaker can be taken out of service for maintenance. 4. High reliability.	1. Most expensive. 2. Would lose half the circuits for breaker failure if circuits are not connected to both buses.
3. Main and transfer	1. Low initial and ultimate cost. 2. Any breaker can be taken out of service for maintenance. 3. Potential devices may be used on the main bus for relaying.	1. Requires one extra breaker for the bus tie. 2. Switching is somewhat complicated when maintaining a breaker. 3. Failure of bus or any CB results in shutdown of the entire substation.
4. Double bus-single breaker	1. Permits some flexibility with two operating buses. 2. Either main bus may be isolated for maintenance. 3. Circuit can be transferred readily from one bus to the other by the use of bus-tie breaker and bus selector disconnect switches.	1. One extra breaker is required for the bus tie. 2. Four switches are required per circuit. 3. Bus protection scheme may cause loss of substation when it operates if all circuits are connected to that bus. 4. High exposure to bus faults. 5. Line breaker failure takes all circuits connected to that bus out of service. 6. Bus-tie breaker failure takes entire substation out of service.

(Continued)

TABLE 2.2 (Continued)
Summary of Comparison of Switching Schemes

Switching Scheme	Advantages	Disadvantages
5. Ring bus	1. Low initial and ultimate cost. 2. Flexible operation for breaker maintenance. 3. Any breaker can be removed for maintenance without interrupting load. 4. Requires only one breaker per circuit. 5. Does not use main bus. 6. Each circuit is fed by two breakers. 7. All switching is done with breakers.	1. If a fault occurs during a breaker maintenance period, the ring can be separated into two sections. 2. Automatic reclosing and protective relaying circuitry rather complex. 3. If a single set of relays is used, the circuit must be taken out of service to maintain the relays (common on all schemes). 4. Requires potential devices on all circuits since there is no definite potential reference point. These devices may be required in all cases for synchronizing, live line, or voltage indication. 5. Breaker failure during a fault on one of the circuits causes loss of one additional circuit owing to operation of breaker failure relaying.
6. Breaker and a half	1. Most flexible operation. 2. High reliability. 3. Breaker failure of bus side breakers removes only one circuit from service. 4. All switching is done with breakers. 5. Simple operation; no disconnect switching required for normal operation. 6. Either main bus can be taken out of service at any time for maintenance. 7. Bus failure does not remove any feeder circuits from service.	1. One and a half breakers per circuit. 2. Relaying and automatic reclosing are somewhat involved since the middle breaker must be responsive to either of its associated circuits.

2.7.4 SUBSTATION BUSES

The substation buses, in HV substations or EHV substations, are the most important part of the substation structure due to the fact that they carry a large amount of energy in a confined space. The design of substation buses is a function of a number of elements. For example, it includes current-carrying capacity, short-circuit stresses, and establishing maximum electrical clearances.

They are designed and built in a manner so that the bus construction is strong enough to withstand the maximum stresses imposed on the conductors, and on the structure, by heavy currents under short-circuit conditions. In the past, the HV substations usually had the strain buses. The strain bus is similar to a transmission line and was merely a conductor such as an aluminum conductor, steel reinforced (ACSR) that was strung between substation structures.

On the other hand, EHV substations use the rigid-bus technique. The use of rigid buses has the advantages of low substation profile and ease of maintenance and operation. In a conventional substation arrangement, it is normally a combination of a mixing of rigid- and strain-bus construction. For example, the 765 kV EHV substation design has both rigid- and strain-bus arrangements. According to Ref. [6], the advantages of using the rigid-bus design are as follows:

- Less steel is used and structures are simple.
- The rigid bus is lower in height.

- Low profile with the rigid bus provides good visibility of conductors and equipment. Hence, it gives a good appearance to the substation.
- Rigid conductors are not under constant strain.
- Individual pedestal-mounted insulators are more accessible for cleaning.

The disadvantages of using the rigid bus are as follows:

- Rigid-bus designs are more expensive.
- Rigid-bus designs require more land.
- It requires more insulators and supports. (Hence, it has more insulators to clean.)
- This design is more sensitive to structural deflections that result in misalignment problems and possible bus damage.

On the other hand, the advantages of using strain buses are as follows:

- Fewer structures are required.
- It needs a lesser land to occupy.
- It has a lesser cost.

The disadvantages of using strain buses are as follows:

- It requires larger structures and foundations.
- Painting of high steel structures is costly and hazardous.
- Its insulators are not conveniently accessible for cleaning.
- Conductor repairs are more difficult in an emergency.

The current-carrying capacity of a bus is restricted by the heating effects generated by the current. Buses are rated according to the temperature rise that can be allowed without heating equipment terminals, bus connections, and joints. According to IEEE, NEMA, and ANSI standards, the permissible temperature rise for plain copper and aluminum buses is restricted to 30°C above an ambient temperature of 40°C. EHV substation bus phase spacing is based on the clearance required for switching-surge impulse values plus an allowance for energized equipment projections and corona rings.

2.7.4.1 Open-Bus Scheme

A typical conventional open-bus substation scheme has basically open-bus construction that has either only rigid- or strain-bus design or combinations of rigid and strain buses.

In arrangements employing double-bus schemes (e.g., the breaker-and-a half scheme), the buses are arranged to run the length of the substation. They are usually located toward the outside of the station.

The transmission line exists usually crossover the main bus and is dead-ended on takeoff tower structures. The line drops into one of the bays of the substation and connects to the disconnecting switches and CBs. In such an arrangement, three distinct bus levels are required to make the necessary crossovers and connections to each substation bay. The open-bus scheme has the advantage of requiring a minimum of land area per bay and relative ease of maintenance [6].

2.7.4.2 Inverted-Bus Scheme

In designing EHV substations, this scheme is usually preferred. Figure 2.23 shows a one-line diagram of a substation illustrating many variations of the inverted-bus scheme. In this scheme, all of the outgoing circuit takeoff towers are located on the outer perimeter of the substation. This eliminates the line crossovers and exit facilities. Main buses are located in the middle of the substation, with all disconnecting switches, CBs, and all bay equipment located outboard of the main buses. Such inverted-bus scheme provides a very low-profile substation. It has the advantages of beauty and aesthetics, resulting in better public relations.

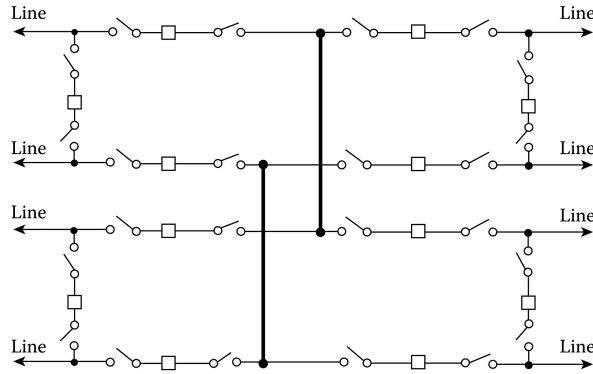


FIGURE 2.23 A low-profile EHV substation using an inverted breaker-and-a-half scheme.

2.8 SF₆-INSULATED SUBSTATIONS

Today, there are various types of sulfur hexafluoride (SF₆) substations ranging from 69 kV up to 765 kV, up to 4,000 A continuous current, and up to 80 kA symmetric interrupting rating.

In such a substation, the buses, CBs, isolators, instrument transformers, cable sealing ends, and connections are contained in metal enclosures filled with SF₆. The advantages of SF₆ substations are little space requirement, short installation time, positive protection against contact, low noise, very little maintenance, protection against pollution, and modular design for all components, which can be installed horizontally or vertically.

Basically, a SF₆ substation has the same components as a conventional substation, including CBs, buses, bushings, isolators and grounding switches, and instrument transformers. The metal enclosure, made up of tubular elements, totally covers all live parts. In addition, SF₆-insulated cables are also being used in the following applications: (1) line crossings, (2) connections of EHV OH lines, (3) HV and/or high-current links in underground power stations, (4) HV links from offshore power plants, (5) HV cable links in city networks and substation areas, (6) power transmission in road tunnels, and (7) power transmission to airports.

2.9 TRANSMISSION LINE CONDUCTORS

In transmission line design, the determination of conductor type and size is very important. This is done due to the fact that the selection of conductor affects the cost of construction of the line but it affects perhaps more crucially the cost of transmitting power through the transmission line throughout its life.

2.9.1 CONDUCTOR CONSIDERATIONS

When selecting transmission line conductors, the following factors have to be taken into account:

1. The maximum amount of allowed current in the conductor
2. The maximum amount of power loss allowed on the line
3. The maximum amount of voltage loss allowed
4. The required spa and sag between spans
5. The tension in the conductor
6. The climate conditions at the line location (the possibility of wind and ice loading)
7. The possibility of conductor vibration
8. The possibility of having corrosive atmospheric conductors

The selected conductor should be suitable to overcome these conditions.

2.9.2 CONDUCTOR TYPES

The most commonly used transmission types are the following:

- ACSR (aluminum conductor, steel reinforced)
- ACSR/AW (aluminum conductor, aluminum-clad steel reinforced)
- ACSR-SD (aluminum conductor, steel reinforced/self-damping)
- ACAR (aluminum conductor, allow reinforced)
- AAC-1350 (aluminum alloy conductor composed of 1350 aluminum alloy)
- AAAC-6201 (all aluminum alloy conductors composed of 6201 alloy)

ACSR consists of a central core of steel strands surrounded by layers of aluminum strands. Thus, an ACSR conductor with a designation of 26/7 means that it has 7 strands of galvanized steel wires in its core and 26 strands of aluminum wires surrounding its core. The galvanizing is a zinc coating placed on each of the steel wire strands. The thickness of the coating is listed as *class A* for normal thickness, *class B* for medium, and *class C* for heavy duty. The degree of conductor and atmospheric contamination dictates the class of galvanization for the core.

ACSR/AW conductor is similar to ACSR with the exception that its core is made up of high-strength steel clad in an aluminum coating. It is more expensive than ACSR. However, it can be used in worse corrosive atmospheric conditions than the ACSR with *class C* galvanizing.

ACSR-SD conductor has two layers of trapezoidal-shaped strands or two layers of trapezoidal strands and one of round strands around a conventional steel core. They are built to have a self-damping against aeolian vibration. They can be used at very high tensions without having any auxiliary dampers.

ACAR conductors have a high-strength aluminum core. It is lighter than the ACSR and is just as strong, but higher in cost. They are used in long spans in a corrosive atmosphere.

AAC-1350 is used for any construction that needs good conductivity and has short spans. AAAC-6201 has high-strength aluminum alloy strands. It is as strong as ACSR but is much lighter and more expensive. It is used in long spans in a corrosive atmosphere.

2.9.3 CONDUCTOR SIZE

When subjected to motions such as wind gusts and ice droppings, large conductors are more mechanically stable than small conductors, mainly due to their higher inertia. However, the choice of conductor size is often largely based on electrical (power loss and voltage drop considerations), thermal capacity (ampacity), and economic requirements rather than on motion considerations. Other factors include the required tensions for span and sag considerations and the breakdown voltage of the air. The voltage per unit surface area is a function of the voltage and the circumference of the chosen conductor.

Conductor sizes are based on the circular mil. A *circular mil* is the area of a circle that has a diameter of 1 mil. A mil is equal to 1×10^{-3} in. The cross-sectional area of a wire in square inches equals its area in circular mils multiplied by 0.7854×10^{-6} .

For smaller conductors, up to 211,600 circular mils, the size is usually given by a gauge number according to the American Wire Gauge (AWG) standard, formerly known as the Brown and Sharpe (B&S) wire gauge. Gauge sizes decrease as the wire increases in size. The larger the gauge size, the smaller the wire. These numbers start at 40, the smallest, which is assigned to a wire with a diameter of 3.145 mils. The largest size is number 0000, written as 4/0 and read as four odds. Above 4/0, the size is determined by cross-sectional area in circular mils. In summary,

$$\begin{aligned} 1 \text{ linear mil} &= 0.001 \text{ in.} \\ &= 0.0254 \text{ mm} \end{aligned}$$

One thousand circular mils is often used as a unit. For example, a size given as 250 kcmil (or MCM) refers to 250,000 circular mils or 250,000 cmil.

A given conductor may consist of a single strand or several strands. If of a single strand, it is solid; if of more than one strand, it is stranded. A solid conductor is often called a *wire*, whereas a stranded conductor is called a *cable*. A general formula for the total number of strands in concentrically stranded cables is

$$\text{Number of strands} = 3n^2 - 3n + 1$$

where n is the number of layers, including the single center strand.

In general, distribution conductors larger than 2 AWG are stranded. Insulated conductors for underground distribution or aerial cable lines are classified as cables and are usually stranded. Table 2.3 gives standard conductor sizes.

2.9.3.1 Voltage Drop Considerations

Also, voltage drop considerations dictate that not only must the given conductor meet the minimum size requirements but must transmit power at an acceptable loss. Common minimum size conductors that are typically used for the given voltages are as follows:

For 69 kV	4/0
For 138 kV	336.4 MCM (or kcmil)
For 230 kV	795 MCM (or kcmil) single conductor
For 345 kV	795 MCM (or kcmil) bundle of two conductors
For 500 kV	795 MCM (or kcmil) bundle of three conductors
For 750 kV	795 MCM (or kcmil) bundle of four conductors

Note that Europeans have adopted a standard of 556 mm bundle of four for 500 kV.

TABLE 2.3
Standard Conductor Sizes

Size (AWG or kcmil)	Circular Mils	Number of Wires	Solid or Stranded
18	1,620	1	Solid
16	2,580	1	Solid
14	4,110	1	Solid
12	6,530	1	Solid
10	10,380	1	Solid
8	16,510	1	Solid
7	20,820	1	Solid
6	26,250	1	Solid
6	26,250	3	Stranded
5	33,100	3	Stranded
5	33,100	1	Solid
4	41,740	1	Solid
4	41,740	3	Stranded
3	52,630	3	Stranded
3	52,630	7	Stranded
3	52,630	1	Solid
2	66,370	1	Solid

(Continued)

TABLE 2.3 (Continued)
Standard Conductor Sizes

Size (AWG or kcmil)	Circular Mils	Number of Wires	Solid or Stranded
2	66,370	3	Stranded
2	66,370	7	Stranded
1	83,690	3	Stranded
1	83,690	7	Stranded
0 (or 1/0)	105,500	7	Stranded
00 (or 2/0)	133,100	7	Stranded
000 (or 3/0)	167,800	7	Stranded
000 (or 3/0)	167,800	12	Stranded
0000 (or 4/0)	211,600	7	Stranded
0000 (or 4/0)	211,600	12	Stranded
0000 (or 4/0)	211,600	19	Stranded
250	250,000	12	Stranded
250	250,000	19	Stranded
300	300,000	12	Stranded
300	300,000	19	Stranded
350	350,000	12	Stranded
350	350,000	19	Stranded
400	400,000	19	Stranded
450	450,000	19	Stranded
500	500,000	19	Stranded
500	500,000	37	Stranded
600	600,000	37	Stranded
700	700,000	37	Stranded
750	750,000	37	Stranded
800	800,000	37	Stranded
900	900,000	37	Stranded
1,000	1,000,000	37	Stranded

This requirement is often expressed as a maximum voltage drop of 5% across the transmission line for a particular system. The total series impedance of the line is equal to the maximum allowable voltage drop divided by the maximum load current. Hence,

$$Z_L = |R + jX_L| = \frac{VD_{\max}}{I_{\max}} \tag{2.1}$$

where

- Z_L is the magnitude of the total impedance of the line
- R is the total resistance of the line
- X_L is the total inductive reactance of the line
- $VD_{\max}$ is the maximum allowable voltage drop for the line
- $I_{\max}$ is the maximum load current

Note that R is inversely proportional to the area of the conductor size.

2.9.3.2 Thermal Capacity Considerations

When a phase conductor is sized, the thermal capacity of the conductor (ampacity) has to be taken into account. In other words, *the conductor should be able to carry the maximum expressed long-term load current without experiencing any overheating*. Typically, a conductor must be able to

withstand a temperature of 75°C (167°F) without a decrease in the strength. Above that temperature, the strength of the conductor decreases as a function of the amount and duration of the excessive heat.

In general, the ampacity of a conductor is a function of the generated heat by the current itself, the heat from the sun, and the cooling of the winds. Conductor heating is expressed as ambient temperature plus load temperature, less cooling effects of the wind.

2.9.3.3 Economic Considerations

Economic considerations are very important in the determination of the conductor size of a transmission line. Usually, the conductor that meets the minimum aforementioned factors is not the most economical one.

The present worth of the savings that result from the lower power losses during the entire useful life of a conductor has to be taken into account. Hence, a larger conductor, than the one that just barely meets the minimum requirements, is often more justifiable. In other words, the marginal additional cost involved will be more than offset by the cost savings of the future.

To make any meaningful conductor size selection, the transmission planning engineer should make a cost study associated with the line. The cost analysis for the proper conductor size should include the following: (1) investment cost of installed line with the particular conductor being considered, (2) cost of energy loss due to total I^2R losses in the line conductors, and (3) cost of demand lost, that is, the cost of useful system capacity lost (including generation, transmission, and distribution systems), in order to resupply the line losses. Hence, the total present worth of line cost (TPWL) at a given conductor size is

$$\text{TPWL} = \text{PWIC} + \text{PWEC} + \text{PWDC} \text{ \$ / mi} \quad (2.2)$$

where

TPWL is the total present worth of line cost in dollar per mile

PWIC is the present worth of the investment cost of the installed feeder in dollar per mile

PWEC is the present worth of energy cost due to PR losses in the line conductors in dollar per mile

PWDC is the present worth of the demand cost incurred to maintain adequate system capacity to resupply I^2R losses in the line conductors in order to compensate for the line losses in dollar per mile

In addition to these considerations, the future load growth is also needed to be considered.

2.9.4 OVERHEAD GROUND WIRES

OHWs are also called shield wires. They are the wires that are installed above the phase conductors (or wires). They are used to protect the line from lightning and to even out the ground potential and are sometimes even used for low-voltage (LV) communication. The OHGWs do not conduct the load current, but they very rapidly conduct the very heavy current of a lightning strike to the ground, through their many grounded connections. Every transmission structure is all grounded and the OHGW is grounded at every structure (whether it is a pole or tower).

High-strength or extra-strength galvanized steel wires are used. The allowable sizes for the high-strength wires are 3/8 and 7/16 in., while the allowable sizes for the extra-strength wires are 5/26, 3/8, and 7/16 in. The sags of the OHGWs must be the same as the sags of the phase conductors.

2.9.5 CONDUCTOR TENSION

The conductor tension of a transmission line may vary between 10% and 60% or even more of its rated conductor strength. This is due to the change in line loading and temperature. Normal tensions may be more important for determining the life of the conductor of a line than higher tensions that do not occur frequently. The proper conductor tensions are given in the NESC based on ice and wind loadings in the loading districts of heavy, medium, and light loading.

2.10 INSULATORS

2.10.1 TYPES OF INSULATORS

An *insulator* is a material that prevents the flow of an electric current and can be used to support electrical conductors. The function of an insulator is to provide the necessary clearances between the line conductors, between conductors and ground, and between conductors and the pole or tower. Insulators are made of porcelain, glass, and fiberglass treated with epoxy resins. However, porcelain is still the most common material used for insulators.

The basic types of insulators include *pin-type insulators*, *suspension insulators*, and *strain insulators*. The pin insulator gets its name from the fact that it is supported on a pin. The pin holds the insulator, and the insulator has the conductor tied to it. They may be made in one piece for voltages below 23 kV, in two pieces for voltages from 23 to 46 kV, in three pieces for voltages from 46 to 69 kV, and in four pieces for voltages from 69 to 88 kV. Pin insulators are seldom used on transmission lines having voltages above 44 kV, although some 88 kV lines using pin insulators are in operation. The glass pin insulator is mainly used on LV circuits. The porcelain pin insulator is used on secondary mains and services, as well as on primary mains, feeders, and transmission lines.

A modified version of the pin-type insulator is known as the *post-type insulator*. The post-type insulators are used on distribution, subtransmission, and transmission lines and are installed on wood, concrete, and steel poles. The line postinsulators are constructed for vertical or horizontal mountings. The line postinsulators are usually made as one-piece solid porcelain units. Figure 2.24 shows a typical post-type porcelain insulator. Suspension insulators consist of a string of interlinking separate disks made of porcelain. A string may consist of many disks depending on the line voltage.¹ For example, as an average, for 115 kV lines, usually 7 disks are used and for 345 kV lines, usually 18 disks are used.

The *suspension insulator*, as its name implies, is suspended from the crossarm (or pole or tower) and has the line conductor fastened to the lower end. When there is a dead end of the line, or if there is a corner or a sharp curve, or if the line crosses a river, etc., then the line will withstand great strain. The assembly of suspension units arranged to dead-end the conductor of a structure is called a *dead-end*, or *strain*, insulator.

In such an arrangement, suspension insulators are used as strain insulators. The dead-end string is usually protected against damage from arcs by using one to three additional units and installing arcing horns or rings, as shown in Figure 2.25. Such devices are designed to ensure that an arc (e.g., due to lightning impulses) will hold free of insulator string.

The arcing horns protect the insulator string by providing a shorter path for the arc, as shown in Figure 2.25a. Contrarily, the effectiveness of the arcing ring (or grading shield), shown in Figure 2.25b, is due to its tendency to equalize the voltage gradient over the insulator, causing a more uniform field.

Thus, the protection of the insulator is not dependent on simply providing a shorter arcing path, as is the case with horns. Figure 2.25c shows a control ring developed by The Ohio Brass Company that can be used to *control* the voltage stress at the line end of the insulator strings.

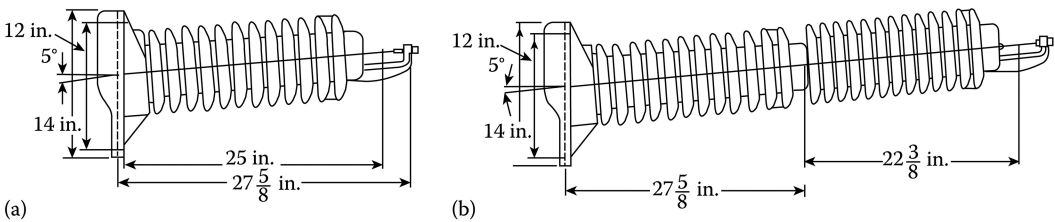


FIGURE 2.24 Typical (side) post-type insulators used in (a) 69 kV and (b) 138 kV.

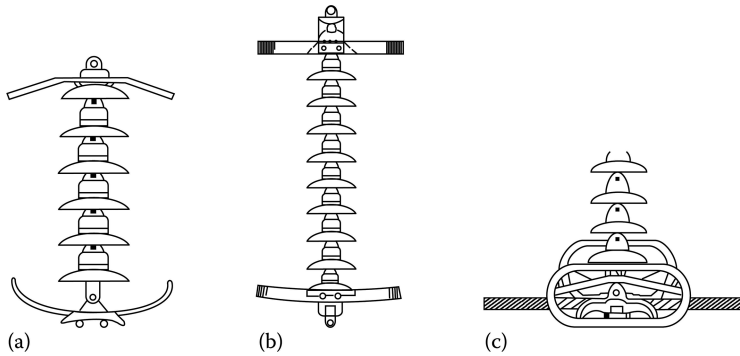


FIGURE 2.25 Devices used to protect insulator strings: (a) suspension string with arcing horns, (b) suspension string with grading shields (or *arcing rings*), and (c) suspension string with control ring. (Courtesy The Ohio Brass Company.)

It has been shown that their use can also reduce the corona formation on the line hardware. Control rings are used on single-conductor HV transmission lines operating above 250 kV. Transmission lines with bundled conductors do not require the use of arcing horns and rings nor control rings, provided that the bundle is not made of two conductors one above the other.

2.10.2 TESTING OF INSULATORS

The operating performance of a transmission line depends largely on the insulation. Experience has shown that for a satisfactory operation, the dry flashover operating voltage of the assembled insulator must be equal to three to five times the nominal operating voltage and its leakage path must be about twice the shortest air gap distance. Insulators used on OH lines are subject to tests that can generally be classified as (1) design tests, (2) performance tests, and (3) routine tests. The *design tests* include the dry flashover test, the pollution flashover test, the wet flashover test, and the impulse test.

The *flashover voltage* is defined as the voltage at which the insulator surface breaks down (by ionization of the air surrounding the insulator), allowing current to flow on the outside of the insulator between the conductor and the crossarm. Whether or not an insulator breaks down depends not only on the magnitude of the applied voltage but also on the rate at which the voltage increases.

Since insulations have to withstand steep-fronted lightning and switching surges when they are in use, their design must provide the flashover voltage² on a steep-fronted impulse waveform that is greater than that on a normal system waveform. The ratio of these voltages is defined as the *impulse ratio*. Hence,

$$\text{Impulse ratio} = \frac{\text{Impulse flashover voltage}}{\text{Power frequency flashover voltage}} \quad (2.3)$$

Table 2.4 gives flashover characteristics of suspension insulator strings and air gaps [7]. The performance tests include puncture tests, mechanical tests, temperature tests, porosity tests, and electro-mechanical tests (for suspension insulators only). The event that takes place when the dielectric of the insulator breaks down and allows current to flow inside the insulator between the conductor and the crossarm is called the *puncture*.

Therefore, the design must facilitate the occurrence of flashover at a voltage that is lower than the voltage for puncture. An insulator may survive flashover without damage but must be replaced when punctured. The test of the glaze on porcelain insulators is called the *porosity test*. The routine tests include proof tests, corrosion tests, and HV tests (for pin insulators only).³

TABLE 2.4
Flashover Characteristics of Suspension Insulator Strings and Air Gaps

Impulse Air Gap		Impulse Flashover (Positive Critical) (kV)	Number of Insulator Units ^a	Wet 60 Hz Flashover (kV)	Wet 60 Hz Air Gap	
in.	mm				mm	in.
8	203	150	1	50	254	10
14	356	255	2	90	305	12
21	533	355	3	130	406	16
26	660	440	4	170	508	20
32	813	525	5	215	660	26
38	965	610	6	255	762	30
43	1,092	695	7	295	889	35
49	1,245	780	8	335	991	39
55	1,397	860	9	375	111	44
60	1,524	945	10	415	1,245	49
66	1,676	1,025	11	455	1,346	53
71	1,803	1,105	12	490	1,473	58
77	1,956	1,185	13	525	1,575	62
82	2,083	1,265	14	565	1,676	66
88	2,235	1,345	15	600	1,778	70
93	2,362	1,425	16	630	1,880	74
99	2,515	1,505	17	660	1,981	78
104	2,642	1,585	18	690	2,083	82
110	2,794	1,665	19	720	2,183	86
115	2,921	1,745	20	750	2,286	90
121	3,073	1,825	21	780	2,388	94
126	3,200	1,905	22	810	2,464	97
132	3,353	1,985	23	840	2,565	101
137	3,480	2,065	24	870	2,692	106
143	3,632	2,145	25	900	2,794	110
148	3,759	2,225	26	930	2,921	115
154	3,912	2,305	27	960	3,023	119
159	4,039	2,385	28	990	3,124	123
165	4,191	2,465	29	1,020	3,251	128
171	4,343	2,550	30	1,050	3,353	132

Source: Edison Electric Institute, *EHV Transmission Line Reference Book*, EEL, New York, 1968. A

Insulator units are $146 \times 254 \text{ mm}$ ($5\frac{3}{4} \times 10 \text{ in.}$) or $146 \times 267 \text{ mm}$ ($5\frac{3}{4} \times 10\frac{1}{2} \text{ in.}$).

2.10.3 VOLTAGE DISTRIBUTION OVER A STRING OF SUSPENSION INSULATORS

Figure 2.26 shows the voltage distribution along the surface of a single clean insulator disk (known as the *cap-and-pin insulator unit*) used in suspension insulators. Note that the highest voltage gradient takes place close to the cap and pin (which are made of metal), whereas much lower voltage gradients take place along most of the remaining surfaces. The underside (i.e., the inner skirt) of the insulator has been given the shape, as shown in Figure 2.26, to minimize the effects of moisture and contamination and to provide the longest path possible for the leakage currents that might flow on the surface of the insulator.

In the figure, the voltage drop between the cap and the pin has been taken as 100% of the total voltage. Approximately, 24% of this voltage is distributed along the surface of the insulator from the

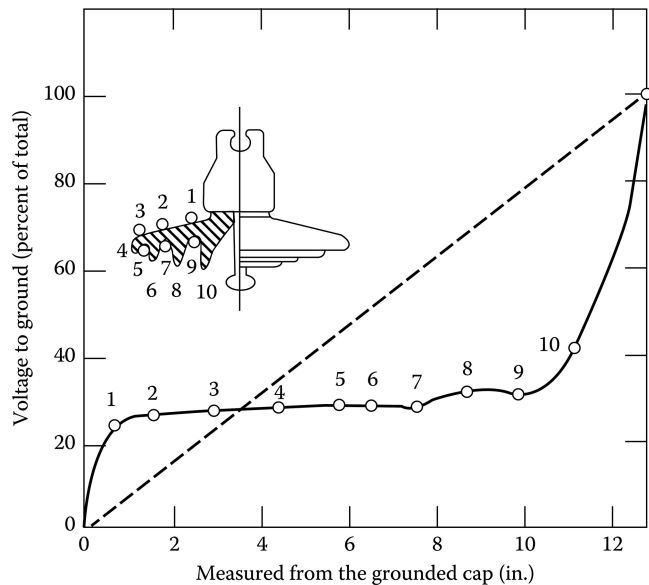


FIGURE 2.26 Voltage distribution along the surface of a single clean cap-and-pin suspension insulator.

cap to point 1 and only 6% from point 1 to point 9. The remaining 70% of this voltage is distributed between point 9 and the pin.

The main problem with suspension insulators having a string of identical insulator disks is the nonuniform distribution voltage over the string. Each insulator disk with its hardware (i.e., cap and pin) constitutes a capacitor, the hardware acting as the plates or electrodes, and the porcelain as the dielectric. Figure 2.27 shows the typical voltage distribution on the surfaces of three clean cap-and-pin insulator units connected in series [7]. The figure clearly illustrates that when several units are connected in series, (1) the voltage on each insulator over the string is not the same, (2) the location of the unit within the insulator string dictates the voltage distribution, and (3) the maximum voltage gradient takes place at the (pin of the) insulator unit nearest to the line conductor.

As shown in Figure 2.28, when several insulator units are placed in series, two sets of capacitances take place: the series capacitances C_i (i.e., the capacitance of each insulator unit) and the shunt capacitances to ground, C_2 . Note that all the charging current I for the series and shunt capacitances

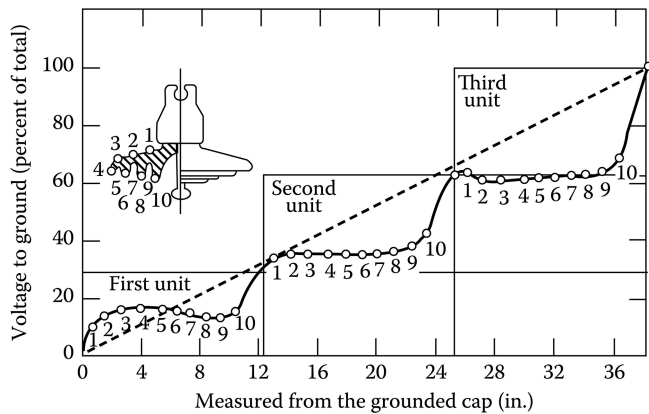


FIGURE 2.27 A typical voltage distribution on surfaces of three clean cap-and-pin suspension insulator units in series.

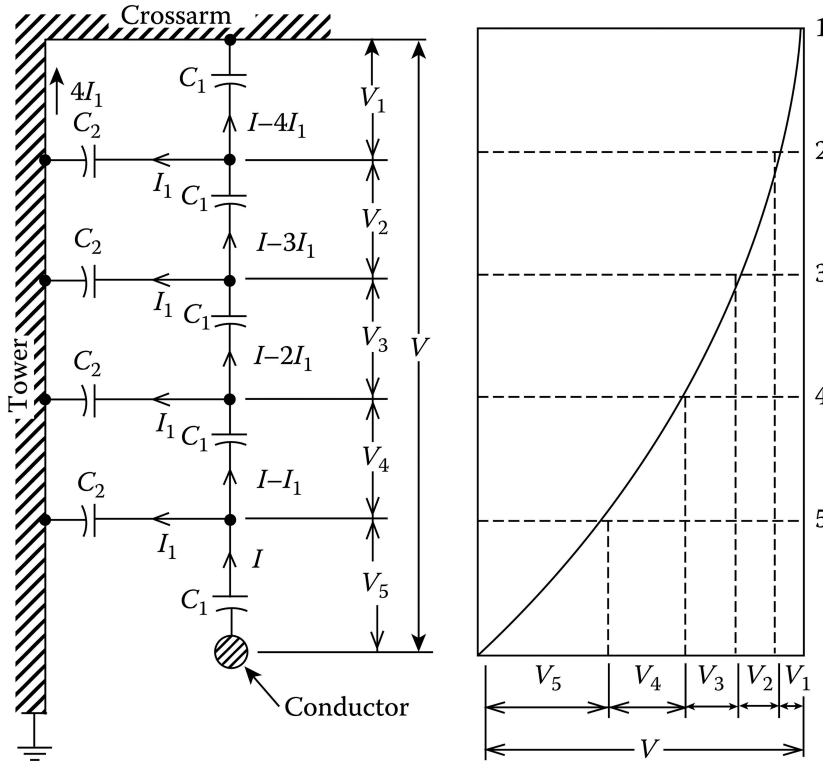


FIGURE 2.28 Voltage distribution among suspension insulator units.

flows through the first (with respect to the conductor) of the series capacitances C_1 . The I_1 portion of this current flows through the first shunt capacitance C_2 , leaving the remaining I_1 portion of the current to flow through the second series capacitance, and so on. The diminishing current flow through the series capacitances C_1 results in a diminishing voltage (drop) distribution through them from conductor end to ground end (i.e., crossarm), as illustrated in Figure 2.28. Thus,

$$V_5 > V_4 > V_3 > V_2 > V_1$$

In summary, the voltage distribution over a string of identical suspension insulator units is not uniform due to the capacitances formed in the air between each cap/pin junction and the grounded (metal) tower.

However, other air capacitances exist between metal parts at different potentials. For example, there are air capacitances between the cap/pin junction of each unit and the line conductor.

Figure 2.29 shows the resulting equivalent circuit for the voltage distribution along a clean eight-unit insulator string. The voltage distribution on such a string can be expressed as

$$V_k = \frac{V_n}{\beta^2 \sinh \beta n} \left[\frac{C_2}{C_1} \sinh \beta k + \frac{C_3}{C_1} \sinh \beta (k-n) + \frac{C_3}{C_1} \sinh \beta n \right] \quad (2.4)$$

where

V_k is the voltage across k units from ground end

V_n is the voltage across n units (i.e., applied line-to-ground voltage in volts)

$$\beta = \text{a constant} = \left[\frac{C_2 + C_3}{2} \right]^{1/2} \quad (2.5)$$

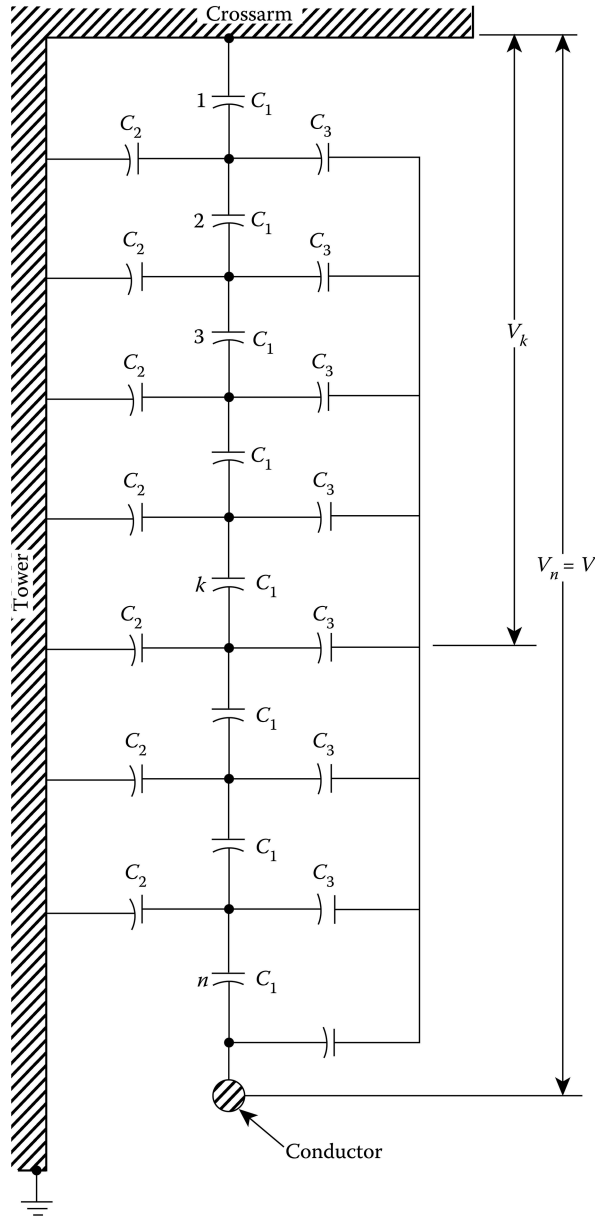


FIGURE 2.29 An equivalent circuit for voltage distribution along clean eight-unit insulator string. (Adopted from Edison Electric Institute, *EHV Transmission Line Reference Book*, EEI, New York, 1968.)

C_1 is the capacitance between cap and pin of each unit

C_2 is the capacitance of one unit to ground

C_3 is the capacitance of one unit to line conductor

The capacitance C_3 is usually very small, and therefore, its effect on the voltage distribution can be neglected. Hence, Equation 2.4 can be expressed as

$$V_k = V_n \left(\frac{\sinh \alpha k}{\sinh \alpha n} \right) \quad (2.6)$$

where

$$\alpha = \text{a constant} = \left(\frac{C_2}{C_1} \right)^{1/2} \quad (2.7)$$

Figure 2.30 shows how the voltage changes along the eight-unit string of insulators when the ratio C_2 / C_1 is about 1/12 and the ratio C_3 / C_1 is about zero (i.e., $C_3 = 0$). However, a calculation based on Equation 2.33 gives almost the same result. The ratio C_2 / C_1 is usually somewhere between 0.1 and 0.2.

Furthermore, there is also the air capacitance that exists between the conductor and the tower. But, it has no effect on the voltage distribution over the insulator string, and therefore, it can be neglected. This method of calculating the voltage distribution across the string is based on the assumption that the insulator units involved are clean and dry, and thus, they act as a purely capacitive voltage divider. In reality, however, the insulator units may not be clean or dry.

Thus, in the equivalent circuit of the insulator string, each capacitance C_1 should be shunted by a resistance R representing the leakage resistance. Such resistance depends on the presence of contamination (i.e., pollution) on the insulator surfaces and is considerably modified by rain and fog. If, however, the units are badly contaminated, the surface leakage (resistance) currents could be greater than the capacitance currents, and the extent of the contamination could vary from unit to unit, causing an unpredictable voltage distribution.

It is also interesting to note that if the insulator unit nearest to the line conductor is electrically stressed to its safe operating value, then all the other units are electrically understressed, and consequently, the insulation string as a whole is being inefficiently used. The string efficiency (in per units) for an insulator string made of n series units can be defined as

$$\text{String efficiency} = \frac{\text{Voltage across string}}{n(\text{Voltage across unit adjacent to line conductor})} \quad (2.8)$$

If the unit adjacent to the line conductor is about to flashover, then the whole string is about to flash-over. Here, the string efficiency can be reexpressed as

$$\text{String efficiency} = \frac{\text{Flashover voltage of string}}{n(\text{Flashover voltage across of one unit})} \quad (2.9)$$

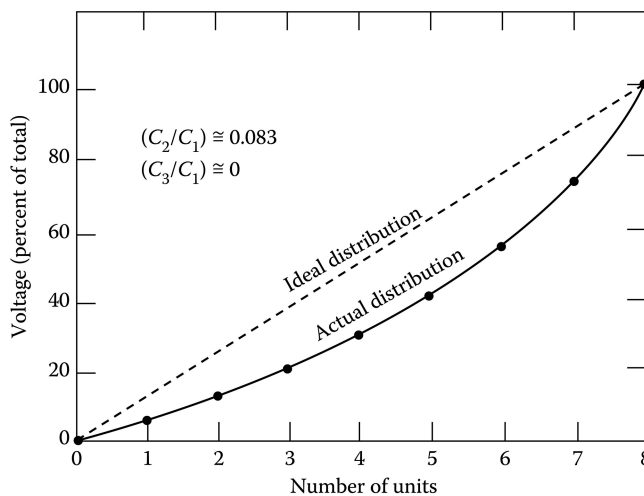


FIGURE 2.30 Voltage distribution along a clean eight-unit cap-and-pin insulator string.

Note that the string efficiency decreases as the number of units increases.

The methods to improve the string efficiency (grading) include the following:

1. By grading the insulators so that the top unit has the minimum series capacitance C_x whereas the bottom unit has the maximum capacitance. This may be done by using different sizes of disks and hardware, or by putting metal caps on the disks, or by a combination of both methods.⁴ But this is a rarely used method since it would involve stocking spares of different types of units, which is contrary to the present practice of the utilities to standardize on as few types as possible.
2. By installing a large circular or oval grading shield ring (i.e., an arcing ring) at the line end of the insulator string [7]. This method introduces a capacitance C_3 , as shown in Figure 2.29, from the ring to the insulator hardware to neutralize the capacitance C_2 from the hardware to the tower. This method substantially improves string efficiency. However, it is not usually possible in practice to achieve completely uniform voltage distribution by using the gradient shield, especially if the string has a large number of units.
3. By reducing the air (shunt) capacitances C_3 , between each unit and the tower (i.e., the ground), and by increasing the length of the crossarms. However, this method is restricted in practice due to the reduction in crossarm rigidity and the increase in tower cost.
4. By using a semiconducting (or stabilizing) high-resistance glaze on the insulator units to achieve a resistor voltage divider effect. This method is based on the fact that the string efficiency increases due to the increase in surface leakage resistance when the units are wet. Thus, the leakage resistance current becomes the same for all the units, and the voltage distribution improves since it does not depend on the capacitance currents only. This method is restricted by the risk of thermal instability.

2.10.4 INSULATOR FLASHOVER DUE TO CONTAMINATION

An insulator must be capable of enduring extreme sudden temperature changes such as ice, sleet, and rain as well as environmental contaminants such as smoke, dust, salt, fogs, saltwater sprays, and chemical fumes without deterioration from chemical action, breakage from mechanical stresses, or electric failure. Further, the insulating material must be thick enough to resist puncture by the combined working voltage of the line, and any probable transient whose time lag to spark over is great. If this thickness is greater than the desirable amount, then two or more pieces are used to achieve the proper thickness.

The thickness of a porcelain part must be so related to the distance around it that it will flashover before it will puncture. The ratio of puncture strength to flashover voltage is called the *safety factor* of the part or of the insulator against puncture. This ratio should be high enough to provide sufficient protection for the insulator from puncture by the transients.

The insulating materials mainly used for the line insulators are (1) wet-process porcelain, (2) dry-process porcelain, and (3) glass. The wet-process porcelain is used much more than dry porcelain. One of the reasons for this is that wet porcelain has greater resistance to impact and is practically incapable of being penetrated by moisture without glazing, whereas dry porcelain is not.

However, in general, dry-process porcelain has somewhat higher crushing strength. Dry-process porcelain is only used for the lowest voltage lines. As a result of recent developments in the technology of glass manufacturing, glass insulators that can be very tough and have low internal resistance can be produced. Because of this, the usage of glass insulators is increasing.

In order to select insulators properly for a given OH line design, not only the aforementioned factors but also the geographic location of the line needs to be considered. For example, the OH lines that will be built along the seashore, especially in California, will be subjected to winds blowing in from the ocean, which carry a fine salt vapor that deposits salt crystals on the windward side of the insulator.

On the other hand, if the line is built in areas where rain is seasonal, the insulator surface leakage resistance may become so low during the dry seasons that insulators flashover without warning. Another example is that if the OH line is going to be built near gravel pits, cement mills, and refineries, its insulators may become so contaminated that extra insulation is required.

Contamination flashover on transmission systems is initiated by airborne particles deposited on the insulators. These particles may be of natural origin or they may be generated by pollution that is mostly a result of industrial, agricultural, or construction activities. When line insulators are contaminated, many insulator flashovers occur during light fogs unless arcing rings protect the insulators or special fog-type insulators are used.

Table 2.5 lists the types of contaminants causing contamination flashover [1]. The mixed contamination condition is the most commonly caused by the combination of industrial pollution and sea salt or by the combination of several industrial pollutions. Table 2.5 also presents the prevailing

TABLE 2.5
Numbers of Flashovers Caused by Various Contaminant, Weather, and Atmospheric conditions

Type of Contaminant	Weather and Atmospheric Conditions								
	Fog	Dew	Drizzle, Mist	Ice	Rain	No Wind	High Wind	Wet Snow	Fair
Sea salt	14	11	22	1	12	3	12	3	—
Cement	12	10	16	2	11	3	1	4	—
Fertilizer	7	5	8	—	1	1	—	4	—
Fly ash	11	6	19	1	6	3	1	3	1
Road salt	8	2	6	—	4	2	—	6	—
Potash	3	3	—	—	—	—	—	—	—
Cooling tower	2	2	2	—	2	—	—	—	—
Chemicals	9	5	7	1	1	—	—	1	1
Gypsum	2	1	2	—	2	—	—	2	—
Mixed	32	19	37	—	13	1	—	1	—
Contamination									
Limestone	2	1	2	—	4	—	2	2	—
Phosphate and sulfate	4	1	4	—	3	—	—	—	—
Paint	1	1	—	—	1	—	—	—	—
Paper mill	2	2	4	—	2	—	—	1	—
Acid exhaust	2	3	—	—	—	—	1	—	—
Bird droppings	2	2	3	—	1	2	—	—	2
Zinc industry	2	1	2	—	1	—	—	1	—
Carbon	5	4	5	—	—	4	3	3	—
Soap	2	2	1	—	—	1	—	—	—
Steel works	6	5	3	2	2	—	—	1	—
Carbide residue	2	1	1	1	—	—	—	1	—
Sulfur	3	2	2	—	—	1	—	1	—
Copper and nickel salt	2	2	2	—	—	2	—	1	—
Wood fiber	1	1	1	—	1	—	—	1	—
Bulldozing dust	2	1	1	—	—	—	—	—	—
Aluminum plant	2	2	1	—	1	—	—	—	—
Sodium plant	1	1	—	—	—	—	—	—	—
Active pump	1	1	1	—	—	—	—	—	—
Rock crusher	3	3	5	—	1	—	—	—	—
Total flashover	146	93	166	8	68	26	19	38	4
Percent weather	25.75	16.4	29.3	1.4	12	4.58	3.36	6.52	0.71

weather conditions at the time of flashover. Fog, dew, drizzle, and mist are common weather conditions, accounting for 72% of the total. In general, a combination of dew and fog is considered the most severe wetting condition, even though fog is not necessary for the wetting process.

The surface leakage resistance of an insulator is unaffected by the dry deposits of dirt. However, when these contamination deposits become moist or wet, they constitute continuous conducting layers. Leakage current starts to flow in these layers along the surface of the insulators. This leakage current heats the wet contamination, and the water starts to evaporate from those areas where the product of current density and surface resistivity is greater, causing the surface resistivity further to increase.

This, in turn, produces more heat, which evaporates the moisture in the surrounding regions, causing the formation of circular patterns known as *dry bands* until the leakage currents decrease to a value insufficient to sustain further evaporation and the voltage builds up across the dry bands.

Further wetting results in further reduction of the resistance, and small flashovers taking place on the insulator are in the same condition; the arcs extend rapidly over the whole surface, forcing all the dry bands to discharge in a rapid cascade known as the *flashover* of the insulator. Figure 2.31 illustrates the phenomenon of insulator flashover due to contamination.

Severe contamination may reduce the 60Hz flashover voltage from ~50kV root-mean-square (rms) per unit to as low as 6–9kV rms per unit. The condition of such flashover may be developed during the melting of contaminated ice on the insulator by leakage currents.

An insulator flashover due to contamination is easily distinguished from other types of flashover due to the fact that the arc always begins close to the surface of the insulator unit, as shown in Figure 2.31a. As shown in Figure 2.31c, only in the final stage does the flashover resemble an air strike. Furthermore, since the insulator unit at the conductor end has the greatest voltage, the flashover phenomenon usually starts at that insulator unit.

To prevent insulator flashovers, the insulators of an OH transmission line may be cleaned simply by washing them, a process that can be done basically either by the conventional techniques or by the new technique. In conventional techniques, the line is deenergized, and its conductors are grounded at each pole or tower where the members of an insulator cleaning crew wash and wipe the insulators by hand.

In the new technique, the line is kept energized, while the insulators may be cleaned by high-pressure water jets produced by a truck-mounted high-pressure pump that forces water through a nozzle at 500–850 psi, developing a round solid stream. The water jets strike the insulator with a high velocity, literally tearing the dirt and other contaminants from the insulator surface. The cost

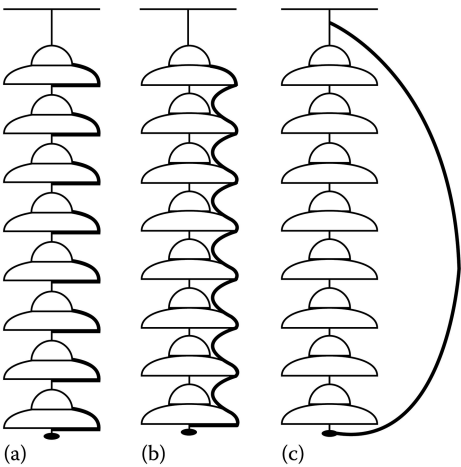


FIGURE 2.31 Changes in channel position of contaminated flashover. (a) without contaminated flashover, (b) with contamination, (c) with contaminated flashover.

of insulator cleaning per unit is very low with this technique. Certain lines may need insulator cleaning as often as three times a year.

To overcome the problem of surface contamination, some insulators may be covered with a thin film of silicone grease that absorbs the dirt and makes the surface water form into droplets rather than a thin film. This technique is especially effective for spot contamination where maintenance is possible, and it is also used against sea salt contamination. Finally, specially built semiconducting glazed insulators having an arc-resistive coating are used. The heat produced by the resistive coating keeps the surface dry and provides for relatively linear potential distribution.

2.10.5 INSULATOR FLASHOVER ON OVERHEAD HVDC LINES

Even though mechanical considerations are similar for both AC and DC lines, electrical characteristics of insulators on DC lines are significantly different from those on AC lines, and flashover takes place much more frequently than on an AC line of equivalent voltage. This is caused partly by the electrostatic forces of the steady DC field, which increases the deposit of pollution on the insulator surface. Further, arcs tend to develop into flashovers more readily in the absence of voltage zero.

To improve the operating performance and reduce the construction cost of OH HVDC lines by using new insulating materials and new insulator configurations particularly suited to DC voltages' stress, a more compact line design can be produced, therefore, saving money on towers and ROWs.

For example, to improve the operating performance and reduce the construction cost of OH HVDC lines, EPRI has sponsored the development of a new insulator. One of the more popular designs, the composite insulator, uses a fiberglass rod for mechanical and electrical strength and flexibility skirts made of organic materials for improved flashover performance. The composite insulator appears to be especially attractive for use on HVDC lines because it is better able to withstand flashover in all types of contaminated environments, particularly in areas of light and medium contamination.

Furthermore, there are various measures that may be taken into account to prevent contamination flashovers, for example, overinsulation, installation of v-string insulators, and installment of horizontal string insulators. Overinsulation may be applicable in the areas of heavy contamination. Up to 345 kV, the overinsulation is often achieved by increasing the number of insulators. However, several contaminations may dictate the use of very large leakage distances that may be as large as double the minimal requirements. Thus, electrical, mechanical, and economic restrictions may limit the use of this design measure. The use of v-string insulators can prevent the insulation contamination substantially. They self-clean more effectively in rain than vertical insulators since both sides of each insulator disk are somewhat exposed to rain. They can be used in heavy contamination areas very effectively. The installment of horizontal insulator strings is the most effective design measure that can be used to prevent contamination flashovers in the very heavy contamination areas. The contaminants are most effectively washed away on such strings. However, they may require a strain tower support depending on the tower type.

Other techniques used include the installation of specially designed and built insulators. For example, the use of fog-type insulators has shown that the contamination flashover can be effectively reduced since most of the flashovers occur in conditions where there is mist, dew, and fog.

2.11 SUBSTATION GROUNDING

2.11.1 ELECTRICAL SHOCK AND ITS EFFECTS ON HUMANS

To properly design a grounding (called *equipment grounding*) for the HV lines and/or substations, it is important to understand the electrical characteristics of the most important part of the circuit, the human body. In general, shock currents are classified based on the degree of severity of the shock they cause. For example, currents that produce direct physiological harm are called primary shock currents.

Whereas currents that cannot produce direct physiological harm but may cause involuntary muscular reactions are called *secondary shock currents*. These shock currents can be either steady state or transient in nature. In AC power systems, steady-state currents are sustained currents of 60 Hz or their harmonics. The transient currents, on the other hand, are capacitive discharge currents whose magnitudes diminish rapidly with time.

Table 2.6 gives the possible effects of electrical shock currents on humans. Note that the threshold value for a normally healthy person to be able to feel a current is about 1 mA. (Experiments have long ago established the well-known fact that *electrical shock effects are due to current, not voltage* [8].) This is the value of current at which a person is just able to detect a slight tingling sensation on the hands or fingers due to current flow. Currents of approximately 10–30 mA can cause a lack of muscular control. In most humans, a current of 100 mA will cause ventricular fibrillation. Currents of higher magnitudes can stop the heart completely or cause severe electrical burns. Ventricular fibrillation is a condition where the heart beats in an abnormal and ineffective manner, with fatal results. Therefore, its threshold is the main concern in grounding design.

Currents of 1 mA or more but <6 mA are often defined as secondary shock currents (*let-go currents*). The let-go current is the maximum current level at which a human holding an energized conductor can control his muscles enough to release it. The 60 Hz minimum required body current leading to possible fatality through ventricular fibrillation can be expressed as

$$I = \frac{0.116}{\sqrt{t}} \text{ A} \tag{2.10}$$

Equipment protection is only part of the reason that substations are so well grounded. Personnel protection is a major consideration. A continuous current of 0.15 A flowing through the trunk part of the body is almost always fatal. To properly design a grounding (called *equipment grounding*) for the HV lines and/or substations, it is important to understand the electrical characteristics of the most important part of the circuit, the human body.

In general, shock currents are classified based on the degree of severity of the shock they cause. For example, currents that produce direct physiological harm are called *primary shock currents*. However, currents that cannot produce direct physiological harm but may cause involuntary muscular reactions are called *secondary shock currents*. These shock currents can be either steady state or transient in nature. In AC power systems, steady-state currents are sustained currents of 60 Hz or

TABLE 2.6
Effect of Electric Current (in mA) on Men and Women

Effects	DC		AC (60 Hz)	
	Men	Women	Men	Women
1. No sensation on hand	1	0.6	0.4	0.3
2. Slight tingling; per caption threshold	5.2	3.5	1.1	0.7
3. Shock not painful and muscular control not lost	9	6	1.8	1.2
4. Painful shock painful but muscular control not lost	62	41	9	6
5. Painful shock—let-go threshold ^a	76	51	16	10.5
6. Painful and severe shock, muscular contractions, breathing difficult	90	60	23	15
7. Possible ventricular fibrillation from short shocks:				
(a) Shock duration 0.03 s	1,300	1,300	1,000	1,000
(b) Shock duration 3.0 s	500	500	100	100
(c) Almost certain ventricular fibrillation (if shock duration over one heartbeat interval)	1,375	1,375	275	275

^a Threshold for 50% of the males and female tested.

its harmonics. The transient currents, on the other hand, are capacitive currents whose magnitudes diminish rapidly with time.

The threshold value for a normally healthy person to be able to feel a current is about 1 mA. (Experiments have long ago established the well-known fact that *electrical shock effects are due to current, not voltage*.) This is the value of current at which a person is just able to detect a slight tingling sensation on the hands or fingers due to current flow.

Currents of approximately 10–30 mA can cause a lack of muscular control. In most humans, a current of 100 mA will cause ventricular fibrillation. Currents of higher magnitudes can stop the heart completely or cause severe electrical burns.

Ventricular fibrillation is a condition where the heart beats in an abnormal and inefficient manner, with fatal results. Therefore, its threshold is the main concern in grounding design. IEEE Std. 80-2000 gives the following equation to find that the nonfibrillating current of magnitude I_B at durations ranging from 0.03 to 3.0 s is related to the energy absorbed by the body as

$$S_B = (I_B)^2 \times t_s \quad (2.11)$$

where

I_B is the rms magnitude of the current through the body in amperes

t_s is the duration of the current exposure in seconds

S_B is the empirical constant related to the electrical shock energy tolerated by a certain percent of a given population

The effects of an electric current passing through the vital parts of a human body depend on the duration, magnitude, and frequency of this current. The body resistance considered is usually between two extremities, either from one hand to both feet or from one foot to the other one.

Experiments have shown that the body can tolerate much more current flowing from one leg to the other than it can when current flows from one hand to the legs. Treating the foot as a circular plate electrode gives an approximate resistance of $3\rho_s$, where ρ_s is the soil resistivity. The resistance used for the body itself is usually about 2,300 Ω hand to hand or 1,100 Ω hand to foot [9]. However, IEEE Std. 80-2000 [10] recommends the use of 1,000 Ω as a reasonable approximation for body resistance. Figure 2.32a shows a touch contact with current flowing from hand to feet. On the other hand, Figure 2.32b shows a step contact where current flows from one foot to the other. Note that in each case, the body current I_B is driven by the potential difference points between A and B.

For 99.5% of the population, the 60 Hz minimum required body current, I_B , leading to *possible fatality through ventricular fibrillation* can be expressed as

$$I_B = \frac{0.116}{\sqrt{t_s}} \text{ A for 50 kg body weight} \quad (2.12a)$$

or

$$I_B = \frac{0.157}{\sqrt{t_s}} \text{ A for 70 kg body weight} \quad (2.12b)$$

where t is in seconds in the range from ~8.3 ms to 5 s.

The effects of an electric current passing through the vital parts of a human body depend on the duration, magnitude, and frequency of this current. The body resistance considered is usually between two extremities, either from one hand to both feet or from one foot to the other one. Figure 2.33 shows five basic situations involving a person and grounded facilities during a fault.

On the other hand, the *touch voltage* represents the potential difference between the ground potential rise (GPR) and the surface potential at the point where a person is standing while at the

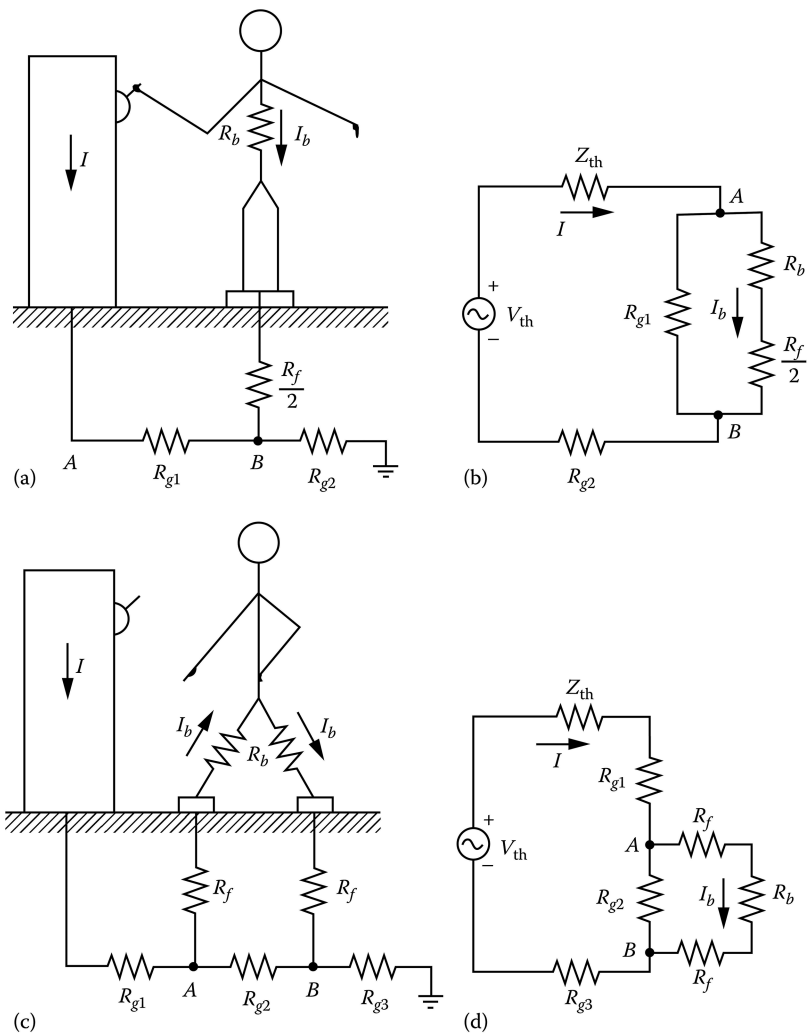


FIGURE 2.32 Typical electrical shock hazard situations: (a) touch potential, (b) its equivalent circuit, (c) step potential, and (d) its equivalent circuit.

same time having a hand in contact with a grounded structure. The *transferred voltage* is a special case of the touch voltage where a voltage is transferred into or out of the substation from or to a remote point external to the substation site [10].

Finally, GPR is the maximum electrical potential that a substation grounding grid may have relative to a distant grounding point assumed to be at the potential of the remote earth. This voltage, GPR, is equal to the maximum grid current times the grid resistance. Under normal conditions, the grounded electrical equipment operates at near-zero ground potential. That is, the potential of a grounded neutral conductor is nearly identical to the potential of remote earth. During a ground fault, the portion of fault current that is conducted by substation grounding grid into the earth causes the rise of the grid potential with respect to remote earth.

Exposure to touch potential normally poses a greater danger than exposure to step potential. The step potentials are usually smaller in magnitude (due to the greater corresponding body resistance), and the allowable body current is higher than the touch contacts. In either case, the value of the body resistance is difficult to establish.

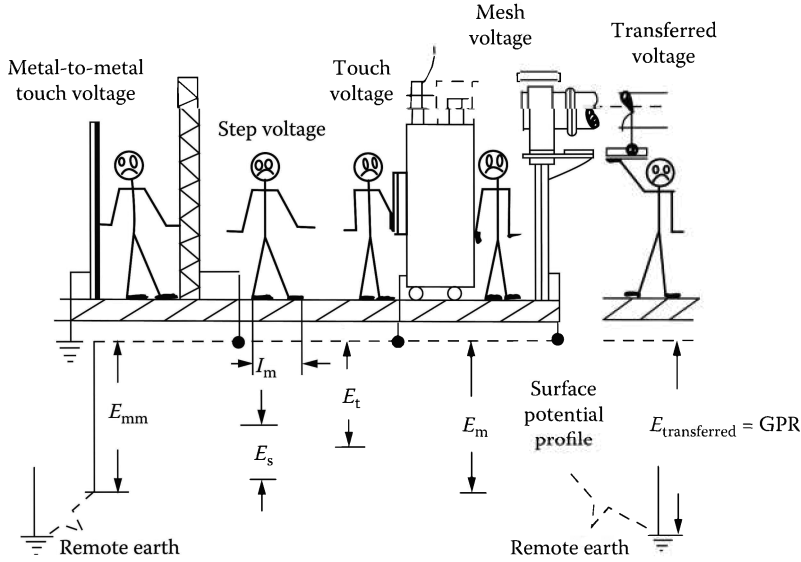


FIGURE 2.33 Possible basic shock situations. (From Keil, R. P., Substation grounding, in *Electric Power Substation Engineering*, Chapter 11, Figure 11.6, CRC Press, Boca Raton, FL, 2003, p. 7. With permission.)

Therefore, the total branch resistance, for *hand-to-foot currents*, can be expressed as

$$R_B = 1,000 + 1.5\rho_s \, \Omega \text{ for touch voltage} \quad (2.13a)$$

and, for *foot-to-foot currents*,

$$R_B = 1,000 + 6\rho_s \, \Omega \text{ for touch voltage} \quad (2.13b)$$

where ρ_s is the soil resistivity in ohmmeters. If the surface of the soil is covered with a layer of crushed rock or some other high-resistivity material, its resistivity should be used in Equations 2.13a and b.

The *touch voltage limit* can also be determined from

$$V_{\text{touch}} = \left(R_B + \frac{R_f}{2} \right) I_B$$

and the *step voltage limit* can also be determined from

$$V_{\text{step}} = (R_B + 2R_f) I_B$$

where

$$R_f = 3C_s \rho_s$$

where

R_B is the resistance of human body, typically $1,000 \, \Omega$ for 50 and 60 Hz

R_B is the ground resistance of one foot

I_B is the rms magnitude of the current going through the body in A, per Equations 2.12a and b

C_s is the surface layer derating factor based on the thickness of the protective surface layer spread above the earth grade at the substation (per IEEE Std. 80-2000, if no protective layer is used, then $C_s = 1$)

$$R_B = 1,000 + 1.5\rho_s \, \Omega \text{ for touch voltage}$$

and, for foot-to-foot currents,

$$R_B = 1,000 + 6\rho_s \Omega \text{ for touch voltage}$$

where ρ_s is the soil resistivity in ohmmeters. If the surface of the soil is covered with a layer of crushed rock or some other high-resistivity material, its resistivity should be used in Equations 2.13 and 2.17.

Since it is much easier to calculate and measure potential than current, the fibrillation thresholds, given by Equations 2.12a and b, are usually given in terms of voltage.

If no protective surface layer is used, the maximum allowable (or tolerable) touch voltages, for a person with a body weight of 50 or 70 kg, respectively, can be expressed as

$$V_{\text{touch } 50} = \frac{0.116(1,000 + 1.5\rho_s)}{\sqrt{t_s}} \text{ V for 50 kg body weight} \quad (2.14a)$$

and

$$V_{\text{touch } 70} = \frac{0.157(1,000 + 1.5\rho_s)}{\sqrt{t_s}} \text{ V for 70 kg body weight} \quad (2.14b)$$

If no protective surface layer is used, the maximum allowable (or tolerable) step voltages, for a person with a body weight of 50 or 70 kg, respectively, can be expressed as

$$V_{\text{step } 50} = \frac{0.116(1,000 + 6\rho_s)}{\sqrt{t_s}} \text{ V for 50 kg body weight} \quad (2.15a)$$

and

$$V_{\text{step } 70} = \frac{0.157(1,000 + 6\rho_s)}{\sqrt{t_s}} \text{ V for 70 kg body weight} \quad (2.15b)$$

If no protective surface layer is used, for the metal-to-metal touch in V, since $p_s = 0$, the aforementioned equations become

$$V_{\text{mm-touch } 50} = \frac{116}{\sqrt{t_s}} \text{ V for 50 kg body weight} \quad (2.16a)$$

and

$$V_{\text{mm-touch } 70} = \frac{157}{\sqrt{t_s}} \text{ V for 70 kg body weight} \quad (2.16b)$$

If a protective layer does exist, then the maximum allowable (or tolerable) step voltages, for a person with a body weight of 50 or 70 kg, are given, respectively, as

$$V_{\text{step } 50} = \frac{0.116(1,000 + 6C_s\rho_s)}{\sqrt{t_s}} \text{ V for 50 kg body weight} \quad (2.17a)$$

and

$$V_{\text{step } 70} = \frac{0.157(1,000 + 6C_s\rho_s)}{\sqrt{t_s}} \text{ V for 70 kg body weight} \quad (2.17b)$$

If a protective layer does exist, then the maximum allowable (or tolerable) touch voltages, for a person with a body weight of 50 or 70 kg, are given, respectively, as

$$V_{\text{step } 50} = \frac{116(1,000 + 6C_s\rho_s)}{\sqrt{t_s}} \text{ V for 50 kg body weight} \quad (2.18a)$$

and

$$V_{\text{step } 70} = \frac{0.157(1,000 + 6C_s\rho_s)}{\sqrt{t_s}} \text{ V for 70 kg body weight} \quad (2.18b)$$

Again, these equations are applicable only in the event that a protection surface layer is used. For metal-to-metal contacts, use $\rho_s = 0$ and $C_s = 1$. For more detailed applications, see IEEE Std. 2000 [9]. Also, it is important to note that in using these equations, it is assumed that they are applicable to 99.5% of the population. There are always exceptions.

Furthermore, the *touch voltage limit* can also be expressed as

$$V_{\text{touch}} = \left(R_B + \frac{R_f}{2} \right) I_B \quad (2.19)$$

Similarly, the *step voltage limit* can also be expressed as

$$V_{\text{step}} = (R_B + 2R_f) I_B \quad (2.20)$$

where

$$R_f = 3C_s\rho_s \quad (2.21)$$

where

R_B is the resistance of human body, typically 1,000 Ω for 50 and 60 Hz

R_f is the ground resistance of one foot

I_B is the rms magnitude of the current going through the body in A, per Equations 2.12 and 2.13

C_s is the surface layer derating factor based on the thickness of the protective surface layer spread above the earth grade at the substation (per IEEE Std. 80-2000, if no protective layer is used, then $C_s = 1.0$.)

Since it is much easier to calculate and measure potential than current, the fibrillation thresholds, given by Equations 2.12 and 2.13, are usually given in terms of voltage.

2.11.2 REDUCTION OF FACTOR C_s

Note that according to IEEE Std. 80-2000, a *thin layer of highly resistive protective surface material* such as gravel spread across the earth at a substation greatly reduces the possible shock current at a substation. IEEE Std. 80-2000 gives the required equations to determine the ground resistance of one foot on a thin layer of surface material as

$$C_s = 1 + \frac{1.6b}{\rho_s} \sum_{n=1}^{\infty} K^n R_{m(2nh_s)} \quad (2.22)$$

and

$$C_s = 1 - \frac{0.09(1 - (\rho / \rho_s))}{2h_s} \quad (2.23)$$

where

$$K = \frac{\rho - \rho_s}{\rho + \rho_s} \quad (2.24)$$

where

C_s is the surface layer derating factor (it can be considered as a corrective factor to compute the effective foot resistance in the presence of a finite thickness of surface material) (see Figure 2.34)

ρ_s is the surface material resistivity in ohmmeters

K is the reflection factor between different material resistivities

ρ is the resistivity of earth beneath the substation in ohmmeters

h_s is the thickness of the surface material in meters

b is the radius of a circular metallic disk representing the foot in meters

$R_m(2nh_s)$ is the mutual ground resistance between two similar, parallel, coaxial plates that are separated by a distance of $(2nh_s)$ in ohmmeters

Again, note that Figure 2.34 gives the exact value of C_s instead of using the empirical Equation 2.22 for it. The empirical equation gives approximate values that are within 5% of the values that can be found in the equation.

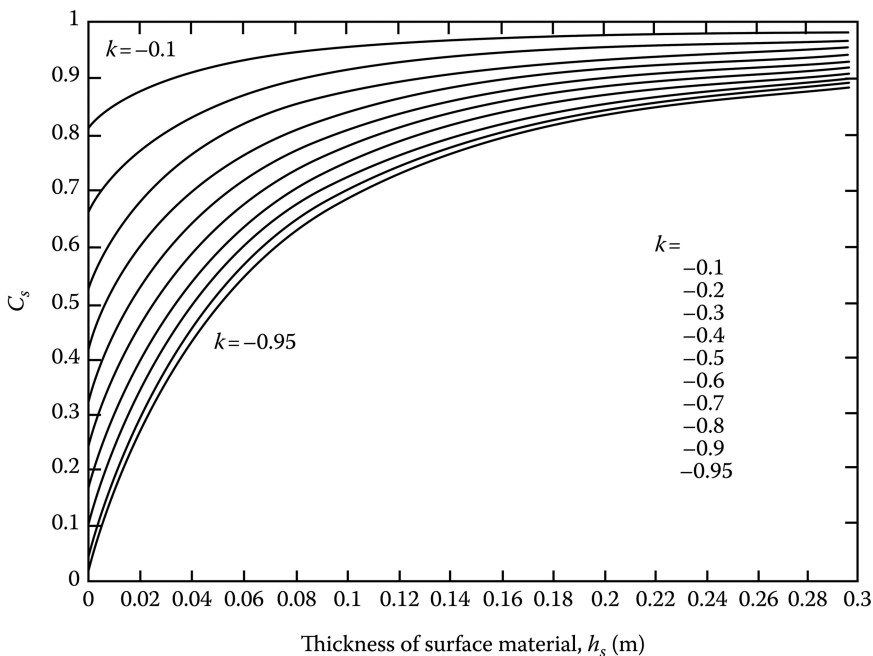


FIGURE 2.34 Surface layer derating factor C_s versus thickness of surface material in meters. (From Keil, R. P., Substation grounding, in *Electric Power Substation Engineering*, Chapter 11, CRC Press, Boca Raton, FL, 2003. With permission.)

Example 2.1

Assume that a human body is part of a 60 Hz electric power circuit for about 0.25 s and that the soil type is average earth. Based on the IEEE Std. 80-2000, determine the following:

- Tolerable touch potential for 50 kg body weight
- Tolerable step potential for 50 kg body weight

Solution

- Using Equation 2.18a, for 50 kg body weight,

$$V_{\text{touch}} = \frac{0.116(1,000 + 1.5\rho_s)}{\sqrt{t}} = \frac{0.116(1,000 + 1.5 \times 100)}{\sqrt{0.25}} \cong 267 \text{ V}$$

- Using Equation 2.19b, for 50 kg body weight,

$$V_{\text{touch}} = \frac{0.116(1,000 + 6\rho_s)}{\sqrt{t}} = \frac{0.116(1,000 + 6 \times 100)}{\sqrt{0.25}} \cong 371 \text{ V}$$

Example 2.2

Assume that a human body is part of a 60 Hz electric power circuit for about 0.49 s and that the soil type is average earth. Based on the IEEE Std. 80-2000, determine the following:

- Tolerable touch potential for 50 kg body weight
- Tolerable step potential for 50 kg body weight
- Tolerable touch voltage limit for metal-to-metal contact if the person is 50 kg
- Tolerable touch voltage limit for metal-to-metal contact if the person is 70 kg

Solution

- Using Equation 2.18a, for 50 kg body weight,

$$\begin{aligned} V_{\text{touch } 50} &= \frac{0.116(1,000 + 1.5\rho_s)}{\sqrt{t_s}} \\ &= \frac{0.116(1,000 + 1.5 \times 100)}{\sqrt{0.49}} \\ &\cong 191 \text{ V} \end{aligned}$$

- Using Equation 2.18c,

$$\begin{aligned} V_{\text{touch } 50} &= \frac{0.116(1,000 + 1.5\rho_s)}{\sqrt{t_s}} \\ &= \frac{0.116(1,000 + 1.5 \times 100)}{\sqrt{0.49}} \\ &\cong 191 \text{ V} \end{aligned}$$

c. Since $\rho_s = 0$,

$$V_{\text{mm-touch } 50} = \frac{116}{\sqrt{t_s}} = \frac{116}{\sqrt{0.49}} = 165.7 \text{ V for 50 kg body weight}$$

d. Since $\rho_s = 0$,

$$V_{\text{mm-touch } 70} = \frac{157}{\sqrt{t_s}} = \frac{157}{\sqrt{0.49}} = 224.3 \text{ V for 70 kg body weight}$$

Table 2.7 gives typical values for various ground types. However, the resistivity of ground also changes as a function of temperature, moisture, and chemical content. Therefore, in practical applications, the only way to determine the resistivity of soil is by measuring it.

2.11.3 GROUND RESISTANCE

Ground is defined as a conducting connection, either intentional or accidental, by which an electric circuit or equipment becomes grounded. Therefore, *grounded* means that a given electric system, circuit, or device is connected to the earth serving in the place of the former with the purpose of establishing and maintaining the potential of conductors connected to it approximately at the potential of the earth and allowing for conducting electric currents from and to the earth of its equivalent. A *safe grounding design* should provide the following:

- 1. A means to carry and dissipate electric currents into ground under normal and fault conditions without exceeding any operating and equipment limits or adversely affecting the continuity of service
- 2. Assurance for such a degree of human safety so that a person working or walking in the vicinity of grounded facilities is not subjected to the danger of critical electrical shock

However, low ground resistance is not, in itself, a guarantee of safety. For example, about three or four decades ago, a great many people assumed that any object grounded, however crudely, could be safely touched. This misconception probably contributed to many tragic accidents in the past. Since there is no simple relation between the resistance of the ground system as a whole and the maximum shock current to which a person might be exposed, a system or system component (e.g., substation or tower) of relatively low ground resistance may be dangerous under some conditions, whereas another system component with very high ground resistance may still be safe or can be made safe by careful design.

TABLE 2.7
Resistivity of Different Soils

Ground Type	Resistivity, ρ_s
Seawater	0.01–1.0
Wet organic soil	10
Moist soil (average earth)	100
Dry soil	1,000
Bedrock	10^4
Pure slate	10^7
Sandstone	10^9
Crushed rock	15×10^8

GPR is a function of fault current magnitude, system voltage, and ground (system) resistance. The current through the ground system multiplied by its resistance measured from a point remote from the substation determines the GPR with respect to remote ground.

The ground resistance can be reduced by using electrodes buried in the ground. For example, metal rods or *counterpoise* (i.e., buried conductors) is used for the lines of the grid system made of copper-stranded copper cable, and rods are used for the substations.

The grounding resistance of a buried electrode is a function of (1) the resistance of the electrode itself and connections to it, (2) contact resistance between the electrode and the surrounding soil, and (3) the resistance of the surrounding soil, from the electrode surface outward. The first two resistances are very small with respect to soil resistance and, therefore, may be neglected in some applications. However, the third one is usually very large depending on the type of soil, chemical ingredients, moisture level, and temperature of the soil surrounding the electrode.

Table 2.8 presents data indicating the effect of moisture contents on the soil resistivity. The resistance of the soil can be measured by using the three-electrode method or by using self-contained instruments such as the Biddle Megger ground resistance tester.

If the surface of the soil is covered with a layer of crushed rock or some other high-resistivity material, its resistivity should be used in the previous equations. Table 2.6 gives typical values for various ground types. However, the resistivity of the ground also changes as a function of temperature, moisture, and chemical content. Thus, in practical applications, the only way to determine the resistivity of soil is to measure it.

In general, soil resistivity investigations are required to determine the soil structure. Table 2.7 gives only very rough estimates. The soil resistivity can vary substantially with changes in temperature, moisture, and chemical content. To determine the soil resistivity of a specific site, soil resistivity measurements are required to be taken. Since soil resistivity can change both horizontally and vertically, it is necessary to take more than one set of measurements. IEEE Std. 81-1983 [11] describes various measuring techniques in detail. There are commercially available computer programs that use the soil data and calculate the soil resistivity and provide a confidence level based on the test. There is also a graphical method that was developed by Sunde [12] to interpret the test results.

Figure 2.35 shows a ground rod driven into the soil and conducting current in all directions. Resistance of the soil has been illustrated in terms of successive shells of the soil of equal thickness. With increased distance from the electrode, the soil shells have greater area, and therefore, lower resistance. Thus, the shell nearest the rod has the smallest cross section of the soil and, therefore, the highest resistance. Measurements have shown that 90% of the total resistance surrounding an electrode is usually with a radius of 6–10 ft.

The assumptions that have been made in deriving these formulas are that the soil is perfectly homogeneous and the resistivity is of the same known value throughout the soil surrounding the

TABLE 2.8
Effect of Moisture Content on Soil Resistivity

Moisture Content (wt.%)	Resistivity (Ω - cm)	
	Topsoil	Sandy Loam
0	> 10 ⁹	> 10 ⁹
2.5	250,000	150,000
5	165,000	43,000
10	53,000	18,500
15	19,000	10,500
20	12,000	6,300
30	6,400	4,200

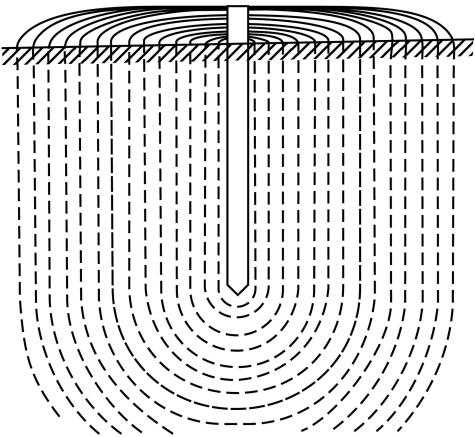


FIGURE 2.35 Resistance of earth surrounding an electrode.

electrode. Of course, these assumptions are seldom true. The only way one can be sure of the resistivity of the soil is by actually measuring it at the actual location of the electrode and at the actual depth.

Figure 2.36 shows the variation of soil resistivity with depth for a soil having uniform moisture content at all depths. In reality, however, deeper soils have greater moisture content, and the advantage of depth is more visible. Some nonhomogeneous soils can also be modeled by using the two-layer method.

Figure 2.37 shows the approximate ground resistivity distribution in the United States.

If the surface of the soil is covered with a layer of crushed rock or some other high-resistivity material, its resistivity should be used in the previous equations. Table 2.9 gives typical values for various ground types. However, the resistivity of the ground also changes as a function of temperature, moisture, and chemical content. Thus, in practical applications, the only way to determine the resistivity of soil is to measure it.

In general, soil resistivity investigations are required to determine the soil structure. Table 2.9 gives only very rough estimates. The soil resistivity can vary substantially with changes in temperature, moisture, and chemical content. To determine the soil resistivity of a specific site, soil resistivity measurements are required to be taken. Since soil resistivity can change both horizontally and vertically,

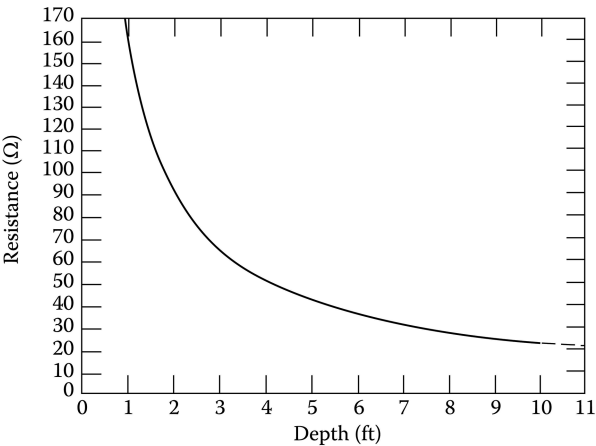


FIGURE 2.36 Variation of soil resistivity with depth for soil having uniform moisture content at all depths. (From National Bureau of Standards Technical Report 108.)

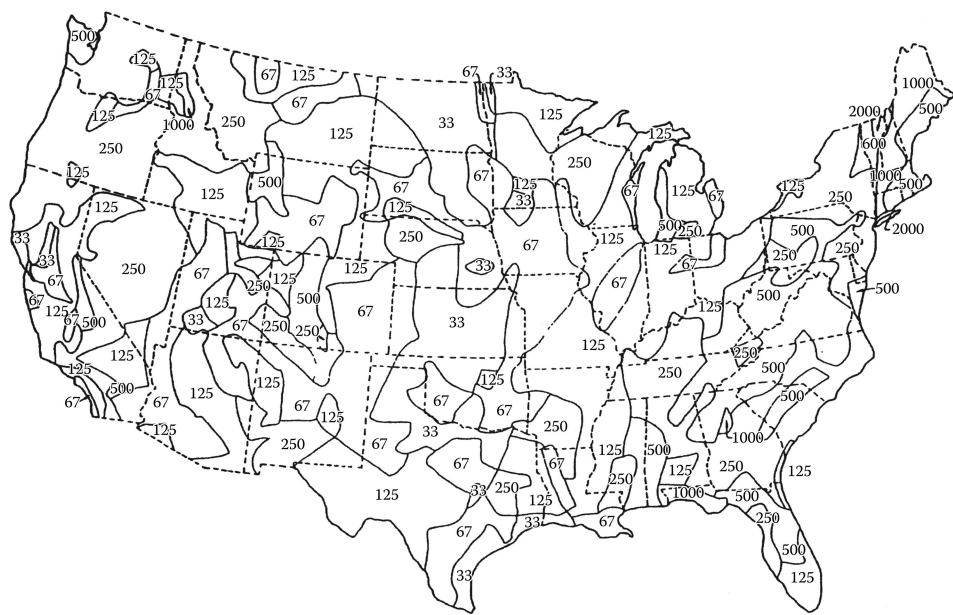


FIGURE 2.37 Approximate ground resistivity distribution in the United States. *Notes:* All figures on this map indicate ground resistivity (ρ) in ohmmeters. These data are taken from FCC Figure M3, February 1954. The FCC data indicate ground conductivity in milliohms per meter. Resistivities of special note from Transmission Line Reference Book by EPRI in ohmmeters: Swampy ground (10–100), pure slate (10,000,000), and sandstone (100,000,000). (From Keil, R. P., Substation grounding, in *Electric Power Substation Engineering*, Chapter 11, CRC Press, Boca Raton, FL, 2003.)

TABLE 2.9
Material Constants of the Typical Grounding Material Used

Description	K_f	T_m (°C)	α , Factor at 20°C (1/°C)	ρ , 20°C ($\mu\Omega \cdot \text{cm}$)	K_0 at 20°C (°C)	Fusing Temperature T_m (°C)	Material Conducting (%)	Thermal Capacity TCAP (J/cm ³ ·°C)
Copper annealed, soft drawn	7	1,083	0.0393	1.72	234	1,083	100	3.42
Copper annealed, hard drawn	1,084	1,084	0.00381	1.78	242	1,084	97	3.42
Copper-clad steel wire	1,084	12.06	0.00378	5.86	245	1,084	30	3.85
Stainless steel 304	1,510	14.72	0.00130	15.86	749	1,400	2.4	3.28
Zinc-coated steel rod	28.96	28.96	0.0030	72	293	419	8.6	4.03

it is necessary to take more than one set of measurements. IEEE Std. 80-2000 [9] describes various measuring techniques in detail. There are commercially available computer programs that use the soil data and calculate the soil resistivity and provide a confidence level based on the test. There is also a graphical method that was developed by Sunde [12] to interpret the test results.

2.11.4 SOIL RESISTIVITY MEASUREMENTS

Table 2.9 gives estimates of soil classification that are only an approximation of the actual resistivity of a given site. Actual resistivity tests are, therefore, crucial. They should be made at a number of places within the site. In general, substation sites where the soil has uniform resistivity throughout the entire area and to a considerable depth are seldom found.

2.11.4.1 Wenner Four-Pin Method

More often than not, there are several layers, each having a different resistivity. Furthermore, lateral changes also take place, however with respect to the vertical changes; these changes usually are more gradual. Hence, soil resistivity tests should be made to find out if there are any substantial changes in resistivity with depth. If the resistivity varies considerably with depth, it is often desirable to use an increased range of probe spacing in order to get an estimate of the resistivity of deeper layers.

IEEE Std. 81-1983 describes a number of measuring techniques. The Wenner four-pin method is the most commonly used technique. Figure 2.38 illustrates this method. In this method, four probes (or pins) are driven into the earth along a straight line, at equal distances apart, driven to a depth b . The voltage between the two inner (i.e., potential) electrodes is then measured and divided by the current between the two outer (i.e., current) electrodes to give a value of resistance R . The apparent resistivity of soil is determined from

$$\rho_a = \frac{4\pi a R}{1 + 2a / \left(\sqrt{a^2 + 4b^2} \right)} - \frac{a}{\sqrt{a^2 + 4b^2}} \quad (2.25)$$

where

ρ_a is the apparent resistivity of the soil in ohmmeters

R is the measured resistivity in ohms

a is the distance between adjacent electrodes in meters

b is the depth of the electrodes in meters

In the event that b is small in comparison to a , then

$$\rho_a = 2\pi a R \quad (2.26)$$

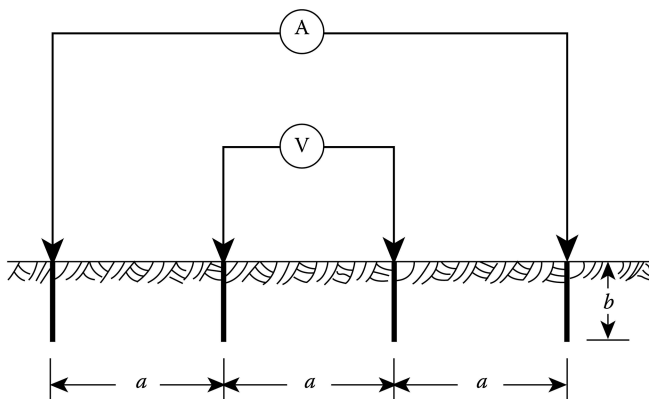


FIGURE 2.38 Wenner four-pin method.

The current tends to flow near the surface for the small probe spacing, whereas more of the current penetrates deeper soils for the large spacing. Because of this fact, the previous two equations can be used to determine the apparent resistivity ρ_a at a depth a .

The Wenner four-pin method obtains the soil resistivity data for deeper layers without driving the test pins to those layers. No heavy equipment is needed to do the four-pin test. The results are not greatly affected by the resistance of the test pins or the holes created in driving the test pins into the soil. Because of these advantages, the Wenner method is the most popular method.

2.11.4.2 Three-Pin or Driven-Ground Rod Method

IEEE Std. 81-1983 describes *a second method of measuring soil resistivity*. It is illustrated in Figure 2.39. In this method, the depth (L_r) of the driven rod located in the soil to be tested is varied.

The other two rods are known as *reference rods*. They are driven to a shallow depth in a straight line. The location of the voltage rod is varied between the test rod and the current rod. Alternatively, the voltage rod can be placed on the other side of the driven rod. The apparent resistivity is found from

$$\rho_a = \frac{2\pi L_r R}{\ln(8L_r / d) - 1} \quad (2.27)$$

where

L_r is the length of the driven rod in meters

d is the diameter of the rod in meters

R is the measured resistivity in ohms

A plot of the measured resistivity value ρ_a versus the rod length (L_r) provides a visual aid for finding out earth resistivity variations with depth. An advantage of the driven-rod method, even though not related necessarily to the measurements, is the ability to determine to what depth the ground rods can be driven. This knowledge can save the need to redesign the ground grid. Because of hard layers in the soil such as rock and hard clay, it becomes practically impossible to drive the test rod any further resulting in insufficient data.

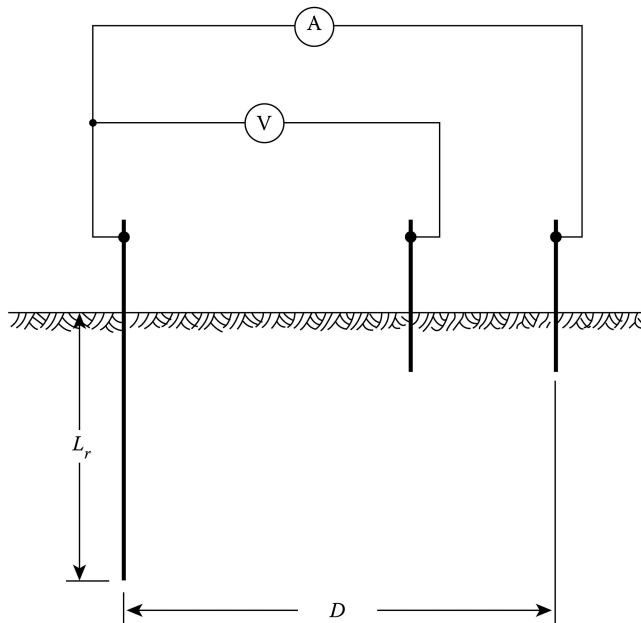


FIGURE 2.39 Circuit diagram for a three-pin or driven-ground rod method.

A *disadvantage of the driven-rod method* is that when the test rod is driven deep in the ground, it usually losses contact with the soil due to the vibration and the larger diameter couplers resulting in higher measured resistance values. A ground grid designed with these higher soil resistivity values may be unnecessarily conservative. Thus, this method presents an uncertainty in the resistance value.

2.12 SUBSTATION GROUNDING

Grounding at substations has paramount importance. Again, the purpose of such a grounding system includes the following:

1. To provide the ground connection for the grounded neutral for transformers, reactors, and capacitors
2. To provide the discharge path for lightning rods, arresters, gaps, and similar devices
3. To ensure safety of operating personnel by limiting potential differences that can exist in a substation
4. To provide a means of discharging and deenergizing equipment in order to proceed with the maintenance of the equipment
5. To provide a sufficiently low-resistance path to ground to minimize the rise in ground potential with respect to remote ground

A multigrounded, common neutral conductor used for a primary distribution line is always connected to the substation grounding system where the circuit originates and to all grounds along the length of the circuit. If separate primary and secondary neutral conductors are used, the conductors have to be connected together provided the primary neutral conductor is effectively grounded.

The substation grounding system is connected to every individual equipment, structure, and installation so that it can provide the means by which grounding currents are connected to remote areas. It is extremely important that the substation ground has a low ground resistance, adequate current-carrying capacity, and safety features for personnel. It is crucial to have the substation ground resistance very low so that the total rise of the ground system potential will not reach values that are unsafe for human contact.⁵

The substation grounding system is normally made of buried horizontal conductors and driven-ground rods interconnected (by clamping, welding, or brazing) to form a continuous grid (also called mat) network. A continuous cable (usually it is 4/0 bare copper cable buried 12–18 in. below the surface) surrounds the grid perimeter to enclose as much ground as possible and to prevent current concentration and thus high gradients at the ground cable terminals. Inside the grid, cables are buried in parallel lines and with uniform spacing (e.g., about 10×20 ft).

All substation equipment and structures are connected to the ground grid with large conductors to minimize the grounding resistance and limit the potential between equipment and the ground surface to a safe value under all conditions. All substation fences are built inside the ground grid and attached to the grid in short intervals to protect the public and personnel. The surface of the substation is usually covered with crushed rock or concrete to reduce the potential gradient when large currents are discharged to the ground and to increase the contact resistance to the feet of personnel in the substation.

IEEE Std. 80-1976 [13] provides a formula for a quick simple calculation of the grid resistance to ground after a minimum design has been completed. It is expressed as

$$R_{\text{grid}} = \frac{\rho_s}{4r} + \frac{\rho_s}{L_T} \quad (2.28)$$

where

ρ_s is the soil resistivity in ohmmeters

L_T is the total length of grid conductors in meters

R is the radius of circle with an area equal to that of grid in meters

IEEE Std. 80-2000 [11] provides the following equation to determine the grid resistance after a minimum design has been completed:

$$R_{\text{grid}} = \frac{\rho_s}{4r} \sqrt{\frac{\pi}{A}} \quad (2.29)$$

Also, IEEE Std. 80-2000 provides the following equation to determine *the upper limit for grid resistance to ground after a minimum design has been completed*:

$$R_{\text{grid}} = \frac{\rho_s}{4r} \sqrt{\frac{\pi}{A}} + \frac{\rho_s}{L_T} \quad (2.30)$$

where

R_{grid} is the grid resistance in ohms

ρ is the soil resistance in ohmmeters

A is the area of the ground in square meters

L_T is the total buried length of conductors in meters

But Equation 2.30 requires a uniform soil resistivity. Hence, a substantial engineering judgment is necessary for reviewing the soil resistivity measurements to decide the value of soil resistivity. However, it does provide a guideline for the uniform soil resistivity to be used in the ground grid design. Alternatively, Ref. [11] provides the following formula for the grid resistance:

$$R_{\text{grid}} = \rho_s \left[\frac{1}{L_T} + \frac{1}{\sqrt{20A}} \left(1 + \frac{1}{1 + h\sqrt{20/A}} \right) \right] \quad (2.31)$$

where

R_{grid} is the substation ground resistance in ohms

ρ_s is the soil resistivity in ohmmeters

A is the area occupied by the ground grid in square meters

H is the depth of the grid in meters

L_T is the total buried length of conductors in meters

IEEE Std. 80-1976 also provides formulas to determine the effects of the grid geometry on the step and mesh voltage (which is the worst possible value of the touch voltage) in volts. *Mesh voltage* is the worst possible value of a touch voltage to be found within a mesh of a ground grid if standing at or near the center of the mesh. They can be expressed as

$$E_{\text{step}} = \frac{\rho_s \times K_s \times K_i \times I_G}{L_s} \quad (2.32)$$

and

$$E_{\text{mesh}} = \frac{\rho_s \times K_m \times K_i \times I_G}{L_m} \quad (2.33)$$

where

ρ_s is the average soil resistivity in ohmmeters

K_s is the step coefficient

K_m is the mesh coefficient

K_i is the irregularity coefficient

I_G is the maximum rms current flowing between ground grid and earth in amperes

L_s is the total length of buried conductors, including cross connections and (optionally) the total effective length of ground rods in meters

L_m is the total length of buried conductors, including cross connections and (optionally) the combined length of ground rods in meters

Many utilities have computer programs for performing grounding grid studies. The number of tedious calculations that must be performed to develop an accurate and sophisticated model of a system is no longer a problem.

In general, in the event of a fault, OHGWs, neutral conductors, and directly buried metal pipes and cables conduct a portion of the ground fault current away from the substation ground grid and have to be taken into account when calculating the maximum value of the grid current. Based on the associated equivalent circuit and resultant current division, one can determine what portion of the total current flows into the earth and through other ground paths. It can be used to determine the approximate amount of current that does not use the ground as a flow path. The fault current division factor (also known as the *split factor*) can be expressed as

$$S_{\text{split}} = \frac{I_{\text{grid}}}{3I_{\text{ao}}} \quad (2.34)$$

where

S_{split} is the fault current division factor

I_{grid} is the rms symmetrical grid current in amperes

I_{ao} is the zero-sequence fault current in amperes

The *split factor* is used to determine the approximate amount of current that did not use the ground flow path. Computer programs can determine the split factor easily, but it is also possible to determine the split factor through graphs. With the Y ordinate representing the split factor and the X axis representing the grid resistance, it is obvious that the grid resistance has to be known to determine the split factor.

As previously said, the split factor determines the approximate amount of current that does use the earth as return path. The amount of current that does enter the earth is found from the following equation. Hence, the design value of the maximum grid current can be found from

$$I_G = D_f \times I_{\text{grid}} \quad (2.35)$$

where

I_G is the maximum grid current in amperes

D_f is the decrement factor for the entire fault duration of t_f given in seconds

I_{grid} is the rms symmetrical grid current in amperes

Here, Figure 2.40 illustrates the relationship between asymmetrical fault current, DC decaying component, and symmetrical fault current and the relationship between variables I_F , I_f , and D_f for the fault duration t_f .

The *decrement factor* is an adjustment factor that is used in conjunction with the symmetrical ground fault current parameter in safety-oriented grounding calculations. It determines the rms equivalent of the asymmetrical current wave for a given fault duration, accounting for the effect of initial DC offset and its attenuation during the fault. The decrement factor can be calculated from

$$D_f = \sqrt{1 + \frac{T_a}{I_f}} \left(1 - e^{-2t_f/T_a} \right) \quad (2.36)$$

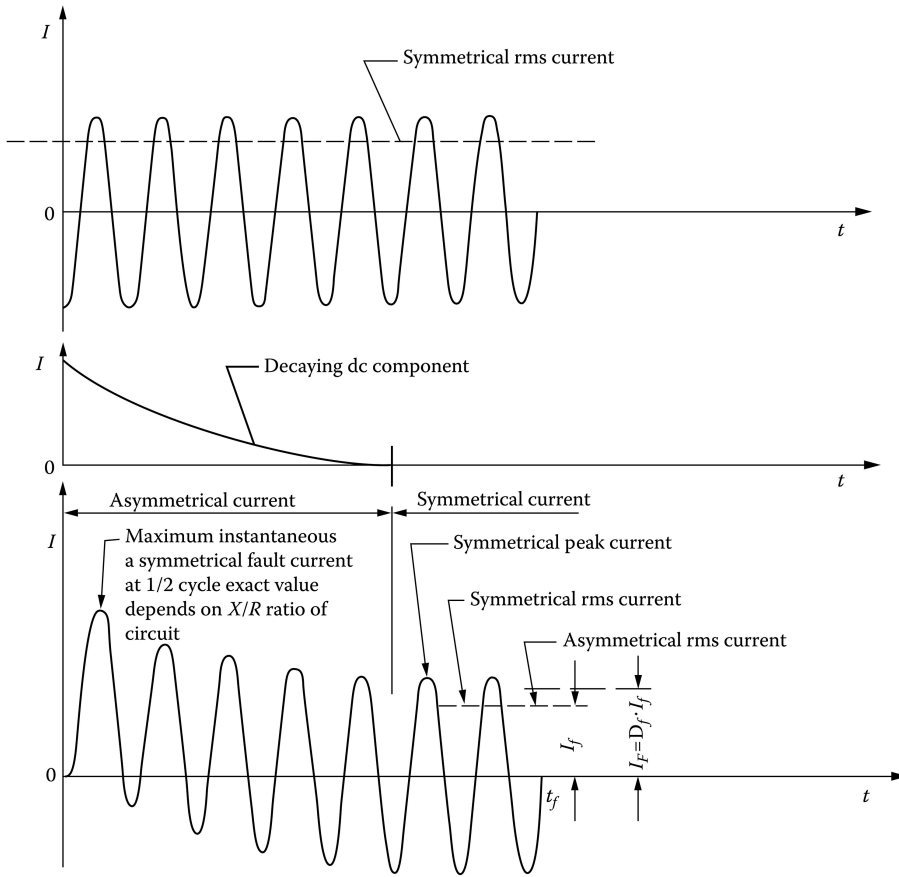


FIGURE 2.40 The relationship between asymmetrical fault current, DC decaying component, and symmetrical fault current.

where t_f is the time duration of fault in seconds.

$$T_a = \frac{X}{\omega R} = \text{dc offset time constant in seconds}$$

Here, t_f should be chosen as the fastest clearing time. The fastest clearing time includes breaker and relay time for transmission substations. It is assumed here that the AC components do not decay with time.

The *symmetrical grid current* is defined as that portion of the symmetrical ground fault current that flows between the grounding grid and the surrounding earth. It can be expressed as

$$I_{\text{grid}} = S_f \times I_f \quad (2.37)$$

where

I_f is the rms value of symmetrical ground fault current in amperes

S_f is the fault current division factor

IEEE Std. 80-2000 provides a series of currents based on computer simulations for various values of ground grid resistance and system conditions to determine the grid current. Based on those split-current curves, one can determine the maximum grid current.

2.13 GROUND CONDUCTOR SIZING FACTORS

The flow of excessive currents will be very dangerous if the right equipment is not used to help dissipate the excessive currents. Ground conductors are means of providing a path for excessive currents from the substation to the ground grid. Hence, the ground grid then can spread the current into the ground, creating a zero potential between the substation and the ground. Table 2.9 gives the list of possible conductors that can be used for such conductors.

In the United States, there are only two types of conductors that are used, namely, copper and/or copper-clad steel conductors that are used for this purpose. The copper one is mainly used due to its high conductivity and high resistance to corrosion. The next step is to determine the size of ground conductor that needs to be buried underground.

Thus, based on the *symmetrical conductor current*, the required conductor size can be found from

$$I_f = A_{\text{mm}^2} \left[\left(\frac{\text{TCAP} \times 10^{-4}}{t_c \times \alpha_r \times \rho_r} \right) \ln \left(\frac{K_0 + T_{\text{max}}}{K_0 + T_{\text{amb}}} \right) \right]^{1/2} \quad (2.38)$$

If the conductor size needs to be found in mm^2 , the conductor size can be found from

$$A_{\text{mm}^2} = \frac{I_f}{\left[\left(\frac{\text{TCAP} \times 10^{-4}}{t_c \times \alpha_r \times \rho_r} \right) \ln \left(\frac{K_0 + T_{\text{max}}}{K_0 + T_{\text{amb}}} \right) \right]^{1/2}} \quad (2.39)$$

Alternatively, in the event that the conductor size needs to be found in kcmil, since

$$A_{\text{kcmil}} = 1.974 \times A_{\text{mm}^2} \quad (2.40)$$

then, Equation 2.31 can be expressed as

$$I_f = 5.07 \times 10^{-3} A_{\text{kcmil}} \left[\left(\frac{\text{TCAP} \times 10^{-4}}{t_c \times \alpha_r \times \rho_r} \right) \ln \left(\frac{K_0 + T_{\text{max}}}{K_0 + T_{\text{amb}}} \right) \right]^{1/2} \quad (2.41)$$

Note that both α_r and ρ_r can be found at the same reference temperature of $T_r^\circ\text{C}$. Also, note that Equations 2.38 and 2.39 can also be used to determine the short-time temperature rise in a ground conductor. Thus, taking other required conversions into account, the conductor size in kcmil can be found from

$$A_{\text{kcmil}} = \frac{197.4 \times I_f}{\left[\left(\frac{\text{TCAP} \times 10^{-4}}{t_c \times \alpha_r \times \rho_r} \right) \ln \left(\frac{K_0 + T_{\text{max}}}{K_0 + T_{\text{amb}}} \right) \right]^{1/2}} \quad (2.42)$$

where

I_f is the rms current (without DC offset) in kiloamperes

A_{mm^2} is the conductor cross section in square millimeters

A_{kcmil} is the conductor cross section in kilocircular mils

TCAP is the thermal capacity per unit volume, $\text{J}/(\text{cm}^3 \cdot ^\circ\text{C})$ (it is found from Table 2.9, per IEEE Std. 80-2000)

t_c is the duration of current in seconds

α_r is the thermal coefficient of resistivity at reference temperature T_r , $1/^\circ\text{C}$ (it is found from Table 2.9, per IEEE Std. 80-2000 for 20°C)

ρ_r is the resistivity of the ground conductor at reference temperature T_r , microohm centimeters (it is found from Table 2.9, per IEEE Std. 80-2000 for 20°C)

$$K_0 = 1/\alpha_0 \text{ or } (1/\alpha_r) - T_r \text{ in degree celsius}$$

$T_{\max}$ is the maximum allowable temperature in degree celsius

T_{amb} is the ambient temperature in degree celsius

I_f is the rms current (without DC offset) in kiloamperes

For a given conductor material, the TCAP is found from Table 2.9 or calculated from

$$\text{TCAP} \left[\frac{\text{J}}{(\text{cm}^3 \cdot ^\circ\text{C})} \right] = 4.184 \left(\frac{\text{J}}{\text{cal}} \right) \times \text{SH} \left[\frac{\text{cal}}{\text{g} \cdot ^\circ\text{C}} \right] \times \text{SW} \left(\frac{\text{g}}{\text{cm}^3} \right) \quad (2.43)$$

where SH is the specific heat, in $\text{cal}/(\text{cm}^3 \cdot ^\circ\text{C})$, and is related to the thermal capacity per unit volume in

$$\frac{\text{J}}{(\text{cm}^3 \cdot ^\circ\text{C})}$$

SW is the specific weight, in g/cm^3 , and is related to the thermal capacity per unit volume in

$$\frac{\text{J}}{(\text{cm}^3 \cdot ^\circ\text{C})}$$

Thus, TCAP is defined by

$$\text{TCAP} \left[\frac{\text{J}}{(\text{cm}^3 \cdot ^\circ\text{C})} \right] = 4.184 \left(\frac{\text{J}}{\text{cal}} \right) \times \text{SH} \left[\frac{\text{cal}}{\text{g} \cdot ^\circ\text{C}} \right] \times \text{SW} \left(\frac{\text{g}}{\text{cm}^3} \right) \quad (2.44)$$

Asymmetrical fault currents consist of subtransient, transient, and steady-state AC components and the DC offset current component. To find the *asymmetrical fault current* (i.e., if the effect of the DC offset is needed to be included in the fault current), the equivalent value of the asymmetrical current I_F is found from

$$I_F = D_f \times I_f \quad (2.45)$$

where I_F is representing the rms value of an asymmetrical current integrated over the entire fault duration, t_c , which can be found as a function of X/R by using D_f , before using Equation 2.36 or 2.39 and where D_f is the decrement factor and is found from

$$D_f = \left[1 + \frac{T_a}{t_f} (1 - e^{-2t_f/T_a}) \right]^{1/2} \quad (2.46)$$

where

t_f is the time duration of fault in seconds

T_a is the DC offset time constant in seconds

Note that

$$T_a = \frac{X}{\omega R} \quad (2.47)$$

and for 60 Hz,

$$T_a = \frac{X}{120\pi R} \quad (2.48)$$

The resulting I_F is always greater than I_f . However, if the X/R ratio is less than five and the fault duration is >1 s, the effects of the DC offset are negligible.

2.14 MESH VOLTAGE DESIGN CALCULATIONS

If the GPR value exceeds the tolerable touch and step voltages, it is necessary to perform the mesh voltage design calculations to determine whether the design of a substation is safe. If the design is again unsafe, conductors in the form of ground rods are added to the design until the design is considered safe. The mesh voltage is the maximum touch voltage and it is found from

$$E_{\text{mesh}} = \frac{\rho \times K_m \times K_i \times I_G}{L_M} \quad (2.49)$$

where

ρ is the soil resistivity in ohmmeters

K_m is the mesh coefficient

K_i is the correction factor for grid geometry

I_G is the maximum grid current that flows between ground grid and surrounding earth in amperes

L_m is the length of $L_c + L_R$ for mesh voltage in meters

L_c is the total length of grid conductor in meters

L_R is the total length of ground rods in meters

The mesh coefficient K_m is determined from

$$K_m = \frac{1}{2\pi} \left[\ln \left(\frac{D^2}{16 \times h \times d} + \frac{(D + 2 \times h)^2}{8 \times D \times d} - \frac{h}{4 \times D} \right) + \frac{K_{ii}}{K_h} \ln \left(\frac{8}{\pi(2 \times 14 - 1)} \right) \right] \quad (2.50)$$

where

d is the diameter of grid conductors in meters

D is the spacing between parallel conductors in meters

K_{ii} is the irregularity factor (*corrective weighting factor* that adjusts for the effects of inner conductors on the corner mesh)

K_h is the corrective weighting factor that highlights the effects of grid depth

n is the geometric factor

h is the depth of ground grid conductors in meters

As it can be observed from Equation 2.50, the geometric factor K_m has the following variables: D , the spacing between the conductors; n , the number of conductors; d , the diameter of the conductors used; and h , the depth of the grid. The effect of each variable on the K_m is different. Figure 2.41 shows the effect of the spacing (D) between conductors on K_m . Figure 2.42 shows the effect of the number of conductors (n) on the K_m . Figure 2.43 shows the relationship between the diameter of the conductor (d) and the K_m . Figure 2.44 shows the relationship between the depth of the conductor (h) and K_m [14].

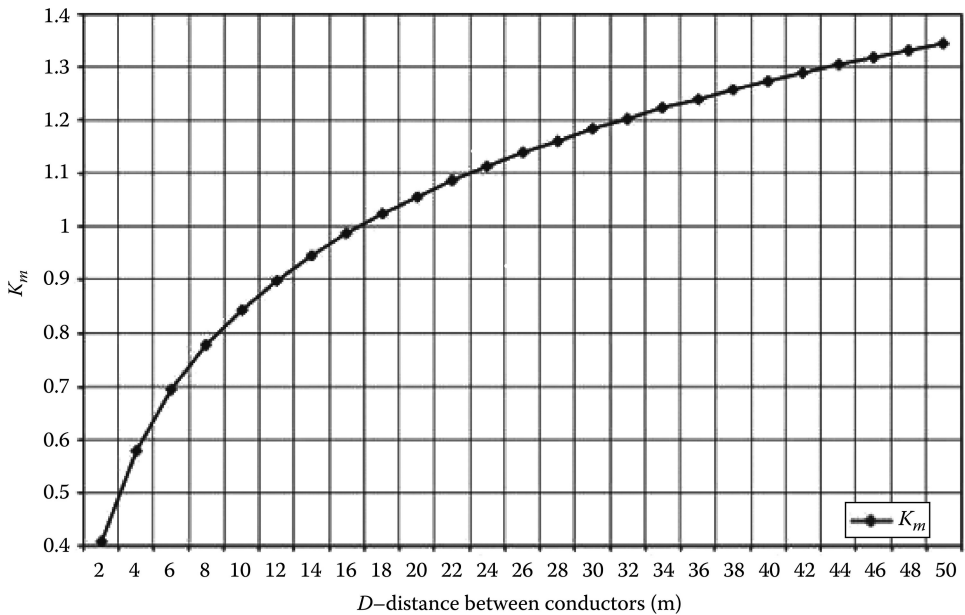


FIGURE 2.41 The effect of the spacing (D) between conductors on K_m . (From Keil, R. P., Substation grounding, in *Electric Power Substation Engineering*, Chapter 11, CRC Press, Boca Raton, FL, 2003. With permission.)

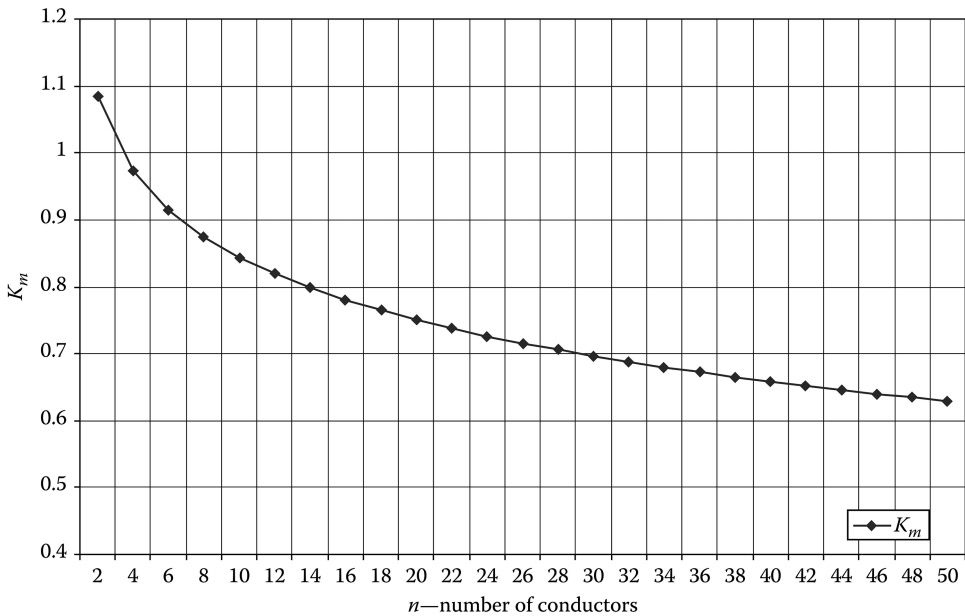


FIGURE 2.42 The effect of the number of conductors (n) on the K_m . (From Keil, R. P., Substation grounding, in *Electric Power Substation Engineering*, Chapter 11, CRC Press, Boca Raton, FL, 2003. With permission.)

Note that the value of K_{ii} depends on the following circumstances:

1. For the grids with ground rods existing in grid corners as well as perimeter,

$$K_{ii} = 1 \tag{2.51}$$

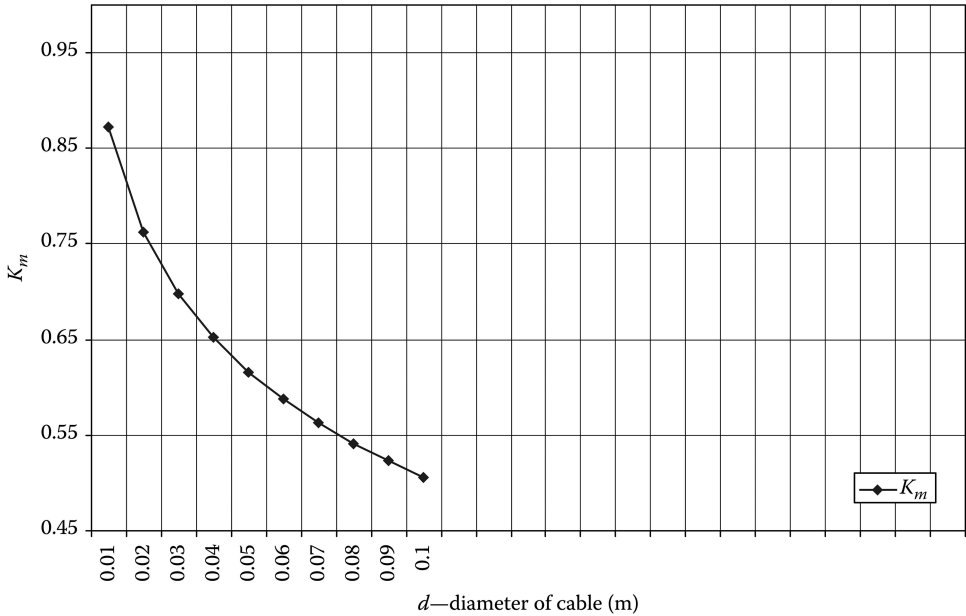


FIGURE 2.43 The relationship between the diameter of the conductor (d) and the K_m . (From Keil, R. P., Substation grounding, in *Electric Power Substation Engineering*, Chapter 11, CRC Press, Boca Raton, FL, 2003. With permission.)

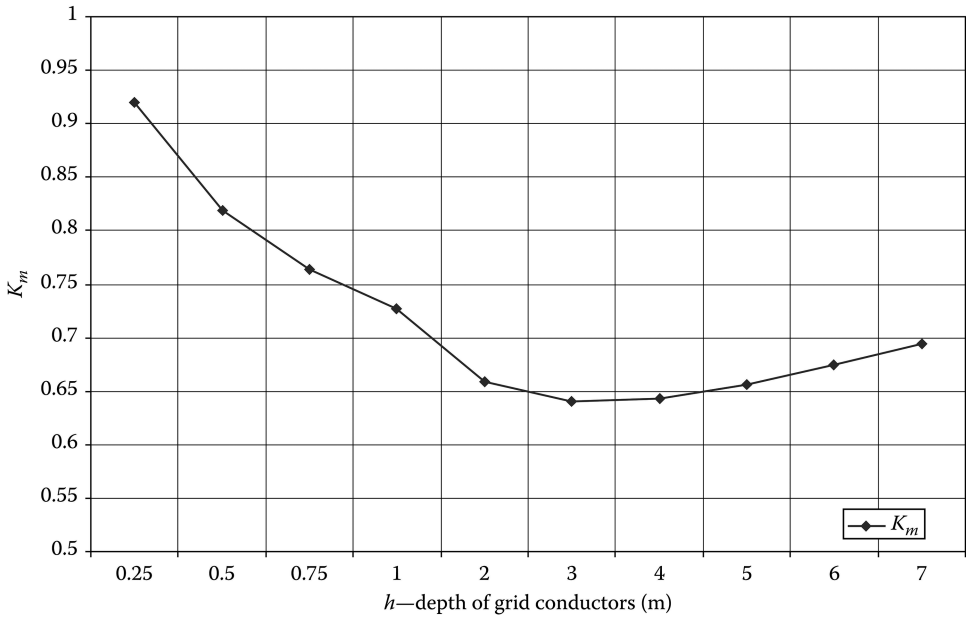


FIGURE 2.44 The relationship between the depth of the conductor (h) and K_m . (From Keil, R. P., Substation grounding, in *Electric Power Substation Engineering*, Chapter 11, CRC Press, Boca Raton, FL, 2003. With permission.)

2. For the grids with no or few ground rods with none existing in corners or perimeter,

$$K_{ii} = \frac{1}{(2n)^{2/n}} \tag{2.52}$$

and

$$K_h = \sqrt{1 + \frac{h}{h_o}} \quad (2.53)$$

where h_o is the grid reference depth = 1 m.

The effective number of parallel conductors (n) given in a given grid is found from

$$n = n_a \times n_b \times n_c \times n_d \quad (2.54)$$

where

$$n_a = 2 L_c / L_p$$

$$n_b = 1, \text{ for square grids}$$

$$n_c = 1, \text{ for square and rectangular grids}$$

$$n_d = 1, \text{ for square, rectangular, and L-shaped grids}$$

Otherwise, the following equations are used to determine the n_b , n_c , and n_d so that

$$n_b = \sqrt{\frac{L_p}{4\sqrt{A}}} \quad (2.55)$$

$$n_c = \left(\sqrt{\frac{L_X \times L_Y}{A}} \right)^{0.7 A / L_X \times L_Y} \quad (2.56)$$

$$n_d = \frac{D_m}{\sqrt{L_X^2 + L_Y^2}} \quad (2.57)$$

where

L_p is the peripheral length of the grid in meters

L_c is the total length of the conductor in the horizontal grid in meters

A is the area of the grid in square meters

L_X is the maximum length of the grid in the x direction in meters

L_Y is the maximum length of the grid in the y direction in meters

d is the diameter of grid conductors in meters

D is the spacing between parallel conductors in meters

D_m is the maximum distance between any two points on the grid in meters

h is the depth of ground grid conductors in meters

Note that the irregularity factor is determined from

$$K_{ii} = 0.644 + 0.148n \quad (2.58)$$

The effective buried length (L_M) for grids:

1. With little or no ground rods but not located in the corners or along the perimeter of the grid,

$$L_M = L_C + L_R \quad (2.59)$$

where

L_R is the total length of all ground rods in meters

L_C is the total length of the conductor in the horizontal grid in meters

2. With ground rods in corners and along the perimeter and throughout the grid,

$$L_M = L_C \left[1.55 + 1.22 \left(\frac{L_g}{\sqrt{L_X^2 + L_Y^2}} \right) \right] L_R \quad (2.60)$$

where L_R is the length of each ground rod in meters.

2.15 STEP VOLTAGE DESIGN CALCULATIONS

According to IEEE Std. 80-2000, in order for the ground system to be safe, the step voltage has to be less than the tolerable step voltage. Furthermore, step voltages within the grid system designed for safe mesh voltages will be well within the tolerable limits; the reason for this is that both feet and legs are in series rather than in parallel and the current takes the path from one leg to the other rather than through vital organs. The step voltage is determined from

$$E_{\text{step}} = \frac{\rho \times K_s \times K_i \times I_G}{L_s} \quad (2.61)$$

where

K_s is the step coefficient

L_s is the buried conductor length in meters

Again, for grids with or without ground rods,

$$L_s = 0.75L_C + 0.85L_R \quad (2.62)$$

so that the step coefficient can be found from

$$K_s = \frac{1}{\pi} \left[\frac{1}{2h} + \frac{2}{D+h} + \frac{1}{D} (1 - 0.5^{n-2}) \right] \quad (2.63)$$

where h is the depth of ground grid conductors in meters, usually between 0.25 m < h < 2.5 m.

As in Equation 2.63, the geometric factor K_s is a function of D , n , d , n , and h . Figure 2.45 shows the relationship between the distance (D) between the conductors and the geometric factor K_s .

Figure 2.46 shows the relationship between the number of conductors (n) and the geometric factor K_s . Figure 2.47 shows the relationship between the depth of grid conductors (D) in meters and the geometric factor K_s .

2.16 TYPES OF GROUND FAULTS

In general, it is difficult to determine which fault type and location will result in the greatest flow of current between the ground grid and surrounding earth because no simple rule applies. IEEE Std. 80-2000 recommends not to consider multiple simultaneous faults since their probability of occurrence is negligibly small. Instead, it recommends investigating single line-to-ground (SLG) and line-to-line-to-ground faults.

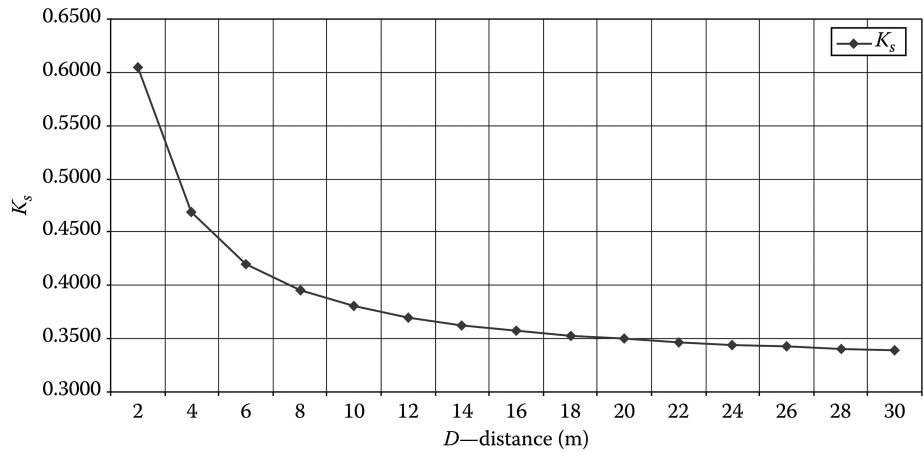


FIGURE 2.45 The relationship between the distance (D) between the conductors and the geometric factor K_s . (From Keil, R. P., Substation grounding, in *Electric Power Substation Engineering*, Chapter 11, CRC Press, Boca Raton, FL, 2003. With permission.)

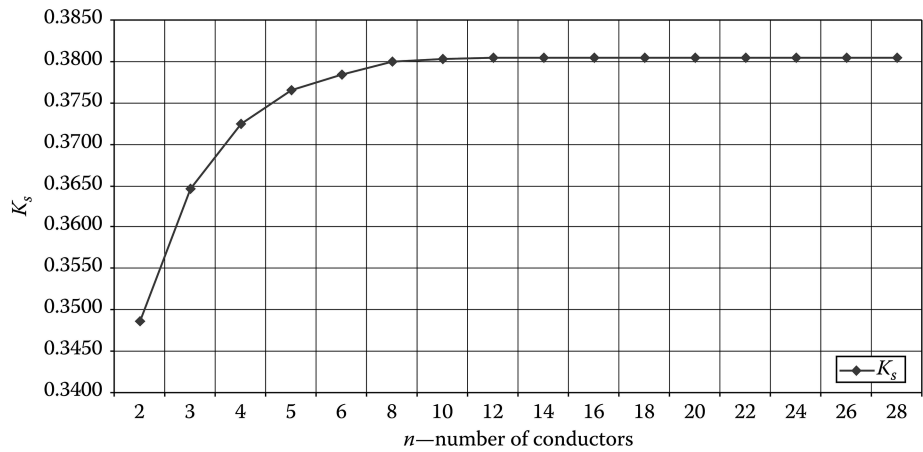


FIGURE 2.46 The relationship between the number of conductors (n) and the geometric factor K_s . (From Keil, R. P., Substation grounding, in *Electric Power Substation Engineering*, Chapter 11, CRC Press, Boca Raton, FL, 2003. With permission.)

2.16.1 LINE-TO-LINE-TO-GROUND FAULT

For a line-to-line-to-ground (i.e., double line-to-ground) fault, IEEE Std. 80-2000 gives the following equation to calculate the zero-sequence fault current:

$$I_{a0} = \frac{E(R_2 + jX_2)}{(R_1 + jX_1) \left[R_0 + R_2 + 3R_f + j(X_0 + X_2) + (R_2 + jX_2)(R_0 + 3R_f + jX_0) \right]} \tag{2.64}$$

where

- I_{a0} is the symmetrical rms value of zero-sequence fault current in amperes
- E is the phase-to-neutral voltage in volts
- R_f is the estimated resistance of the fault in Ω (normally it is assumed R_f is 0)

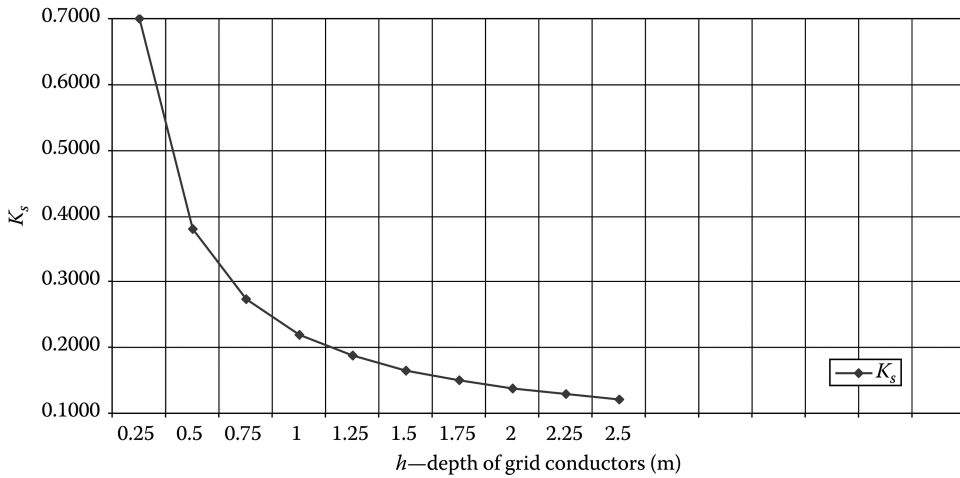


FIGURE 2.47 The relationship between the depth of grid conductors (h) in meter and the geometric factor K_s . (From Keil, R. P., Substation grounding, in *Electric Power Substation Engineering*, Chapter 11, CRC Press, Boca Raton, FL, 2003. With permission.)

R_1 is the positive-sequence system resistance in ohms

R_2 is the negative-sequence system resistance in ohms

R_0 is the zero-sequence system resistance in ohms

X_1 is the positive-sequence system reactance (subtransient) in ohms

X_2 is the negative-sequence system reactance in ohms

X_0 is the zero-sequence system reactance in ohms

The values of R_0 , R_1 , R_2 , and X_0 , X_1 , X_2 are determined by looking into the system from the point of fault. In other words, they are determined from the Thevenin equivalent impedance at the fault point for each sequence.⁶ Often, however, the resistance quantities given in the previous equation are negligibly small. Hence,

$$I_{a0} = \frac{E \times X_2}{X_1(X_0 + X_2)(X_0 + X_2)} \quad (2.65)$$

2.16.2 SLG FAULT

For an SLG fault, IEEE Std. 80-2000 gives the following equation to calculate the zero-sequence fault current:

$$I_{a0} = \frac{E}{3R_f + R_0 + R_1 + R_2 + j(X_0 + X_1 + X_2)} \quad (2.66)$$

Often, however, the resistance quantities in the previous equation are negligibly small. Hence,

$$I_{a0} = \frac{E}{X_0 + X_1 + X_2} \quad (2.67)$$

2.17 GROUND POTENTIAL RISE

The GPR is a function of fault current magnitude, system voltage, and ground system resistance. The GPR with respect to remote ground is determined by multiplying the current flowing through the ground system by its resistance measured from a point remote from the substation. Here, the current flowing through the grid is usually taken as the maximum available line-to-ground fault current.

GPR is a function of fault current magnitude, system voltage, and ground (system) resistance. The current through the ground system multiplied by its resistance measured from a point remote from the substation determines the GPR with respect to remote ground. Hence, GPR can be found from

$$V_{\text{GPR}} = I_G \times R_g \quad (2.68)$$

where

V_{GPR} is the GPR in volts

R_g is the ground grid resistance in ohms

For example, if a ground fault current of 20,000 A is flowing into a substation ground grid due to a line-to-ground fault and the ground grid system has a 0.5Ω resistance to the earth, the resultant IR voltage drop would be 10,000 V. It is clear that such 10,000 V IR voltage drop could cause serious problems to communication lines in and around the substation in the event that the communication equipment and facilities are not properly insulated and/or neutralized. The ground grid resistance can be found from

$$R_g = \rho \left[\frac{1}{L_T} + \frac{1}{\sqrt{20A}} \left(1 + \frac{1}{1 + h\sqrt{20/A}} \right) \right] \quad (2.69)$$

where

L_T is the total buried length of conductors in meters

h is the depth of the grid in meters

A is the area of substation ground surface in square meters

Figure 2.48 shows the effects of the number of grid conductors (n), without ground rods, on the ground grid resistance. It shows that area (A) has a substantial influence on the grid resistance. Figure 2.49 shows the relationship between the burial depth of the grid (h), in meter, and the grid resistance. Here, the depth is varied from 0.5 to 2.5 m and the number of conductors from 4 to 10 [14].

2.18 TRANSMISSION LINE GROUNDS

HV transmission lines are designed and built to withstand the effects of lightning with a minimum damage and interruption of operation. If the lightning strikes an OHGW (also called *static wire*) on a transmission line, the lightning current is conducted to ground through the ground wire (GW) installed along the pole or through the metal tower. The top of the line structure is raised in potential to a value determined by the magnitude of the lightning current and the surge impedance of the ground connection.

In the event that the impulse resistance of the ground connection is large, this potential can be in the magnitude of thousands of volts. If the potential is greater than the insulation level of the apparatus, a flashover will take place, causing an arc. The arc, in turn, will start the operation of protective relays, causing the line to be taken out of service. In the event that the transmission structure is well grounded and there is sufficient coordination between the conductor insulation and the ground resistance, flashover can generally be avoided.

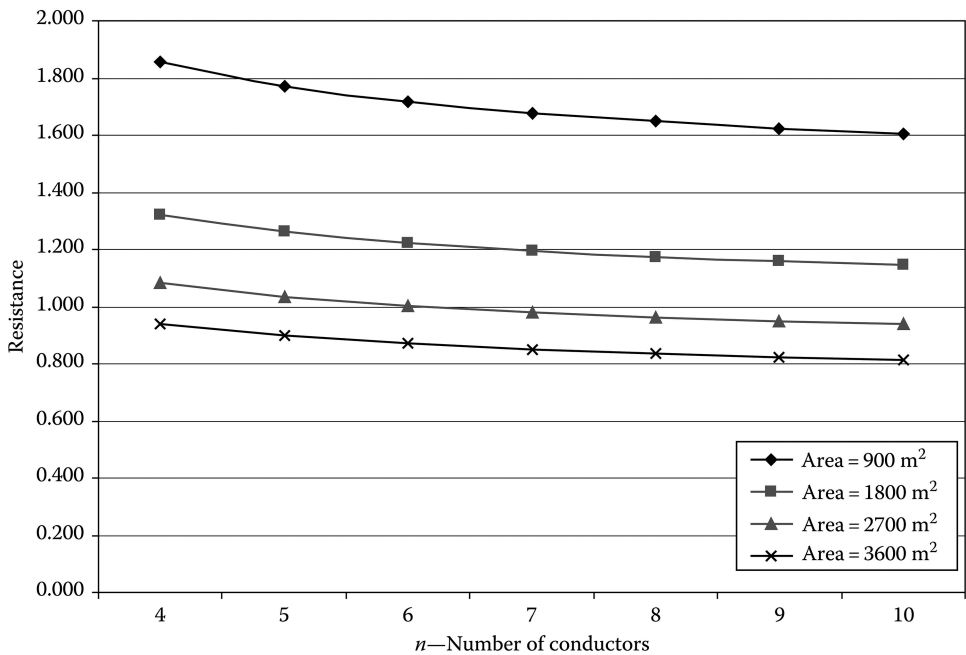


FIGURE 2.48 The effects of number of grid conductors (n), without ground rods, on the ground grid resistance.

The transmission line grounds can be used in various ways to achieve a low ground resistance. For example, a pole butt grounding plate or butt coil can be employed on wood poles. A butt coil is a spiral coil of bare copper wire installed at the bottom of a pole. The wire of the coil is extended up the pole as the GW lead. In practice, usually one or more ground rods are employed instead to achieve the required low ground resistance.

The sizes of the rods used are usually 5/8 or 3/4 in. in diameter and 10 ft in length. The thickness of the rod does not play a major role in reducing the ground resistance as does the length of the rod. Multiple rods are usually used to provide the low ground resistance required by the high-capacity structures. But, if the rods are moderately close to each other, the overall resistance will be more than if the same number of rods were spaced far apart. In other words, adding a second rod does not provide a total resistance of half that of a single rod unless the two are several rod lengths apart (actually infinite distance). Lewis [15] has shown that at 2 ft apart, the resistance of two pipes (used as ground rods) in parallel is about 61% of the resistance of one of them, and at 6 ft apart, it is about 55% of the resistance of one pipe.

Where there is bedrock near the surface or where sand is encountered, the soil is usually very dry and therefore has high resistivity. Such situations may require a grounding system known as the *counterpoise*, made of buried metal (usually galvanized steel wire) strips, wires, or cables. The counterpoise for an OH transmission line consists of a special grounding terminal that reduces the surge impedance of the ground connection and increases the coupling between the GW and the conductors.

The basic types of counterpoises used for transmission lines located in areas with sandy soil or rock close to the surface are the continuous type (also called the *parallel type*) and the radial (also called the *crowfoot type*), as shown in Figure 2.50. The continuous counterpoise is made of one or more conductors buried under the transmission line for its entire length.

The counterpoise wires are connected to the OH ground (or *static*) wire at all towers or poles. But, the radial-type counterpoise is made of a number of wires and extends radially (in some fashion) from the tower legs. The number and length of the wires are determined by the tower location and the soil conditions. The counterpoise wires are usually installed with a cable plow at a length of 18 in. or more so that they will not be disturbed by cultivation of the land.

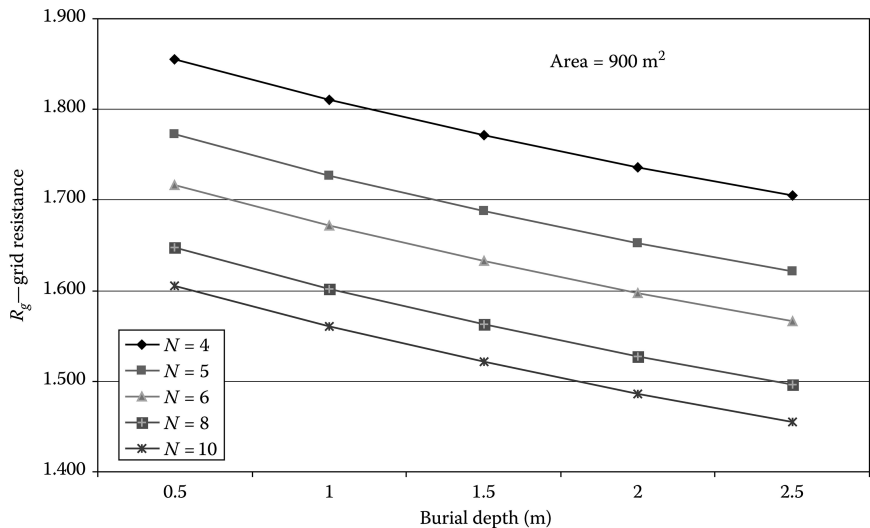


FIGURE 2.49 The effects of varying the depth of burial of the grid (h) from 0.5 to 2.5 m and the number of conductors from 4 to 10. (From Keil, R. P., Substation grounding, in *Electric Power Substation Engineering*, Chapter 11, CRC Press, Boca Raton, FL, 2003; Electric Power Research Institute, *Transmission Line Reference Book: 345 kV and Above*, 2nd edn., EPRI, Palo Alto, CA, 1982. With permission.)

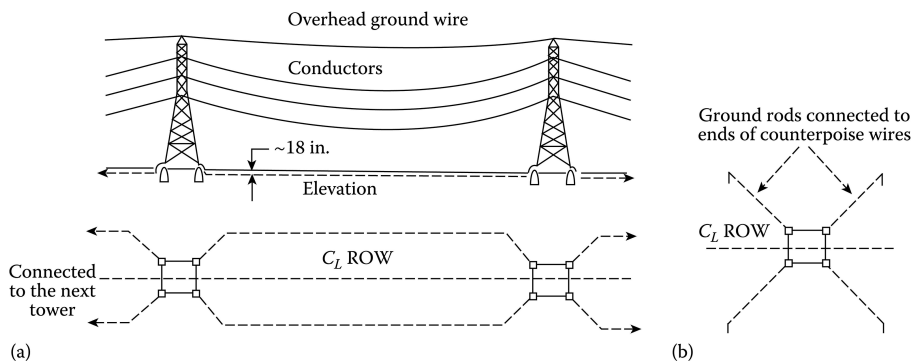


FIGURE 2.50 Two basic types of counterpoises: (a) continuous (parallel) and (b) radial.

A multigrounded, common neutral conductor used for a primary distribution line is always connected to the substation grounding system where the circuit originates and to all grounds along the length of the circuit. If separate primary and secondary neutral conductors are used, the conductors have to be connected together provided that the primary neutral conductor is effectively grounded. The resistance of a single buried horizontal wire, when it is used as a radial counterpoise, can be expressed as [16]

$$R = \frac{\rho}{\pi l} \left(\ln \frac{2l}{2(ad)^{1/2}} - 1 \right) \text{ when } d \ll l \tag{2.70}$$

where

- ρ is the ground resistivity in ohmmeters
- l is the length of wire in meters
- a is the radius of wire in meters
- d is the burial depth in meters

It is assumed that the potential is uniform over the entire length of the wire. This is only true when the wire has ideal conductivity. If the wire is very long, such as with the radial counterpoise, the potential is not uniform over the entire length of the wire. Hence, Equation 2.39 cannot be used. Instead, the resistance of such a continuous counterpoise when $l(rp)^{1/2}$ is large can be expressed as

$$R = (rp)^{1/2} \coth \left[l \left(\frac{r}{p} \right)^{1/2} \right] \quad (2.71)$$

where r is the resistance of wire in ohmmeters.

If the lightning current flows through a counterpoise, the effective resistance is equal to the surge impedance of the wire. The wire resistance decreases as the surge propagates along the wire. For a given length counterpoise, the transient resistance will diminish to the steady-state resistance if the same wire is used in several shorter radial counterpoises rather than as a continuous counterpoise. Thus, the first 250 ft of counterpoise is most effective when it comes to grounding of lightning currents.

2.19 TYPES OF GROUNDING

In general, transmission and subtransmission systems are solidly grounded. Transmission systems are usually connected grounded wye, but subtransmission systems are often connected in delta. Delta systems may also be grounded through grounding transformers. In most HV systems, the neutrals are solidly grounded, that is, connected directly to the ground. The advantages of such grounding are as follows:

1. Voltages to ground are limited to the phase voltage.
2. Intermittent ground faults and HVs due to arcing faults are eliminated.
3. Sensitive protective relays operated by ground fault currents clear these faults at an early stage.

The grounding transformers used are normally either small distribution transformers (which are connected normally in wye–delta, having their secondaries in delta) or small grounding autotransformers with interconnected wye or *zigzag* windings, as shown in Figure 2.51. The three-phase autotransformer has a single winding. If there is a ground fault on any line, the ground current flows equally in the three legs of the autotransformer. The interconnection offers the minimum impedance to the flow of the single-phase fault current.

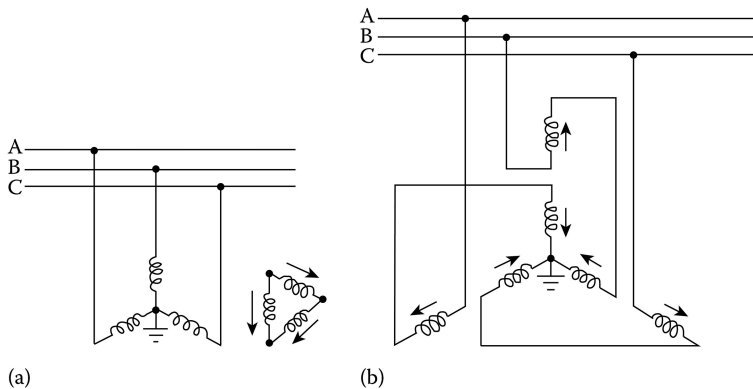


FIGURE 2.51 Grounding transformers used in delta-connected systems: (a) using wye–delta-connected small distribution transformers or (b) using grounding autotransformers with interconnected wye or *zigzag* windings.

The transformers are only used for grounding and carry little current except during a ground fault. Because of that, they can be fairly small. Their ratings are based on the stipulation that they carry current for no more than 5 min since the relays normally operate long before that. The grounding transformers are connected to the substation ground.

All substation equipment and structures are connected to the ground grid with large conductors to minimize the grounding resistance and limit the potential between equipment and the ground surface to a safe value under all conditions. All substation fences are built inside the ground grid and attached to the grid at short intervals to protect the public and personnel. Furthermore, the surface of the substation is usually covered with crushed rock or concrete to reduce the potential gradient when large currents are discharged to the ground and to increase the contact resistance to the feet of personnel in the substation.

As said before, the substation grounding system is connected to every individual equipment, structure, and installation in order to provide the means by which grounding currents are conducted to remote areas. Thus, it is extremely important that the substation ground has a low ground resistance, adequate current-carrying capacity, and safety features for personnel.

It is crucial to have the substation ground resistance very low so that the total rise of the grounding system potential will not reach values that are unsafe for human contact. Therefore, the substation grounding system is normally made up of buried horizontal conductors and driven-ground rods interconnected (by clamping, welding, or brazing) to form a *continuous grid* (also called *mat*) network.

Notice that a continuous cable (usually it is 4/0 bare stranded copper cable buried 12–18 in. below the surface) surrounds the grid perimeter to enclose as much ground as possible and to prevent current concentration and thus high gradients at the ground cable terminals. Inside the grid, cables are buried in parallel lines and with uniform spacing (e.g., about 10×20 ft).

Today, many utilities have computer programs for performing grounding grid studies. Thus, the number of tedious calculations that must be performed to develop an accurate and sophisticated model of a system is no longer a problem.

The GPR depends on grid burial depth, diameter, and length of conductors used, spacing between each conductor, fault current magnitude, system voltage, ground system resistance, soil resistivity, distribution of current throughout the grid, proximity of the fault electrodes, and the system grounding electrodes to the conductors. IEEE Std. 80-1976 [10] provides a formula for a quick simple calculation of the grid resistance to ground after a minimum design has been completed. It is expressed as

$$R = \frac{\rho}{4r} + \frac{\rho}{L} \Omega \quad (2.72)$$

where

ρ is the soil resistivity in ohmmeters

L is the total length of grid conductors in meters

R is the radius of circle with area equal to that of grid in meters

IEEE Std. 80-1976 also provides formulas to determine the effects of the grid geometry on the step and mesh voltage (which is the worst possible value of the touch voltage) in volts. They can be expressed as

$$V_{\text{step}} = \frac{K_s K_i \rho I_G}{L} \quad (2.73)$$

and

$$V_{\text{mesh}} = \frac{K_m K_i \rho I_G}{L} \quad (2.74)$$

where

K_s is the step coefficient

K_m is the mesh coefficient

K_i is the irregularity coefficient

Many utilities have computer programs for performing grounding grid studies. The number of tedious calculations that must be performed to develop an accurate and sophisticated model of a system is no longer a problem.

2.20 TRANSFORMER CLASSIFICATIONS

In power system applications, single- or three-phase transformers with ratings of up to 500 and 34.5 kV are defined as *distribution transformers*, whereas those transformers with ratings of over 500 kVA at voltage levels above 34.5 kV are defined as *power transformers*. Most distribution and power transformers are immersed in a tank of oil for better insulation and cooling purposes.

Today, for reasons of efficiency and economy, most electric energy is generated, transmitted, and distributed using a three-phase system rather than a single-phase system. Three-phase power may be transformed by the use of either a single three-phase transformer or three single-phase transformers, which are properly connected with each other for a three-phase operation. A three-phase transformer, in comparison to a bank of three single-phase transformers, weighs less, costs less, needs less floor space, and has a slightly higher efficiency. In the event of failure, however, the entire three-phase transformer must be replaced.

On the other hand, if three separate single-phase units (i.e., a *three-phase transformer bank*) are used, only one of them needs to be replaced.⁷ Also, a standby three-phase transformer is more expensive than a single-phase spare transformer. There are two versions of three-phase core construction that are normally used: core type and shell type.

In the *core-type* design, both the primary and secondary windings of each phase are placed only on one leg of each transformer. For balanced, three-phase sinusoidal voltages, the sum of the three-core fluxes at any given time must be zero. This is a requirement that does not have to be met in the *shell-type* construction. In the *core-type construction*, the magnetic reluctance of the flux path of the center phase is less than that of the outer two phases.

A *shell-type transformer* is quite different in character from a core-type transformer. In such design, the flux in the outside paths of the core is reduced by 42% since in a *shell-type construction*, the center phase windings are wound in the opposite direction of the other two phases.

Since all yoke cross sections are equal, not only is the amount of core requirement reduced, but also the manufacturing process involved is simplified. Furthermore, in a shell-type transformer, the no-load losses are less than those in a core-type transformer.

OA/FA: Oil-immersed, self-cooled/forced-air-cooled

OA/FA/FOA: Oil-immersed, self-cooled/forced-air-cooled/forced-oil-cooled

FOA: Oil-immersed, forced-oil-cooled with forced-air cooler

FOW: Oil-immersed, forced-oil-cooled with water cooler

In a distribution substation, power transformers are used to provide the conversion from subtransmission circuits to the distribution level. Most are connected in delta–wye grounded to provide a ground source for the distribution neutral and to isolate the distribution grounding system from the subtransmission system.

Substation transformers can range from 5 MVA in smaller rural substations to over 80 MVA at urban stations (in terms of base ratings). As mentioned earlier, power transformers have multiple ratings, depending on cooling methods. The base rating is the self-cooled rating, just due to the natural flow to the surrounding air through radiators. The transformer can supply more load with extra cooling turned on, as explained before.

However, the ANSI ratings were revised in the year 2000 to make them more consistent with IEC designations. This system has a four-letter code that indicates the cooling (IEEE C57.12.00-2000):

- First letter—internal cooling medium in contact with the windings
 - O: Mineral oil or synthetic insulating liquid with fire point=300°C
 - K: Insulating liquid with fire point >300°C
 - L: Insulating liquid with no measurable fire point
- Second letter—circulation mechanism for internal cooling medium
 - N: Natural convection flow through cooling equipment and in windings
 - F: Forced circulation through cooling equipment (i.e., *coolant pumps*); natural convection flow in windings (also called *nondirected flow*)
 - D: Forced circulation through cooling equipment, directed from the cooling equipment into at least the main windings
- Third letter—external cooling medium
 - A: Air
 - W: Water
- Fourth letter—circulation mechanism for external cooling medium
 - N: Natural convection
 - F: Forced circulation, fans (air cooling), pumps (water cooling)

Therefore, *OA/FA/FOA* is equivalent to *ONAN/ONAF/OFAF*. Each cooling level typically provides an extra one-third capability: 21/28/35 MVA. Table 2.10 shows equivalent cooling classes in old and new naming schemes.

Utilities do not overload substation transformers as much as distribution transformers, but they do not run them hot at times. As with distribution transformers, the trade-off is loss of life versus the immediate replacement cost of the transformer. Ambient conditions also affect loading. Summer peaks are much worse than winter peaks. IEEE Std. C57.91-1995 provides detailed loading guidelines and also suggests an approximate adjustment of 1% of the maximum nameplate rating for every degree C above or below 30°C.

The hottest-spot-conductor temperature is the critical point where insulation degrades. Above the hot-spot-conductor temperature of 110°C, life expectancy of a transformer decreases exponentially. *The life of a transformer halves for every 8°C increase in operating temperature.* Most of the time,

TABLE 2.10
Equivalent Cooling Classes

Year 2000 Designations	Designation Prior to Year 2000
ONAN	OA
ONAF	FA
ONAN/ONAF/ONAF	OA/FA/FA
ONAN/ONAF/OFAF	OA/FA/FOA
OFAF	FOA
OFWF	FOW

Source: IEEE Std. C57.12.00-2000.

the hottest temperatures are nowhere near this. The impedance of substation transformers is normally about 7%–10%. This is the impedance on the base rating, the self-cooled rating (OA or ONAN).

2.20.1 TRANSFORMER SELECTION

The selection of the proper transformer can have a major impact on the cost of a substation, since the transformer represents the major cost item. Nameplate rating is only a preliminary guide to the transformer application.

The transformer is applicable as a self-cooled unit, or it can be purchased with additional steps of forced cooling that use a fan or sets of fans and oil pumps, as explained in the previous section. Transformer ratings can be increased from 25% to 66% by the addition of fans and pumps.

The nameplate rating is based on a continuous load that is producing a 55°C conductor temperature rise over ambient. Since many transformers do not carry continuous loads, advantages can be obtained from the thermal time lag to carry higher peak loads without being over the temperature limits.

Transformer ratings are based on the assumption that only an extremely small amount of insulation deterioration takes place due to the aging process under normal operation. A considerable increase in rating can be obtained at the expense of the loss of insulation life. This increase in rating might be close to 200% for an hour or two and about 20% for 24 h.

The additional factors that affect the transformer selection are as follows:

1. Transformer impedances should be chosen after taking into account their effects on short-circuit duties and low-side breaker ratings, both the initial and future stations' developments.
2. When applicable, the transformer impedance should be selected to achieve a proper load division in the parallel operation of transformers.
3. It may be necessary to provide bus regulation if the HV side and LV side voltages vary over a wide range during the load cycle of the transformer.
4. If the bus regulation is needed, determine the actual regulation by using the system and load characteristics. The bus regulation may also be provided in the transformer itself by using load tap-changing equipment.
5. If there is no need for such bus regulation at the present time, consider the possibility of such requirement in the future. If so, it may be economical. For the time being, just to leave space in the substation and bus transformers for installing regulation equipment in the future.

It is important to note that autotransformers are employed almost universally in EHV stations. This is true even for transformations from EHV directly to subtransmission voltage levels. For such applications, low impedance is desirable.

2.21 ENVIRONMENTAL IMPACT OF TRANSMISSION LINES

2.21.1 ENVIRONMENT EFFECTS

Designing a transmission line with minimum environmental effects dictates a study of three key factors, namely, the effects of electric fields, the visual effects of the design, and the effects of physical location.

In addition to the transmission lines, substations also generate electric and magnetic fields (EMFs). In substations, typical sources of EMFs include the following: both transmission and distribution lines entering or exiting the substation, bus work, switchgear, cabling, CBs, transformers, air core reactors, line traps, grounding grid, capacitors, computers, and battery charges.

The HV gradients of EHV lines near the phase conductors can cause breakdowns of the air around the conductors. Such breakdowns may, in turn, cause corona loss, electromagnetic interference, RN,

television interference, AN, and ozone generation. The transmission line designer is guided by the established acceptable levels of each of the previous concerns.

The RN is an undesirable electromagnetic radiation in the radio-frequency band and interferes with the existing radio signals. It can be caused by corona on EHV transmission lines. Hence, the designer must take into account the electric fields near the conductors.

AN is also produced by high-field gradients like the RN. It generates pressure waves in the air that fall within the audible frequency range. The AN manifests itself as a cracking sound or hum and is audible especially at night. The environmental effects mentioned earlier are even more since corona activity is usually greater during heavy rain.

Also, ungrounded equipment located near HV lines will develop an oscillating electric field. Because of this, the line designer has to be sure that the line height is sufficient to keep the discharge current below the proper levels for all apparatus that are located within the ROW.

2.21.2 BIOLOGICAL EFFECTS OF ELECTRIC FIELDS

Electric fields are present whenever voltage exists on a line conductor. Electric fields are not dependent on the current but voltage. Electric substations produce EMFs. In a substation, the strongest fields are located around the perimeter fence and come from transmission and distribution lines entering and leaving the substation. The strength of fields from apparatus that is located inside the fence decreases rapidly with the distance, reaching very low levels at relatively short distances beyond substation fences.

Electric fields are not dependent on the current. The magnitude of the electric field is a function of the operating voltage and decreases with square of the distance from the source. The strength of electric fields is measured in volts per meter or kilovolts per meter. The electric field can be easily shielded (i.e., its strength can be reduced) by any conducting surface, such as trees, fences, walls, building, and most other structures. Furthermore, in substations, the electric field is extremely variable because of the effects of existing grounded steel structures that are used for bus and equipment support.⁸

Due to the public concerns with respect to EMF levels and government regulations, the substation designer has to consider design measures to lower EMF levels. The electric field levels, especially near-HV equipment, can reach to very high levels, but the level decreases significantly toward the fence line. For example, the level of electric field may be 13 kV/m in the vicinity of a 500 kV CB, but the fence line, which has to be located according to NESC at least 6.4 m (21 ft) away from the nearest 500 kV conductor, becomes almost zero.

In general, the electric field produced by a transmission line has been considered having no harmful health effects. Nevertheless, design rules have been established to allow construction of EHV transmission lines to be built with the maximum possible guaranteed protection of people from possible health risks. In Russia [17], the rules for the EHV substations and EHV transmission lines have been established long ago. For example, the limits for the duration of daily work in live substation, which is subject to various electric fields, have been limited, as indicated in Table 2.11.

TABLE 2.11
Russian Rules for Duration of Work in Live Substations

Field Intensity (kV/m)	Permissible Duration (min/day)
>5	No restrictions
5–10	180
10–15	90
15–20	10
20–25	5

For transmission lines, taking into account the frequency and nonsystematic exposure, higher values of the accepted field intensities are as follows:

10–12 kV	For road crossings
15–20 kV/m	For unpopulated regions
20 kV/m	For difficult terrains

PROBLEMS

Problem 2.1

Assume that a human body is part of a 60 Hz electric power circuit for about 0.25 s and that the soil type is average earth. Based on the IEEE Std. 80-2000, determine the following:

- Tolerable touch potential for 50 kg body weight
- Tolerable step potential for 50 kg body weight

Solution

- Using Equation 2.14a, for 50 kg body weight

$$V_{\text{touch}} = \frac{0.116(1,000 + 1.5\rho_s)}{\sqrt{t}} = \frac{0.116(1,000 + 1.5 \times 100)}{\sqrt{0.25}} \cong 267 \text{ V}$$

- Using Equation 2.15a, for 50 kg body weight

$$V_{\text{touch}} = \frac{0.116(1,000 + 6\rho_s)}{\sqrt{t}} = \frac{0.116(1,000 + 6 \times 100)}{\sqrt{0.25}} \cong 371 \text{ V}$$

Problem 2.2

Assume that a human body is part of a 60 Hz electric power circuit for about 0.49 s and that the soil type is average earth. Based on the IEEE Std. 80-2000, determine the following:

- Tolerable touch potential for 50 kg body weight
- Tolerable step potential for 50 kg body weight

Solution

- Using Equation 2.14a, for 50 kg body weight,

$$\begin{aligned} V_{\text{touch } 50} &= \frac{0.116(1,000 + 1.5\rho_s)}{\sqrt{t_s}} \\ &= \frac{0.116(1,000 + 1.5 \times 100)}{\sqrt{0.49}} \\ &\cong 191 \text{ V} \end{aligned}$$

b. Using Equation 2.25a, for 50 kg body weight,

$$\begin{aligned} V_{\text{touch } 50} &= \frac{0.116(1,000 + 6\rho_s)}{\sqrt{t_s}} \\ &= \frac{0.116(1,000 + 6 \times 100)}{\sqrt{0.49}} \\ &\cong 265 \text{ V} \end{aligned}$$

Problem 2.3

Assume that a human body is part of a 60 Hz electric power circuit for about 0.49 s and that the soil type is average earth. Based on the IEEE Std. 80-2000, determine the following:

- Tolerable touch voltage limit for metal-to-metal contact if the person is 50 kg
- Tolerable touch voltage limit for metal-to-metal contact if the person is 70 kg

Solution

a. Using Equation 2.16a, for 50 kg body weight

$$V_{\text{mm-touch } 50} = \frac{116}{\sqrt{t_s}} = \frac{116}{\sqrt{0.49}} = 165.7 \text{ V for 50 kg body weight}$$

b. Using Equation 2.16b, for 70 kg body weight

$$V_{\text{mm-touch } 70} = \frac{157}{\sqrt{t_s}} = \frac{157}{\sqrt{0.49}} = 224.3 \text{ V for 70 kg body weight}$$

NOTES

- In average practice, the number of units used in an insulator string is approximately proportional to the line voltage, with a slight increase for the highest voltages and with some allowance for the length of the insulator unit. For example, 4 or 5 units have generally been used at 69 kV, 7 or 8 at 115 kV, 8–10 at 138 kV, 9–11 at 161 kV, 14–20 at 230 kV, 15–18 at 345 kV, 24–35 at 500 kV (with the 35 unit insulator strings used at high altitudes), 33–35 at 735 kV (Hydro-Quebec), and 30–35 at 765 kV.
- This phenomenon is studied in the laboratory by subjecting insulators to voltage impulses by means of a *lightning generator*.
- For further information, see the ANSI standard C29.1-C29.9.
- Proposed by Peek [8,9].
- Mesh voltage* is the worst possible value of a touch voltage to be found within a mesh of a ground grid if standing at or near the center of the mesh.
- It is often acceptable to use $X_1 = X_2$, especially if an appreciable percentage of the positive-sequence reactance to the point of fault is that of static equipment and transmission lines.
- However, it is not possible to use transformers to convert a single-phase system to a three-phase system for a large amount of power. Relatively very small amounts of power can be developed from a single-phase system using *R-C* phase shift networks (or an induction phase converter) to produce two-phase power, which in turn can be transformed into three-phase power.
- The source for the following information is Electric Power Research Institute (EPRI): “Concerns have been expressed since the advent of EHV transmission above the possible effects of chronic exposure to ac electric fields. (W. B. Kouwenhoven et al., “Medical evaluation of man working in AC electric fields,” *IEEE Transactions on Power Apparatus and Systems*, pp. 506–511, 1967.) Recently, these concerns have increased because of the expansion of EHV transmission systems and because of USSR reports of health complaints by personnel working in EHV substations. (V. P. Korobkova et al., “Influence of the electric fields in 500 kV and 750 kV switchyards on maintenance staff and means for its protection,” CIGRE,

Institute of Electrical and Electronics Engineers, 1972 Session Report 23-06.) (Study in the USSR of medical effects of electric fields on electric power systems, 1978 special publication No. 10, IEEE-PES, 78 CHO 1020-7-PWR.)”

“The body of research literature on effects of electric fields on test animals and plants has been reviewed and commented upon by many organizations.” [(J. W. Bankoske et al., “Some biological effects of high intensity, low frequency (60 Hz) electric fields on small birds and animals,” Electric Power Research Institute, EPRI Research Project RP 129, Final Report, December 1977.) (“Research on the biological effects of electric and magnetic fields,” *Revue Generale D. L’electricite Numero Special*, July 1976.) (IIT Research Institute, “Biological effects of high-voltage electric fields: an update,” EPRI EA-123, Vol. 1 & 2, Project 857-1, Final Report, July 1979.) (J. E. Bridges, “Environmental effects of power frequency (50 or 60 Hz) electrical fields,” *IEEE Transactions on Power Apparatus and Systems*, Vol. PAS-97, Jan/Feb 1978.) (G. E. Atoian, “Are there biological and psychological effects due to extra high voltage installations?” *IEEE Transactions on Power Apparatus and Systems*, Vol. PAS-97, No. 1, Jan/Feb 1978.)]

“Even though it is not presently possible to draw definite conclusions, it is, nevertheless, necessary for systems planners, line designers, and public service commissions to make recommendations and to make decisions on the design, construction, and operation of transmission lines. Some effects have been found in several instances on test animals, but in no case have they been confirmed by independent research.”

“Although health complaints by substation workers in the USSR were reported [(V. P. Korobkova et al., “Influence of the electric fields in 500 kV and 750 kV switchyards on maintenance staff and means for its protection,” CIGRE, Institute of Electrical and Electronics Engineers, 1972 Session Report 23-06) and (Study in the USSR of medical effects of electric fields on electric power systems, 1978 special publication No. 10, IEEE-PES, 78 CHO 1020-7-PWR)], medical examinations of linemen in the USA, in Sweden, and in Canada, failed to find health problems ascribable to ac electric fields. As a result of unclear findings and of research in progress, no rules for electric-field intensity and outside the transmission corridor have been established to allow construction of EHV transmission lines to precede with the maximum possible guaranteed protection of people from possible health risks.”

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3 Flexible AC Transmission System (FACTS) and Other Concepts

A diplomat is a person who tells you to go to hell in such a way that you actually look forward to the trip.

Anonymous

3.1 INTRODUCTION

As previously said, the main function of a transmission system is to transmit electric energy in bulk from generating plants that are located at various distances from the load centers. Such transmission systems carry economically dispatched power not only during normal conditions but also during emergency conditions. In addition to sharing the lowest-cost generated power, the transmission system facilitates large reductions in the required reserve capacities among the utilities.

3.2 FACTORS AFFECTING TRANSMISSION GROWTH

The factors affecting transmission growth, especially at extrahigh voltage (EHV)–ultrahigh voltage (UHV) levels, are

1. Load growth
2. Generation siting
3. Fuel cost and availability
4. Reliability
5. Ecology
6. Government
7. Energy centers

The main influence on transmission growth in the past has been the increase in electrical load. Increasingly, the growth in loads is being met by building transmission lines that operate at EHV and/or UHV levels in order to make the transmission process economical. In urban areas, new generating sites are almost impossible to have due to environmental concerns and the unavailability of suitable land. Hence, the electric power is increasingly being transmitted from remote areas, some of them being several hundred miles from load centers.

The rising cost of fuel and increasing dependency on foreign oil have already influenced the use of transmission systems to supply electric energy from remote coal, hydro, and nuclear plants. Even without considering load growth, new transmission systems can be justified to improve reliability during emergency conditions and to supply less expensive base loading from remote generating sites.

The growth in transmission beyond that demanded by load growth requires greater reliability as the margin between peak load and generating capability decreases, especially in interties between adjacent companies and regions. It is often more economical to add the needed reliability by strengthening interties at EHV and UHV levels. Also, increased interregional power transfer

without added transmission reduces stability margins and leaves subtransmission lines vulnerable to overload. But if the required reliability is to be maintained, a new transmission with stronger interties is required.

The environmental impacts of transmission lines are mainly visual impact, land usage, biological interaction, and communications interference. Minimization of the biological and visual impact dictates a thorough study of the compatibility of alternative transmission routes with the various tower types, vegetation, and terrain types. Occasionally, a considerable number of proposed lines are delayed or rerouted due to legal intervention by the public.

The electrical load growth for some good number of years in the future will be strongly influenced by government regulations, the cost of funds, and the establishment of a sustainable national energy policy, and perhaps government-financed projects are needed. The reduced availability of unacceptable generating sites near load centers will increasingly be forcing the development of energy centers with ever-increasing power-generating capacities.

3.3 STABILITY CONSIDERATIONS

Power system stability can be defined as the ability of the system that enables the synchronous machines of the system to respond to a disturbance from a normal operating condition so as to return to a condition where their operation is again normal. In other words, the state of operating equilibrium, after being subject to a physical disturbance such as a transmission fault, sudden load changes, loss of generating units, or line switching, is kept intact; hence, the system integrity is preserved. The integrity of the system is preserved when practically the entire power system remains intact with no tripping of generators and loads, with the exception of those disconnected by isolation of the faulted elements or intentionally tripped elements to preserve the continuity of operation of the rest of the system.

In a broad definition, stability is a condition of equilibrium between opposing forces. By the same token, instability can be defined as a disturbance that leads to a sustained imbalance between the opposing forces. In the event that the system is unstable, it will result in a runaway situation. As a result, there will be a progressive increase in angular separation of generator rotors or a progressive decrease in bus voltages.

However, the loss of synchronism is not the only cause of an unstable operation. For example, an alternator that supplies power to an induction motor may become unstable due to the collapse of load voltage. Here, the problem is the stability and control of voltage instead of the issue of synchronism.

In general, stability problems, for the sake of convenience of analysis, are divided into two major problems by the IEEE [1]. These are steady-state instability and transient instability:

1. *Steady-state instability* occurs when the power system is forced into a condition for which there is an equilibrium condition. For example, the power output of an alternator may be slowly increased until maximum power is transferred. At this point, either an increase or a decrease in alternator angle will result in a reduction in power transferred. Any further increase in alternator output will cause a steady-state instability and a loss of synchronism between that alternator and the rest of the system. *Dynamic instability*, another form of steady-state instability, is characterized by hunting or steadily growing oscillations, ultimately leading to a loss of synchronism.
2. *Transient instability* applies to a system's inability to survive a major disturbance. Hence, it causes an abrupt and large transient change in the electric power supplied by the synchronous machines. For example, the occurrence of a fault or the sudden outage of a transmission line carrying a heavy load from an alternator will cause a severe momentary unbalance between the input power and the electrical load on one or more generators. If the input/output power unbalance is large enough or lasts long enough, the result will be a transient instability [1].

In some sense, a transmission system is designed so that all generators remain in synchronism under steady-state and transient operating conditions. The power that is sent over a transmission line is inversely proportional to the inductive reactance of the system. In that sense, reactance sets a limit on the maximum power that can be transmitted by a line for a given transmission voltage. For example, consider a system in which a transmission line connects a generator to a remote system. The amount of power transferred over the line is expected as

$$P = \left(\frac{E_{\text{gen}} \times E_{\text{sys}}}{X_L} \right) \sin \delta \quad (3.1)$$

where

P is the power transferred

E_{gen} is the generator (or source) voltage

E_{sys} is the system voltage

X_L is the total inductive reactance between E_{gen} and E_{sys} , including the reactance of the transmission line and terminal connections

δ is the angle between the source voltage E_{gen} and the remote system voltage E_{sys}

In most systems, $Z_L (= R + jX_L)$ is predominantly inductive reactance and R can be neglected with little error. For a given system operating at a constant voltage, the power transmitted is proportional to the sine of the power angle δ . The maximum power that can be transferred under stable steady-state conditions takes place at an angular displacement of 90° and is

$$P_{\text{max}} = \frac{E_{\text{gen}} \times E_{\text{sys}}}{X_L} \quad (3.2)$$

A transmission system with its connected synchronous machines must also be able to withstand, without loss of stability, sudden changes in generation, loads, and faults. All of these disturbances cause transients in the system voltage and power angle. In the United States, the reliability coordinating council of each region dictates the stability requirements that have to be met under such transient conditions, forcing the power angle to be limited to an angle that is much $<90^\circ$ for the maximum power transfer. Typically, it is usually somewhere between 30° and 45° . The speed of the circuit breakers and the operation time of the backup relay, in the event of primary circuit-breaker failure, are crucial to transient stability.

Consider that a three-phase line fault has taken place so that there is no power that is being sent from the alternator to the system during the fault interval. This causes the whole turbine output to accelerate the generator rotor during this time period.

If the fault is cleared, the system tries to return to a normal state. But the speed of the rotor is now above the synchronous speed. This, in turn, causes the electric output power to be greater than the mechanical input power. This difference will now decelerate the rotor, but not before the power angle has increased still further. However, the power angle starts to decrease after the rotor speed reaches the synchronous speed. The electric output power of the alternator will continue to oscillate around the mechanical input power until damping stabilizes the system.

If the fault exists in the long run, the swing may be greater than the point where the power angle will continue to increase even with the electric power output less than the mechanical input power. If this happens, the system will become unstable, and the alternator has to be shut down.

Thus, the more rapidly the fault is removed by the circuit-breaker operation, the more stable the system becomes. In a sense, circuit breakers with independent pole operation improve transient stability by guaranteeing that a three-phase fault is reduced to a single-phase fault when there is a stuck pole because of a circuit-breaker tripping failure.

In general, the ability of the power to adjust to its previous steady state or to a new stable operating condition, without loss of synchronism, is a function of the inertias of the connected machines, the response of their exciters and turbine governors, and the system voltage and reactance. It is also important to point out that the transient stability criterion usually dictates that the transmission line loading and therefore the power angle be restricted to a value that is considerably below the steady-state limit [2].

It is well known that the power system stability can be improved by reducing the inductive reactance between the generators and the rest of the system. The use of additional lines, conductor bundling, and series capacitors (SCs) can produce such a result.

3.4 POWER TRANSMISSION CAPABILITY OF A TRANSMISSION LINE

It can be observed that the higher-voltage transmission lines with higher loading capabilities continue to experience a higher growth rate. Higher voltages mean higher power transfer capability, as illustrated by the SIL capabilities of typical EHV transmission lines in Table 3.1.

3.5 SURGE IMPEDANCE AND SURGE IMPEDANCE LOADING OF A TRANSMISSION LINE

For a single-phase lossless line, the *surge impedance* (also called *characteristic impedance*) is expressed as

$$Z_s = \sqrt{\frac{X_L}{Y_C}} \Omega, \tag{3.3}$$

where X_L and Y_C are the series impedance and the shunt admittance per unit length of line, respectively. The line losses are ignored, Z_s is dimensionally a pure resistance. For a three-phase lossless line, the SIL is expressed as

$$\text{SIL} = \frac{|\text{kV}_{R(L-L)}|^2}{Z_s} \text{ MW} \tag{3.4}$$

TABLE 3.1
SIL Capability

Nominal System Voltage (kV)	Maximum System Voltage (kV)	Line (or Tower Top) Type	Phase Conductor Diameter (in.)	Conductor Per Phase	Phase Spacing (ft)	Surge Impedance (Ω)	SIL Capability (MVA)
345	362	Horizontal	1.76	1	24.6	366	325
345	362	Horizontal	1.11	2	24.6	285	418
345	362	Delta	1.11	2	29.5	283	421
500	550	Horizontal	1.76	2	32.8	287	871
500	550	Vertical	1.17	4	29.5	235	1,064
500	550	Delta	1.60	3	32.8	247	1,012
765	800	Horizontal	1.38	4	45.9	258	2,268
765	800	Delta	1.38	4	55.1	257	2,277
1,100	1,200	Horizontal	1.60	8	60.7	232	5,216
1,100	1,200	Delta	1.60	8	72.2	231	5,238
1,500	—	Horizontal	1.60	12	73.8	225	10,000

A loaded transmission line or its SIL has no net reactive power flow into or out of the line and will have approximately a flat voltage profile along its length. SILs are given in Table 3.1 for a variety of typical and proposed EHV and UHV transmission lines.

Example 3.1

A 345 kV three-phase transmission line with a horizontal tower top configuration has a 24.6 ft phase spacing between the adjacent conductors. Each phase conductor has a diameter of 1.76 in. Its surge impedance is 366 Q. Determine the SIL of the line.

Solution

The SIL of the line is

$$\begin{aligned} \text{SIL} &= \frac{|\text{kV}_{R(L-L)}|^2}{Z_s} \\ &= \frac{345^2}{366} \cong 3.25 \text{ MW} \end{aligned}$$

3.6 LOADABILITY CURVES

The line loadability is defined simply as that degree of line loading, in terms of percent of surge impedance load, as a function of surge impedance load and as a function of line length that is allowable considering thermal limits, voltage drop, or stability limits. Also, the voltage drop and the stability limits have to be considered for both steady-state and transient conditions. Dunlop et al. [3] developed a set of curves that represent loadability characteristics and practical limits on line loading of EHV and UHV transmission lines.

Consider the system model shown in Figure 3.1 for developing the transmission line loadability curves. Assume that the terminal short-circuit capacities at each end of the line are 50 kA. Use the heavy loading criteria of having a maximum voltage drop of 5% along the transmission line and an angular displacement of 44° across the system as shown in Figure 3.1. Here, the 44° corresponds to the steady-state stability margin of 30%. The percent stability margin is expressed as

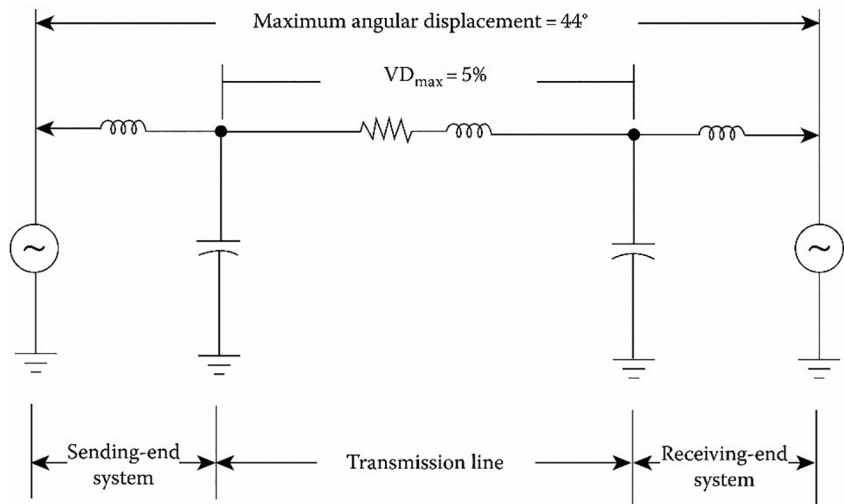


FIGURE 3.1 Illustration of the power system model used for the transmission line loadability curves.

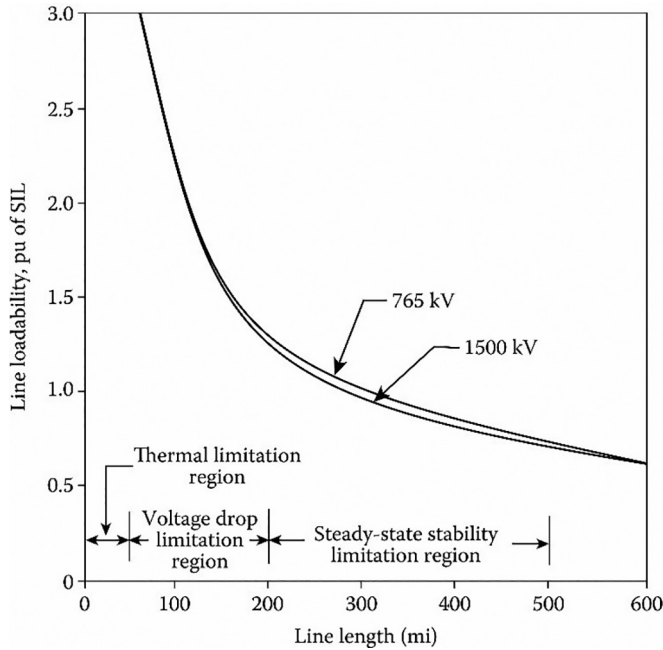


FIGURE 3.2 Transmission line loadability curves for EHV and UHV lines.

$$\% \text{ Stability margin} = \frac{P_{\max} - P_{\text{rated}}}{P_{\max}} \times 100 \quad (3.5)$$

where

$P_{\max}$ is the maximum power transfer capability of the system

P_{rated} is the operating level

Note that the governing criteria of the loading of the transmission line are thermal limitations for its first 50 mi segment voltage drop limitations for its 50–200 mi segment and stability limitations for the segment that is beyond 200 mi. No series shunt compensation is considered in developing the curves that are shown in Figure 3.2. It shows the EHV and UHV transmission line loadability (in terms of per unit of SIL) curves as a function of the line length.

It is important for a good line design to study the cost sensitivity, in terms of both relative and absolute, with regard to line loading. In general, economic loadings are determined for a given transmission line using a conductor economics program. Figure 3.3 shows the cost of power in \$/kW/year/mi versus the load in MW for the voltage levels of 230, 345, and 765 kV. It is clear that there is a considerable economic benefit for increasing line voltage. Also, it can be observed that as system voltage is increased, the U curves get to be flatter.

3.7 COMPENSATION

Figure 3.4 shows a power system that has lines with both series compensation and shunt compensation. Here, shunt compensation will be considered first. The general purpose of shunt compensation is to keep the voltage rise down during light-or no-load conditions. In general, shunt compensation can be implemented by the use of shunt reactors, shunt capacitors, static var control (SVC), and synchronous condensers. The most widely used shunt compensation is shunt capacitors. But with the arrival of higher-voltage lines, the need for and usage of shunt reactors have increased considerably.

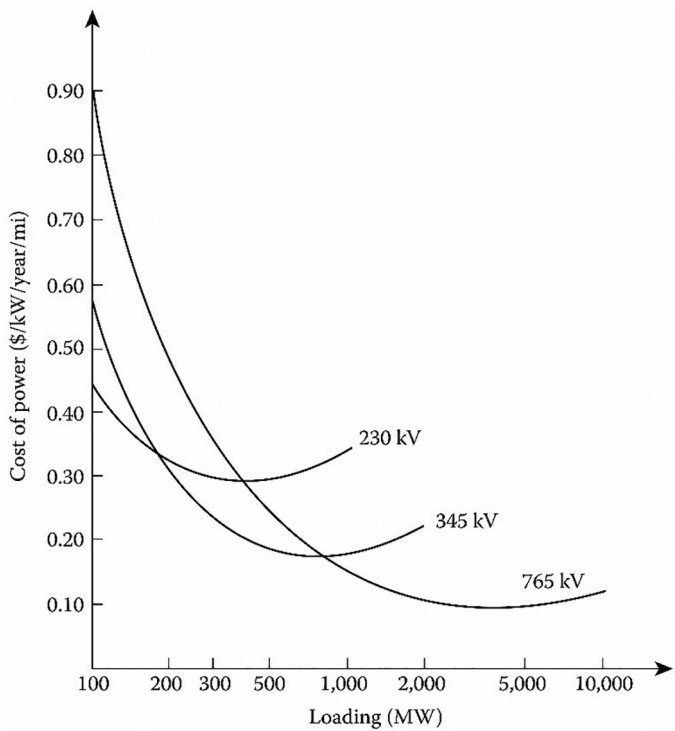


FIGURE 3.3 Cost of power versus loading of the line.

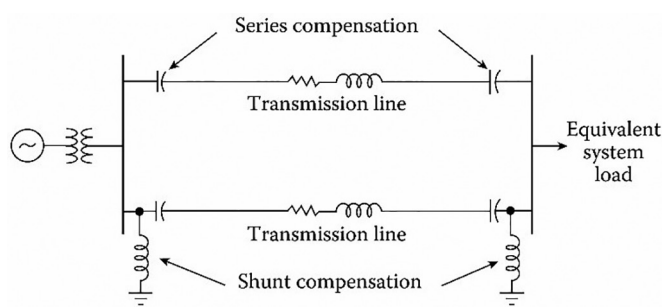


FIGURE 3.4 A transmission system with both series and shunt compensation.

For example, today, shunt reactors are fundamental shunt compensation used on EHV lines. These reactors are implemented to compensate for the unwanted voltage effects due to the line capacitance.

The amount of shunt compensation provided by a reactor is based on a percentage of the positive-sequence susceptance of the transmission line. For EHV lines, this percentage is usually between 0% and 90%. It depends on various factors, including the line characteristics, the expected loading, and the system operating policy. A given transmission line's reactive power increases directly as the square of its voltage and is proportional to its line capacitance and length.

The line capacitance has two related voltage effects. The first one is known as the *Ferranti effect*. It is the rise in voltage along the line due to the capacitive current of the line flowing through the line inductance. The second one is the rise in voltage due to the capacitive current of the line flowing through the source impedance at the line terminations. Under no-load or particularly light-load

conditions, these two effects may produce undesirably HVs. The application of shunt reactors can reduce these voltages.

3.8 SHUNT COMPENSATION

3.8.1 EFFECTS OF SHUNT COMPENSATION ON TRANSMISSION LINE LOADABILITY

Consider the power system model shown in Figure 3.1 for the transmission line loadability. Still assume that the terminal short-circuit capacities at each end of the line are 50 kA. Use the *heavy loading criteria* of having a maximum voltage drop of 5% along the transmission line and an angular displacement of 44° that corresponds to the steady-state stability margin of 30%.

Assume that a 765 kV three-phase transmission line has an SIL of 2,250 MW and is made up of 4–1,351 kcmil aluminum conductor steel-reinforced cable (ACSR) conductors. The shunt compensations of 0% and 100% are considered for two separate cases. For the first case, its short-circuit capacity (S/C) and its reactance are given as 50 kA and 0.151%, respectively. For the second case, the S/C and its reactance are given as 12.5 kA and 0.604%, respectively.

Figure 3.5 shows the effects of shunt reactance compensation on the line loadability. As can be observed in the figure, for transmission lines with low source impedance, the effects of shunt compensation on the loadability are small. However, sources with high impedance can reduce the loadability of a given transmission line and increase the sensitivity of loadability to the changes in shunt compensation, as it can be observed in Figure 3.5.

On the other hand, when reactive power is supplied by using shunt compensation apparatus such as shunt capacitors, synchronous condensers, and static var control, the transmission line loadability can be increased.

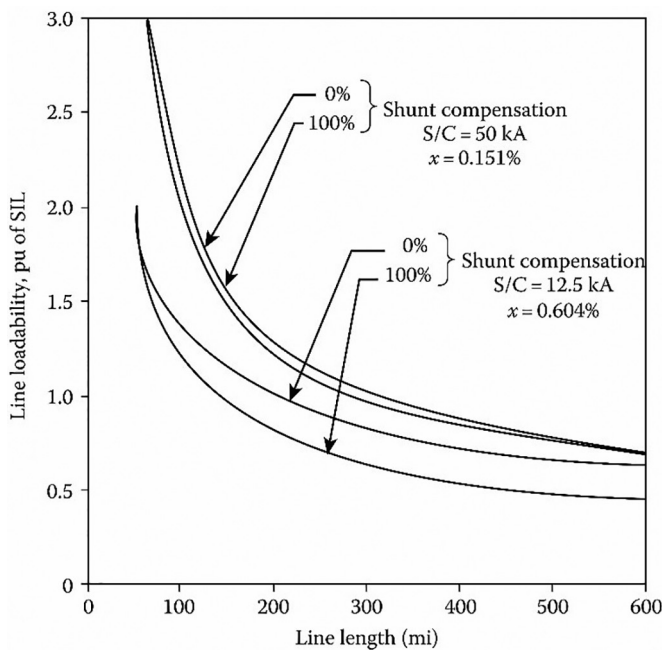


FIGURE 3.5 Effects of having only shunt reactor compensation on the line loadability.

3.8.2 SHUNT REACTORS AND SHUNT CAPACITOR BANKS

Shunt reactors may be either line-connected or bus-connected. It is often that they are connected on the tertiary windings of large-network transformers due to overvoltage concerns. Shunt capacitor banks are always bus, rather than line, connected. The main purpose of transmission system shunt compensation on the transmission system near load areas is load stabilization or voltage control. Mechanically switched shunt capacitor (MSC) banks are installed at major substations in load areas. The MSCs have several disadvantages. For example, the switching may not be fast enough for some applications. But compared to static var compensation, MSC banks have the advantage of much lower cost. However, capacitor bank energization allowing a transmission line outage should be adequately delayed to allow time for line reclosing. Current limiting reactors minimize switching transients. For voltage stability, shunt capacitor banks are very beneficial in allowing nearby generators to operate near-unity power factor.

3.9 SERIES COMPENSATION

Series compensation is the application of SCs to a transmission line. SCs improve the stability by canceling part of the inductive reactance. For example, a 50% compensation means canceling one-half of the transmission line reactance. This results in improved transient and steady-state stability, more economical loading, improved loading balance between parallel transmission lines, and minimum voltage dip on load buses. Studies [4] have shown that the addition of SCs on EHV transmission lines can more than double the *transient stability load limit* of having lines at a fraction of the cost of a transmission line.

However, despite all these aforementioned benefits, there has been a reluctance to use SCs in such applications. This is primarily due to the lack of a reliable high-speed protective device to limit the voltage across the capacitor bank during disturbances and to bypass the high currents during faults. The customary solution for this problem is to provide an automatic bypass during faults and then to reinsert the capacitors after the clearing of the fault.

3.9.1 EFFECTS OF SERIES COMPENSATION ON TRANSMISSION LINE LOADABILITY

The series compensation has a profound effect on the loadability of a transmission line. Also, the series compensation has a great impact on the criteria of voltage drop and stability. They, in turn, reduce the electrical length of the line.

Consider the same power system model that is shown in Figure 3.1. Assume that a 1,100 kV three-phase transmission line has an SIL of 5,185 MW and is made up of 8–1,781 kcmil ACSR conductors. The series compensations of 0% and 75% are considered for two separate cases. Figure 3.6 shows the effects of series reactance compensation on the line loadability for both cases. For the first case of a terminal system (given in solid lines in the figure), the S/C and its reactance are given as 50 kA and 0.105%, respectively. For the second case (given in dashed lines in the figure), the S/C and its reactance are given as 12.5 kA and 0.420%, respectively. The criteria for both cases are given as 5% for line voltage drop and 30% for steady-state stability margin.

The considerations of having series or shunt compensations are determined by the system impedance that is expressed in terms of terminal system S/C. Consider a 765 kcmil three-phase transmission system that has 4–1,351 kcmil ACSR conductors per phase, having an SIL of 2,250 MW. The angular stability limit of 44° and the voltage drop criterion of 5% are given for the transmission line. Figure 3.7 shows the effects of system impedance on the line loadability, without having any series or shunt compensation, for a range of S/C from 12.5 to 75 kA.

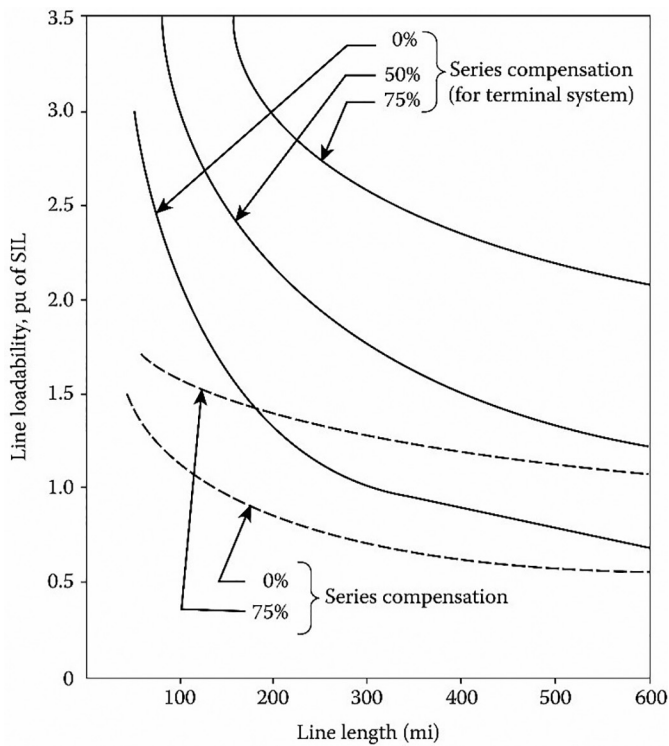


FIGURE 3.6 Effects of having only series compensation on the line loadability.

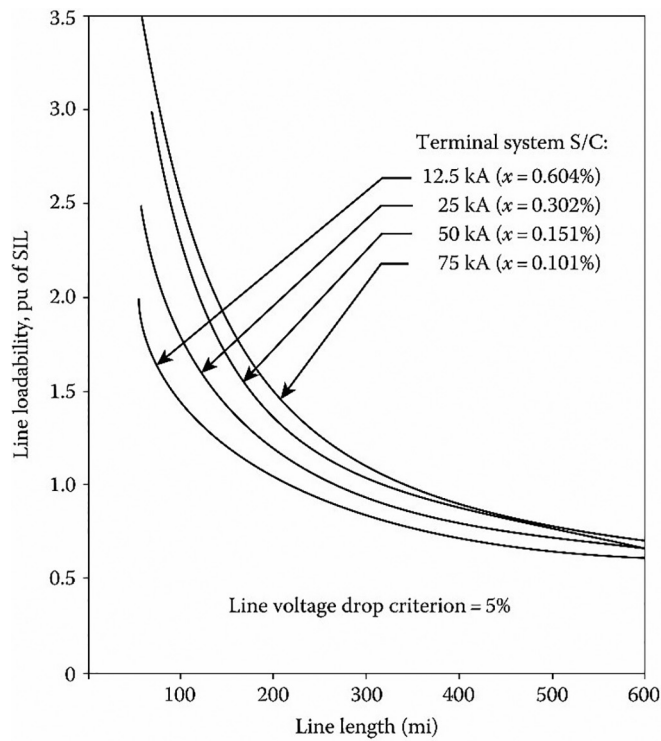


FIGURE 3.7 Effects of system impedance on line loadability without having any series or shunt compensation.

3.9.2 SERIES CAPACITORS

Consider the power flow through a transmission line, as shown in Figure 3.8. The amount of power that is transmitted from bus 1 (sending-end bus) to bus 2 (receiving-end bus) can be expressed as

$$P_{12} = \frac{V_1 \times V_2}{X_L} \sin \delta \quad (3.6)$$

where

P_{12} is the power transmitted through the transmission system

V_1 is the voltage at the sending end of the line

V_2 is the voltage at the receiving end of the line

X_L is the reactance of the transmission line

δ is the phase angle between phasors V_1 and V_2 , that is, $\delta = \theta_1 - \theta_2$

If the total reactance of a transmission system is reduced by the installation of capacitors in series with the line, the power transmitted through the line can be increased. In that case, the amount of power that is transmitted can be expressed as

$$P_{12} = \frac{V_1 \times V_2}{X_L - X_C} \sin \delta \quad (3.7)$$

or

$$P_{12} = \frac{V_1 \times V_2}{X_L (1 - K)} \sin \delta \quad (3.8)$$

where $K = (X_C/X_L)$ is the *degree of compensation*.

The degree of compensation K is usually expressed in percent. For example, 60% compensation means that the value of the SC in ohms is equal to 60% of the line reactance.

As said earlier, SCs are used to compensate for the inductive reactance of the transmission line. They may be installed remotely from the load, for example, at an intermediate point on a long transmission line. The benefits of SC compensation are

1. Improved line loadability
2. Improved system steady-state stability
3. Improved system transient-state stability
4. Better load division on parallel circuits
5. Reduced voltage drops in load areas during severe disturbances
6. Reduced transmission losses
7. Better adjustment of line loadings

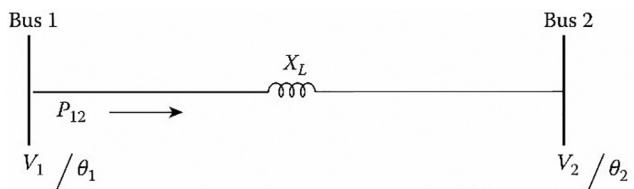


FIGURE 3.8 Power flow through a transmission line.

Figure 3.9 shows a simplified schematic diagram of an SC segment. Figure 3.10 shows a schematic of typical SCs that are almost always in transmission lines, rather than within a substation bus arrangement.

SC compensation equipment is usually mounted on a platform at line potential and has the necessary amount of capacitors, spark gap protection, metal-oxide varistor (MOV), bypass switch (or breaker), and control and protection, as shown in Figure 3.9.

In three-phase applications, the capacitors are connected as a capacitor bank. Such capacitor banks are usually rated to withstand the line current for normal power flow considerations and power swing conditions. But, it is not economical to design the capacitors to withstand the currents and voltages associated with faults. Under these conditions, capacitors are protected by MOV bank.

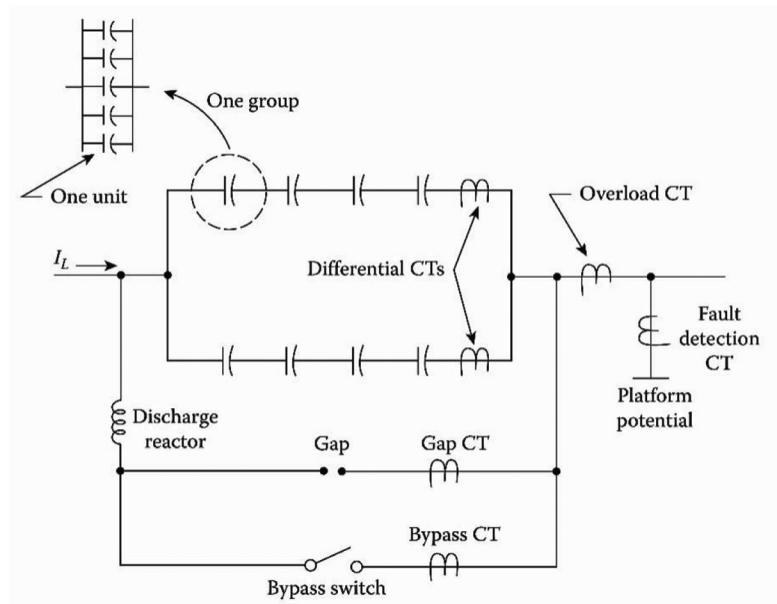


FIGURE 3.9 A simplified schematic diagram of an SC segment.

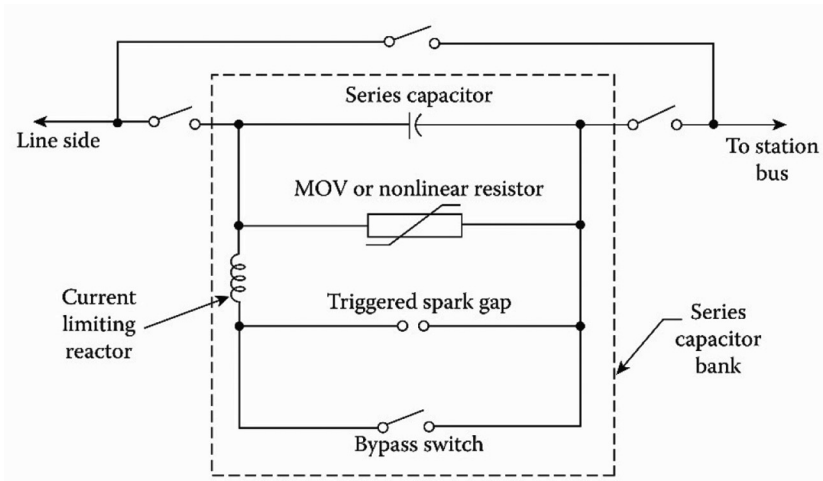


FIGURE 3.10 Schematic of typical SC compensation equipment.

The MOV has a highly nonlinear resistive characteristic and conducts an ignorable amount of current until the voltage across it reaches the protective level.

In the event of internal faults, fault currents can be very high. Here, the internal faults are defined as the faults within the line section in which the SC bank is located. In such cases, both the capacitor bank and MOV will be bypassed by the “triggered spark gap.” The current limiting reactor (also called *damping reactor*) will limit the capacitor discharge current and will dampen the oscillations. Usually, such oscillations are caused by spark gap operations or when the bypass breaker is closed.

Here, the circuit parameters of C (of SC), L (of the current limiting reactor), and R (of the circuit) determine the amplitude, frequency of oscillations, and rate of damping of the SC discharge current. The energy discharge through the MOV is continually checked, and if it exceeds its rated value, the MOV will be protected by the firing of a triggered air gap, which will bypass the MOV. The triggered air gap provides a fast means of bypassing the SC bank and the MOV system when the triggered signal is issued under certain fault conditions (such as internal faults) or when the energy discharge passing through the MOV is greater than its rated value. In general, the bypass breaker is a standard line circuit breaker. It has a rated voltage that is suitable for the voltage across the capacitor bank.

As said earlier, series compensation reduces the net inductive reactance of the transmission line. The reactive power generation of I^2X_C compensates for the reactive power consumption I^2X_L of the transmission line. As the load increases to the maximum value, the generation of reactive power by the capacitor also increases with the current squared. Hence, it provides reactive power when most needed. Here, the need for self-regulation becomes very obvious.

The application of series compensation increases the effective SIL of a transmission line. Contrarily, the application of shunt reactor compensation decreases the effective SIL.

In the event that the lumped compensation is approximated by the uniformly distributed compensation, the effective SIL for a compensated line can be determined from

$$\text{SIL}_{\text{comp}} = \text{SIL}_{\text{uncomp}} \sqrt{\frac{1 - \Gamma_{\text{shunt}}}{1 - \Gamma_{\text{series}}}} \quad (3.9)$$

where

SIL_{comp} is the surge impedance of a compensated line

$\text{SIL}_{\text{uncomp}}$ is the surge impedance of an uncompensated line

Γ_{shunt} is the degree of shunt compensation using capacitors

Γ_{series} is the degree of series compensation using capacitors

Consider two parallel transmission lines and assume that one of them is experiencing an outage. In such cases, the current in the remaining line almost doubles. Also, the reactive power generated by SCs quadruples.

In the SC applications, the reactive power rating and the cost of series compensation are proportional to the current squared. Because of this, the advantage is taken of short-time overload capability in such applications. For example, standards allow the current or voltage overload of 135% for 30 min or 150% for 5 min. This allows the dispatchers to reschedule generation, bring gas turbines on line, or shed load [5].

3.10 FLEXIBLE AC TRANSMISSION SYSTEMS

A flexible AC transmission system (*FACTS*) is a power industry term for technologies that enhance the security, capacity, and flexibility of power transmission networks. IEEE defines FACTS as “a power electronic based system and other static equipment that provide control of one or more ac transmission system parameters to enhance controllability and increase power transfer capability.”

FACTS solutions help power utility companies improve transmission capacity over existing AC power lines and their efficiency and enhance security. It provides fast voltage regulation and active power control and power flow control in power networks. Succinctly put, its basic purpose is to minimize bottlenecks in existing transmission systems and improve the availability, reliability, stability, and quality of the power supply.

FACTS technology provides an alternative to building new power transmission lines or power generation facilities, which is an expensive and time-consuming process. Therefore, the use of FACTS technology is an alternatively inexpensive and fast way to provide more power and control in existing networks, with minimum environmental impact.

In short, FACTS refers to a group of resources that are used to overcome certain limitations in the static and dynamic transmission capacity of electrical networks. These systems supply the power network as quickly as possible with inductive or capacitive reactive power that is adapted to its specific requirements while also improving transmission quality and efficiency of the electric power transmission system. Also, thanks to this technology, it is possible now to transmit power even over longer distances. The first FACTS installation was at the C.J. Slatt substation in Northern Oregon; it is a 500kV, 60Hz, three-phase substation and was developed by the Electric Power Research Institute and the Bonneville Power Administration (BPA). Transmission lines can be classified as:

3.10.1 UNCOMPENSATED TRANSMISSION LINE

Figure 3.11 shows an uncompensated transmission line and its voltage-phasor diagram.

3.10.2 TRANSMISSION LINE WITH SERIES COMPENSATION

When FACTS is used for series compensation, it modifies line impedance. Thus, line impedance reactance X is decreased so as to increase the transmittable real power. However, this requires more reactive power. Here, the real and reactive powers, respectively, are

$$P = \frac{V^2}{X - X_c} \sin(\gamma) \quad (3.10)$$

and

$$Q = \frac{V^2}{X - X_c} (1 - \cos \delta) \quad (3.11)$$

Series compensators provide an increase in transmission system stability and thus increase the capacity to transmit electric power on transmission lines. Applications of SCs include fixed series capacitors, thyristor-controlled series capacitors (TCSCs), and thyristor-protected series capacitors.

Figure 3.12a shows a transmission line with series compensation where the FACTS device is connected in series with the power system. In all AC transmission lines, a series inductance exists.

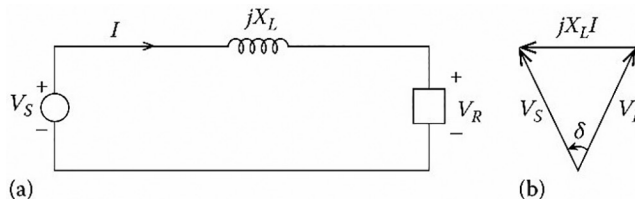


FIGURE 3.11 (a) An uncompensated transmission line and (b) its voltage-phasor diagram.

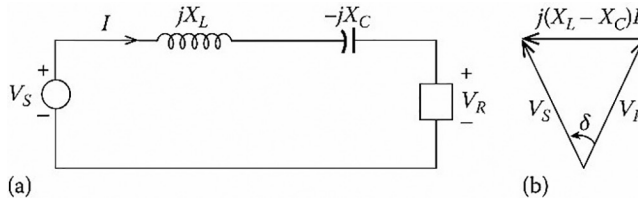


FIGURE 3.12 (a) A transmission line with series compensation and (b) its voltage-phasor diagram.

On long transmission lines, when a current flows, it causes a large voltage drop. In order to compensate, SCs are connected in the line. They decrease the effect of the line reactance.

In the case of a no-loss line, voltage magnitude at the receiving end is the same as voltage magnitude at the sending end, that is,

$$V_S = V_R = V$$

Thus, the transmission results in a phase lag of *eight* that depends on line reactance X . It can be expressed that

$$\bar{V}_S = V \cos\left(\frac{\delta}{2}\right) + V \sin\left(\frac{\delta}{2}\right) \quad (3.12)$$

and

$$\bar{V}_S = V \cos\left(\frac{\delta}{2}\right) + V \sin\left(\frac{\delta}{2}\right) \quad (3.13)$$

and the current can be expressed as

$$I = \frac{\bar{V}_S - \bar{V}_R}{jX} = \frac{2V \sin\left(\frac{\delta}{2}\right)}{X} \quad (3.14)$$

since the line is a no-loss line, real power is the same at any point of the line. Hence,

$$P_S = P_R = P = V \cos\left(\frac{\delta}{2}\right) \left(\frac{2V \sin\left(\frac{\delta}{2}\right)}{X} \right) \quad (3.15)$$

or

$$P_S = P_R = P = \frac{V^2}{X} \sin(\delta) \quad (3.16)$$

Reactive power at the sending end is the opposite of reactive power at the receiving end. Thus,

$$Q_S = -Q_R = Q = V \sin\left(\frac{\delta}{2}\right) \left(\frac{2V \sin\left(\frac{\delta}{2}\right)}{X} \right) \quad (3.17)$$

and

$$Q_s = -Q_R = Q = \frac{V^2}{X}(1 - \cos \delta) \quad (3.18)$$

When FACTS is used for series compensation, it modifies line impedance. Thus, line reactance X is decreased so as to increase the transmittable real power. However, more reactive power must be provided. Here, the real and reactive powers, respectively, are

$$P = \frac{V^2}{X - X_c} \sin(\delta) \quad (3.19)$$

and

$$Q = \frac{V^2}{X - X_c}(1 - \cos \delta) \quad (3.20)$$

Examples of series compensation include the following:

1. Static synchronous series compensation.
2. TCSC, that is, an SC bank that is shunted by a thyristor-controlled reactor (TCR).
3. Thyristor-controlled series reactor, that is, a series reactor bank that is shunted by a TCR.
4. TSSC, that is, an SC bank that is shunted by a thyristor-switched reactor (TSR).
5. Thyristor-switched series reactor, that is, a series reactor bank that is shunted by a TSR.

3.10.3 TRANSMISSION LINES WITH SHUNT COMPENSATION

Figure 3.13a shows a transmission line with shunt compensation. Here, the FACTS is connected in shunt (parallel) with the power system. The FACTS here operates as a controllable current source. The shunt compensation is of two types:

3.10.3.1 Shunt Capacitive Compensation

This method is primarily used to improve the power factor. Any time an inductive load is connected to the transmission line, the power factor lags due to lagging current. In order to compensate for this, a shunt capacitor is connected, which draws current that leads the source voltage. As a result, there is an improvement in the power factor. Examples of shunt compensation include the following:

1. *Static synchronous compensator (STATCOM)*: It is previously known as a static condenser (STATCON). It is connected in parallel with the line. It is a shunt-connected device injecting dynamically inductive or capacitive reactive power into the transmission grid. Its main functions are voltage stability and reactive power control of transmission systems and system buses. A different version of static var control is static var control Plus.

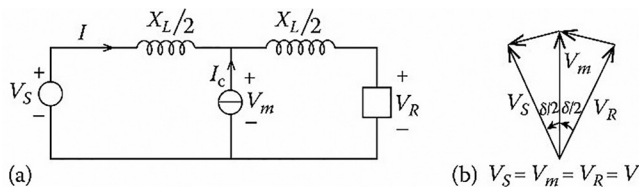


FIGURE 3.13 (a) A transmission line with shunt compensation and (b) its voltage-phasor diagram.

It is a cost-efficient, space-saving, flexible solution to increase dynamic stability and power quality of transmission systems, based on multilevel voltage-source converter technology.

2. *Static var compensators (SVCs)*: They are a fast and reliable means of controlling voltage of lines and system's buses. The reactive power is changed by switchgear controlling reactive power elements connected to the secondary side of the transformer. Each capacitor bank is switched on or off by thyristor valve (thyristor-switched capacitor [TSC]).

The reactor can be either switched (TSR) or controlled (TCR) by thyristor valves. When the system voltage is low, the SVC supplies reactive power and raises the network voltage. When the system voltage is high, the SVC generates inductive reactive power and reduces the system voltage. The most common SVCs are as follows:

- a. *TCR*: This is a reactor that is connected in series with a bidirectional thyristor valve. The thyristor valve is phase-controlled.
- b. *TSR*: It is the same as TCR, but the thyristor is in either zero or full conduction. Here, the equivalent reactance is varied in a stepwise manner.
- c. *TSC*: The capacitor is connected in series with a bidirectional thyristor valve. The thyristor is either in zero or full conduction. Equivalent reactance is varied in a stepwise manner.
- d. *MSC/MSCDN*: The capacitor is switched mechanically by a circuit breaker. It compensates for steady-state reactive power. It is only switched a few times a day. MSCs are a robust solution for voltage control and network stabilization under steady-state conditions.

The MSCDN is the advanced variation of MSC with a damping network to avoid resonance conditions in the electrical HV system.

3.10.3.2 Shunt Inductive Compensation

This method is employed either when charging the transmission line or when there is very low load at the receiving end. Due to very light load, or no load, a very small amount of current flows through the transmission line and shunt capacitance in transmission line causes voltage increase. This is known as the *Ferranti effect*. Occasionally, the receiving-end voltage may become double the sending-end voltage (usually in very long lines). In order to compensate, shunt inductors are connected across the transmission line. Therefore, the power transfer capability is increased as a result of the following equation:

$$P = \left(\frac{EV}{X} \right) \sin(\delta)$$

where δ is the power angle.

In such shunt compensation, reactive current is injected into the line to maintain voltage magnitude. This increases the transmittable real power, but more reactive power needs to be provided. Thus, the reactive power becomes

$$P = \frac{2V^2}{X} \sin\left(\frac{\delta}{2}\right)$$

and the reactive power becomes

$$Q = \frac{2V^2}{X} \left[1 - \cos\left(\frac{\delta}{2}\right) \right]$$

3.11 STATIC VAR CONTROL

In the past, shunt capacitor and SC (and synchronous condensers) have been used in many applications successfully. But in certain situations, it is crucial to have some form of compensation that will respond to rapid fluctuations in the system load with a minimum of delay of the order of a few milliseconds. The variable compensator (also known as *variable static compensator*) was a static device that could provide leading or lagging vars based on the requirements. The compensator also known as *static var supply* (SVC) device was made up of a reactor shunted across the supply and connected in parallel with a fixed or variable HV bank. The proportion of the lagging and leading vars to be supplied is totally dependent upon the individual requirements of a given transmission line or system.

A thyristor valve, made up of two thyristors connected in antiparallel, will allow smooth regulation of the current flowing through a shunt reactor, as shown in Figure 3.12a. The current has a high content of harmonics, and because of this, the device must have additional harmonic filters to help smooth the current waveform. Since such filters are very expensive, they share a large part of the compensator cost.

However, it is not possible to have smooth control of the current with capacitor because of the long time constant associated with the capacitor charge/discharge cycle. Hence, the thyristor valve can only switch the capacitor on or off, as shown in Figure 3.14b.

The thyristor firing circuits used in SVCs are usually controlled by a voltage regulator, which tries to keep bus voltage constant by controlling the amount and polarity of the reactive power injected into the bus. The regulator can also be employed to damp power swings in the system, following a system disturbance.

Unfortunately, the cost of SVCs is typically several times that of an uncontrolled bank of shunt reactors or fixed capacitors (FCs). Hence, their use is somewhat restricted to those parts of a system where heavy fluctuations of real power take place and consequently, compensation of both inductive and capacitive vars is needed.

Today's SVCs are shunt-connected power electronic devices. They vary the reactive power output by controlling (or switching) the reactive impedance components by means of power electronics. Typical SVC equipment classification includes the following:

1. TCRs with FCs
2. TCRs in combination with MSC or TSCs
3. TSCs

Typically, SVCs are used in the following applications:

1. Voltage regulation
2. Reduce temporary overvoltages
3. Reduce voltage flicker caused by varying loads such as arc furnaces

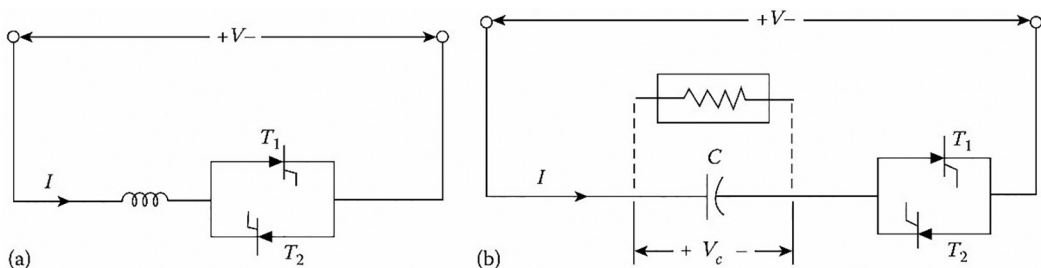


FIGURE 3.14 Principles of SVC compensation: (a) TCR and (b) TSC.

- 4. Increase the power transfer capacity of transmission systems
- 5. Increase transient stability limits of a power system
- 6. Increase damping of power oscillations
- 7. Damp subsynchronous oscillations

The SVCs are generally cheaper than the synchronous condensers. The synchronous condensers have higher investment and operating and maintenance (O&M) costs. Their investment costs may be about 20%–30% higher than SVCs. However, the use of synchronous condensers has some advantages over SVC in voltage weak networks. The schematic representation of three types of SVCs, which include a TCR with FC bank, a TCR with switched capacitor banks, and a TSC compensator, is shown in Figure 3.15.

Note that a capacitor bank can be switched by mechanical breakers, if time delay, which is usually five to ten cycles, is not an important factor, as shown in Figure 3.15b. Alternatively, they can be switched fast, in less than one cycle, by using thyristor switches, as shown in Figure 3.15c. Figure 3.16 illustrates the reactive power variation of a TCR with switched capacitor banks.

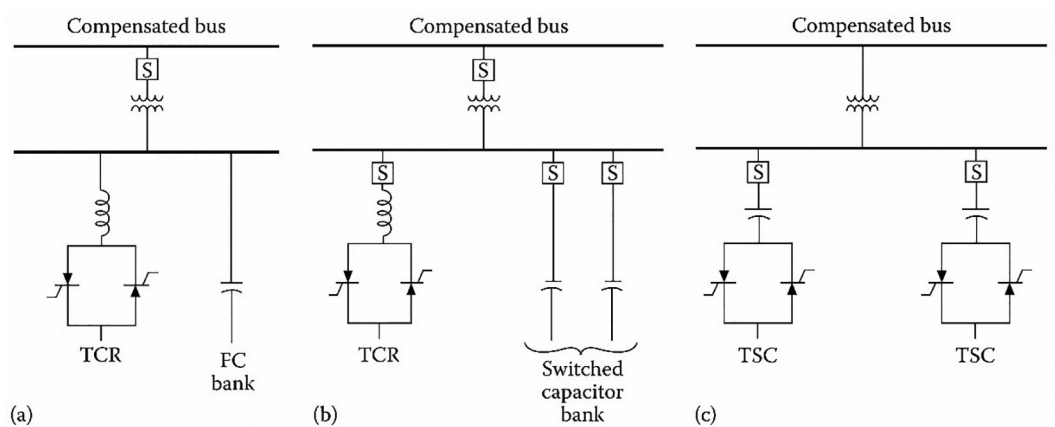


FIGURE 3.15 Schematic representation of three types of SVCs: (a) TCR with FC bank, (b) TCR with switched capacitor banks, and (c) TSC compensator.

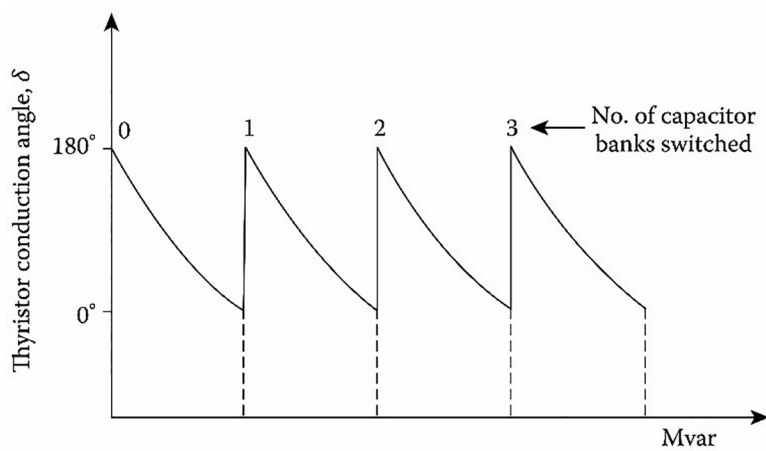


FIGURE 3.16 Reactive power variation of TCR with switched capacitor banks.

3.12 THYRISTOR-CONTROLLED SERIES COMPENSATOR

It provides fast control and variation of the impedance of the SC bank. It is part of the FACTS. The FACTS, in turn, is an application of power electronics for control of the AC system to improve the power flow, operation, and control of the AC system. It has been shown that TCSC improves the system performance for subsynchronous resonance (SSR) damping, power swing damping, transient stability, and power flow control. However, since it is a relatively new system, there have been only a few applications. Figure 3.18 shows a one-line diagram of a TCSC installed at a substation.

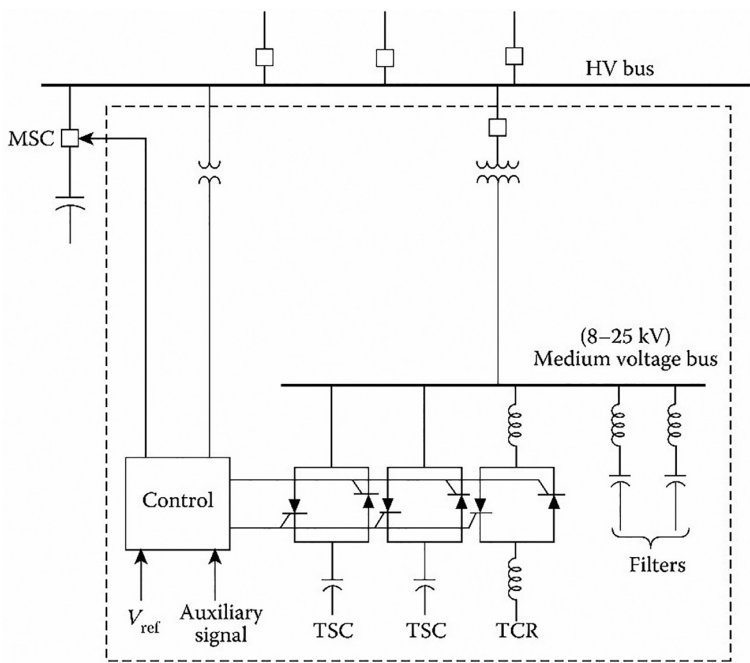


FIGURE 3.17 Schematic diagram of a typical static var system (as indicated by the dash signs).

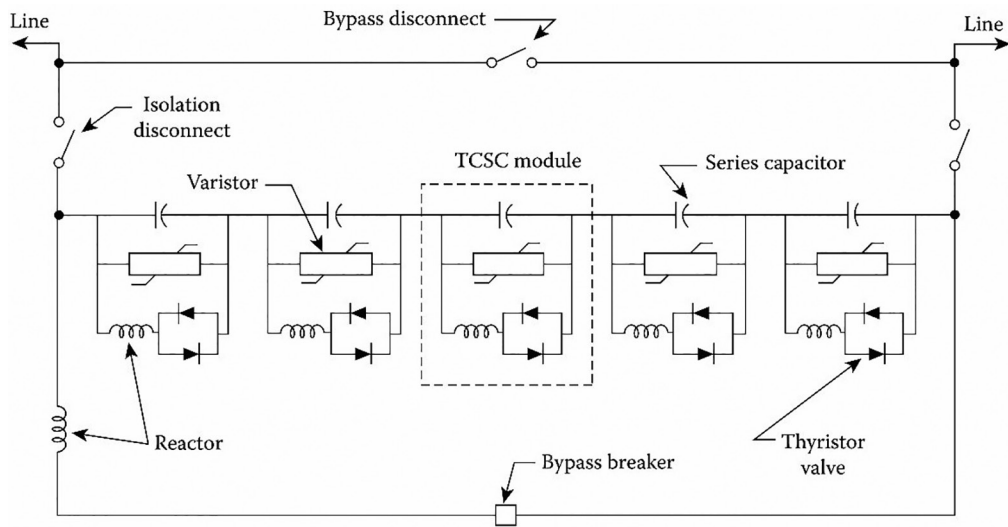


FIGURE 3.18 One-line diagram of a TCSC installed at a substation.

3.13 STATIC COMPENSATOR

A STATCOM is also called “gate turn-off (GTO) SVC” or “*advanced SVC*.” It provides variable lagging or leading reactive powers without using inductors or capacitors for the var generation. Reactive power generation is produced by regulating the terminal voltage of the converter.

The STATCOM is made up of a voltage-source inverter by using GTO thyristor that produces an AC voltage source, which is in phase with the transmission line voltage.

It is connected to the line through a series inductance. This reactance can be the transformer leakage inductance that is required to match the inverter voltage of the line voltage. When the terminal voltage of the voltage-source inverter is greater than the bus voltage, then STATCOM produces leading reactive power. On the other hand, when the terminal voltage is lower than the bus voltage, STATCOM produces lagging reactive power. In some sense, STATCOM is smaller than a synchronous condenser. In addition to being used for voltage control and var compensation, STATCOM can also be used to damp out electromechanical oscillations.

The operating principle of a STATCOM is illustrated in Figure 3.19. The GTO converter produces a fundamental frequency voltage V_2 , which is in phase with the power system voltage V_1 . As V_2 and V_1 are in phase, the difference between them results in a reactive current I , flowing through the transformer reactance X , which can be expressed as

$$I = \frac{V_1 - V_2}{jX} \quad (3.21)$$

When $V_2 > V_1$, then I leads V_1 ; thus, the reactive power is delivered to the bus that is connected to the line. Hence, the *converter behaves like a capacitor*.

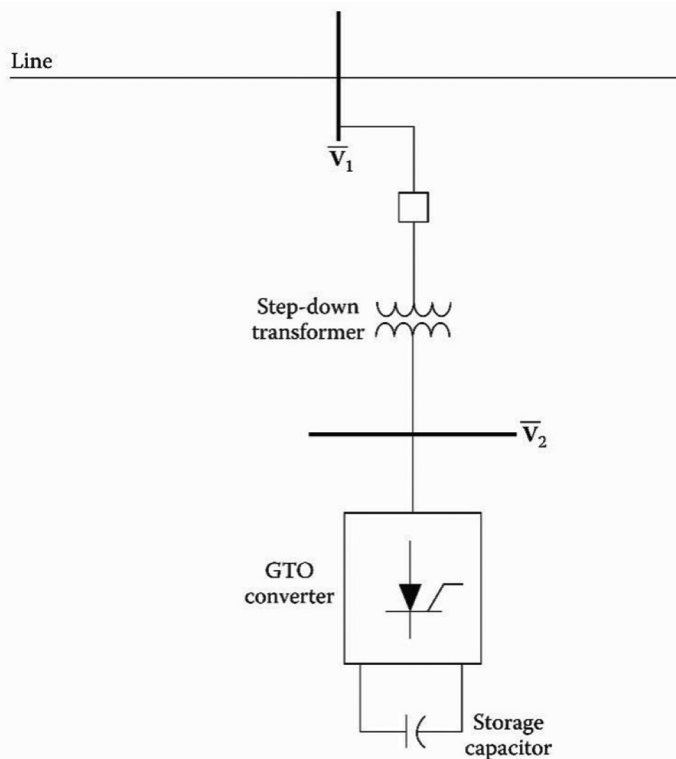


FIGURE 3.19 An illustration of the operation principle of STATCOM (or *advanced SVC*).

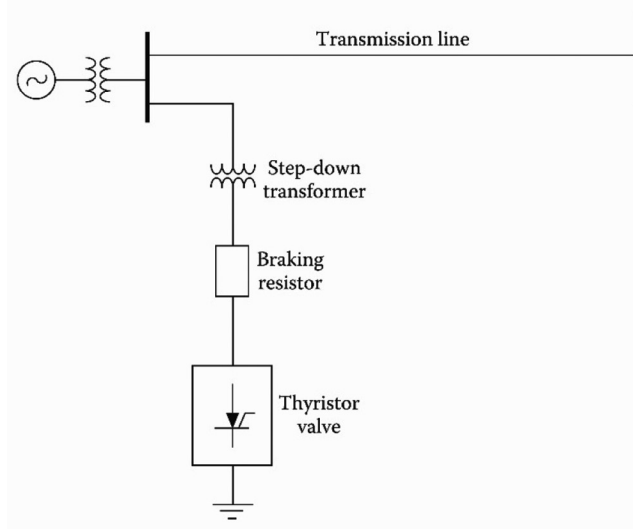


FIGURE 3.20 A thyristor-controlled braking resistor.

On the other hand, if $V_2 < V_1$, then I lags V_1 ; thus, the reactive power is drawn from the bus and the *converter acts like a reactor*.

Note that for a transformer reactance of 0.1 pu, when there is a $\pm 10\%$ change on V_2 , it produces ± 1 pu change in the inserted reactive power. In order to improve transient stability, a thyristor-controlled braking resistor can be used.

As said earlier, the application of SCs is a very effective way of increasing the power transfer capability of a power system that has long transmission lines. SCs significantly increase transient and steady-state limits, in addition to being a near-perfect means of var and voltage control. For a 500 kV transmission project with 1,000 mi long lines, it was estimated that the application of SCs reduced the project cost by 25%. In the past, it was believed that up to 70% series compensation could be used in any transmission line with little or no concern.

However, there is an important problem with the use of series compensation. That is, series-compensated transmission systems and steam turbine generators can interact in a phenomenon that is known as SSR. This phenomenon may be described as the addition of SCs establishes a series-resonant circuit that can oscillate at a natural frequency below the normal synchronous frequency when stimulated by a disturbance. In certain EHV transmission circuit configurations with a high percentage of series compensation, the net resistance of the circuit can be negative, causing the oscillations to increase until they are limited by saturation effects. If the synchronous frequency minus the electrical resonant frequency approaches the frequency of one of the turbine-alternator natural torsional modes, substantial damage to the turbine-alternator shaft can occur. It may also cause insulation failure of the windings of the generator.

Also, some equipment damage may also take place due to switching series-compensated lines even though the steady-state net resistance for these oscillations is positive. The SSR problem can be corrected by modifying the alternator's excitation system, SC protective equipment, and the addition of special relaying and series blocking filters [2].

3.14 ENERGY MANAGEMENT SYSTEM

The main purpose of an electric power system is to efficiently generate, transmit, and distribute electric energy. The operations involved dictate geographically dispersed and functionally complex monitoring and control systems, as shown in Figure 3.22.

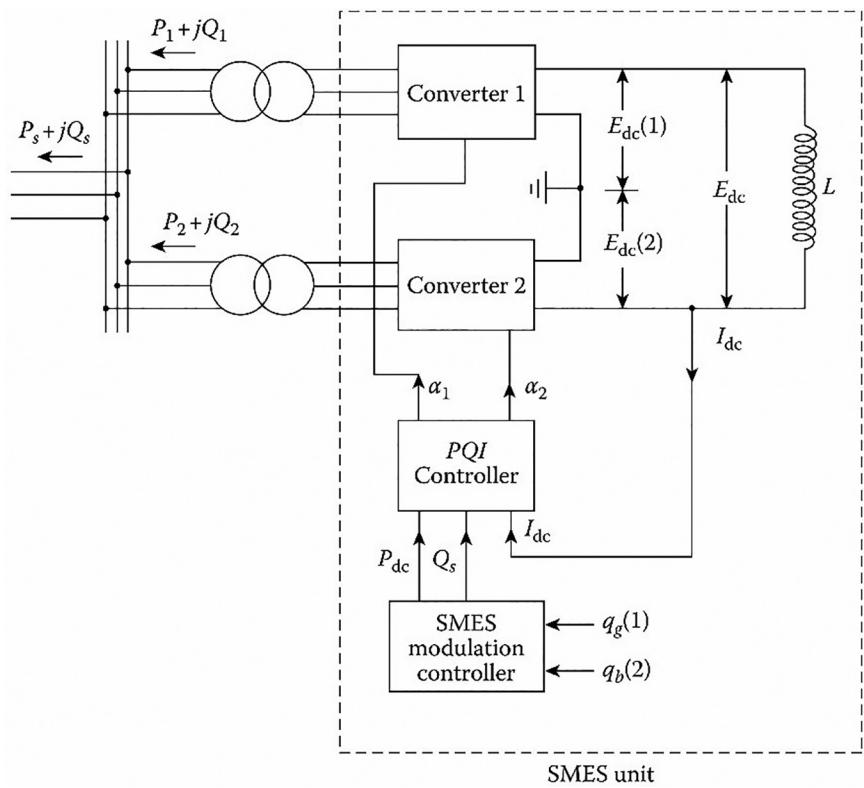


FIGURE 3.21 SMES unit with double GTO thyristor bridge.

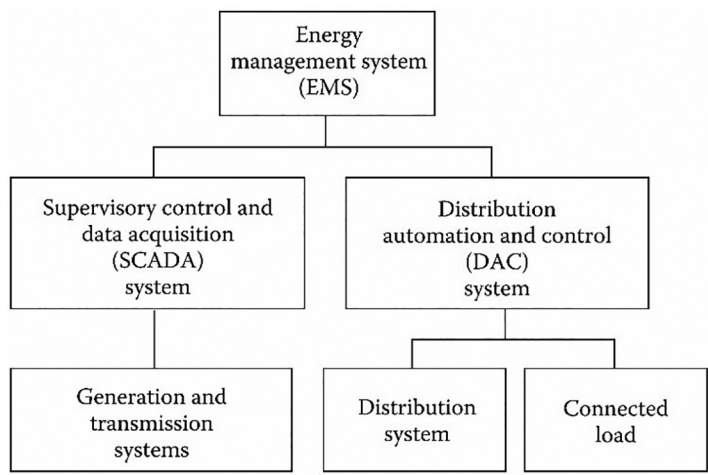


FIGURE 3.22 Monitoring and controlling an electric power system.

As illustrated in the figure, the *energy management system* (EMS) exercises overall control over the total system. The SCADA system involves generation and transmission systems. The *distribution automation and control* (DAC) system oversees the distribution system, including connected load. Automatic monitoring and control features have long been a part of the SCADA system.

More recently, automation has become a part of the overall EMS, including the distribution system. Motivating objectives of the DAC system are

- 1. Improved overall system efficiency in the use of both capital and energy
- 2. Increased market penetration of coal, nuclear, and renewable domestic energy sources
- 3. Reduced reserve requirements in both transmission and generation
- 4. Increased reliability of service to essential load

Advances in digital technology have made the true EMS a reality. It is clear that future electric power systems will be more complex than those of today. If the systems being developed are to be operational with respect to construction costs, capitalization, performance reliability, and operating efficiency, and better automation and controls are required.

3.15 SUBSTATION CONTROLLERS

In the future, remote terminal unit (RTUs) will not only provide station telemetry and control to the master station but also will provide other primary functions such as system protection, local operation, *graphical user interface*, and data gathering/concentration from other subsystems. Therefore, the future's RTUs will evolve into a class of devices that perform multiple substation control, protection, and operation functions. Besides these functions, the substation controller also develops and processes data required by the SCADA master, and it processes control commands and messages received from the SCADA master.

The substation controller will provide a gateway function to process and transmit data from the substation to the wide area network (WAN). The substation controller is basically a computer system designed to operate in a substation environment. As shown in Figure 3.23, it has hardware modules and software in terms of the following:

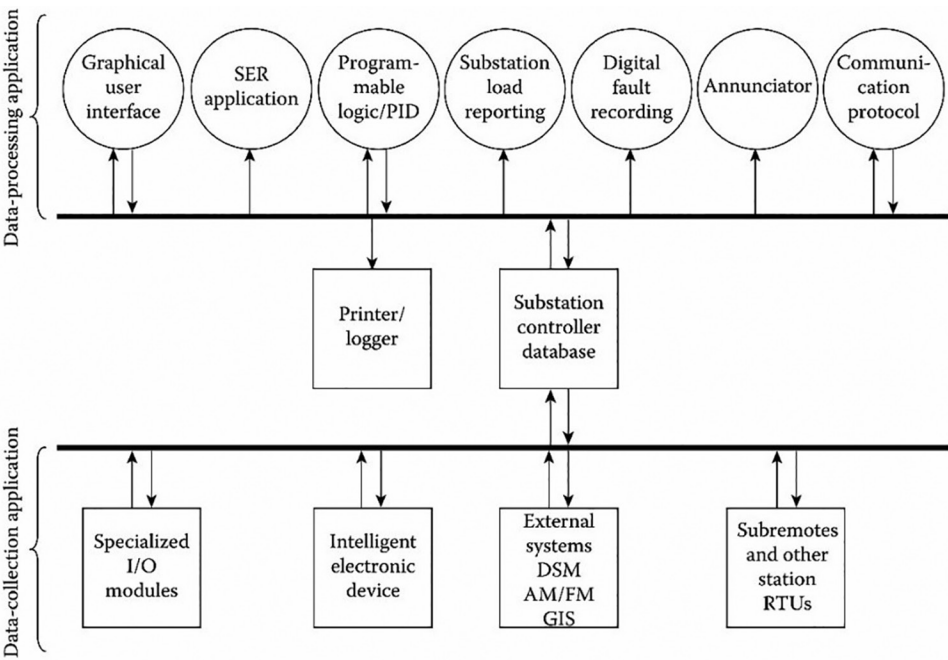


FIGURE 3.23 Substation controller.

1. *Data processing applications*: These software applications provide various users' access to the data of the substation controller in order to provide instructions and programming to the substation controller, collect data from the substation controller, and perform the necessary functions.
2. *Data collection applications*: These software applications provide the access to other systems and components that have data elements necessary for the substation controller to perform its functions.
3. *Control database*: All data reside in a single location, whether from a data processing application, data collection application, or derived from the substation controller itself.

Therefore, the substation controller is a system that is made up of many different types of hardware and software components and may not even be in a single location. Here, RTU may exist only as a software application within the substation controller system. Substation controllers will make all data available on WANs. They will eliminate separate stand-alone systems and thus provide greater cost savings to the utility company.

According to Chawda et al. [6], the SCADA planner must look beyond the traditional roles of SCADA. For example, the planner must consider the following issues:

1. Reduction of substation design and construction costs
2. Reduction of substation operating costs
3. Overall lowering of power system operating costs
4. Development of information for non-SCADA functions
5. Utilization of existing resources and company standards for hardware, software, and database generation
6. Expansion of automated operations at the subtransmission and distribution levels
7. Improved customer relations

To accomplish these, the SCADA planner must join forces with the substation engineer to become an integrated team. Each must ask the other, "How can your requirements be met in a manner that provides positive benefits for my business?"

3.16 SIX-PHASE TRANSMISSION LINES

Recently, high-phase (i.e., 6-, 9-, and 12-phase) order transmission lines have been proposed to transmit more than three phases of electric power. Six-phase transmission lines are especially designed to increase power transfer over existing lines and reduce electrical environmental impacts [7–10]. The advantages of six-phase systems are as follows:

1. Increased thermal loading capacity of lines.
2. For a given conductor size and tower configuration, the stress on the conductor surface decreases with the number of phases, leading to reduced corona losses.
3. Their transmission efficiency is higher.
4. The double-circuit lines, with two three-phase circuits on each tower, can easily be converted to single-circuit six-phase lines.
5. The higher the number of phases, the smaller the line-to-line voltage becomes relative to the phase voltage. As a result, the existing rights of way can be better used since there is less need for phase-to-phase insulation requirement in the six-phase transmission.

In the three-phase AC systems, there are three phasors that are offset with respect to each other by 120° . Similarly, in the six-phase AC systems, there are six phasors that are offset with respect to

each other by 60° . On the other hand, 9-phase AC systems have 9 phasors that are offset by 40° and 12-phase AC systems consist of 12 phasors offset by 30° .

However, the three-phase transmission was accepted as the standard for AC transmission due to the following reasons:

1. Three phases are the least number required for power flow that is constant with time.
2. The power of an electric machine does not increase as phases are increased more than three phases.

But electric power transmission with more than three phases has some advantages. For example, in six-phase transmission lines,¹ the conductor gradients are lower, which reduces both AN and electrostatic effects without requiring additional insulation. In multiphase transmission lines, if the line-to-ground voltage is fixed, then the line-to-line voltage decreases as the number of phases increases, thereby enabling the line-to-line insulation distance to be reduced. Figure 3.24 shows polyphase voltage phasors in three-phase phasor versus six-phase phasor systems. In the three-phase systems,

$$V_L = \sqrt{3}V_\phi$$

but in the six-phase systems,

$$V_L = V_\phi$$

That is, the line and phase voltages are the same. Hence, for example, for a given phase-to-ground voltage of 79.6 kV, the line-to-line voltage is 138 kV for three-phase systems. But it is 79.6 kV for six-phase systems. Similarly, for a phase-to-ground voltage of 199.2 kV, the line-to-line voltage is 345 kV for three-phase systems, but it is 199.2 kV for six-phase systems. The maximum complex power that six-phase transmission lines can carry is

$$S_{6\phi} = 6V_\phi I_L^* \quad (3.22)$$

and the maximum complex power that a double-circuit three-phase line of the same phase voltage can carry is

$$\begin{aligned} S_{3\phi} &= 2(3V_\phi I_L^*) \\ &= 6V_\phi I_L^* = S_{6\phi} \end{aligned}$$

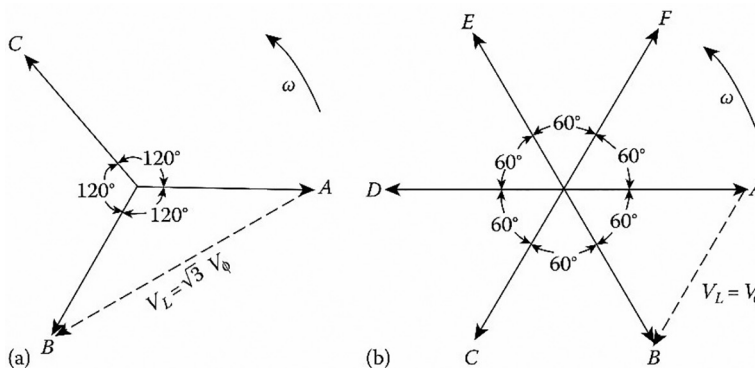


FIGURE 3.24 Polyphase phasor systems: (a) three-phase system and (b) six-phase system.

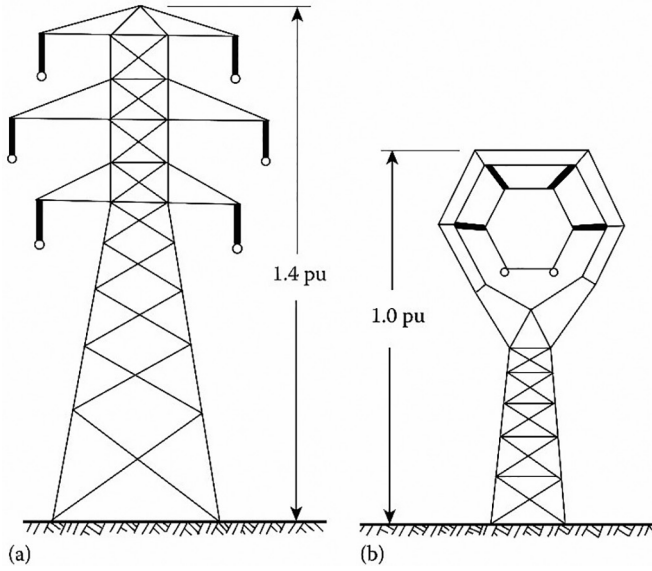


FIGURE 3.25 Comparative tower heights for a double-circuit (a) three-phase transmission line versus (b) a six-phase transmission line.

which is the same as a six-phase transmission line. It is clear that the lower line-to-line voltage of the six-phase line permits the tower and other structures to be smaller than an equivalent double-circuit three-phase transmission line, as shown in Figure 3.25. As a result of this, the same amount of complex power can be transmitted using a smaller six-phase ROW for the same phase voltage and the same conductor current capacity.

Similarly, the power capacity of a six-phase transmission line with the same line voltage as an equivalent double-circuit three-phase transmission line is

$$S_{6\phi} = 6(\sqrt{3}V_{\phi}I_L^*) \quad (3.23)$$

or

$$S_{6\phi} = \sqrt{3}6V_{\phi}I_L^* \quad (3.24)$$

Therefore, for the same line voltage, the capacity of a six-phase line is 173% that of an equivalent double-circuit three-phase system. Also, the magnetic fields are three to four times lower in six-phase lines than in an equivalent double-circuit three-phase line.

Since the electric field gradients on the conductors are lower in six-phase lines, its corona losses are also lower. Today, the need for six-phase transformers is met by using two regular three-phase transformers that are connected delta–wye and delta-inverted wye or wye–wye and wye-inverted wye, as illustrated in Figure 3.26.

The following types of protections are provided for the six-phase 93 kV transmission line that was built between Goudey and Oakdale in New York:

1. Current differential relaying employing pilot signal over a fiber-optic-based communication channel.
2. Phase-distance impedance relays with directional ground current relays.
3. Segregated phase comparison relays for backup. These relays can determine if an internal fault has taken place by comparing the phase at the ends of each conductor, using a fiber-optic communications system.

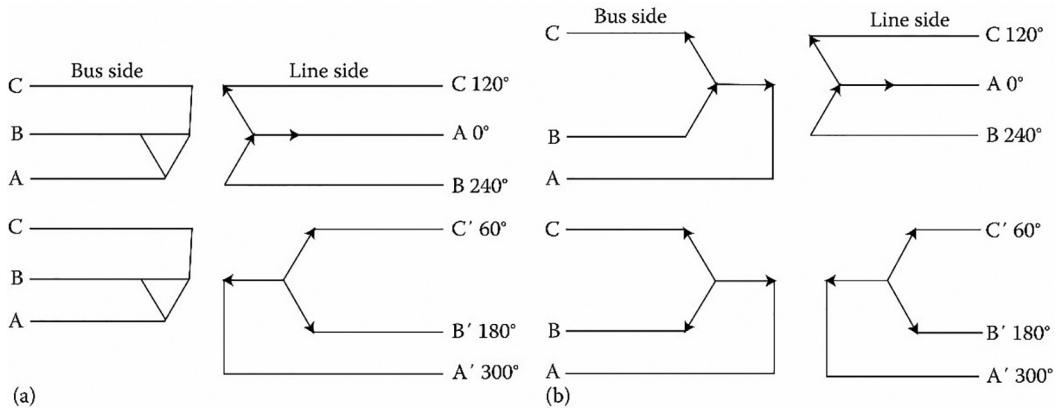


FIGURE 3.26 Six-phase transformer bank made up of two three-phase transformers connected as (a) delta-wye and delta-inverted wye and (b) wye-wye and wye-inverted wye.

In general, protection of a six-phase transmission line is more involved than for a double-circuit three-phase transmission line. There are more combinations of line-to-line and line-to-neutral faults that can take place.

PROBLEMS

Problem 3.1

A 345 kV three-phase transmission line with a horizontal tower top configuration has a 24.6 ft phase spacing between the adjacent conductors. Each phase conductor has a diameter of 1.76 in. Its surge impedance is 366 Ω . Determine the SIL of the line.

Solution

The SIL of the line is

$$\begin{aligned} \text{SIL} &= \frac{|\text{kV}_{R(L-L)}|^2}{Z_s} \\ &= \frac{345^2}{366} \cong 3.25 \text{ MW} \end{aligned}$$

Problem 3.2

Consider the 345 kV transmission line given in Example 3.1. In that example, the SIL was found to be 325 Ω . Investigate various compensation methods to improve the SIL of the transmission line. Determine the effective SIL for the following compensation choices:

- A 50% shunt capacitive compensation and no series compensation
- A 0% series capacitive compensation and 50% shunt compensation using shunt reactors
- A 50% series capacitive compensation and no shunt compensation
- A 50% series capacitive compensation and 20% shunt capacitive compensation

Solution

a.

$$\begin{aligned} \text{SIL}_{\text{comp}} &= \text{SIL}_{\text{uncomp}} \sqrt{\frac{1 - \Gamma_{\text{shunt}}}{1 - \Gamma_{\text{series}}}} \\ &= (325 \, \Omega) \sqrt{\frac{1 - 0.50}{1 - 0.0}} = 230 \, \Omega \end{aligned}$$

b.

$$\begin{aligned} \text{SIL}_{\text{comp}} &= \text{SIL}_{\text{uncomp}} \sqrt{\frac{1 + \Gamma_{\text{shunt}}}{1 - \Gamma_{\text{series}}}} \\ &= (325 \, \Omega) \sqrt{\frac{1 + 0.50}{1 - 0.0}} = 398 \, \Omega \end{aligned}$$

c.

$$\begin{aligned} \text{SIL}_{\text{comp}} &= \text{SIL}_{\text{uncomp}} \sqrt{\frac{1 - \Gamma_{\text{shunt}}}{1 - \Gamma_{\text{series}}}} \\ &= (325 \, \Omega) \sqrt{\frac{1 - 0.0}{1 - 0.50}} = 460 \, \Omega \end{aligned}$$

d.

$$\begin{aligned} \text{SIL}_{\text{comp}} &= \text{SIL}_{\text{uncomp}} \sqrt{\frac{1 - \Gamma_{\text{shunt}}}{1 - \Gamma_{\text{series}}}} \\ &= (325 \, \Omega) \sqrt{\frac{1 - 0.20}{1 - 0.50}} = 411 \, \Omega \end{aligned}$$

Problem 3.3

Consider two parallel transmission lines that are series compensated by using capacitor banks. Allow 150% voltage and current overload for a short period. The capacitor bank that is being considered to be employed must withstand twice the normal voltage and current. Determine the following:

- The rated current in terms of per unit of the normal load current.
- The amount of necessary increase in the bank's Mvar rating in per unit.
- If the capacitor bank has a normal full-load current of 1,000 A, find the rated current value.

Solution

- Since the capacitor bank must be able to withstand twice the normal voltage and current,

$$(1.5 \, \text{pu}) I_{\text{rated}} = (2.0 \, \text{pu}) I_{\text{normal}}$$

from which the rated current is

$$I_{\text{rated}} = (1.33 \, \text{pu}) I_{\text{normal}}$$

- b. The increase in the bank's Mvar rating is

$$\text{Mvar rating increase} = (1.33 \text{ pu})^2 = 1.78 \text{ pu}$$

- c. The rated current value is

$$I_{\text{rated}} = (1.33)(1,000 \text{ A}) = 1,333 \text{ A}$$

NOTE

- 1 A six-phase 93 kV transmission line was built between Goudey and Oakdale in New York by New York State Electric and Gas Company.

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4 Overhead Power Transmission

To see a world in a Grain of Sand and a Heaven in a Wild Flower.
Hold Infinity in the palm of your hand, and Eternity in an hour.

William Blake

4.1 INTRODUCTION

In this section, a brief review of fundamental concepts associated with steady-state AC circuits, especially with three-phase circuits, is presented. It is hoped that this brief review is sufficient to provide a common base, in terms of notation and references, that is necessary to be able to follow in the forthcoming chapters.

Also, a brief review of transmission system modeling is presented in this chapter. Transmission lines are modeled and classified according to their lengths as

1. Short transmission lines
2. Medium-length transmission lines
3. Long transmission lines

The short transmission lines are those lines that have lengths up to 50 mi or 80 km. The medium-length transmission lines are those lines that have lengths up to 150 mi or 240 km. Similarly, the long transmission lines are those lines that have lengths above 150 mi or 240 km.

OH construction¹ is only 15%–60% as costly as underground and is therefore more economical. The first consideration in the design of an OH line, of course, is its electrical characteristics. As explained in the previous chapters, the electrical design of the line must be sufficient for the required power to be transmitted without excessive voltage drop and/or energy losses, and the line insulation must be adequate to cope with the system voltage. The mechanical factors influencing the design must then be considered. For example, the poles supporting the conductors must have sufficient mechanical strength to withstand all expected loads. Another example is that the material chosen for the conductors must be strong enough to withstand the forces to which it is subjected.

The conductors and poles must have sufficient strength with a predetermined safety factor to withstand the loads due to the line itself and stresses imposed by ice and wind loads. Thus, the OH line should provide satisfactory service over a long period of time without the necessity for too much maintenance. Ultimate economy is provided by a good construction since excessive maintenance or especially short life can easily more than overbalance a saving in the first cost.

The OH line must have a proper strength to withstand the stresses imposed on its component parts by the line itself. These include stresses set up by the tension in conductors at dead-end points, compression stresses due to guy tension, transverse loads due to angles in the line, vertical stresses due to the weight of conductors, and the vertical component of conductor tension. The tension in the conductors should be adjusted so that it is well within the permissible load of the material. This will mean in practice that one must allow for an appreciable amount of sag.

The poles must have sufficient height and be so located, taking into account the topography of the land, as to provide adequate ground clearances at both maximum loading and maximum temperature conditions. The conductor ground clearance for railroad tracks and wire line crossings, as well as from buildings and other objects, must meet the requirements of the National Electric Safety Code (NESC).²

A proper mechanical design is one of the essentials in providing good service to customers. A large majority of service interruptions can be traced to physical failures on the distribution system, broken wires, broken poles, damaged insulation, damaged equipment, etc. Many of these service interruptions are more or less unavoidable. But their numbers can be reduced if the design and construction of the various physical parts can withstand, with reasonable safety factors, not only normal conditions but also some probable abnormal conditions.

The OH line must be designed from the mechanical point of view to withstand the worst probable, but not the worst possible, conditions. For example, the cost of an OH line that would withstand a severe hurricane would be tremendous, and thus from an economical point of view, it may be justifiable to run the risk of failure under such conditions.

4.2 REVIEW OF BASICS

4.2.1 COMPLEX POWER IN BALANCED TRANSMISSION LINES

Figure 4.1a shows a per-phase representation (or one-line diagram) of a short three-phase balanced transmission line connecting buses i and j . Here, the term bus defines a specific nodal point of a transmission network. Assume that the bus voltages V_i and V_j are given in phase values (i.e., line-to-neutral values) and that the line impedance is $Z = R + jX$ per phase. Since the transmission line is a short one, the line current I can be assumed to be approximately the same at any point in the line. However, because of the line losses, the complex powers S_{ij} and S_{ji} are not the same.

Therefore, the complex power per phase³ that is being transmitted from bus i to bus j can be expressed as

$$S_{ij} = P_{ij} + jQ_{ij} = V_i I^* \quad (4.1)$$

Similarly, the complex power per phase that is being transmitted from bus j to bus i can be expressed as

$$S_{ji} = P_{ji} + jQ_{ji} = V_j (-I)^* \quad (4.2)$$

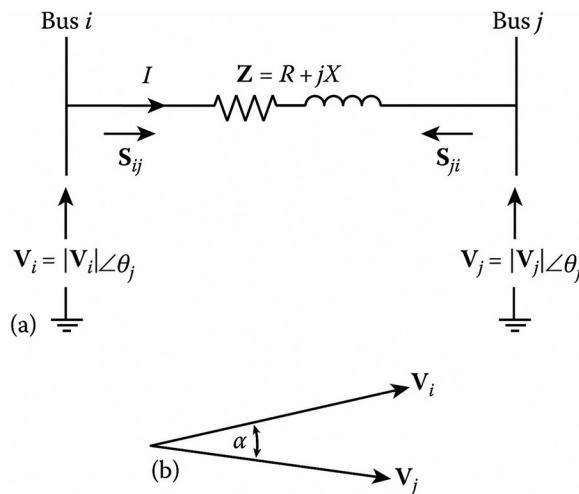


FIGURE 4.1 Per-phase representation of a short transmission line: (a) a short transmission line and (b) a voltage phasor diagram.

Since

$$I = \frac{V_j - V_i}{Z} \quad (4.3)$$

substituting Equation 4.3 into Equations 4.1 and 4.2,

$$S_{ij} = V_i \left(\frac{V_i^* - V_j^*}{Z^*} \right) = \frac{|V_i|^2 - |V_i||V_j|\angle\theta_i - \theta_j}{R - jX} \quad (4.4)$$

and

$$S_{ji} = V_j \left(\frac{V_j^* - V_i^*}{Z^*} \right) = \frac{|V_j|^2 - |V_j||V_i|\angle\theta_j - \theta_i}{R - jX} \quad (4.5)$$

However, as shown in Figure 4.1b, if the power angle (i.e., the phase angle between the two bus voltages) is defined as

$$\gamma = \theta_i - \theta_j \quad (4.6)$$

then the real and reactive power per phase values can be expressed, respectively, as

$$P_{ij} = \frac{1}{R^2 + X^2} \left(R|V_i|^2 - R|V_i||V_j|\cos\gamma + X|V_i|V_j|\sin\gamma \right) \quad (4.7)$$

and

$$Q_{ij} = \frac{1}{R^2 + X^2} \left(X|V_i|^2 - X|V_i||V_j|\cos\gamma - R|V_i|V_j|\sin\gamma \right) \quad (4.8)$$

Similarly,

$$P_{ji} = \frac{1}{R^2 + X^2} \left(R|V_j|^2 - R|V_i||V_j|\cos\gamma - X|V_i|V_j|\sin\gamma \right) \quad (4.9)$$

and

$$Q_{ji} = \frac{1}{R^2 + X^2} \left(X|V_j|^2 - X|V_i||V_j|\cos\gamma + R|V_i|V_j|\sin\gamma \right) \quad (4.10)$$

The three-phase real and reactive power can directly be found from Equations 4.7–4.10 if the phase values are replaced by the line values.

In general, the reactance of a transmission line is much greater than its resistance. Therefore, the line impedance value can be approximated as

$$Z = jX \quad (4.11)$$

by setting $R=0$. Therefore, Equations 4.7–4.10 can be expressed as

$$P_{ij} = \frac{|V_i||V_j|}{X} \sin\gamma \quad (4.12)$$

$$Q_{ij} = \frac{1}{X} \left(|V_i|^2 - |V_i||V_j| \cos \gamma \right) \quad (4.13)$$

and

$$P_{ji} = -\frac{|V_j||V_i|}{X} \sin \gamma = -P_{ij} \quad (4.14)$$

$$Q_{ji} = \frac{1}{X} \left(|V_j|^2 - |V_j||V_i| \cos \gamma \right) \quad (4.15)$$

Example 4.1

Assume that the impedance of a transmission line connecting buses 1 and 2 is $100 \angle 60^\circ \Omega$ and that the bus voltages are $73,034.8 \angle 30^\circ$ and $66,395.3 \angle 20^\circ$ V per phase, respectively. Determine the following:

- Complex power per phase that is being transmitted from bus 1 to bus 2
- Active power per phase that is being transmitted
- Reactive power per phase that is being transmitted

Solution

a.

$$\begin{aligned} S_{12} &= V_1 \left(\frac{V_1^* - V_2^*}{Z^*} \right) \\ &= (73,034.8 \angle 30^\circ) \left(\frac{73,034.8 \angle -30^\circ - 66,395.3 \angle -20^\circ}{100 \angle -60^\circ} \right) \\ &= 10,104,766.7 \angle 3.56^\circ \\ &= 10,085,280.6 + j627,236.5 \text{ VA} \end{aligned}$$

b.

$$P_{12} = 10,085,280.6 \text{ W}$$

c.

$$Q_{12} = 627,236.5 \text{ vars}$$

4.2.2 ONE-LINE DIAGRAM

In general, electric power systems are represented by a one-line diagram, as shown in Figure 4.2a. The one-line diagram is also referred to as the single-line diagram. Figure 4.2b shows the three-phase equivalent impedance diagram of the system given in Figure 4.2a. However, the need for the three-phase equivalent impedance diagram is almost nil in usual situations. This is due to the fact that a balanced three-phase system can always be represented by an equivalent impedance diagram per phase, as shown in Figure 4.2c. Furthermore, the per-phase equivalent impedance can also be simplified by neglecting the neutral line and representing the system components by standard symbols rather than by their equivalent circuits [1]. The result is the one-line diagram shown

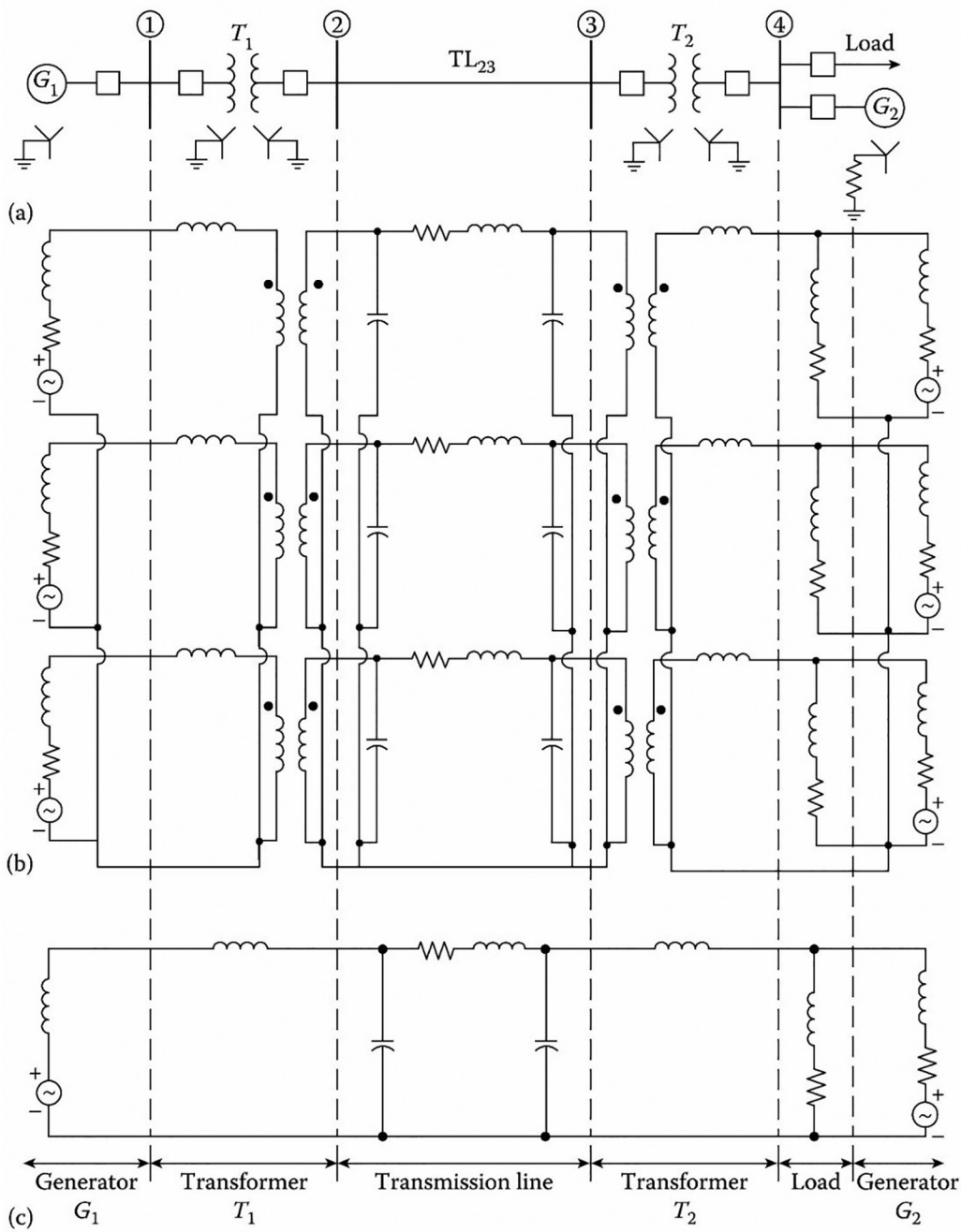
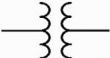
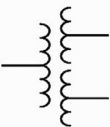
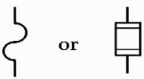
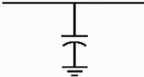


FIGURE 4.2 Power system representations: (a) one-line diagram, (b) three-phase equivalent impedance diagram, and (c) equivalent impedance diagram per phase.

in Figure 4.2a. Table 4.1 gives some of the symbols that are used in one-line diagrams. Additional standard symbols can be found in Neuenswander [2].

At times, as a need arises, the one-line diagram may also show peripheral apparatus such as instrument transformers [i.e., Current Transformers (CTs) and Voltage Transformers (VTs)], protective relays, and lighting arrestors. Therefore, the details shown on a one-line diagram depend

TABLE 4.1
Symbols Used in One-Line Diagrams

Symbol	Usage	Symbol	Usage
	Rotating machine		Circuit breaker
	Bus		Circuit breaker (air)
	Two-winding transformer		Disconnect
	Three-winding transformer		Fuse
	Delta connection (3 ϕ , three wire)		Fused disconnect
	Wye connection (3 ϕ , neutral grounded)		Lightning arrester
	Wye connection (3 ϕ , neutral grounded)		Current transformer (CT)
	Transmission line		Voltage transformer (VT)
	Static load		Capacitor

on its purpose. For example, the one-line diagrams that will be used in load flow studies do not show CBs or relays, contrary to the ones that will be used in stability studies. Furthermore, the ones that will be used in unsymmetrical fault studies may even show the positive-, negative-, and zero-sequence networks separately.

Note that the buses (i.e., the *nodal points* of the transmission network) that are shown in Figure 4.2a have been identified by their bus numbers. Also note that the neutral of generator 1 has been *solidly grounded*, that is, the neutral point has been directly connected to the earth, whereas the neutral of generator 2 has been *grounded through impedance* using a resistor. Sometimes, it is grounded using an inductance coil. In either case, they are used to limit the current flow to ground under fault conditions.

Usually, the neutrals of the transformers used in transmission lines are solidly grounded. In general, a proper generator grounding for generators is facilitated by burying a ground electrode system made of grids of buried horizontal wires. As the number of meshes in the grid is increased, its conductance becomes greater. Sometimes, a metal plate is buried instead of a mesh grid.

Transmission lines with Overhead ground wires (OHGWs) have a ground connection at each supporting structure to which the GW is connected. In some circumstances, a *counterpoise*, that is, a bare conductor, is buried under a transmission line to decrease the ground resistance, if the soil resistance is high. The best-known example is the one that has been installed for the transmission line crossing the Mojave Desert. The counterpoise is buried alongside the line and connected directly to the towers and the OHGWs.

Note that the equivalent circuit of the transmission line shown in Figure 4.2c has been represented by a nominal π . The line impedance, in terms of the resistance and the series reactance of

a single conductor for the length of the line, has been lumped. The line-to-neutral capacitance (or *shunt capacitive reactance*) for the length of the line has been calculated, and half of this value has been put at each end of the line.

The transformers have been represented by their equivalent reactances, neglecting their magnetizing currents and consequently their shunt admittances. Also neglected are the resistance values of the transformers and generators due to the fact that their inductive reactance values are much greater than their resistance values. Also not shown in Figure 4.2c is the ground resistor. This is due to no current flowing in the neutral under balanced conditions. The impedance diagram shown in Figure 4.2c is also referred to as the positive-sequence network or diagram. The reason is that the phase order of the balanced voltages at any point in the system is the same as the phase order of the generated voltage, and they are positive. The per-phase impedance diagrams may represent a system given either in ohms or per unit.

4.2.3 PER-UNIT SYSTEM

Because of the various advantages involved, it is customary in power system analysis calculations to use impedances, currents, voltages, and powers in per-unit values (which are scaled or normalized values) rather than in physical values of ohms, amperes, kilovolts, and megavolt-amperes (or megavars, or megawatts). A per-unit system is a means of expressing quantities for ease in comparing them. The per-unit value of any quantity is defined as the ratio of the quantity to an *arbitrarily* chosen base (i.e., *reference*) value having the same dimensions. Therefore, the per-unit value of any quantity can be defined as a physical quantity:

$$\text{Quantity in per unit} = \frac{\text{Physical quantity}}{\text{Base value of quantity}} \quad (4.16)$$

where *physical quantity* refers to the value given in ohms, amperes, volts, etc. The *base value* is also called unit value since in the per-unit system, it has a value of 1, or unity. Therefore, a base current is also referred to as a unit current. Since both the physical quantity and base quantity have the same dimensions, the resulting per-unit value expressed as a decimal has no dimension and therefore is simply indicated by a subscript pu. The base quantity is indicated by a subscript *B*. The symbol for per unit is pu or 0/1. The percent system is obtained by multiplying the per-unit value by 100. Therefore,

$$\text{Quantity in percent} = \frac{\text{Physical quantity}}{\text{Base value of quantity}} \times 100 \quad (4.17)$$

However, the percent system is somewhat more difficult to work with and more subject to possible error since it must always be remembered that the quantities have been multiplied by 100. Therefore, factor 100 has to be continually inserted or removed for reasons that may not be obvious at the time. For example, 40% reactance times 100% current is equal to 4,000% voltage, which, of course, must be corrected to 40% voltage. Thus, the per-unit system is preferred in power system calculations. The advantages of using the per-unit system include the following:

1. Network analysis is greatly simplified since all impedances of a given equivalent circuit can directly be added together regardless of the system voltages.
2. It eliminates the $\sqrt{3}$ multiplications and divisions that are required when balanced three-phase systems are represented by per-phase systems. Therefore, the factors $\sqrt{3}$ and 3 associated with delta and wye quantities in a balanced three-phase system are directly taken into account by the base quantities.

3. Usually, the impedance of an electrical apparatus is given in percent or per unit by its manufacturer based on its nameplate ratings (e.g., its rated volt-amperes and rated voltage).
4. Differences in operating characteristics of many electrical apparatus can be estimated by a comparison of their constants expressed in per unit.
5. Average machine constants can easily be obtained since the parameters of similar equipment tend to fall in a relatively narrow range and therefore are comparable when expressed as per units based on rated capacity.
6. The use of per-unit quantities is more convenient in calculations involving digital computers.

4.2.3.1 Single-Phase System

In the event that any two of the four base quantities (i.e., base voltage, base current, base volt-amperes, and base impedance) are *arbitrarily* specified, the other two can be determined immediately. Here, the term arbitrarily is slightly misleading since in practice the base values are selected so as to force the results to fall into specified ranges. For example, the base voltage is selected such that the system voltage is normally close to unity.

Similarly, the base volt-ampere is usually selected as the kilovolt-ampere or megavolt-ampere rating of one of the machines or transformers in the system or a convenient round number such as 1, 10, 100, or 1,000 MVA, depending on the system size. As mentioned earlier, on determining the base volt-amperes and base voltages, the other base values are fixed. For example, the current base can be determined as

$$I_B = \frac{S_B}{V_B} = \frac{\text{VA}_B}{V_B} \quad (4.18)$$

where

I_B is the current base in amperes

S_B is the selected volt-ampere base in volt-amperes

V_B is the selected voltage base in volts

Note that

$$S_B = \text{VA}_B = P_B = Q_B = V_B I_B \quad (4.19)$$

Similarly, the impedance base⁴ can be determined as

$$Z_B = \frac{V_B}{I_B} \quad (4.20)$$

where

$$Z_B = X_B = R_B \quad (4.21)$$

Similarly,

$$Y_B = B_B = G_B = \frac{I_B}{V_B} \quad (4.22)$$

Note that by substituting Equation 4.18 into Equation 4.20, the impedance base can be expressed as

$$Z_B = \frac{V_B}{\text{VA}_B/V_B} = \frac{V_B^2}{\text{VA}_B} \quad (4.23)$$

or

$$Z_B = \frac{(\text{kV}_B)^2}{\text{MVA}_B} \quad (4.24)$$

where

kV_B is the voltage base in kilovolts

MVA_B is the volt-ampere base in megavolt-amperes

The per-unit value of any quantity can be found by the *normalization process*, that is, by dividing the physical quantity by the base quantity of the same dimension. For example, the per-unit impedance can be expressed as

$$Z_{\text{pu}} = \frac{Z_{\text{physical}}}{Z_B} \quad (4.25)$$

or

$$Z_{\text{pu}} = \frac{Z_{\text{physical}}}{V_B^2 / (\text{kVA}_B \times 1,000)} \quad (4.26)$$

or

$$Z_{\text{pu}} = \frac{(Z_{\text{physical}})(\text{kVA}_B)(1,000)}{V_B^2} \quad (4.27)$$

or

$$Z_{\text{pu}} = \frac{(Z_{\text{physical}})(\text{kVA}_B)}{(\text{kV}_B)^2 (1,000)} \quad (4.28)$$

or

$$Z_{\text{pu}} = \frac{(Z_{\text{physical}})}{(\text{kV}_B)^2 / \text{MVA}_B} \quad (4.29)$$

or

$$Z_{\text{pu}} = \frac{(Z_{\text{physical}})(\text{MVA}_B)}{(\text{kV}_B)^2} \quad (4.30)$$

Similarly, the others can be expressed as

$$I_{\text{pu}} = \frac{I_{\text{physical}}}{I_B} \quad (4.31)$$

or

$$V_{\text{pu}} = \frac{V_{\text{physical}}}{V_B} \quad (4.32)$$

or

$$kV_{pu} = \frac{kV_{\text{physical}}}{kV_B} \quad (4.33)$$

or

$$VA_{pu} = \frac{VA_{\text{physical}}}{VA_B} \quad (4.34)$$

or

$$kVA_{pu} = \frac{kVA_{\text{physical}}}{kVA_B} \quad (4.35)$$

or

$$MVA_{pu} = \frac{MVA_{\text{physical}}}{MVA_B} \quad (4.36)$$

Note that the base quantity is always a real number, whereas the physical quantity can be a complex number. For example, if the actual impedance quantity is given as $Z \angle \theta \, \Omega$, it can be expressed in the per-unit system as

$$Z_{pu} = \frac{Z \angle \theta}{Z_B} = Z_{pu} \angle \theta \quad (4.37)$$

that is, it is the magnitude expressed in per-unit terms. Alternatively, if the impedance has been given in rectangular form as

$$Z = R + jX \quad (4.38)$$

then

$$Z_{pu} = R_{pu} + jX_{pu} \quad (4.39)$$

where

$$R_{pu} = \frac{R_{\text{physical}}}{Z_B} \quad (4.40)$$

and

$$X_{pu} = \frac{X_{\text{physical}}}{Z_B} \quad (4.41)$$

Similarly, if the complex power has been given as

$$S = P + jQ \quad (4.42)$$

then

$$S_{pu} = P_{pu} + jQ_{pu} \quad (4.43)$$

where

$$P_{\text{pu}} = \frac{P_{\text{physical}}}{S_B} \quad (4.44)$$

and

$$Q_{\text{pu}} = \frac{Q_{\text{physical}}}{S_B} \quad (4.45)$$

If the actual voltage and current values are given as

$$V = V \angle \theta_V \quad (4.46)$$

and

$$I = I \angle \theta_I \quad (4.47)$$

the complex power can be expressed as

$$S = VI^* \quad (4.48)$$

or

$$S \angle \theta = (V \angle \theta_V)(I \angle -\theta_I) \quad (4.49)$$

Therefore, dividing through by S_B ,

$$\frac{S \angle \theta}{S_B} = \frac{(V \angle \theta_V)(I \angle -\theta_I)}{S_B} \quad (4.50)$$

However,

$$S_B = V_B I_B \quad (4.51)$$

Thus,

$$\frac{S \angle \theta}{S_B} = \frac{(V \angle \theta_V)(I \angle -\theta_I)}{V_B I_B} \quad (4.52)$$

or

$$S_{\text{pu}} \angle \theta = (V_{\text{pu}} \angle \theta_V)(I_{\text{pu}} \angle -\theta_I) \quad (4.53)$$

or

$$S_{\text{pu}} = V_{\text{pu}} I_{\text{pu}}^* \quad (4.54)$$

4.2.3.2 Converting from Per-Unit Values to Physical Values

The physical values (or system values) and per-unit values are related by the following relationships:

$$I = I_{\text{pu}} \times I_B \quad (4.55)$$

$$V = V_{pu} \times V_B \quad (4.56)$$

$$Z = Z_{pu} \times Z_B \quad (4.57)$$

$$R = R_{pu} \times Z_B \quad (4.58)$$

$$X = X_{pu} \times Z_B \quad (4.59)$$

$$S = VA = VA_{pu} \times VA_B \quad (4.60)$$

$$P = P_{pu} \times VA_B \quad (4.61)$$

$$Q = Q_{pu} \times VA_B \quad (4.62)$$

4.2.3.3 Change of Base

In general, the per-unit impedance of a power apparatus is given based on its own volt-ampere and voltage ratings and consequently based on its own impedance base. When such an apparatus is used in a system that has its own bases, it becomes necessary to refer all the given per-unit values to the system base values. Assume that the per-unit impedance of the apparatus is given based on its nameplate ratings as

$$Z_{pu(given)} = (Z_{physical}) \frac{MVA_{B(given)}}{[kV_{B(given)}]^2} \quad (4.63)$$

and that it is necessary to refer the very same physical impedance to a new set of voltage and volt-ampere bases such that

$$Z_{pu(new)} = (Z_{physical}) \frac{MVA_{B(new)}}{[kV_{B(new)}]^2} \quad (4.64)$$

By dividing Equation 4.63 by Equation 4.64 side by side,

$$Z_{pu(new)} = (Z_{pu(given)}) \left[\frac{MVA_{B(new)}}{MVA_{B(given)}} \right] \left[\frac{kV_{B(given)}}{kV_{B(new)}} \right]^2 \quad (4.65)$$

In certain situations, it is more convenient to use subscripts 1 and 2 instead of subscripts *given* and *new*, respectively. Equation 4.65 can be expressed as

$$Z_{pu(2)} = (Z_{pu(1)}) \left[\frac{MVA_{B(2)}}{MVA_{B(1)}} \right] \left[\frac{kV_{B(1)}}{kV_{B(2)}} \right]^2 \quad (4.66)$$

In the event that the kV bases are the same but the MVA bases are different, from Equation 4.65,

$$Z_{pu(new)} = (Z_{pu(given)}) \frac{MVA_{B(new)}}{MVA_{B(given)}} \quad (4.67)$$

Similarly, if the megavolt-ampere bases are the same but the kilovolt bases are different, from Equation 4.65,

$$Z_{pu(new)} = \left(Z_{pu(given)} \right) \left[\frac{kV_{B(given)}}{kV_{B(new)}} \right]^2 \quad (4.68)$$

Equations 4.65–4.68 must only be used to convert the given per-unit impedance from the base to another but not for referring the physical value of an impedance from one side of the transformer to another [3].

4.2.4 THREE-PHASE SYSTEMS

The three-phase problems involving balanced systems can be solved on a per-phase basis. In that case, the equations that are developed for single-phase systems can be used for three-phase systems as long as per-phase values are used consistently. Therefore,

$$I_B = \frac{S_{B(1\phi)}}{V_{B(L-N)}} \quad (4.69)$$

or

$$I_B = \frac{VA_{B(1\phi)}}{V_{B(L-N)}} \quad (4.70)$$

and

$$Z_B = \frac{V_{B(L-N)}}{I_B} \quad (4.71)$$

or

$$Z_B = \frac{[kV_{B(L-N)}]^2 (1,000)}{kVA_{B(1\phi)}} \quad (4.72)$$

or

$$Z_B = \frac{[kV_{B(L-N)}]^2}{MVA_{B(1\phi)}} \quad (4.73)$$

where the subscripts 1ϕ and $L-N$ denote per phase and line to neutral, respectively. Note that, for a balanced system,

$$V_{B(L-N)} = \frac{V_{B(L-L)}}{\sqrt{3}} \quad (4.74)$$

and

$$S_{B(1\phi)} = \frac{S_{B(3\phi)}}{3} \quad (4.75)$$

However, it has been customary in three-phase system analysis to use line-to-line voltage and three-phase volt-amperes as the base values. Therefore,

$$I_B = \frac{S_{B(3\phi)}}{\sqrt{3}V_{B(L-L)}} \quad (4.76)$$

or

$$I_B = \frac{\text{kVA}_{B(3\phi)}}{\sqrt{3}\text{kV}_{B(L-L)}} \quad (4.77)$$

and

$$Z_B = \frac{V_{B(L-L)}}{\sqrt{3}I_B} \quad (4.78)$$

$$Z_B = \frac{[\text{kV}_{B(L-L)}]^2 (1,000)}{\text{kVA}_{B(3\phi)}} \quad (4.79)$$

or

$$Z_B = \frac{[\text{kV}_{B(L-N)}]^2}{\text{MVA}_{B(3\phi)}} \quad (4.80)$$

where the subscripts 3ϕ and $L-L$ denote per three phase and line, respectively. Furthermore, base admittance can be expressed as

$$Y_B = \frac{1}{Z_B} \quad (4.81)$$

or

$$Y_B = \frac{\text{MVA}_{B(3\phi)}}{[\text{kV}_{B(L-L)}]^2} \quad (4.82)$$

where

$$Y_B = B_B = G_B \quad (4.83)$$

The data for transmission lines are usually given in terms of the line resistance R in ohms per mile at a given temperature, the line inductive reactance X_L in ohms per mile at 60 Hz, and the line shunt capacitive reactance X_c in megaohms per mile at 60 Hz. Therefore, the line impedance and shunt susceptance in per unit for 1 mi of line can be expressed as⁵

$$Z_{\text{pu}} = (Z, \Omega/\text{mi}) = \frac{\text{MVA}_{B(3\phi)}}{[\text{kV}_{B(L-L)}]^2} \text{ pu} \quad (4.84)$$

where

$$Z = R + jX_L = Z \angle \theta \Omega/\text{mi}$$

and

$$B_{\text{pu}} = \frac{[\text{kV}_{B(L-L)}]^2 \times 10^{-6}}{[\text{MVA}_{B(3\phi)}][X_c \text{ M}\Omega/\text{mi}]} \quad (4.85)$$

In the event that the admittance for a transmission line is given in microsiemens per mile, the per-unit admittance can be expressed as

$$Y_{pu} = \frac{[kV_{B(L-L)}]^2 (Y, \mu S)}{[MVA_{B(3\phi)}] \times 10^6} \quad (4.86)$$

Similarly, if it is given as reciprocal admittance in megohms per mile, the per-unit admittance can be found as

$$Y_{pu} = \frac{[kV_{B(L-L)}]^2 \times 10^{-6}}{[MVA_{B(3\phi)}][Z, M\Omega/mi]} \quad (4.87)$$

Figure 4.3 shows conventional three-phase transformer connections and associated relationships between the High Voltage (HV)- and Low Voltage (LV)-side voltages and currents. The given relationships are correct for a three-phase transformer as well as for a three-phase bank of single-phase transformers. Note that in the figure, n is the turns ratio, that is,

$$n = \frac{N_1}{N_2} = \frac{V_1}{V_2} = \frac{I_2}{I_1} \quad (4.88)$$

where the subscripts 1 and 2 are used for the primary and secondary sides. Therefore, an impedance Z_2 in the secondary circuit can be referred to as the primary circuit provided that

$$Z_1 = n^2 Z_2 \quad (4.89)$$

Thus, it can be observed from Figure 4.3 that in an ideal transformer, voltages are transformed in the direct ratio of turns, currents in the inverse ratio, and impedances in the direct ratio squared; and power and volt-amperes are, of course, unchanged. Note that a balanced delta-connected circuit of Z_Δ Ω /phase is equivalent to a balanced wye-connected circuit of Z_Y Ω /phase as long as

$$Z_Y = \frac{1}{3} Z_\Delta \quad (4.90)$$

The per-unit impedance of a transformer remains the same without taking into account whether it is converted from physical impedance values that are found by referring to the HV side or LV side of the transformer. This can be accomplished by choosing separate appropriate bases for each side of the transformer (whether or not the transformer is connected in wye–wye, delta–delta, delta–wye, or wye–delta since the transformation of voltages is the same as that made by wye–wye transformers as long as the same line-to-line voltage ratings are used).⁶ In other words, the designated per-unit impedance values of transformers are based on the coil ratings.

Since the ratings of coils cannot be altered by a simple change in connection (e.g., from wye–wye to delta–wye), the per-unit impedance remains the same regardless of the three-phase connection. The line-to-line voltage for the transformer will differ. Because of the method of choosing the base in various sections of the three-phase system, the per-unit impedances calculated in various sections can be put together on one impedance diagram without paying any attention to whether the transformers are connected in wye–wye or delta–wye.

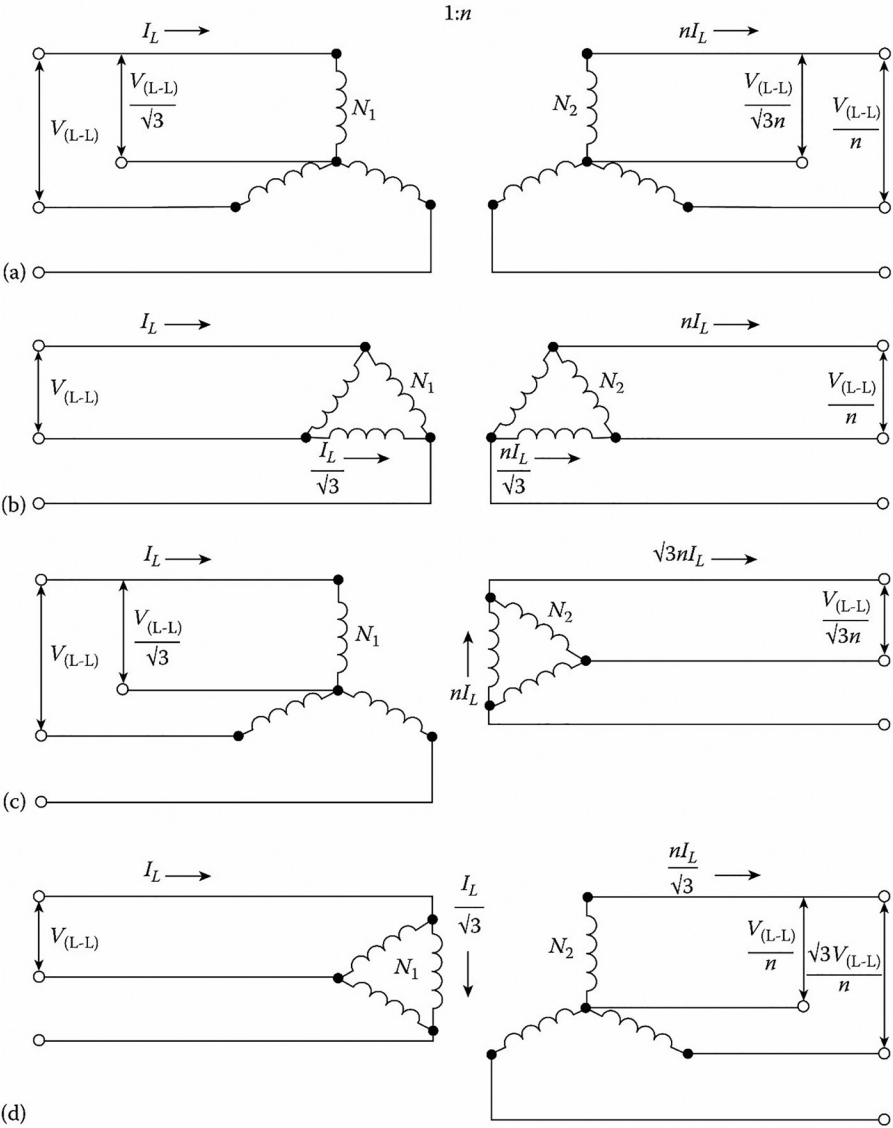


FIGURE 4.3 Conventional three-phase transformer connections: (a) wye–wye connection, (b) delta–delta connection, (c) wye–delta connection, and (d) delta–wye connection.

Example 4.2

Figure 4.4 shows a one-line diagram of a three-phase system. Assume that the line length between the two transformers is negligible and the three-phase generator is rated 4,160 kVA, 2.4 kV, and 1,000 A and that it supplies a purely inductive load of $I_{pu}=2.08\angle-90^\circ$ pu. The three-phase transformer T_1 is rated 6,000 kVA, 2.4Y–24Y kV, with leakage reactance of 0.04 pu. Transformer T_2 is made up of three single-phase transformers and is rated 4,000 kVA, 24Y–12Y kV, with a leakage reactance of 0.04 pu. Determine the following for all three circuits, 2.4, 24, and 12 kV circuits:

- a. Base kilovolt-ampere values.
- b. Base line-to-line kilovolt values.
- c. Base impedance values.

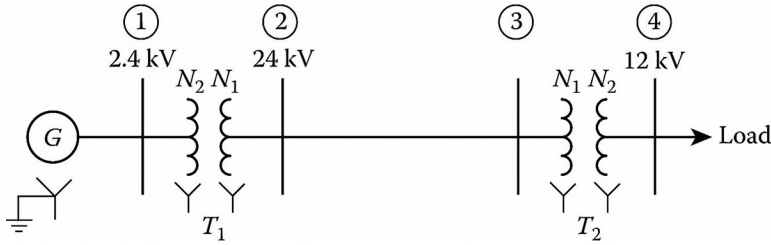


FIGURE 4.4 The one-line diagram for Example 4.4.

- Base current values.
- Physical current values (neglect magnetizing currents in transformers and charging currents in lines).
- Per-unit current values.
- New transformer reactances based on their new bases.
- Per-unit voltage values at buses 1, 2, and 4.
- Per-unit apparent power values at buses 1, 2, and 4.
- Summarize results in a table.

Solution

- The kilovolt-ampere base for all three circuits is arbitrarily selected as 2,080 kVA.
- The base voltage for the 2.4 kV circuit is arbitrarily selected as 2.5 kV. Since the turns ratios for transformers T_1 and T_2 are

$$\frac{N_2}{N_1} = 10 \quad \text{or} \quad \frac{N_1}{N_2} = 0.10$$

and

$$\frac{N'_1}{N'_2} = 2$$

the base voltages for the 24 and 12 kV circuits are determined to be 25 and 12.5 kV, respectively.

- The base impedance values can be found as

$$\begin{aligned} Z_B &= \frac{[\text{kV}_{B(L-L)}]^2 (1,000)}{\text{kVA}_{B(3\phi)}} \\ &= \frac{[2.5 \text{ kV}]^2 1,000}{2,080 \text{ kVA}} = 3.005 \Omega \end{aligned}$$

and

$$Z_B = \frac{[25 \text{ kV}]^2 1,000}{2,080 \text{ kVA}} = 3.005 \Omega$$

and

$$Z_B = \frac{[12.5 \text{ kV}]^2 (1,000)}{2,080 \text{ kVA}} = 75.1 \Omega$$

d. The base current values can be determined as

$$I_B = \frac{\text{kVA}_{B(3\phi)}}{\sqrt{3}\text{kV}_{B(L-L)}} \\ = \frac{2,080 \text{ kVA}}{\sqrt{3}(2.5 \text{ kV})} = 480 \text{ A}$$

and

$$I_B = \frac{2,080 \text{ kVA}}{\sqrt{3}(2.5 \text{ kV})} = 480 \text{ A}$$

and

$$I_B = \frac{2,080 \text{ kVA}}{\sqrt{3}(2.5 \text{ kV})} = 480 \text{ A}$$

e. The physical current values can be found based on the turns ratios as

$$I = 1,000 \text{ A} \\ = \left(\frac{N_1}{N_2} \right) (1,000 \text{ A}) = 100 \text{ A} \\ = \left(\frac{N'_1}{N'_2} \right) (100 \text{ A}) = 200 \text{ A}$$

f. The per-unit current values are the same, 2.08 pu, for all three circuits.

g. The given transformer reactances can be converted based on their new bases using

$$Z_{\text{pu}(\text{new})} = Z_{\text{pu}(\text{given})} \left[\frac{\text{kVA}_{B(\text{new})}}{\text{kVA}_{B(\text{given})}} \right] \left[\frac{\text{kV}_{B(\text{given})}}{\text{kV}_{B(\text{new})}} \right]^2$$

Therefore, the new reactances of the two transformers can be found as

$$Z_{\text{pu}(T_1)} = j0.04 \left[\frac{2,080 \text{ kVA}}{6,000 \text{ kVA}} \right] \left[\frac{2.4 \text{ kV}}{2.5 \text{ kV}} \right]^2 = j0.0128 \text{ pu}$$

and

$$Z_{\text{pu}(T_2)} = j0.04 \left[\frac{2,080 \text{ kVA}}{4,000 \text{ kVA}} \right] \left[\frac{2.4 \text{ kV}}{12.5 \text{ kV}} \right]^2 = j0.0192 \text{ pu}$$

h. Therefore, the per-unit voltage values at buses 1, 2, and 4 can be calculated as

$$V_1 = \frac{2.4 \text{ kV} \angle 0^\circ}{2.5 \text{ kV}} = 0.96 \angle 0^\circ \text{ pu}$$

$$V_2 = V_1 - I_{\text{pu}} Z_{\text{pu}(T_1)} \\ = 0.96 \angle 0^\circ - (2.08 \angle -90^\circ)(0.0128 \angle 90^\circ) = 0.9334 \angle 0^\circ \text{ pu}$$

TABLE 4.2
Results of Example 4.4

Quantity	2.4 kV Circuit	24 kV Circuit	12 kV Circuit
kVA _{B(3ϕ)}	2,080 kVA	2,080 kVA	2,080 kVA
kV _{B(L-L)}	2.5 kV	25 kV	12.5 kV
Z _B	3.005 Ω	300.5 Ω	75.1 Ω
I _B	480 A	48 A	96 A
I _{physical}	1,000 A	100 A	200 A
I _{pu}	2.08 pu	2.08 pu	2.08 pu
V _{pu}	0.96 pu	0.9334 pu	0.8935 pu
S _{pu}	2.00 pu	1.9415 pu	1.8585 pu

$$V_4 = V_2 - I_{pu}Z_{pu(T_2)}$$
$$= 0.9334\angle 0^\circ - (2.08\angle -90^\circ)(0.0192\angle 90^\circ) = 0.8935\angle 0^\circ \text{ pu}$$

i. Thus, the per-unit apparent power values at buses 1, 2, and 4 are

$$S_1 = 2.00 \text{ pu}$$
$$S_2 = V_2 I_{pu} = (0.9334)(2.08) = 1.9415 \text{ pu}$$
$$S_4 = V_4 I_{pu} = (0.8935)(2.08) = 1.8585 \text{ pu}$$

j. The results are summarized in Table 4.2.

4.2.5 CONSTANT-IMPEDANCE REPRESENTATION OF LOADS

Usually, the power system loads are represented by their real and reactive powers, as shown in Figure 4.5a. However, it is possible to represent the same load in terms of series or parallel combinations of its equivalent constant-load resistance and reactance values, as shown in Figure 4.5b and c, respectively [4].

In the event that the load is represented by the series connection, the equivalent constant impedance can be expressed as

$$Z_s = R_s + jX_s \tag{4.91}$$

where

$$R_s = \frac{|V|^2 \times P}{P^2 + Q^2} \tag{4.92}$$

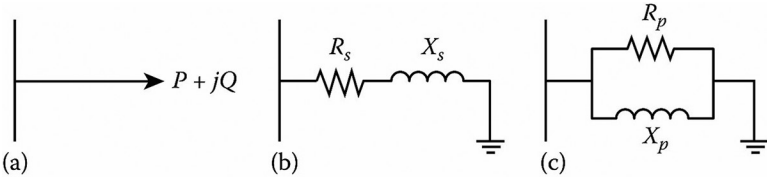


FIGURE 4.5 Load representations as (a) real and reactive powers, (b) constant impedance in terms of series combination, and (c) constant impedance in terms of parallel combination.

$$X_s = \frac{|V|^2 \times Q}{P^2 + Q^2} \quad (4.93)$$

where

R_s is the load resistance in series connection in ohms

X_s is the load reactance in series connection in ohms

Z_s is the constant-load impedance in ohms

V is the load voltage in volts

P is the real, or average, load power in watts

Q is the reactive load power in vars

The constant impedance in per unit can be expressed as

$$Z_{pu(s)} = R_{pu(s)} + jX_{pu(s)} \text{ pu} \quad (4.94)$$

where

$$R_{pu(s)} = (P_{\text{physical}}) \frac{S_B \times (V_{pu})^2}{P^2 + Q^2} \text{ pu} \quad (4.95)$$

$$X_{pu(s)} = (Q_{\text{physical}}) \frac{S_B \times (V_{pu})^2}{P^2 + Q^2} \text{ pu} \quad (4.96)$$

If the load is represented by the parallel connection, the equivalent constant impedance can be expressed as

$$Z_p = j \frac{R_p \times X_p}{R_p \times X_p} \quad (4.97)$$

where

$$R_p = \frac{V^2}{P}$$

$$X_p = \frac{V^2}{Q}$$

where

R_p is the load resistance in parallel connection in ohms

X_p is the load reactance in parallel connection in ohms

Z_p is the constant-load impedance in ohms

The constant impedance in per unit can be expressed as

$$Z_{pu(p)} = j \frac{R_{pu(p)} \times X_{pu(p)}}{R_{pu(p)} \times X_{pu(p)}} \text{ pu} \quad (4.98)$$

where

$$R_{pu(p)} = \frac{S_B}{P} \left(\frac{V}{V_B} \right)^2 \text{ pu} \quad (4.99)$$

or

$$R_{pu(p)} = \frac{V_{pu}^2}{P_{pu}} \text{ pu} \quad (4.100)$$

and

$$X_{pu(p)} = \frac{S_B}{Q} \left(\frac{V}{V_B} \right)^2 \text{ pu} \quad (4.101)$$

or

$$X_{pu(p)} = \frac{V_{pu}^2}{Q_{pu}} \text{ pu} \quad (4.102)$$

4.3 THREE-WINDING TRANSFORMERS

Figure 4.6a shows a single-phase three-winding transformer. They are usually used in the bulk power (transmission) substations to reduce the transmission voltage to the subtransmission voltage level. If excitation impedance is neglected, the equivalent circuit of a three-winding transformer can be represented by a wye of impedances, as shown in Figure 4.6b, where the primary, secondary, and tertiary windings are denoted by P , S , and T , respectively.

Note that the common point 0 is fictitious and is not related to the neutral of the system. The tertiary windings of a three-phase and three-winding transformer bank are usually connected in delta and may be used for (1) providing a path for zero-sequence currents, (2) in-plant power distribution, and (3) application of power-factor-correcting capacitors or reactors. The impedance of any of the branches shown in Figure 4.6b can be determined by considering the short-circuit impedance between pairs of windings with the third open. Therefore,

$$Z_{PS} = Z_P + Z_S \quad (4.103a)$$

$$Z_{TS} = Z_T + Z_S \quad (4.103b)$$

$$Z_{PT} = Z_P + Z_T \quad (4.103c)$$

$$Z_P = \frac{1}{2}(Z_{PS} + Z_{PT} + Z_{TS}) \quad (4.104a)$$

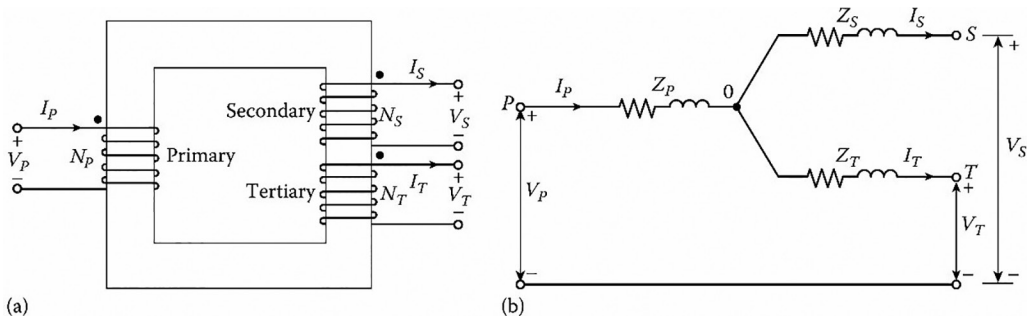


FIGURE 4.6 A single-phase three-winding transformer: (a) winding diagram and (b) equivalent circuit.

$$\mathbf{Z}_S = \frac{1}{2}(\mathbf{Z}_{PS} + \mathbf{Z}_{TS} + \mathbf{Z}_{PT}) \quad (4.104b)$$

$$\mathbf{Z}_T = \frac{1}{2}(\mathbf{Z}_{PT} + \mathbf{Z}_{TS} + \mathbf{Z}_{PS}) \quad (4.104c)$$

where

$\mathbf{Z}_{PS}$ is the leakage impedance measured in primary with secondary short-circuited and tertiary open

$\mathbf{Z}_{PT}$ is the leakage impedance measured in primary with tertiary short-circuited and secondary open

$\mathbf{Z}_{TS}$ is the leakage impedance measured in secondary with tertiary short-circuited and primary open

$\mathbf{Z}_P$ is the impedance of primary winding

$\mathbf{Z}_S$ is the impedance of secondary winding

$\mathbf{Z}_T$ is the impedance of tertiary winding

In most large transformers, the value of $\mathbf{Z}_S$ is very small and can be negative. Contrary to the situation with a two-winding transformer, the kilovolt-ampere ratings of the three windings of a three-winding transformer bank are not usually equal. Therefore, all impedances, as defined earlier, should be expressed on the same kilovolt-ampere base. For three-winding three-phase transformer banks with delta- or wye-connected windings, the positive- and negative-sequence diagrams are always the same. The corresponding zero-sequence diagrams are shown in Figure 9.10.

4.4 AUTOTRANSFORMERS

Figure 4.7a shows a two-winding transformer. Viewed from the terminals, the same transformation of voltages, currents, and impedances can be obtained with the connection shown in Figure 4.7b. Therefore, in the autotransformer, only one winding is used per phase, the secondary voltage is tapped off the primary winding, as shown in Figure 4.7b. The *common winding* is the winding between the LV terminals, whereas the remainder of the winding, belonging exclusively to the HV circuit, is called the *series winding* and, combined with the common winding, forms the *series-common winding* between the HV terminals.

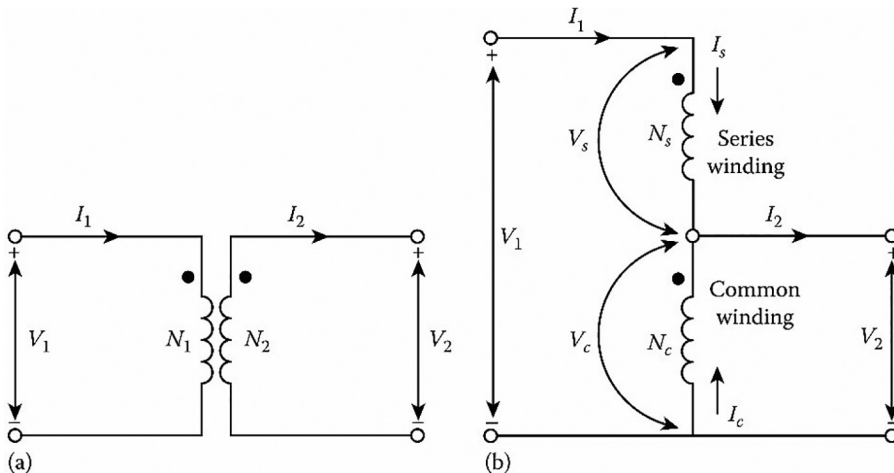


FIGURE 4.7 Schematic diagram of the ideal (step-down) transformer connected as (a) two-winding transformer and (b) autotransformer.

In a sense, an autotransformer is just a normal two-winding transformer connected in a special way. The only structural difference is that the series winding must have extra insulation. In a *variable autotransformer*, the tap is movable. Autotransformers are increasingly used to interconnect two HV transmission lines operating at different voltages. An autotransformer has two separate sets of ratios, namely, circuit ratios and winding ratios. For circuit ratios, consider the equivalent circuit of an ideal autotransformer (neglecting losses) shown in Figure 4.7b. Viewed from the terminals, the voltage and current ratios can be expressed as

$$\begin{aligned} a &= \frac{V_1}{V_2} = \frac{N_1}{N_2} \\ &= \frac{N_c + N_s}{N_c} = \frac{N_1}{N_2} \end{aligned} \quad (4.105a)$$

Since

$$\begin{aligned} I_1 &= \frac{I_2}{a} = \frac{N_2}{N_1} I_2 \\ a &= \frac{I_2}{I_1} = \frac{N_c + N_s}{N_c} \end{aligned} \quad (4.105b)$$

and

$$a = \frac{I_2}{I_1} \quad (4.106)$$

From Equation 4.105b, it can be observed that the ratio a is always larger than 1.

For winding ratios, consider the voltages and currents of the series and common windings, as shown in Figure 4.7b. Therefore, the voltage and current ratios can be expressed as

$$\frac{V_s}{V_c} = \frac{N_s}{N_c} \quad (4.107)$$

and

$$\begin{aligned} \frac{I_c}{I_s} &= \frac{I_2 - I_1}{I_1} \\ &= \frac{I_2}{I_1} - 1 \end{aligned} \quad (4.108)$$

From Equation 4.105b,

$$\frac{N_s}{N_c} = a - 1 \quad (4.109)$$

Therefore, substituting Equation 4.109 into Equation 4.107 yields

$$\frac{V_s}{V_c} = a - 1 \quad (4.110)$$

Similarly, substituting Equations 4.106 and 4.109 into Equation 4.108 simultaneously yields

$$\frac{I_c}{I_s} = a - 1 \quad (4.111)$$

For an ideal autotransformer, the volt-ampere ratings of circuits and windings can be expressed, respectively, as

$$S_{\text{circuits}} = V_1 I_1 = V_2 I_2 \quad (4.112)$$

and

$$S_{\text{windings}} = V_s I_s = V_c I_c \quad (4.113)$$

The advantages of autotransformers are lower leakage reactances, lower losses, smaller exciting currents, and less cost than two-winding transformers when the voltage ratio does not vary too greatly from 1 to 1. For example, if the same core and coils are used as a two-winding transformer and as an autotransformer, the ratio of the capacity as an autotransformer to the capacity as a two-winding transformer can be expressed as

$$\frac{\text{Capacity as autotransformer}}{\text{Capacity as two-winding transformer}} = \frac{V_1 I_1}{V_s I_s} = \frac{V_1 I_1}{(V_1 - V_2) I_1} = \frac{a}{a - 1} \quad (4.114)$$

Therefore, the maximum advantage is obtained with a relatively small difference between the voltages on the two sides (e.g., 161/138 kV, 500/700 kV, and 500/345 kV). Therefore, a large saving in size, weight, and cost can be achieved over a two-winding-per-phase transformer. The disadvantages of an autotransformer are that there is no electrical isolation between the primary and secondary circuits and there is a greater short-circuit current than the one for the two-winding transformer.

Three-phase autotransformer banks generally have wye-connected main windings, the neutral of which is normally connected solidly to the earth. In addition, it is a common practice to include a third winding connected in delta, called the tertiary winding.

An autotransformer is never used as a distribution transformer because the lack of isolation can cause dangerously high voltages in a customer's location if the neutral opens. Autotransformers are generally used for transforming one transmission voltage to another when the ratio is 2:1 or less. They are used in a transmission substation to transform from one HV to another HV or from a transmission voltage to a substation voltage. They are normally connected in wye with the neutral solidly grounded, having a delta-connected tertiary for harmonic suppression.

The tertiary is also used to provide a supply of distribution voltage at the station. Autotransformers are better than two-winding transformers of the same MVA rating in terms of lower cost, smaller size and less weight, better regulation, and cooling requirements. Their main disadvantage is that their impedances are low. Because of this, in the event of a fault, the fault currents are higher than the faults would be for the equivalent two-winding transformers.

4.5 DELTA-WYE AND WYE-DELTA TRANSFORMATIONS

The three-terminal circuits encountered so often in networks are the delta and wye⁷ configurations, as shown in Figure 4.8. In some problems, it is necessary to convert delta to wye or vice versa. If the impedances $\mathbf{Z}_{ab}$, $\mathbf{Z}_{bc}$, and $\mathbf{Z}_{ca}$ are connected in delta, the equivalent wye impedances $\mathbf{Z}_a$, $\mathbf{Z}_b$, and $\mathbf{Z}_c$ are

$$\mathbf{Z}_a = \frac{\mathbf{Z}_{ab} \mathbf{Z}_{ca}}{\mathbf{Z}_{ab} + \mathbf{Z}_{bc} + \mathbf{Z}_{ca}} \quad (4.115)$$

$$\mathbf{Z}_b = \frac{\mathbf{Z}_{ab} \mathbf{Z}_{bc}}{\mathbf{Z}_{ab} + \mathbf{Z}_{bc} + \mathbf{Z}_{ca}} \quad (4.116)$$

$$\mathbf{Z}_c = \frac{\mathbf{Z}_{bc} \mathbf{Z}_{ca}}{\mathbf{Z}_{ab} + \mathbf{Z}_{bc} + \mathbf{Z}_{ca}} \quad (4.117)$$

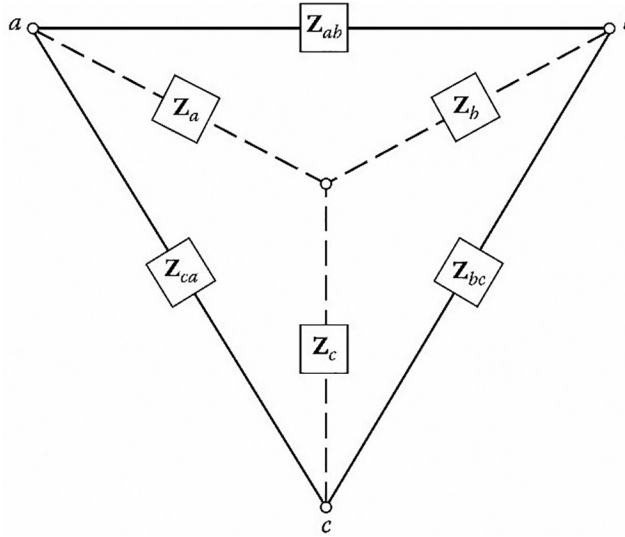


FIGURE 4.8 Delta-to-wye or wye-to-delta transformations.

If $Z_{ab} = Z_{bc} = Z_{ca} = Z$,

$$Z_a = Z_b = Z_c = \frac{Z}{3} \quad (4.118)$$

On the other hand, if the impedances Z_a , Z_b , and Z_c are connected in wye, the equivalent delta impedances Z_{ab} , Z_{bc} , and Z_{ca} are

$$Z_{ab} = Z_a + Z_b + \frac{Z_a Z_b}{Z_c} \quad (4.119)$$

$$Z_{bc} = Z_b + Z_c + \frac{Z_b Z_c}{Z_a} \quad (4.120)$$

$$Z_{ca} = Z_c + Z_a + \frac{Z_c Z_a}{Z_b} \quad (4.121)$$

If $Z_a = Z_b = Z_c = Z$,

$$Z_{ab} = Z_{bc} = Z_{ca} = 3Z \quad (4.122)$$

4.6 TRANSMISSION-LINE CONSTANTS

For the purpose of system analysis, a given transmission line can be represented by its resistance, inductance or inductive reactance, capacitance or capacitive reactance, and leakage resistance (which is usually negligible).

4.7 RESISTANCE

The DC resistance of a conductor is

$$R_{dc} = \frac{\rho l}{A} \Omega \quad (4.123)$$

where

ρ is the conductor resistivity

l is the conductor length

A is the conductor cross-sectional area

In practice, several different sets of units are used in the calculation of the resistance. For example, in the International System of Units (SI units), l is in meters, A is in square meters, and ρ is in ohm-meters. However, in power systems in the United States, ρ is in ohm-circular-mils per foot, l is in feet, and A is in circular mils.

The resistance of a conductor at any temperature may be determined by

$$\frac{R_2}{R_1} = \frac{T_0 + t_2}{T_0 + t_1} \quad (4.124)$$

where

R_1 is the conductor resistance at temperature t_1

R_2 is the conductor resistance at temperature t_2

t_1, t_2 is the conductor temperature in degrees Celsius

T_0 is the constant varying with conductor material

$$\begin{aligned} T_0 &= 234.5 \text{ for annealed copper} \\ &= 241 \text{ for hard-drawn copper} \\ &= 228 \text{ for hard-drawn aluminum} \end{aligned}$$

The phenomenon by which AC tends to flow in the outer layer of a conductor is called *skin effect*. Skin effect is a function of conductor size, frequency, and the relative resistance of the conductor material.

The tables given in Appendix A provide the DC and AC resistance values for various conductors. The resistances to be used in the positive- and negative-sequence networks are the AC resistances of the conductors.

4.8 INDUCTANCE AND INDUCTIVE REACTANCE

4.8.1 SINGLE-PHASE OVERHEAD LINES

Figure 4.9 shows a single-phase OH line. Assume that a current flows out in conductor a and returns in conductor b . These currents cause magnetic field lines that link between the conductors. A change in current causes a change in flux, which in turn results in an induced voltage in the circuit. In an AC circuit, this induced voltage is called the IX drop. In going around the loop, if R is the resistance of each conductor, the total loss in voltage due to resistance is $2IR$. Therefore, the voltage drop in the single-phase line due to loop impedance at 60 Hz is

$$VD = 2l \left(R + j0.2794 \log_{10} \frac{D_m}{D_s} \right) I \quad (4.125)$$

where

VD is the voltage drop due to line impedance in volts

l is the line length in miles

R is the resistance of each conductor in ohms per mile

D_m is the equivalent or geometric mean distance (GMD) between conductor centers in inches

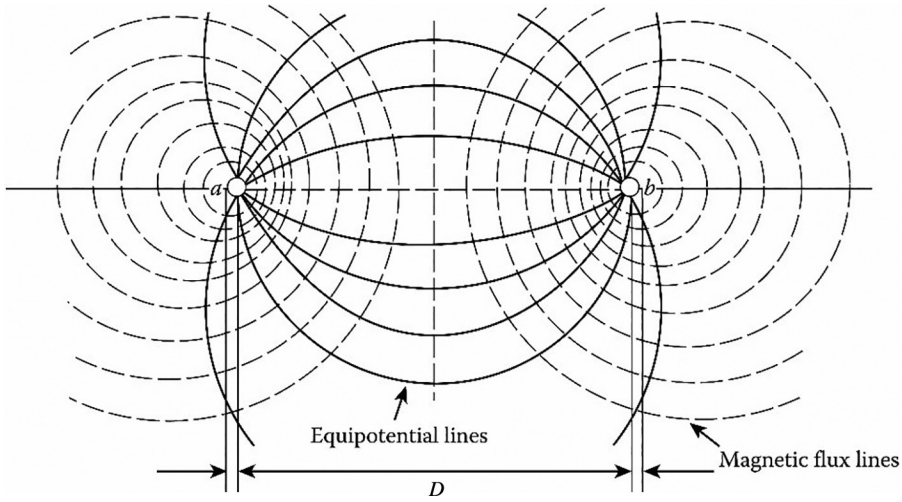


FIGURE 4.9 Magnetic field of a single-phase line.

D_s is the geometric mean radius (GMR) or self-GMD of one conductor in inches, $=0.7788r$ for the cylindrical conductor

r is the radius of the cylindrical conductor in inches (see Figure 4.9)

I is the phase current in amperes

Therefore, the inductance of the conductor is expressed as

$$L = 2 \times 10^{-7} \ln \frac{D_m}{D_s} \text{ H/m} \quad (4.126)$$

or

$$L = 0.7411 \log_{10} \frac{D_m}{D_s} \text{ mH/mi} \quad (4.127)$$

With the inductance known, the inductive reactance⁸ can be found as

$$X_L = 2\pi f L = 2.02 \times 10^{-3} f \ln \frac{D_m}{D_s} \quad (4.128)$$

or

$$X_L = 4.657 \times 10^{-3} f \log_{10} \frac{D_m}{D_s} \quad (4.129)$$

or, at 60 Hz,

$$X_L = 0.2794 \log_{10} \frac{D_m}{D_s} \text{ } \Omega/\text{mi} \quad (4.130)$$

$$X_L = 0.1213 \ln \frac{D_m}{D_s} \text{ } \Omega/\text{mi} \quad (4.131)$$

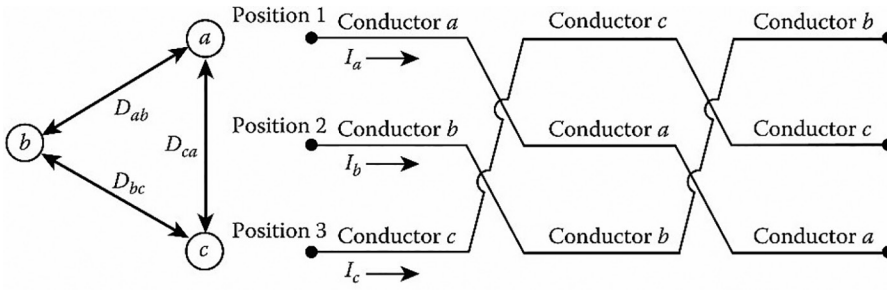


FIGURE 4.10 A complete transposition cycle of a three-phase line.

By using the GMR of a conductor, D_s , the calculation of inductance and inductive reactance can be done easily. Tables give the GMR of various conductors readily.

4.8.2 THREE-PHASE OVERHEAD LINES

In general, the spacings D_{ab} , D_{bc} , and D_{ca} between the conductors of three-phase transmission lines are not equal. For any given conductor configuration, the average values of inductance and capacitance can be found by representing the system by one with equivalent equilateral spacing. The equivalent spacing is calculated as

$$D_{eq} \triangleq D_m = (D_{ab} \times D_{bc} \times D_{ca})^{1/3} \quad (4.132)$$

In practice, the conductors of a transmission line are transposed, as shown in Figure 4.10. The transposition operation, that is, exchanging the conductor positions, is usually carried out at switching stations.

Therefore, the average inductance per phase is

$$L_a = 2 \times 10^{-7} \ln \frac{D_{eq}}{D_s} \text{ H/m} \quad (4.133)$$

or

$$L_a = 0.7411 \log_{10} \frac{D_{eq}}{D_s} \text{ mH/mi} \quad (4.134)$$

and the inductive reactance is

$$X_L = 0.1213 \ln \frac{D_{eq}}{D_s} \Omega/\text{mi} \quad (4.135)$$

$$X_L = 0.2794 \log_{10} \frac{D_{eq}}{D_s} \Omega/\text{mi} \quad (4.136)$$

4.9 CAPACITANCE AND CAPACITIVE REACTANCE

4.9.1 SINGLE-PHASE OVERHEAD LINES

Figure 4.11 shows a single-phase line with two identical parallel conductors a and b of radius r separated by a distance D , center to center, and with a potential difference of V_{ab} in volts. Let conductors

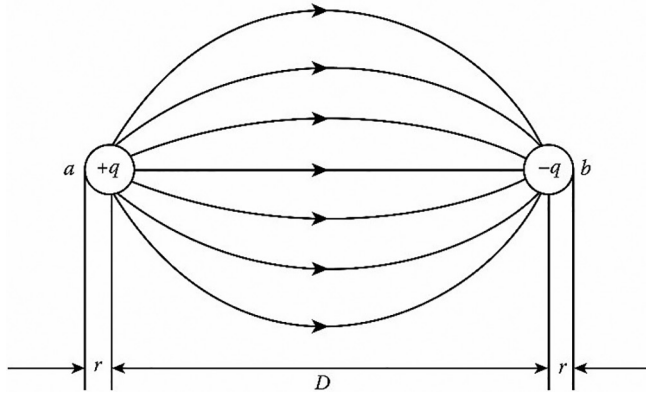


FIGURE 4.11 Capacitance of a single-phase line.

a and b carry charges of $+q_a$ and $-q_b$ in farads per meter, respectively. The capacitance between conductors can be found as

$$\begin{aligned}
 C_{ab} &= \frac{q_a}{V_{ab}} \\
 &= \frac{2\pi\epsilon}{\ln\left(\frac{D^2}{r_a \times r_b}\right)} \text{ F/m}
 \end{aligned} \tag{4.137}$$

If $r_a = r_b = r$,

$$C_{ab} = \frac{2\pi\epsilon}{2\ln\left(\frac{D}{r}\right)} \text{ F/m} \tag{4.138}$$

Since

$$\epsilon = \epsilon_0 \times \epsilon_r$$

where

$$\epsilon_0 = \frac{1}{36\pi \times 10^9} = 8.85 \times 10^{-2} \text{ F/m}$$

and

$$\epsilon_r \cong 1 \text{ for air,}$$

Equation 4.138 becomes

$$C_{ab} = \frac{0.0388}{2\log_{10}\left(\frac{D}{r}\right)} \mu\text{F/mi} \tag{4.139}$$

or

$$C_{ab} = \frac{0.0894}{2 \ln \left(\frac{D}{r} \right)} \mu\text{F/mi} \quad (4.140)$$

or

$$C_{ab} = \frac{0.0241}{2 \log_{10} \left(\frac{D}{r} \right)} \mu\text{F/km} \quad (4.141)$$

Stevenson [3] explains that the capacitance to neutral or capacitance to ground for the two-wire line is twice the line-to-line capacitance or capacitance between conductors, as shown in Figures 4.12 and 4.13. Therefore, the line-to-neutral capacitance is

$$C_N = C_{aN} = C_{bN} = \frac{0.0388}{\log_{10} \left(\frac{D}{r} \right)} \mu\text{F/mi to neutral} \quad (4.142)$$

This can easily be verified since C_N must equal $2C_{ab}$ so that the capacitance between the conductors can be

$$\begin{aligned} C_{ab} &= \frac{C_N \times C_N}{C_N + C_N} \\ &= \frac{C_N}{2} \\ &= C_{ab} \text{ as before} \end{aligned} \quad (4.143)$$

With the capacitance known, the capacitive reactance between one conductor and neutral can be found as

$$X_c = \frac{1}{2\pi f C_n} \quad (4.144)$$

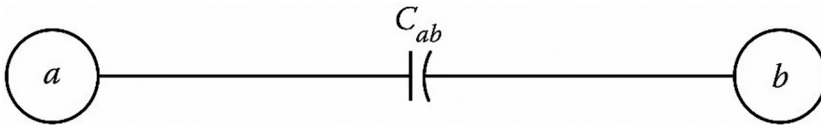


FIGURE 4.12 Line-to-line capacitance.

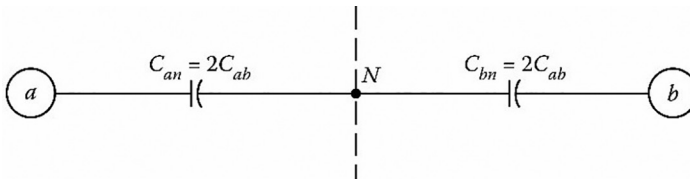


FIGURE 4.13 Line-to-neutral capacitance.

or, for 60 Hz,

$$X_c = 0.06836 \log_{10} \frac{D}{r} \text{ M}\Omega/\text{mi to neutral} \quad (4.145)$$

and the line-to-neutral susceptance is

$$b_c = \omega C_N$$

or

$$b_c = \frac{1}{X_c} \quad (4.146)$$

or

$$b_c = \frac{14.6272}{\log_{10} \left(\frac{D}{r} \right)} \text{ M}\Omega/\text{mi to neutral} \quad (4.147)$$

The charging current of the line is

$$I_c = j\omega C_{ab} V_{ab} \text{ A/mi} \quad (4.148)$$

4.9.2 THREE-PHASE OVERHEAD LINES

Figure 4.14 shows the cross section of a three-phase line with equilateral spacing D . The line-to-neutral capacitance can be found as

$$C_N = \frac{0.0388}{\log_{10} \left[\frac{D}{r} \right]} \mu\text{F}/\text{mi to neutral} \quad (4.149)$$

which is identical to Equation 4.142.

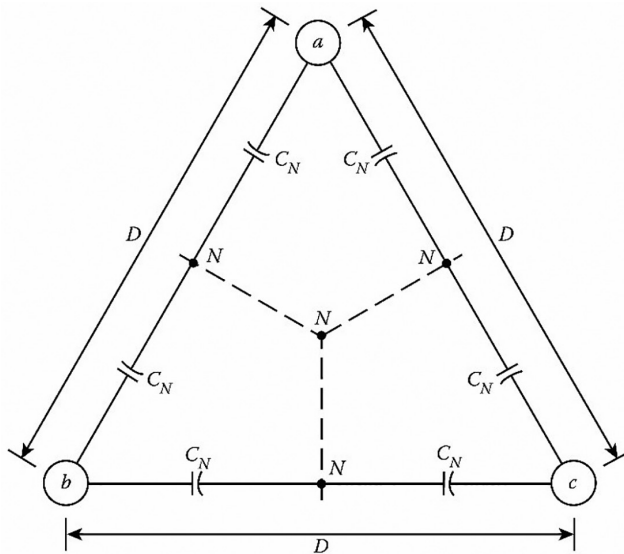


FIGURE 4.14 Three-phase line with equilateral spacing.

On the other hand, if the spacings between the conductors of the three-phase line are not equal, the line-to-neutral capacitance is

$$C_N = \frac{0.0388}{\log_{10} \left[\frac{D_{eq}}{r} \right]} \mu\text{F/mi to neutral} \quad (4.150)$$

where

$$D_{eq} \triangleq D_m = (D_{ab} \times D_{bc} \times D_{ca})^{1/3}$$

The charging current per phase is

$$I_c = j\omega C_N V_{an} \text{ A/mi} \quad (4.151)$$

4.10 TABLES OF LINE CONSTANTS

Tables provide the line constants directly without using equations for calculation. This concept was suggested by Wagner and Evans [5]. According to this concept, Equation 4.131 for inductive reactance at 60 Hz, that is,

$$X_L = 0.1213 \ln \frac{D_m}{D_s} \Omega/\text{mi}$$

can be broken down to

$$X_L = 0.1213 \ln \frac{1}{D_s} + 0.1213 \ln D_m \Omega/\text{mi} \quad (4.152)$$

where

D_s is the GMR, which can be found from the tables for a given conductor

D_m is the GMD between conductor centers

Therefore, Equation 4.152 can be rewritten as

$$X_L = X_a + X_d \Omega/\text{mi} \quad (4.153)$$

where

X_a is the inductive reactance at 1 ft spacing

$$= 0.1213 \ln \frac{1}{D_s} \Omega/\text{mi} \quad (4.154)$$

X_d is the inductive reactance spacing factor

$$= 0.1213 \ln D_m \Omega/\text{mi} \quad (4.155)$$

For a given frequency, the value of X_a depends only on the GMR, which is a function of the conductor type. But X_d depends only on the spacing D_m . If the spacing is greater than 1 ft, X_d has a positive value that is added to X_a . On the other hand, if the spacing is less than 1 ft, X_d has a negative value that is subtracted from X_a . Tables given in Appendix A give X_a and X_d directly.

Similarly, Equation 4.145 for shunt capacitive reactance at 60 Hz, that is,

$$X_c = 0.06836 \log_{10} \frac{D_m}{r} \text{ M}\Omega \times \text{mi}$$

can be split into

$$X_c = 0.06836 \log_{10} \frac{1}{r} + 0.06836 \log_{10} D_m \text{ M}\Omega \times \text{mi} \quad (4.156)$$

or

$$X_c = X'_a + X'_d \text{ M}\Omega \times \text{mi} \quad (4.157)$$

where

X'_a is the capacitive reactance at 1 ft spacing

$$= 0.06836 \log_{10} \frac{1}{r} \text{ M}\Omega \times \text{mi} \quad (4.158)$$

X'_d is the capacitive reactance spacing factor

$$= 0.06836 \log_{10} D_m \text{ M}\Omega \times \text{mi} \quad (4.159)$$

Tables given in Appendix A provide X'_a and X'_d directly. The term X'_d is added or subtracted from X'_a depending on the magnitude of D_m .

Example 4.3

A three-phase, 60 Hz, transposed line has conductors that are made up of 4/0, 7-strand copper. At the pole top, the distances between conductors, center to center, are given as 6.8, 5.5, and 4 ft. The diameter of the conductor copper used is 0.1739 in. Determine the inductive reactances per mile per phase:

- By using Equation 4.135
- By using tables

Solution

- First, calculate the equivalent spacing for the pole top,

$$\begin{aligned} D_{eq} &= D_m = (D_{ab} \times D_{bc} \times D_{ca})^{1/3} \\ &= (6.8 \times 5.5 \times 4)^{1/3} = 5.3086 \text{ ft} \end{aligned}$$

From Table A.1, $D_s = 0.01579$ ft for the conductor. Hence, its inductive reactance is

$$\begin{aligned} X_L &= 0.1213 \ln \frac{D_{eq}}{D_s} \\ &= 0.121 \ln \frac{5.3086 \text{ ft}}{0.01579 \text{ ft}} \\ &= 0.705688 \Omega/\text{mi} \cong 0.7057 \Omega/\text{mi} \end{aligned}$$

- b. From Table A.1, $X_a = 0.503 \text{ } \Omega/\text{mi}$, and from Table A.8, for $D_{eq} = 5.30086 \text{ ft}$, by linear interpolation, $X_d = 0.2026 \text{ fl/mi}$. Thus, the inductive reactance is

$$\begin{aligned} X_L &= X_a + X_d \\ &= 0.503 + 0.2026 \\ &= 0.1056 \end{aligned}$$

4.11 EQUIVALENT CIRCUITS FOR TRANSMISSION LINES

An OH line or a cable can be represented as a distributed constant circuit, as shown in Figure 4.15. The resistance, inductance, capacitance, and leakage conductance of a distributed constant circuit are distributed uniformly along the line length. In the figure, L represents the inductance of a line conductor to neutral per-unit length, r represents the AC resistance of a line conductor per-unit length, C is the capacitance of a line conductor to neutral per-unit length, and G is the leakage conductance per-unit length.

4.12 SHORT TRANSMISSION LINES (UP TO 50 MI OR 80 KM)

The modeling of a short transmission line is the most simplistic one. Its shunt capacitance is so small that it can be omitted entirely with little loss of accuracy. (Its shunt admittance is neglected since the current is the same throughout the line.) Thus, its capacitance and leakage resistance to the earth are usually neglected, as shown in Figure 4.16. Therefore, the transmission line can be treated as a simple, lumped, and constant impedance, that is,

$$\begin{aligned} Z &= R + jX_L \\ &= zl \\ &= rl + jxl \text{ } \Omega \end{aligned} \tag{4.160}$$

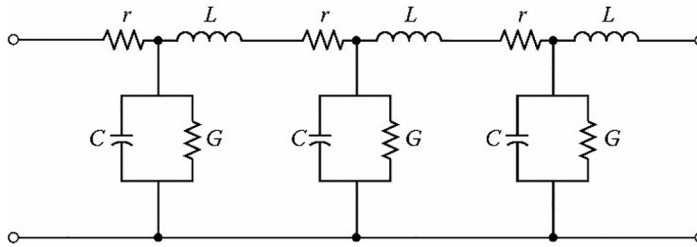


FIGURE 4.15 Distributed constant equivalent circuit of line.

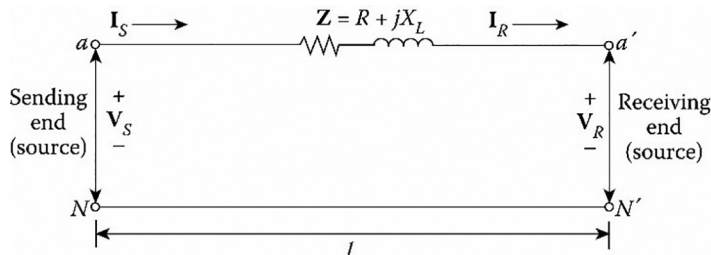


FIGURE 4.16 Equivalent circuit of the short transmission line.

where

Z is the total series impedance per phase in ohms

z is the series impedance of one conductor in ohms per-unit length

X_L is the total inductive reactance of one conductor in ohms

x is the inductive reactance of one conductor in ohms per-unit length

l is the length of line

The current entering the line at the sending end of the line is equal to the current leaving at the receiving end. Figures 4.17 and 4.18 show vector (or phasor) diagrams for a short transmission line connected to an inductive load and a capacitive load, respectively. It can be observed from the figures that

$$V_S = V_R + I_R Z \quad (4.161)$$

$$I_S = I_R = I \quad (4.162)$$

$$V_R = V_S - I_R Z \quad (4.163)$$

where

V_S is the sending-end phase (line-to-neutral) voltage

V_R is the receiving-end phase (line-to-neutral) voltage

I_S is the sending-end phase current

I_R is the receiving-end phase current

Z is the total series impedance per phase

Therefore, using V_R as the reference, Equation 4.161 can be written as

$$V_R = V_S + (I_S \cos \theta_S \pm j I_S \sin \theta_S)(R + jX) \quad (4.164)$$

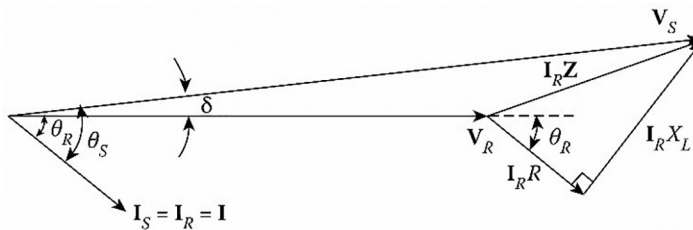


FIGURE 4.17 Phasor diagram of the short transmission line to inductive load.

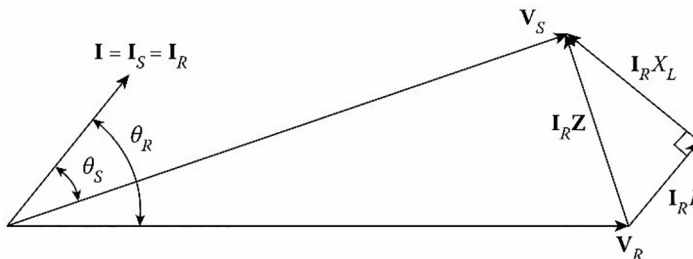


FIGURE 4.18 Phasor diagram of short transmission line connected to capacitive load.

where the plus or minus sign is determined by θ_R , the PF angle of the receiving end or load. If the PF is lagging, the minus sign is employed. On the other hand, if it is leading, the plus sign is used. However, if Equation 4.163 is used, it is convenient to use V_S as the reference. Therefore,

$$V_R = V_S - (I_S \cos \theta_S \pm j I_S \sin \theta_S)(R + jX) \quad (4.165)$$

where θ_S is the sending-end PF angle that determines, as before, whether the plus or minus sign will be used. Also, from Figure 4.17, using V_R as the reference vector,

$$V_S = \left[(V_R + IR \cos \theta_R + IX \sin \theta_R)^2 + (IX \cos \theta_R \pm IR \sin \theta_R)^2 \right]^{1/2} \quad (4.166)$$

and load angle

$$\delta = \theta_S - \theta_R \quad (4.167)$$

or

$$\delta = \arctan \left(\frac{IX \cos \theta_R \pm IR \sin \theta_R}{V_R + IR \cos \theta_R + IX \sin \theta_R} \right) \quad (4.168)$$

The generalized constants, or **ABCD** parameters, can be determined by inspection of Figure 4.16. Since

$$\begin{bmatrix} V_S \\ I_S \end{bmatrix} = \begin{bmatrix} A & B \\ C & D \end{bmatrix} \begin{bmatrix} V_R \\ I_R \end{bmatrix} \quad (4.169)$$

and $AD - BC = 1$, where

$$A = 1, B = Z, C = 0, D = 1 \quad (4.170)$$

then

$$\begin{bmatrix} V_S \\ I_S \end{bmatrix} = \begin{bmatrix} 1 & Z \\ 0 & 1 \end{bmatrix} \begin{bmatrix} V_R \\ I_R \end{bmatrix} \quad (4.171)$$

and

$$\begin{bmatrix} V_R \\ I_R \end{bmatrix} = \begin{bmatrix} 1 & Z \\ 0 & 1 \end{bmatrix}^{-1} \begin{bmatrix} V_S \\ I_S \end{bmatrix} = \begin{bmatrix} 1 & -Z \\ 0 & 1 \end{bmatrix} \begin{bmatrix} V_S \\ I_S \end{bmatrix}$$

The transmission efficiency of the short line can be expressed as

$$\begin{aligned} \eta &= \frac{\text{Output}}{\text{Input}} \\ &= \frac{\sqrt{3} V_R I \cos \theta_R}{\sqrt{3} V_S I \cos \theta_S} \\ &= \frac{V_R \cos \theta_R}{V_S \cos \theta_S} \end{aligned} \quad (4.172)$$

Equation 4.172 is applicable whether the line is single phase.

The transmission efficiency can also be expressed as

$$\eta = \frac{\text{Output}}{\text{Input} + \text{losses}}$$

For a single-phase line,

$$\eta = \frac{V_R I \cos \theta_R}{V_R I \cos \theta_R + 2I^2 R} \quad (4.173)$$

For a three-phase line,

$$\eta = \frac{\sqrt{3} V_R I \cos \theta_R}{\sqrt{3} V_S I \cos \theta_S + 3I^2 R} \quad (4.174)$$

4.12.1 STEADY-STATE POWER LIMIT

Assume that the impedance of a short transmission line is given as $Z = Z \angle \theta$. Therefore, the real power delivered, at a steady state, to the receiving end of the transmission line can be expressed as

$$P_R = \frac{V_S \times V_R}{Z} \cos(\theta - \delta) - \frac{V_R^2}{Z} \cos \theta \quad (4.175)$$

and similarly, the reactive power delivered can be expressed as

$$Q_R = \frac{V_S \times V_R}{Z} \sin(\theta - \delta) - \frac{V_R^2}{Z} \sin \theta \quad (4.176)$$

If V_S and V_R are the line-to-neutral voltages, Equations 4.175 and 4.176 give P_R and Q_R values per phase. Also, if the obtained P_R and Q_R values are multiplied by 3 or the line-to-line values of V_S and V_R are used, the equations give the three-phase real and reactive power delivered to a balanced load at the receiving end of the line.

If, in Equation 4.175, all variables are kept constant with the exception of δ , so that the real power delivered, P_R , is a function of δ only, P_R is maximum when $\delta = 0$, and the maximum powers⁹ obtainable at the receiving end for a given regulation can be expressed as

$$P_{R,\max} = \frac{V_R^2}{Z^2} \left(\frac{V_S}{V_R} Z - R \right) \quad (4.177)$$

where V_S and V_R are the phase (line-to-neutral) voltages whether the system is single phase or three phase.

The equation can also be expressed as

$$P_{R,\max} = \frac{V_S \times V_R}{Z} - \frac{V_R^2 \times \cos \theta}{Z} \quad (4.178)$$

If $V_S = V_R$,

$$P_{R,\max} = \frac{V_R^2}{Z} (1 - \cos \theta) \quad (4.179)$$

or

$$P_{R,\max} = \left(\frac{V_R}{Z} \right)^2 (Z - R) \quad (4.180)$$

and similarly, the corresponding reactive power delivered to the load is given by

$$Q_{R,\max} = -\frac{V_R^2}{Z} \sin \theta \quad (4.181)$$

As can be observed, both Equations 4.180 and 4.181 are independent of voltage V_S . The negative sign in Equation 4.181 points out that the load is a sink of *leading vars*,¹⁰ that is, going to the load or a source of *lagging vars* (i.e., *from the load to the supply*). The total three-phase power transmitted on the three-phase line is three times the power calculated using the aforementioned equations. If the voltages are given in volts, the power is expressed in watts or vars. Otherwise, if they are given in kilovolts, the power is expressed in megawatts or megavars.

In a similar manner, the real and reactive powers for the sending end of a transmission line can be expressed as

$$P_S = \frac{V_S^2}{Z} \cos \theta - \frac{V_S \times V_R}{Z} \cos(\theta + \delta) \quad (4.182)$$

and

$$Q_S = \frac{V_S^2}{Z} \sin \theta - \frac{V_S \times V_R}{Z} \sin(\theta + \delta) \quad (4.183)$$

If, in Equation 4.182, as before, all variables are kept constant with the exception of δ , so that the real power at the sending end, P_S , is a function of θ only, P_S is a maximum when

$$\theta + \delta = 180^\circ$$

Therefore, the maximum power at the sending end, the maximum input power, can be expressed as

$$P_{S,\max} = \frac{V_S^2}{Z} \cos \theta + \frac{V_S \times V_R}{Z} \quad (4.184)$$

or

$$P_{S,\max} = \frac{V_S^2 \times R}{Z^2} + \frac{V_S \times V_R}{Z} \quad (4.185)$$

However, if $V_S = V_R$,

$$P_{S,\max} = \left(\frac{V_S}{Z} \right)^2 (Z + R) \quad (4.186)$$

and similarly, the corresponding reactive power at the sending end, the maximum input vars, is given by

$$Q_S = \frac{V_S^2}{Z} \sin \theta \quad (4.187)$$

As can be observed, both Equations 4.186 and 4.187 are independent of voltage V_R , and Equation 4.187 has a positive sign this time.

4.12.2 PERCENT VOLTAGE REGULATION

The voltage regulation of the line is defined by the rise in voltage when full load is removed, that is,

$$\text{Percentage of voltage regulation} = \frac{|V_S| - |V_R|}{|V_R|} \times 100 \quad (4.188)$$

or

$$\text{Percentage of voltage regulation} = \frac{|V_{R,NL}| - |V_{R,FL}|}{|V_{R,FL}|} \times 100 \quad (4.189)$$

where

$|V_S|$ is the magnitude of the sending-end phase (line-to-neutral) voltage at no load

$|V_R|$ is the magnitude of the receiving-end phase (line-to-neutral) voltage at full load

$|V_{R,NL}|$ is the magnitude of the receiving-end voltage at no load

$|V_{R,FL}|$ is the magnitude of the receiving-end voltage at full load with constant $|V_S|$

Therefore, if the load is connected at the receiving end of the line,

$$|V_S| = |V_{R,NL}|$$

and

$$|V_R| = |V_{R,FL}|$$

An approximate expression for the percentage of voltage regulation is

$$\text{Percentage of voltage regulation} \cong I_R \frac{(R \cos \phi_R \pm X \sin \phi_R)}{V_R} \times 100 \quad (4.190)$$

Example 4.4

Calculate the percentage of voltage regulation for the values given in Example 4.8:

- Using Equation 4.188
- Using Equation 4.190

Solution

- Using Equation 4.188,

$$\begin{aligned} \text{Percentage of voltage regulation} &= \frac{|V_S| - |V_R|}{|V_R|} \times 100 \\ &= \frac{14,820 - 13,294.8}{13,294.8} \times 100 \\ &= 11.5 \end{aligned}$$

b. Using Equation 4.190,

$$\begin{aligned}
 \text{Percentage of voltage regulation} &\equiv I_R \times \frac{R \cos \theta_R \pm X \sin \theta_R}{V_R} \times 100 \\
 &= 266.1 \times \frac{2.48 \times 0.85 + 6.57 \times 0.527}{13,294.8} \times 100 \\
 &= 1.2
 \end{aligned}$$

4.12.3 REPRESENTATION OF MUTUAL IMPEDANCE OF SHORT LINES

Figure 4.19a shows a circuit of two lines, x and y , that have self-impedances of Z_{xx} and Z_{yy} and mutual impedance of Z_{xy} . Its equivalent circuit is shown in Figure 4.19b. Sometimes, it may be required to preserve the electrical identity of the two lines, as shown in Figure 4.20. The mutual impedance Z_{xy} can be in either line and transferred to the other by means of a transformer that has a 1:1 turns ratio. This technique is also applicable for three-phase lines.

Example 4.5

Assume that the mutual impedance between two parallel feeders is $0.09 + j0.3 \, \Omega/\text{mi}$ per phase. The self-impedances of the feeders are $0.604 \angle 50.4^\circ$ and $0.567 \angle 52.9^\circ \, \Omega/\text{mi}$ per phase, respectively. Represent the mutual impedance between the feeders as shown in Figure 4.19b.

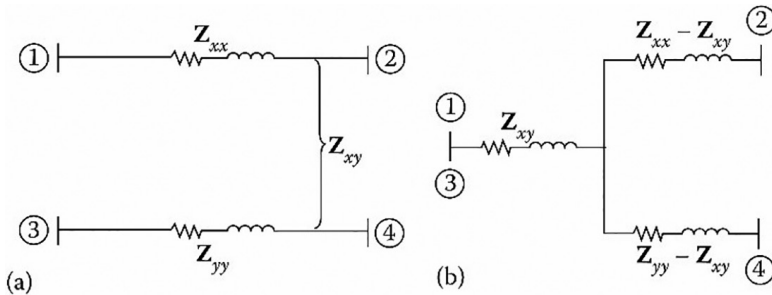


FIGURE 4.19 Representation of mutual impedance: (a) between two circuits and (b) its equivalent circuit.

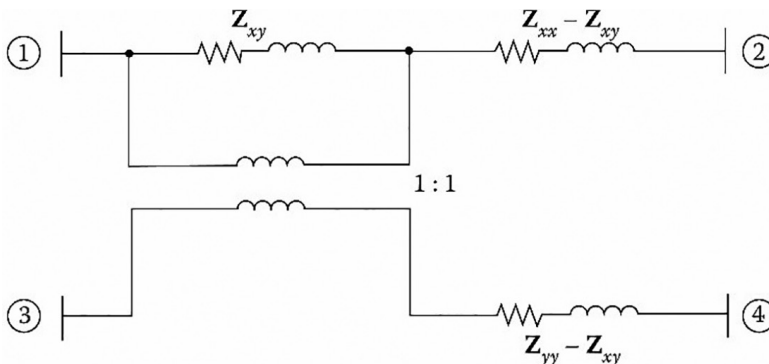


FIGURE 4.20 Representation of mutual impedance between two circuits by means of 1:1 transformer.

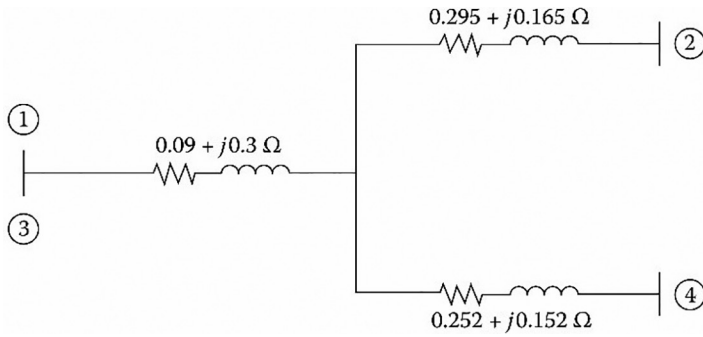


FIGURE 4.21 Resultant equivalent circuit.

Solution

$$Z_{xy} = 0.09 + j0.3 \, \Omega$$

$$Z_{xx} = 0.604 \angle 50.4^\circ = 0.385 + j0.465 \, \Omega$$

$$Z_{yy} = 0.567 \angle 52.9^\circ = 0.342 + j0.452 \, \Omega$$

Therefore,

$$Z_{xx} - Z_{yy} = 0.295 + j0.165 \, \Omega$$

$$Z_{yy} - Z_{xy} = 0.252 + j0.152 \, \Omega$$

Hence, the resulting equivalent circuit is shown in Figure 4.21.

4.13 MEDIUM-LENGTH TRANSMISSION LINES (UP TO 150 MI OR 240 KM)

As the line length and voltage increase, the use of the formulas developed for the short transmission lines gives inaccurate results. Thus, *the effect of the current leaking through the capacitance must be taken into account for a better approximation*. Thus, the shunt admittance is *lumped* at a few points along the line and represented by forming either a *T* or a *n* network, as shown in Figures 4.22 and 4.23.

In the figures,

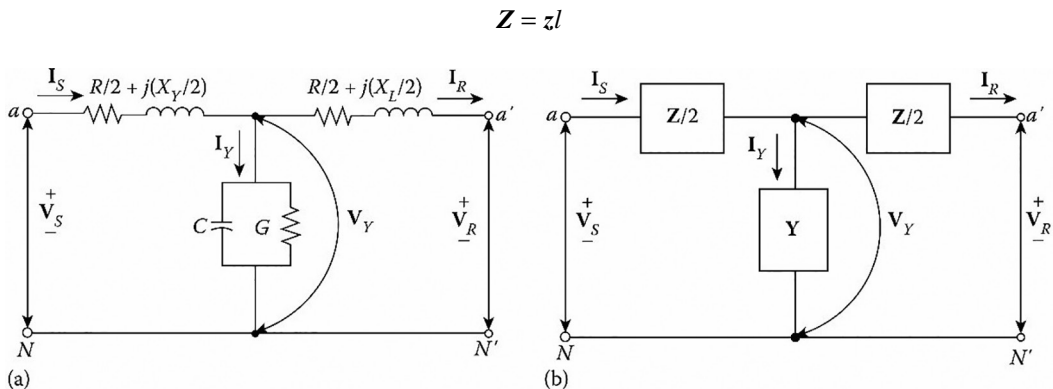


FIGURE 4.22 Nominal-*T* circuit: (a) actual circuit and (b) its equivalent lumped circuit.

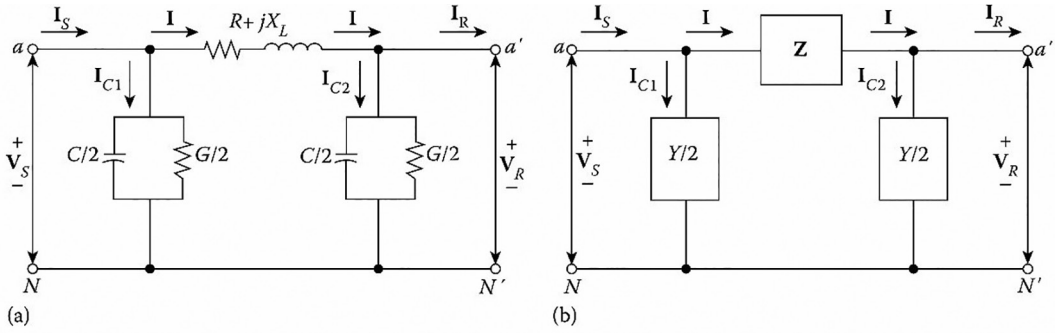


FIGURE 4.23 Nominal- π circuit: (a) actual circuit and (b) its equivalent lumped circuit.

For the T circuit shown in Figure 4.7,

$$\begin{aligned} V_S &= I_S \times \frac{1}{2}Z + I_R + \frac{1}{2}Z + V_R \\ &= \left[I_R + \left(V_R + I_R \times \frac{1}{2}Z \right) Y \right] \frac{1}{2}Z + V_R + I_R \frac{1}{2}Z \end{aligned}$$

or

$$V_S = \underbrace{\left(1 + \frac{1}{2}ZY \right)}_A V_R + \underbrace{\left(Z + \frac{1}{4}YZ^2 \right)}_B I_R \quad (4.191)$$

and

$$I_S = I_R + \left(V_R + I_R \times \frac{1}{2}Z \right) Y$$

or

$$I_S = \underbrace{Y}_{\mathbf{c}} \times V_R + \underbrace{\left(1 + \frac{1}{2}ZY \right)}_{\mathbf{d}} I_R \quad (4.192)$$

Alternatively, neglecting conductance so that

$$I_C = I_Y$$

and

$$V_C = V_Y$$

yields

$$I_C = V_C \times Y$$

$$V_C = V_R + I_R \times \frac{1}{2}Z$$

Hence,

$$\begin{aligned} V_S &= V_C I_S \times \frac{1}{2} Z \\ &= V_R + I_R \times \frac{1}{2} Z + \left[V_R Y + I_R \left(1 + \frac{1}{2} YZ \right) \right] \left(\frac{1}{2} Z \right) \end{aligned}$$

or

$$V_S = \underbrace{\left(1 + \frac{1}{2} YZ \right)}_A V_R + \underbrace{\left(Z + \frac{1}{4} YZ^2 \right)}_B I_R \quad (4.193)$$

Also,

$$\begin{aligned} I_S &= I_R + I_C \\ &= I_R + V_C \times Y \\ &= I_R + \left(V_R + I_R \times \frac{1}{2} Z \right) Y \end{aligned}$$

Again,

$$I_S = \underbrace{Y \times V_R}_C + \underbrace{\left(1 + \frac{1}{2} YZ \right)}_D I_R \quad (4.194)$$

Since

$$A = 1 + \frac{1}{2} YZ \quad (4.195)$$

$$B = Z + \frac{1}{4} YZ^2 \quad (4.196)$$

$$C = Y \quad (4.197)$$

$$D = 1 + \frac{1}{2} YZ \quad (4.198)$$

for a nominal- T circuit, the general circuit parameter matrix, or transfer matrix, becomes

$$\begin{bmatrix} A & B \\ C & D \end{bmatrix} = \begin{bmatrix} 1 + \frac{1}{2} YZ & Z + \frac{1}{4} YZ^2 \\ Y & 1 + \frac{1}{2} YZ \end{bmatrix}$$

Therefore,

$$\begin{bmatrix} V_S \\ I_S \end{bmatrix} = \begin{bmatrix} 1 + \frac{1}{2}YZ & Z + \frac{1}{4}YZ^2 \\ Y & 1 + \frac{1}{2}YZ \end{bmatrix} \begin{bmatrix} V_R \\ I_R \end{bmatrix} \quad (4.199)$$

and

$$\begin{bmatrix} V_R \\ I_R \end{bmatrix} = \begin{bmatrix} 1 + \frac{1}{2}YZ & Z + \frac{1}{4}YZ^2 \\ Y & 1 + \frac{1}{2}YZ \end{bmatrix}^{-1} \begin{bmatrix} V_S \\ I_S \end{bmatrix} \quad (4.200)$$

For the n circuit shown in Figure 4.23,

$$V_S = \left(V_R \times \frac{1}{2}Y + I_R \right) Z + V_R$$

or

$$V_S = \underbrace{\left(1 + \frac{1}{2}YZ \right)}_A V_R + \underbrace{Z}_{\frac{Z}{B}} \times I_R \quad (4.201)$$

and

$$I_S = \frac{1}{2}Y \times V_S + \frac{1}{2}Y \times V_R + I_R \quad (4.202)$$

By substituting Equation 4.199 into Equation 4.200,

$$I_S = \left[\left(1 + \frac{1}{2}YZ \right) V_R + Z I_R \right] \frac{1}{2}Y + \frac{1}{2}Y \times V_R + I_R$$

or

$$I_S = \underbrace{\left(Y + \frac{1}{4}Y^2Z \right)}_C V_R + \underbrace{\left(1 + \frac{1}{2}YZ \right)}_D I_R \quad (4.203)$$

Alternatively, neglecting conductance,

$$I = I_{C2} + I_R$$

where

$$I_{C2} = \frac{1}{2}Y \times V_R$$

yields

$$\mathbf{I} = \frac{1}{2} \mathbf{Y} \mathbf{V}_R + \mathbf{I}_R \quad (4.204)$$

also,

$$\mathbf{V}_S = \mathbf{V}_R + \mathbf{I} \mathbf{Z} \quad (4.205)$$

By substituting Equation 4.204 into Equation 4.205,

$$\mathbf{V}_S = \mathbf{V}_R + \left(\frac{1}{2} \mathbf{Y} \times \mathbf{V}_R + \mathbf{I}_R \right) \mathbf{Z}$$

or

$$\mathbf{V}_S = \mathbf{V}_R \underbrace{\left(1 + \frac{1}{2} \mathbf{Y} \mathbf{Z} \right)}_{\mathbf{A}} + \underbrace{\mathbf{Z}}_{\mathbf{B}} \times \mathbf{I}_R \quad (4.206)$$

and

$$\mathbf{I}_{C1} = \frac{1}{2} \mathbf{Y} \mathbf{V}_S \quad (4.207)$$

By substituting Equation 4.206 into Equation 4.207,

$$\mathbf{I}_{C1} = \frac{1}{2} \mathbf{Y} \times \left(1 + \frac{1}{2} \mathbf{Y} \mathbf{Z} \right) \mathbf{V}_R + \frac{1}{2} \mathbf{Y} \times \mathbf{Z} \mathbf{I}_R \quad (4.208)$$

and since

$$\mathbf{I}_S = \mathbf{I} + \mathbf{I}_{C1} \quad (4.209)$$

by substituting Equation 4.208 into Equation 4.209,

$$\mathbf{I}_S = \frac{1}{2} \mathbf{Y} \mathbf{V}_R + \mathbf{I}_R + \frac{1}{2} \mathbf{Y} \left(1 + \frac{1}{2} \mathbf{Y} \mathbf{Z} \right) \mathbf{V}_R + \frac{1}{2} \mathbf{Y} \mathbf{Z} \mathbf{I}_R$$

or

$$\mathbf{I}_S = \underbrace{\left(\mathbf{Y} + \frac{1}{4} \mathbf{Y}^2 \mathbf{Z} \right)}_{\mathbf{C}} \mathbf{V}_R + \underbrace{\left(1 + \frac{1}{2} \mathbf{Y} \mathbf{Z} \right)}_{\mathbf{D}} \mathbf{I}_R \quad (4.210)$$

Since

$$\mathbf{A} = 1 + \frac{1}{2} \mathbf{Y} \mathbf{Z} \quad (4.211)$$

$$\mathbf{B} = \mathbf{Z} \quad (4.212)$$

$$\mathbf{C} = \mathbf{Y} + \frac{1}{4} \mathbf{Y}^2 \mathbf{Z} \quad (4.213)$$

$$\mathbf{D} = 1 + \frac{1}{2}\mathbf{YZ} \quad (4.214)$$

for a nominal- π circuit, the general circuit parameter matrix becomes

$$\begin{bmatrix} \mathbf{A} & \mathbf{B} \\ \mathbf{C} & \mathbf{D} \end{bmatrix} = \begin{bmatrix} 1 + \frac{1}{2}\mathbf{YZ} & \mathbf{Z} \\ \mathbf{Y} + \frac{1}{4}\mathbf{Y}^2\mathbf{Z} & 1 + \frac{1}{2}\mathbf{YZ} \end{bmatrix} \quad (4.215)$$

Therefore,

$$\begin{bmatrix} \mathbf{V}_S \\ \mathbf{I}_S \end{bmatrix} = \begin{bmatrix} 1 + \frac{1}{2}\mathbf{YZ} & \mathbf{Z} \\ \mathbf{Y} + \frac{1}{4}\mathbf{Y}^2\mathbf{Z} & 1 + \frac{1}{2}\mathbf{YZ} \end{bmatrix} \begin{bmatrix} \mathbf{V}_R \\ \mathbf{I}_R \end{bmatrix} \quad (4.216)$$

and

$$\begin{bmatrix} \mathbf{V}_R \\ \mathbf{I}_R \end{bmatrix} = \begin{bmatrix} 1 + \frac{1}{2}\mathbf{YZ} & \mathbf{Z} \\ \mathbf{Y} + \frac{1}{4}\mathbf{Y}^2\mathbf{Z} & 1 + \frac{1}{2}\mathbf{YZ} \end{bmatrix}^{-1} \begin{bmatrix} \mathbf{V}_S \\ \mathbf{I}_S \end{bmatrix} \quad (4.217)$$

As can be proved easily by using a delta-wye transformation, *the nominal-T and nominal- π circuits are not equivalent to each other*. This result is to be expected since two different approximations are made to the actual circuit, neither of which is absolutely correct. More accurate results can be obtained by splitting the line into several segments, each given by its nominal-T or nominal- π circuits and cascading the resulting segments.

Here, the power loss in the line is given as

$$P_{\text{loss}} = I^2 R \quad (4.218)$$

which varies approximately as the square of the through-line current. The reactive powers absorbed and supplied by the line are given as

$$Q_L = Q_{\text{absorbed}} = I^2 X_L \quad (4.219)$$

and

$$Q_C = Q_{\text{supplied}} = V^2 b \quad (4.220)$$

respectively. The Q_L varies approximately as the square of the through-line current, whereas the Q_C varies approximately as the square of the mean line voltage. The result is that increasing transmission voltages decrease the reactive power absorbed by the line for heavy loads and increase the reactive power supplied by the line for light loads.

The percentage of voltage regulation for the medium-length transmission lines is given by Stevenson [3] as

$$\text{Percentage of voltage regulation} = \frac{\frac{|V_S|}{|A|} - |V_{R,FL}|}{|V_{R,FL}|} \times 100 \quad (4.221)$$

where

$|V_S|$ is the magnitude of sending-end phase (line-to-neutral) voltage

$|V_{R,FL}|$ is the magnitude of receiving-end phase (line-to-neutral) voltage at full load with constant $|V_S|$

$|A|$ is the magnitude of line constant A

Example 4.6

A three-phase 138 kV transmission line is connected to a 49 MW load at a 0.85 lagging PF. The line constants of the 52 mi long line are $Z=95\angle 78^\circ \Omega$ and $Y=0.001\angle 90^\circ \text{ S}$. Using *nominal-T circuit representation*, calculate the following:

- The **A**, **B**, **C**, and **D** constants of the line
- Sending-end voltage
- Sending-end current
- Sending-end PF
- Efficiency of transmission

Solution

$$V_{R(L-N)} = \frac{138 \text{ kV}}{\sqrt{3}} = 79,768.8 \text{ V}$$

Using the receiving-end voltage as the reference,

$$V_{R(L-N)} = 79,768.8\angle 0^\circ \text{ V}$$

The receiving-end current is

$$I_R = \frac{49 \times 10^6}{\sqrt{3} \times 138 \times 10^3 \times 0.85} = 241.17 \text{ A or } 241.17\angle -31.80^\circ \text{ A}$$

- The **A**, **B**, **C**, and **D** constants for the nominal-T circuit representation are

$$\begin{aligned} A &= 1 + \frac{1}{2} YZ \\ &= 1 + \frac{1}{2} (0.001\angle 90^\circ)(95\angle 78^\circ) \\ &= 0.9535 + j0.0099 \\ &= 0.9535\angle 0.6^\circ \\ B &= Z + \frac{1}{4} YZ^2 \\ &= 95\angle 78^\circ + \frac{1}{4} (0.001\angle 90^\circ)(95\angle 78^\circ)^2 \\ &= 18.83 + j90.86 \\ &= 92.79\angle 78.3^\circ \Omega \end{aligned}$$

$$C = Y = 0.001 \angle 90^\circ \text{ S}$$

$$\begin{aligned} D &= 1 + \frac{1}{2} YZ = A \\ &= 0.9536 \angle 0.6^\circ \end{aligned}$$

b.

$$\begin{bmatrix} V_{R(L-N)} \\ I_S \end{bmatrix} = \begin{bmatrix} 0.9536 \angle 0.6^\circ & 92.79 \angle 78.3^\circ \\ 0.001 \angle 90^\circ & 0.9536 \angle 0.6^\circ \end{bmatrix} \begin{bmatrix} 79,768 \angle 0^\circ \\ 241.46 \angle -31.8^\circ \end{bmatrix}$$

The sending-end voltage is

$$\begin{aligned} V_{R(L-N)} &= 0.9536 \angle 0.6^\circ \times 79,768 \angle 0^\circ + 92.79 \angle 78.3^\circ \times 241.46 \angle -31.8^\circ \\ &= 91,486 + j17,048.6 = 93,060.9 \angle 10.4^\circ \text{ V} \end{aligned}$$

or

$$V_{S(L-N)} = 160,995.4 \angle 40.4^\circ \text{ V}$$

c. The sending-end current is

$$\begin{aligned} I_S &= 0.001 \angle 90^\circ \times 79,768.8 \angle 0^\circ + 0.9536 \angle 0.6^\circ \times 241.46 \angle -31.8^\circ \\ &= 196.95 - j39.5 = 200.88 \angle -11.3^\circ \text{ A} \end{aligned}$$

d. The sending-end PF is

$$\begin{aligned} \theta_S &= 10.4^\circ + 11.3^\circ = 21.7^\circ \\ \cos \phi_S &= 0.929 \end{aligned}$$

e. The efficiency of transmission is

$$\begin{aligned} \eta &= \frac{\text{Output}}{\text{Input}} \\ &= \frac{\sqrt{3} V_R I_R \cos \phi_R}{\sqrt{3} V_S I_S \cos \phi_S} \times 100 \\ &= \frac{138 \times 10^3 \times 241.46 \times 0.85}{160,995.4 \times 200.88 \times 0.929} \times 100 \\ &= 94.27\% \end{aligned}$$

4.14 LONG TRANSMISSION LINES (ABOVE 150 MI OR 240 KM)

A more accurate analysis of the transmission lines requires that the parameters of the lines are not lumped, as before, but are distributed uniformly throughout the length of the line.

Figure 4.24 shows a uniform long line with an incremental section dx at a distance x from the receiving end, its series impedance is zdx , and its shunt admittance is ydx , where z and y are the impedance and admittance per-unit length, respectively.

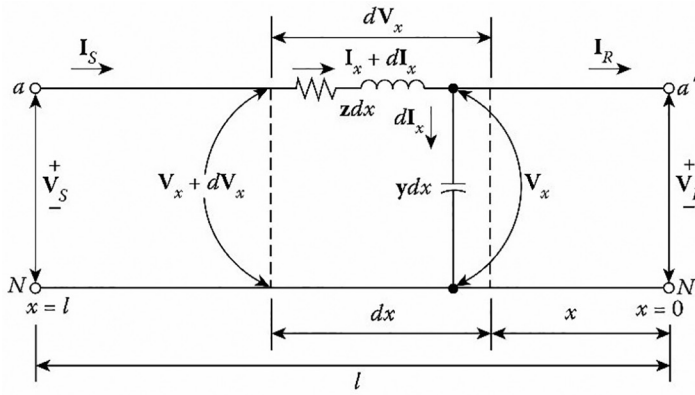


FIGURE 4.24 One phase and neutral connection of three-phase transmission line.

The voltage drop in the section is

$$\begin{aligned} dV_x &= (V_x + dV_x) - V_x = dV_x \\ &= (I_x + dI_x) z \, dx \end{aligned}$$

or

$$dV_x \cong I_x z \quad (4.222)$$

Similarly, the incremental charging current is

$$dI_x = V_x y \, dx \quad (4.223)$$

Therefore,

$$\frac{dV_x}{dx} = z I_x \quad (4.224)$$

and

$$\frac{dI_x}{dx} = y V_x \quad (4.225)$$

Differentiating Equations 4.224 and 4.225 with respect to x ,

$$\frac{d^2 V_x}{dx^2} = z \frac{dI_x}{dx} \quad (4.226)$$

and

$$\frac{d^2 I_x}{dx^2} = y \frac{dV_x}{dx} \quad (4.227)$$

Substituting the values of dI_x/dx and dV_x/dx from Equations 4.222 and 4.226 into Equations 4.224 and 4.227, respectively,

$$\frac{d^2 I_x}{dx^2} = yzV_x \quad (4.228)$$

and

$$\frac{d^2 V_x}{dx^2} = yzI_x \quad (4.229)$$

At $x=0$, $V_x = V_R$ and $I_x = I_R$. Therefore, the solution of the ordinary second-order differential Equations 4.228 and 4.229 gives

$$V_{(x)} = \underbrace{\left(\cosh \sqrt{yz} x \right)}_A V_R + \underbrace{\left(\sqrt{\frac{z}{y}} \sinh \sqrt{yz} x \right)}_B I_R \quad (4.230)$$

Similarly,

$$I_{(x)} = \underbrace{\left(\sinh \sqrt{yz} x \right)}_C V_R + \underbrace{\left(\cosh \sqrt{yz} x \right)}_D I_R \quad (4.231)$$

Equations 4.230 and 4.231 can be rewritten as

$$V_{(x)} = (\cosh \gamma x) V_R + (Z_c \sinh \gamma x) I_R \quad (4.232)$$

and

$$I_{(x)} = (Y_c \sinh \gamma x) V_R + (\cosh \gamma x) I_R \quad (4.233)$$

where

γ is the propagation constant per-unit length, $= \sqrt{yz}$

Z_c is the characteristic (or surge or natural) impedance of line per-unit length, $= \sqrt{z/y}$

Y_c is the characteristic (or surge or natural) admittance of line per-unit length, $= \sqrt{y/z}$

Further,

$$\gamma = a + j\beta \quad (4.234)$$

where

a is the attenuation constant (measuring decrement in voltage and current per-unit length in the direction of travel) in nepers per-unit length

β is the phase (or phase change) constant in radians per-unit length (i.e., change in phase angle between two voltages, or currents, at two points one per-unit length apart on infinite line)

When $x=l$, Equations 4.229 and 4.230 become

$$V_s = (\cosh \gamma l) V_R + (Z_c \sinh \gamma l) I_R \quad (4.235)$$

and

$$\mathbf{I}_S = (\mathbf{Y}_c \sinh \gamma l) \mathbf{V}_R + (\cosh \gamma l) \mathbf{I}_R \quad (4.236)$$

Equations 4.235 and 4.236 can be written in matrix form as

$$\begin{bmatrix} \mathbf{V}_S \\ \mathbf{I}_S \end{bmatrix} = \begin{bmatrix} \cosh \gamma l & \mathbf{Z}_c \sinh \gamma l \\ \mathbf{Y}_c \sinh \gamma l & \cosh \gamma l \end{bmatrix} \begin{bmatrix} \mathbf{V}_R \\ \mathbf{I}_R \end{bmatrix} \quad (4.237)$$

and

$$\begin{bmatrix} \mathbf{V}_R \\ \mathbf{I}_R \end{bmatrix} = \begin{bmatrix} \cosh \gamma l & \mathbf{Z}_c \sinh \gamma l \\ \mathbf{Y}_c \sinh \gamma l & \cosh \gamma l \end{bmatrix}^{-1} \begin{bmatrix} \mathbf{V}_S \\ \mathbf{I}_S \end{bmatrix} \quad (4.238)$$

or

$$\begin{bmatrix} \mathbf{V}_R \\ \mathbf{I}_R \end{bmatrix} = \begin{bmatrix} \cosh \gamma l & -\mathbf{Z}_c \sinh \gamma l \\ -\mathbf{Y}_c \sinh \gamma l & \cosh \gamma l \end{bmatrix} \begin{bmatrix} \mathbf{V}_S \\ \mathbf{I}_S \end{bmatrix} \quad (4.239)$$

Therefore,

$$\mathbf{V}_R = (\cosh \gamma l) \mathbf{V}_S - (\mathbf{Z}_c \sinh \gamma l) \mathbf{I}_S \quad (4.240)$$

and

$$\mathbf{I}_R = -(\mathbf{Y}_c \sinh \gamma l) \mathbf{V}_S + (\cosh \gamma l) \mathbf{I}_S \quad (4.241)$$

In terms of ABCD constants,

$$\begin{bmatrix} \mathbf{V}_S \\ \mathbf{I}_S \end{bmatrix} = \begin{bmatrix} \mathbf{A} & \mathbf{B} \\ \mathbf{C} & \mathbf{D} \end{bmatrix} \begin{bmatrix} \mathbf{V}_R \\ \mathbf{I}_R \end{bmatrix} = \begin{bmatrix} \mathbf{A} & \mathbf{B} \\ \mathbf{C} & \mathbf{A} \end{bmatrix} \begin{bmatrix} \mathbf{V}_R \\ \mathbf{I}_R \end{bmatrix} \quad (4.242)$$

and

$$\begin{bmatrix} \mathbf{V}_R \\ \mathbf{I}_S \end{bmatrix} = \begin{bmatrix} \mathbf{A} & -\mathbf{B} \\ -\mathbf{C} & \mathbf{D} \end{bmatrix} \begin{bmatrix} \mathbf{V}_S \\ \mathbf{I}_S \end{bmatrix} = \begin{bmatrix} \mathbf{A} & -\mathbf{B} \\ -\mathbf{C} & \mathbf{A} \end{bmatrix} \begin{bmatrix} \mathbf{V}_S \\ \mathbf{I}_S \end{bmatrix} \quad (4.243)$$

where

$$\mathbf{A} = \cosh \gamma l = \cosh \sqrt{\mathbf{Y}\mathbf{Z}} = \cosh \theta \quad (4.244)$$

$$\mathbf{B} = \mathbf{Z}_c \sinh \gamma l = \sqrt{\mathbf{Z}/\mathbf{Y}} \sinh \gamma l = \mathbf{Z}_c \sinh \theta \quad (4.245)$$

$$\mathbf{C} = \mathbf{Y}_c \sinh \gamma l = \sqrt{\mathbf{Y}/\mathbf{Z}} \sinh \gamma l = \mathbf{Y}_c \sinh \theta \quad (4.246)$$

$$\mathbf{D} = \mathbf{A} = \cosh \gamma l = \cosh \sqrt{\mathbf{Y}\mathbf{Z}} = \mathbf{Y}_c \sinh \theta \quad (4.247)$$

$$\theta = \sqrt{\mathbf{Y}\mathbf{Z}} \quad (4.248)$$

$$\sinh \gamma l = \frac{1}{2} \left(e^{r'l} - e^{-r'l} \right) \quad (4.249)$$

$$\cosh \gamma l = \frac{1}{2} \left(e^{r'l} + e^{-r'l} \right) \quad (4.250)$$

Also,

$$\sinh(\alpha + j\beta) = \frac{e^{\alpha} e^{j\beta} - e^{-\alpha} e^{-j\beta}}{2} = \frac{1}{2} [e^{\alpha} \angle \beta - e^{-\alpha} \angle -\beta]$$

and

$$\cosh(\alpha + j\beta) = \frac{e^{\alpha} e^{j\beta} + e^{-\alpha} e^{-j\beta}}{2} = \frac{1}{2} [e^{\alpha} \angle \beta + e^{-\alpha} \angle -\beta]$$

Note that β in these equations is the radian, and the radian is the unit found for β by computing the quadrature component of γ . Since 2π radians = 360° , one radian is 57.3° . Thus, the β is converted into degrees by multiplying its quantity by 57.3° . For a line length of l ,

$$\sinh(\alpha l + j\beta l) = \frac{e^{\alpha l} e^{j\beta l} - e^{-\alpha l} e^{-j\beta l}}{2} = \frac{1}{2} [e^{\alpha l} \angle \beta l - e^{-\alpha l} \angle -\beta l]$$

and

$$\cosh(\alpha l + j\beta l) = \frac{e^{\alpha l} e^{j\beta l} + e^{-\alpha l} e^{-j\beta l}}{2} = \frac{1}{2} [e^{\alpha l} \angle \beta l + e^{-\alpha l} \angle -\beta l]$$

Equations 4.235–4.248 can be used if tables of complex hyperbolic functions or pocket calculators with complex hyperbolic functions are available.

Alternatively, the following expansions can be used:

$$\sinh \gamma l = \sinh(\alpha l + j\beta l) = \sinh \alpha l \cos \beta l + j \cosh \alpha l \sin \beta l \quad (4.251)$$

$$\cosh \gamma l = \cosh(\alpha l + j\beta l) = \cosh \alpha l \cos \beta l + j \sinh \alpha l \sin \beta l \quad (4.252)$$

The correct mathematical unit for βl is the radian, and the radian is the unit found for βl by computing the quadrature component of γl .

Furthermore, substituting for γl and $\mathbf{Z}_c$ in terms of $\mathbf{Y}$ and $\mathbf{Z}$, that is, the total line shunt admittance per phase and the total line series impedance per phase, in Equation 4.242 gives

$$\mathbf{V}_S = (\cosh \sqrt{\mathbf{Y}\mathbf{Z}}) \mathbf{V}_R + \left(\sqrt{\frac{\mathbf{Z}}{\mathbf{Y}}} \sinh \sqrt{\mathbf{Y}\mathbf{Z}} \right) \mathbf{I}_R \quad (4.253)$$

and

$$\mathbf{I}_S = \left(\sqrt{\frac{\mathbf{Y}}{\mathbf{Z}}} \sinh \sqrt{\mathbf{Y}\mathbf{Z}} \right) \mathbf{V}_R + (\cosh \sqrt{\mathbf{Y}\mathbf{Z}}) \mathbf{I}_R \quad (4.254)$$

or, alternatively,

$$\mathbf{V}_S = (\cosh \sqrt{\mathbf{Y}\mathbf{Z}}) \mathbf{V}_R + \left(\frac{\sinh \sqrt{\mathbf{Y}\mathbf{Z}}}{\sqrt{\mathbf{Y}\mathbf{Z}}} \right) \mathbf{Z} \mathbf{I}_R \quad (4.255)$$

and

$$I_S = \left(\frac{\sinh \sqrt{YZ}}{\sqrt{YZ}} \right) YV_R + \left(\cosh \sqrt{YZ} \right) I_R \quad (4.256)$$

The factors in parentheses in Equations 4.253–4.256 can readily be found by using Woodruff's charts, which are not included here but can be found in L. F. Woodruff, *Electric Power Transmission* (Wiley, New York, 1952).

The **ABCD** parameters in terms of infinite series can be expressed as

$$A = 1 + \frac{YZ}{2} + \frac{Y^2 Z^2}{24} + \frac{Y^3 Z^3}{720} + \frac{Y^4 Z^4}{40,320} + \dots \quad (4.257)$$

$$B = Z \left(1 + \frac{YZ}{6} + \frac{Y^2 Z^2}{120} + \frac{Y^3 Z^3}{5,040} + \frac{Y^4 Z^4}{362,880} + \dots \right) \quad (4.258)$$

$$C = Y \left(1 + \frac{YZ}{6} + \frac{Y^2 Z^2}{120} + \frac{Y^3 Z^3}{5,040} + \frac{Y^4 Z^4}{362,880} + \dots \right) \quad (4.259)$$

where

Z = Total line series impedance per phase

$$= zl$$

$$= (r + jx_L)l\Omega$$

Y = Total line shunt admittance per phase

$$= yl$$

$$= (g + jb)lS$$

In practice, usually not more than three terms are necessary in Equations 4.257–4.259. Weedy [6] suggests the following approximate values for the **ABCD** constants if the OH transmission line is <500 km in length:

$$A = 1 + \frac{1}{2}YZ \quad (4.260)$$

$$B = Z \left(1 + \frac{1}{6}YZ \right) \quad (4.261)$$

$$C = Y \left(1 + \frac{1}{6}YZ \right) \quad (4.262)$$

However, the error involved may be too large to be ignored for certain applications.

The percentage of voltage regulation for the long-length transmission lines is given by Stevenson [3] as

$$\text{Percentage of voltage regulation} = \frac{\frac{|V_S|}{|A|} - |V_{R,FL}|}{|V_{R,FL}|} \times 100 \quad (4.263)$$

where

$|V_S|$ is the magnitude of sending-end phase (line-to-neutral) voltage

$|V_{R,FL}|$ is the magnitude of receiving-end phase (line-to-neutral) voltage at full load with constant $|V_S|$

$|A|$ is the magnitude of line constant A

4.14.1 EQUIVALENT CIRCUIT OF LONG TRANSMISSION LINE

Using the values of the **ABCD** parameters obtained for a transmission line, it is possible to develop an exact π or an exact T , as shown in Figure 4.25.

For the equivalent- π circuit,

$$\begin{aligned} Z_\pi &= B = Z_C \sinh \theta \\ &= Z_C \sinh \gamma l \\ &= Z \left(\frac{\sinh \sqrt{YZ}}{\sqrt{YZ}} \right) \end{aligned} \quad (4.264)$$

and

$$\frac{Y_\pi}{2} = \frac{A-1}{B} = \frac{\cosh \theta - 1}{-Z_C \sinh \theta} \quad (4.265)$$

or

$$Y_\pi = \frac{2 \tanh \left(\frac{\gamma l}{2} \right)}{Z_C} \quad (4.266)$$

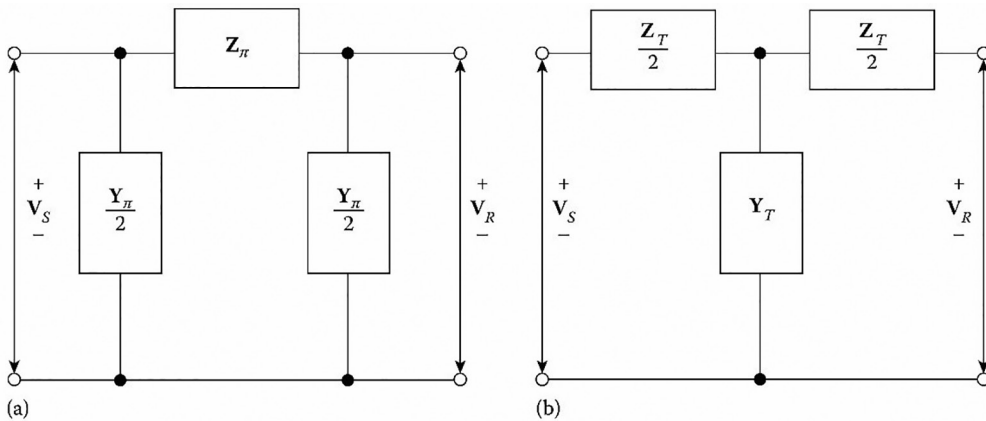


FIGURE 4.25 Equivalent- π and equivalent- T circuits for a long transmission line: (a) equivalent- π circuit and (b) equivalent- T circuit.

or

$$\frac{Y_{\pi}}{2} = \frac{Y}{2} \frac{2 \tanh\left(\frac{\gamma l}{2}\right)}{\frac{\sqrt{YZ}}{2}} \quad (4.267)$$

For the equivalent- T circuit,

$$\frac{Z_T}{2} = \frac{A-1}{C} = \frac{\cosh \theta - 1}{Y_c \sinh \theta} \quad (4.268)$$

or

$$Z_T = 2Z_c \tanh \frac{\gamma l}{2} \quad (4.269)$$

or

$$\frac{Z_T}{2} = \frac{Z}{2} \left(\frac{\tanh \frac{\sqrt{YZ}}{2}}{\frac{\sqrt{YZ}}{2}} \right) \quad (4.270)$$

and

$$Y_T = C = Y_c \sinh \theta \quad (4.271)$$

or

$$Y_T = \frac{\sinh \gamma l}{Z_c} \quad (4.272)$$

or

$$Y_T = Y \frac{\sinh \sqrt{YZ}}{\sqrt{YZ}} \quad (4.273)$$

Example 4.7

Find the equivalent- π and the equivalent- T circuits for the line described and compare them with the nominal- π and the nominal- T circuits.

Solution

Figures 4.26 and 4.27 show the equivalent- π and the nominal- n circuits, *equivalent- π circuit*,

$$Z_{\pi} = B = 148.54 \angle 79.44^{\circ} \Omega$$

$$I \frac{Y_{\pi}}{2} = \frac{A-1}{B} = \frac{0.9497 \angle 0.57^{\circ} - 1}{148.54 \angle 79.44^{\circ}} = 0.000345 \angle 89.89^{\circ} S$$

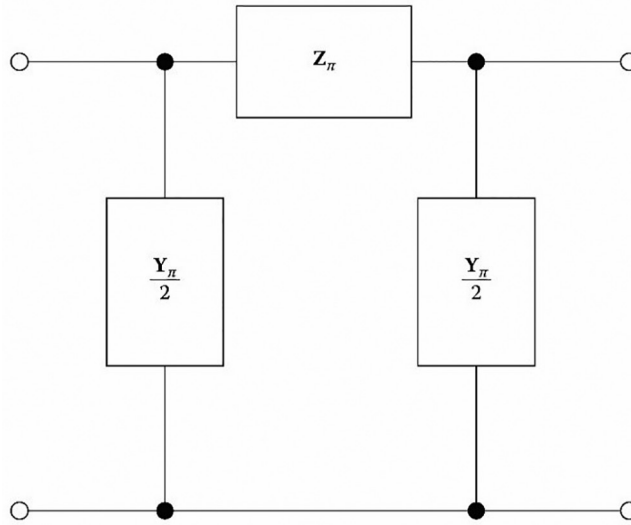


FIGURE 4.26 Equivalent- π circuit.

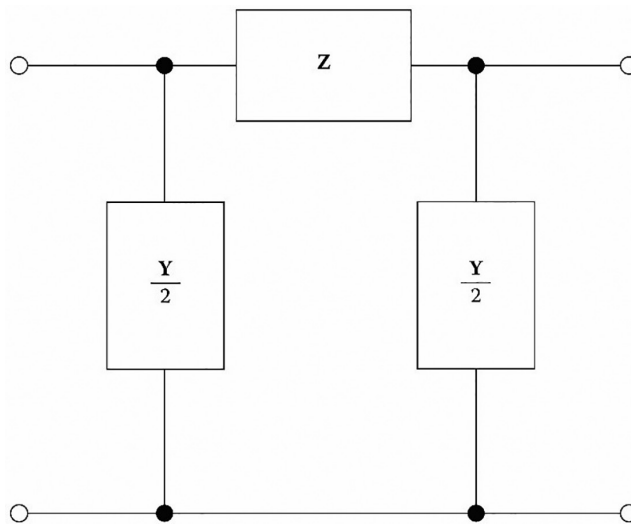


FIGURE 4.27 Nominal- π circuit.

For the nominal- π circuit,

$$Z = 150 \times 0.9977 \angle 79.27^\circ = 149.655 \angle 79.27^\circ \Omega$$

$$\frac{Y}{2} = \frac{150 (4.5239 \times 10^{-6} \angle 90^\circ)}{2} = 0.000339 \angle 90^\circ \text{ S}$$

Figure 4.28a and b shows the equivalent- T and nominal- T circuits, respectively. For the equivalent- T circuit,

$$\frac{Z_T}{2} = \frac{A-1}{C} = \frac{0.9497 \angle 0.57^\circ - 1}{0.00067 \angle 90.18^\circ} = 76.57 \angle 79.15^\circ \Omega$$

$$Y_T = C = 0.0006 \angle 90.18^\circ \text{ S}$$

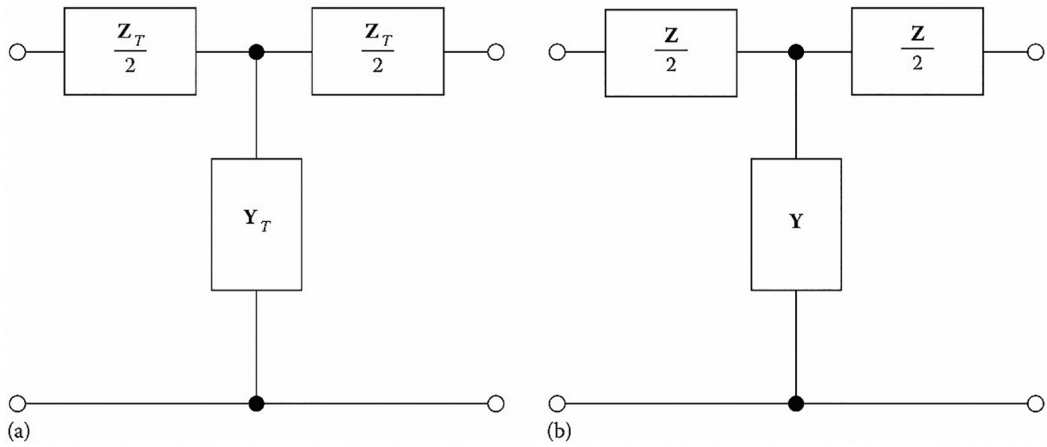


FIGURE 4.28 The T circuits: (a) equivalent T and (b) nominal T .

For the nominal- T circuit,

$$\frac{Z}{2} = \frac{149.655 \angle 79.27^\circ}{2} = 74.83 \angle 79.27^\circ \Omega$$

$$Y = 0.000678 \angle 90^\circ \text{S}$$

As can be observed from the results, the difference between the values for the equivalent and nominal circuits is very small for a 150 mi long transmission line.

4.14.2 INCIDENT AND REFLECTED VOLTAGES OF LONG TRANSMISSION LINE

Previously, the propagation constant has been given as

$$\gamma = \alpha + j\beta \text{ per-unit length} \quad (4.274)$$

and also

$$\cosh \gamma l = \frac{e^{\gamma l} - e^{-\gamma l}}{2} \quad (4.275)$$

$$\sinh \gamma l = \frac{e^{\gamma l} - e^{-\gamma l}}{2} \quad (4.276)$$

The sending-end voltage and current have been expressed as

$$V_S = (\cosh \gamma l) V_R + (Z_c \sinh \gamma l) I_R \quad (4.277)$$

and

$$I_S = (Y_c \sinh \gamma l) V_R + (\cosh \gamma l) I_R \quad (4.278)$$

By substituting Equations 4.274–4.276 into Equations 4.277 and 4.278,

$$V_S = \frac{1}{2}(V_R + I_R Z_c) e^{\alpha l} e^{j\beta l} + \frac{1}{2}(V_R - I_R Z_c) e^{-\alpha l} e^{-j\beta l} \quad (4.279)$$

and

$$\mathbf{I}_S = \frac{1}{2}(\mathbf{V}_R \mathbf{Y}_C + \mathbf{I}_R) e^{\alpha l} e^{j\beta l} - \frac{1}{2}(\mathbf{V}_R \mathbf{Y}_C - \mathbf{I}_R) e^{-\alpha l} e^{-j\beta l} \quad (4.280)$$

In Equation 4.279, the first and the second terms are called the *incident voltage* and the *reflected voltage*, respectively. They act like *traveling waves* as a function of the line length l . The incident voltage increases in magnitude and phase as the l distance from the receiving end increases and decreases in magnitude and phase as the distance from the sending end toward the receiving end decreases, whereas the reflected voltage decreases in magnitude and phase as the l distance from the receiving end toward the sending end increases.

Therefore, for any given line length l , the voltage is the sum of the corresponding incident and reflected voltages. Here, the term $e^{\alpha l}$ changes as a function of l , whereas $e^{j\beta l}$ always has a magnitude of 1 and causes a phase shift of β radians per-unit length of the line.

In Equation 4.279, when the two terms are 180° out of phase, a cancelation will occur. This happens when there is no load on the line, that is, when

$$\mathbf{I}_R = 0 \quad \text{and} \quad \alpha = 0$$

and when $\beta x = \pi/2$ radians, or one-quarter wavelengths.

The *wavelength* λ is defined as the distance l along a line between two points to develop a phase shift of 2π radians, or 360° , for the incident and reflected waves. If β is the phase shift in radians per mile, the wavelength in miles is

$$\lambda = \frac{2\pi}{\beta} \quad (4.281)$$

Since the propagation velocity is

$$v = \lambda f \text{ mi/s} \quad (4.282)$$

and is approximately equal to the speed of light, that is, 186,000 mi, at a frequency of 60 Hz, the wavelength is

$$\lambda = \frac{186,000 \text{ mi/s}}{60 \text{ Hz}} = 3,100 \text{ mi}$$

whereas at a frequency of 50 Hz, the wavelength is $\sim 6,000$ km. If a finite line is terminated by its characteristic impedance $\mathbf{Z}_c$ that impedance could be imagined to be replaced by an infinite line. In this case, there is no reflected wave of either voltage or current since

$$\mathbf{V}_R = \mathbf{I}_R \mathbf{Z}_c$$

in Equations 4.277 and 4.278, and the line is called an *infinite* (or *flat*) line.

Stevenson [3] gives the typical values of $\mathbf{Z}_c$ as 400 Ω for a single-circuit line and 200 Ω for two circuits in parallel. The phase angle of $\mathbf{Z}_c$ is usually between 0° and -15° [3].

Example 4.8

Using the data given in Example 4.13, determine the following:

- Attenuation constant and phase change constant per mile of the line
- Wavelength and velocity of propagation

- c. Incident and reflected voltages at the receiving end of the line
- d. Line voltage at the receiving end of the line
- e. Incident and reflected voltages at the sending end of the line
- f. Line voltage at the sending end

Solution

- a. Since the propagation constant of the line is

$$\gamma = \sqrt{yz} = 0.0002 + j0.0021$$

the attenuation constant is 0.0002 Np/mi, and the phase change constant is 0.0021 rad/mi.

- b. The wavelength of propagation is

$$\lambda = \frac{2\pi}{\beta} = \frac{2\pi}{0.0021} = 2,991.99 \text{ mi}$$

and the velocity of propagation is

$$v = \lambda f = 2,991 \times 60 = 179,519.58 \text{ mi/s}$$

- c. From Equation 4.279,

$$V_s = \frac{1}{2}(V_R + I_R Z_C) e^{\alpha l} e^{j\beta l} + \frac{1}{2}(V_R - I_R Z_C) e^{-\alpha l} e^{-j\beta l}$$

Since, at the receiving end, $l=0$,

$$V_s = \frac{1}{2}(V_R + I_R Z_C) + \frac{1}{2}(V_R - I_R Z_C)$$

Therefore, the incident and reflected voltage at the receiving end are

$$\begin{aligned} V_{R(\text{incident})} &= \frac{1}{2}(V_R + I_R Z_C) \\ &= \frac{1}{2}[79,674.34 \angle 0^\circ + (209.18 \angle -31.8^\circ)(469.62 \angle -5.37^\circ)] \\ &= 84,367.77 \angle -20.59^\circ \text{ V} \end{aligned}$$

and

$$\begin{aligned} V_{R(\text{reflected})} &= \frac{1}{2}(V_R - I_R Z_C) \\ &= \frac{1}{2}[79,674.34 \angle 0^\circ - (209.18 \angle -31.8^\circ)(469.62 \angle -5.37^\circ)] \\ &= 29,684.15 \angle -88.65^\circ \text{ V} \end{aligned}$$

- d. The line-to-neutral voltage at the receiving end is

$$V_{R(L-N)} = V_{R(\text{incident})} + V_{R(\text{reflected})} = 79,674 \angle 0^\circ \text{ V}$$

Therefore, the line voltage at the receiving end is

$$V_{R(L-L)} = \sqrt{3} V_{R(L-N)} = 138,000 \text{ V}$$

e. At the sending end,

$$\begin{aligned} V_{S(\text{incident})} &= \frac{1}{2}(V_R + I_R Z_C) e^{\alpha l} e^{j\beta l} \\ &= (84,367.77 \angle -20.59^\circ) e^{0.0301} \angle 18.35^\circ = 86,946 \angle -2.24^\circ \text{ V} \end{aligned}$$

and

$$\begin{aligned} V_{S(\text{reflected})} &= \frac{1}{2}(V_R - I_R Z_C) e^{-\alpha l} e^{-j\beta l} \\ &= (29,684.15 \angle 88.65^\circ) e^{-0.0301} \angle -18.35^\circ = 28,802.5 \angle 70.3^\circ \text{ V} \end{aligned}$$

f. The line-to-neutral voltage at the sending end is

$$\begin{aligned} V_{S(L-N)} &= V_{S(\text{incident})} + V_{S(\text{reflected})} \\ &= 86,946 \angle -2.24^\circ + 28,802.5 \angle 70.3^\circ = 99,458.1 \angle 13.8^\circ \text{ V} \end{aligned}$$

Therefore, the line voltage at the sending end is

$$V_{S(L-N)} = \sqrt{3} V_{S(L-N)} = 172,266.5 \text{ V}$$

4.14.3 SURGE IMPEDANCE LOADING OF TRANSMISSION LINE

In power systems, if the line *is lossless*,¹¹ the characteristic impedance Z_c of a line is sometimes called *surge impedance*. Therefore, for a loss-free line,

$$R = 0$$

and

$$Z_L = jX_L$$

Thus,

$$Z_c = \sqrt{\frac{X_L}{Y_C}} \cong \sqrt{\frac{L}{C}} \Omega \quad (4.283)$$

and its series resistance and shunt conductance are zero. It is a function of the line inductance and capacitance as shown and is independent of the line length.

The surge impedance loading (SIL) (or the *natural loading*) of a transmission line is defined as the power delivered by the line to a purely resistive load equal to its surge impedance. Therefore,

$$\text{SIL} = \frac{|kV_{R(L-L)}|^2}{Z_C^*} \text{ MW} \quad (4.284)$$

or

$$\text{SIL} \cong \frac{|kV_{R(L-L)}|^2}{\sqrt{\frac{L}{C}}} \text{ MW} \quad (4.285)$$

or

$$\text{SIL} = \sqrt{3} |V_{R(L-L)}| |I_L| \text{ W} \quad (4.286)$$

where

$$|I_L| = \frac{|V_{R(L-L)}|}{\sqrt{3} \times \sqrt{\frac{L}{C}}} \text{ A} \quad (4.287)$$

SIL is the surge impedance loading in megawatts or watts

$|kV_{R(L-L)}|$ is the magnitude of line-to-line receiving-end voltage in kilovolts

$|V_{R(L-L)}|$ is the magnitude of line-to-line receiving-end voltage in volts

Z_C is the surge impedance in ohms $= \sqrt{L/C}$

I_L is the line current at SIL in amperes

In practice, the allowable loading of a transmission line may be given as a fraction of its SIL. Thus, SIL is used as a means of comparing the load-carrying capabilities of lines.

However, the SIL in itself is not a measure of the maximum power that can be delivered over a line. For the maximum delivered power, the line length, the impedance of sending- and receiving-end apparatus, and all of the other factors affecting stability must be considered.

Since the characteristic impedance of underground cables is very low, the SIL (or *natural load*) is far larger than the rated load of the cable. Therefore, *a given cable acts as a source of lagging vars*.

The best way of increasing the SIL of a line is to increase its voltage level, since, as it can be seen from Equation 4.282, the SIL increases with its square. However, increasing the voltage level is expensive. Therefore, instead, the surge impedance of the line is reduced. This can be accomplished by adding capacitors or induction coils. There are four possible ways of changing the line capacitance or inductance, as shown in Figures 4.29 and 4.30.

For a lossless line, the characteristic impedance and the propagation constant can be expressed as

$$Z_C = \sqrt{\frac{L}{C}} \quad (4.288)$$

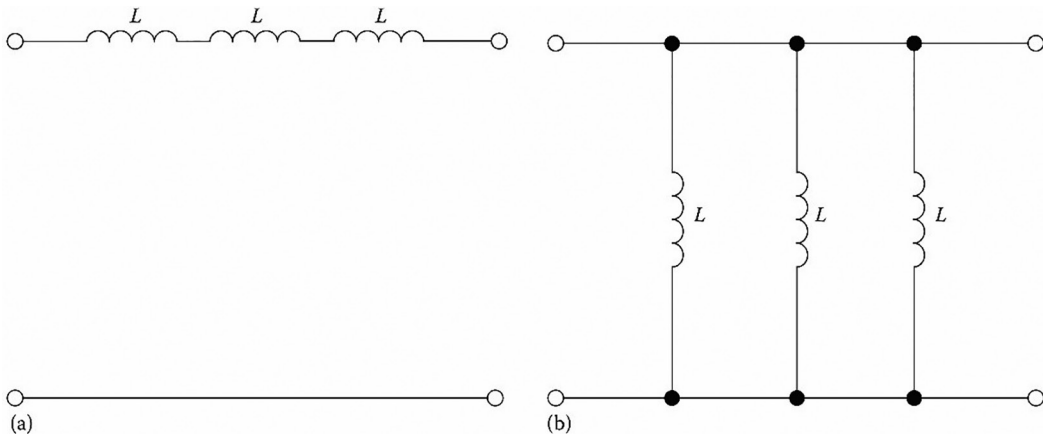


FIGURE 4.29 Transmission-line compensation by adding lump inductances in (a) series and (b) parallel (i.e., shunt).

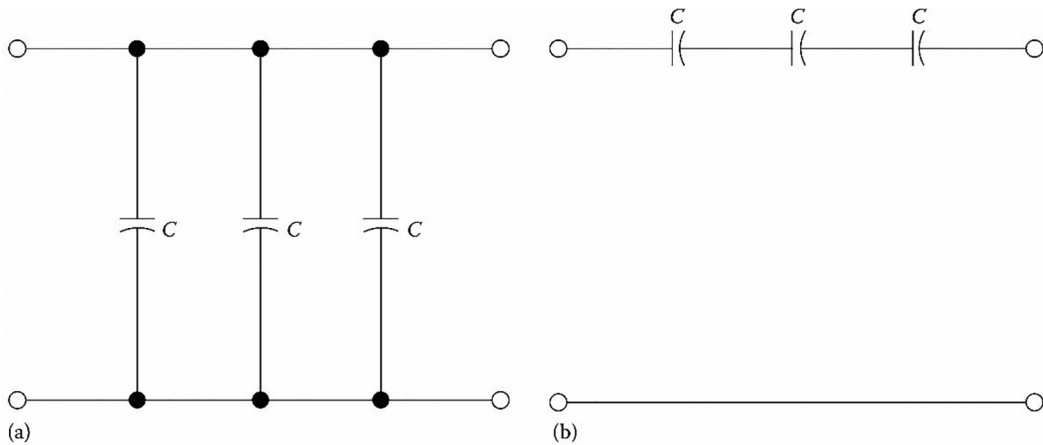


FIGURE 4.30 Transmission-line compensation by adding capacitances in (a) parallel (i.e., shunt) and (b) series.

and

$$\gamma = \sqrt{LC} \quad (4.289)$$

Therefore, the addition of lumped inductances in series will increase the line inductance, and thus, the characteristic impedance and the propagation constant will be increased, which is not desirable.

The addition of lumped inductances in parallel will decrease the line capacitance. Therefore, the propagation constant will be decreased, but the characteristic impedance will be increased, which again is not desirable.

The addition of capacitances in parallel will increase the line capacitance. Hence, the characteristic impedance will be decreased, but the propagation constant will be increased, which affects negatively the system stability. However, for *the short lines, this method can be used effectively*.

Finally, the addition of capacitances in series will decrease the line inductance. Therefore, the characteristic impedance and the propagation constant will be reduced, which is desirable. Thus, *the SC compensation of transmission lines is used to improve stability limits and voltage regulation, to provide a desired load division, and to maximize the load-carrying capability of the system*. However, having the full line current going through the capacitors connected in series causes harmful overvoltages on the capacitors during short circuits. Therefore, they introduce special problems for line protective relaying.¹² Under fault conditions, they introduce an impedance discontinuity (negative inductance) and subharmonic currents, and when the capacitor protective gap operates, they impress high-frequency currents and voltages on the system. All of these factors result in incorrect operation of the conventional relaying schemes. The series capacitance compensation of distribution lines has been attempted from time to time for many years. However, it is not widely used.

4.15 GENERAL CIRCUIT CONSTANTS

Figure 4.31 shows a general two-port, four-terminal network consisting of passive impedances connected in some fashion. From the general network theory,

$$V_S = \mathbf{A}V_R + \mathbf{B}I_R \quad (4.290)$$

and

$$I_S = \mathbf{C}V_R + \mathbf{D}I_R \quad (4.291)$$

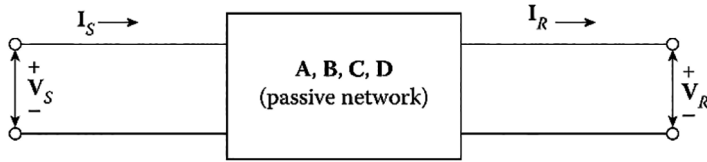


FIGURE 4.31 General two-port, four-terminal network.

Also,

$$V_R = DV_S - BI_S \quad (4.292)$$

and

$$I_R = -CV_S + AI_S \quad (4.293)$$

It is always true that the determinant of Equations 4.288 and 4.289 or 4.290 and 4.291 is always unity, that is,

$$AD - BC = 1 \quad (4.294)$$

In these equations, A , B , C , and D are constants for a given network and are called general circuit constants. Their values depend on the parameters of the circuit concerned and the particular representation chosen. In general, they are complex numbers. For a network that has the symmetry of the uniform transmission line,

$$A = D \quad (4.295)$$

4.15.1 DETERMINATION OF A , B , C , AND D CONSTANTS

The A , B , C , and D constants can be calculated directly by network reduction. For example, when $I_R = 0$, from Equation 4.132,

$$A = \frac{V_S}{V_R} \quad (4.296)$$

and from Equation 4.289,

$$C = \frac{I_S}{V_R} \quad (4.297)$$

Therefore, the A constant is the ratio of the sending- and receiving-end voltages, whereas the C constant is the ratio of sending-end current to receiving-end voltage when the receiving end is open-circuited. When $V_R = 0$, from Equation 4.288,

$$B = \frac{V_S}{I_R} \quad (4.398)$$

When $V_R = 0$, from Equation 4.289,

$$D = \frac{I_S}{I_R} \quad (4.399)$$

Therefore, the **B** constant is the ratio of the sending-end voltage to the receiving-end current when the receiving end is short-circuited, whereas the **D** constant is the ratio of the sending-end and receiving-end currents when the receiving end is short-circuited.

Alternatively, the **A**, **B**, **C**, and **D** generalized circuit constants can be calculated indirectly from a knowledge of the system impedance parameters as shown in the previous sections. Table 4.3 gives general circuit constants for different network types. Table 4.4 gives network conversion formulas to convert a given parameter set into another one.

As can be observed in Equations 4.132 and 4.133, the dimensions of the **A** and **D** constants are numeric. The dimension of the **B** constant is impedance in ohms, whereas the dimension of the **C** constant is admittance in Siemens.

4.15.2 **A, B, C, AND D** CONSTANTS OF TRANSFORMER

Figure 4.32 shows the equivalent circuit of a transformer *at no load*. Neglecting its series impedance,

$$\begin{bmatrix} V_S \\ I_S \end{bmatrix} = \begin{bmatrix} A & B \\ C & D \end{bmatrix} \begin{bmatrix} V_R \\ I_R \end{bmatrix} \quad (4.300)$$

where the transfer matrix is

$$\begin{bmatrix} A & B \\ C & D \end{bmatrix} = \begin{bmatrix} 1 & 0 \\ Y_T & 1 \end{bmatrix} \quad (4.301)$$

since

$$V_S = V_R$$

and

$$I_S = Y_T V_R + I_R \quad (4.302)$$

where Y_T is the magnetizing admittance of the transformer.

Figure 4.33 shows the equivalent circuit of a transformer *at full load* that has a transfer matrix of

$$\begin{bmatrix} A & B \\ C & D \end{bmatrix} = \begin{bmatrix} 1 + \frac{Z_T Y_T}{2} & Z_T \left[1 + \frac{Z_T Y_T}{4} \right] \\ Y_T & 1 + \frac{Z_T Y_T}{2} \end{bmatrix} \quad (4.303)$$

since

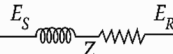
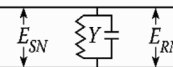
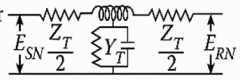
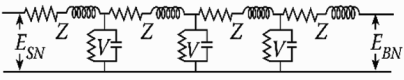
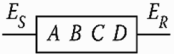
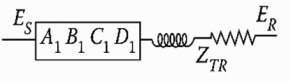
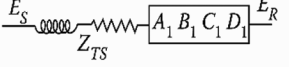
$$V_S = \left[1 + \frac{Z_T Y_T}{2} \right] V_R + Z_T \left[1 + \frac{Z_T Y_T}{4} \right] I_R \quad (4.304)$$

and

$$I_S = (Y_T) V_R + \left[1 + \frac{Z_T Y_T}{2} \right] I_R \quad (4.305)$$

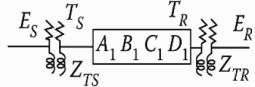
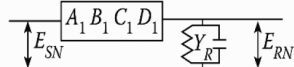
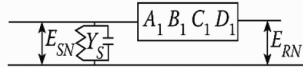
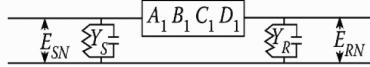
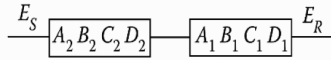
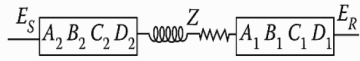
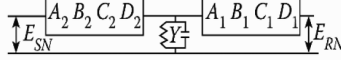
where Z_T is the total equivalent series impedance of the transformer.

TABLE 4.3
General Circuit Contents for Different Network Types

		Equations for General Circuit Constants in Terms of Constants of Component Networks			
Network Number	Type of Network	A =	B =	C =	D =
1	Series impedance 	1	Z	0	1
2	Shunt admittance 	1	0	Y	1
3	Transformer 	$1 + \frac{Z_T Y_T}{2}$	$Z_T \left(1 + \frac{Z_T Y_T}{4} \right)$	Y_T	$1 + \frac{Z_T Y_T}{2}$
4	Transmission line 	$\cosh \sqrt{ZY} = \left(1 + \frac{ZY}{2} + \frac{Z^2 Y^2}{24} + \dots \right)$	$\sqrt{Z/Y} \sinh \sqrt{ZY} = Z \left(1 + \frac{ZY}{6} + \frac{Z^2 Y^2}{120} + \dots \right)$	$\sqrt{Y/Z} \sinh \sqrt{ZY} = Y \left(1 + \frac{ZY}{6} + \frac{Z^2 Y^2}{120} + \dots \right)$	Same as A
5	General network 	A	B	C	D
6	General network and transformer impedance at receiving end 	A_1	$B_1 + A_1 Z_{TR}$	C_1	$D_1 + C_1 Z_{TR}$
7	General network and transformer impedance at sending end 	$A_1 + C_1 Z_{TS}$	$B_1 + D_1 Z_{TS}$	C_1	D_1

(Continued)

TABLE 4.3 (Continued)
General Circuit Contents for Different Network Types

8	General network and transformer impedance at both ends—referred to HV 	$A_1 + C_1 Z_{TS}$	$B_1 + A_1 Z_{TR} + D_1 Z_{TS} + C_1 Z_{TR} Z_{TS}$	C_1	$D_1 + C_1 Z_{TR}$
9	General network and transformer impedance at both ends—transformers having different ratios T_R and T_S —referred to LV 	$\frac{T_R}{T_S} (A_1 + C_1 Z_{TS})$	$\frac{1}{T_{RT} T_S} (B_1 + A_1 Z_{TR} + D_1 Z_{TS} + C_1 Z_{TR} Z_{TS})$	$C_1 T_R T_S$	$\frac{T_S}{T_R} (D_1 + C_1 Z_{TR})$
10	General network and shunt admittance at receiving end 	$A_1 + B_1 Y_R$	B_1	$C_1 + D_1 Y_R$	D_1
11	General network and shunt admittance at sending end 	A_1	B_1	$C_1 + A_1 Y_S$	$D_1 + B_1 Y_S$
12	General network and shunt admittance at both ends 	$A_1 + B_1 Y_R$	B_1	$C_1 + A_1 Y_S + D_1 Y_R + B_1 Y_R Y_S$	$D_1 + B_1 Y_S$
13	Two general networks in series 	$A_1 A_2 + C_1 B_2$	$B_1 A_2 + D_1 B_2$	$A_1 C_2 + C_1 D_2$	$B_1 C_2 + D_1 D_2$
14	Two general networks in series with intermediate impedance 	$A_1 A_2 + C_1 B_2 + C_1 A_2 Z$	$B_1 A_2 + D_1 B_2 + D_1 A_2 Z$	$A_1 C_2 + C_1 D_2 + C_1 C_2 Z$	$B_1 C_2 + D_1 D_2 + B_1 D_2 Z$
15	Two general networks in series with intermediate shunt admittance 	$A_1 A_2 + C_1 B_2 + A_1 B_2 Y$	$B_1 A_2 + D_1 B_2 + B_1 B_2 Y$	$A_1 C_2 + C_1 D_2 + A_1 D_2 Y$	$B_1 C_2 + D_1 D_2 + B_1 D_2 Y$

(Continued)

TABLE 4.3 (Continued)
General Circuit Contents for Different Network Types

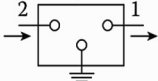
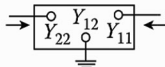
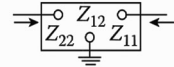
16	Three general networks in series $\frac{E_S}{\boxed{A_3 \ B_3 \ C_3 \ D_3}} - \boxed{A_2 \ B_2 \ C_2 \ D_2} - \boxed{A_1 \ B_1 \ C_1 \ D_1} \frac{E_R}{\quad}$	$\frac{A_3(A_1A_2 + C_1B_2) + B_3(A_1C_2 + C_1D_2)}{B_1 + B_2}$	$\frac{A_3(B_1A_2 + D_1B_2) + B_3(B_1C_2 + D_1D_2)}{B_1 + B_2}$	$\frac{C_3(A_1A_2 + C_1B_2) + D_3(A_1C_2 + C_1D_2)}{B_1 + B_2}$	$\frac{C_3(B_1A_2 + D_1B_2) + D_3(B_1C_2 + D_1D_2)}{B_1 + B_2}$
17	Two general networks in parallel $\frac{E_S}{\boxed{A_1 \ B_1 \ C_1 \ D_1} \parallel \boxed{A_2 \ B_2 \ C_2 \ D_2}} \frac{E_R}{\quad}$	$\frac{A_1B_2 + B_1A_2}{B_1 + B_2}$	$\frac{B_1B_2}{B_1 + B_2}$	$\frac{C_1 + C_2 + (A_1 - A_2) + (D_2 - D_1)}{B_1 + B_2}$	$\frac{B_1D_2 + D_1B_2}{B_1 + B_2}$

Source: Wagner, C.F. and Evans, R.D., *Symmetrical Components*, McGraw-Hill, New York, 1933. With permission.

Note: The exciting current of the receiving-end transformers should be added vectorially to the load current and the exciting current of the sending-end transformers should be added vectorially to the sending-end current.

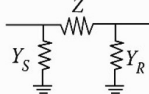
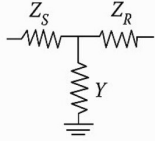
General equations: $E_S - E_R A + I_R B$; $E_R = E_S D - I_S B$; $I_S = I_R D + E_R C$; $I_R = I_S A - E_S C$. As a check in the numerical calculation of the A , B , C , and D constants, note that to all cases, $AD - BC = 1$.

TABLE 4.4
Network Conversion Formulas

	To Convert from					To	
	ABCD	Admittance	Impedance	Equivalent π	Equivalent T		
$A =$	ABCD constants	$\frac{Y_{11}}{Y_{12}}$	$-\frac{Z_{22}}{Z_{12}}$	$1 + ZY_R$	$1 + Z_S Y$	ABCD	$P_1 + jQ_1 = \frac{\hat{A}}{\hat{B}} \bar{E}_1^2 - \frac{1}{\hat{B}} \hat{E}_1 \hat{E}_2$
$B =$		$\frac{1}{Y_{12}}$	$-\frac{Z_{11}Z_{22} - Z_{12}^2}{Z_{12}}$	Z	$Z_R + Z_S + YZ_R Z_S$		$P_2 + jQ_2 = \frac{\hat{D}}{\hat{B}} \bar{E}_2^2 - \frac{1}{\hat{B}} \hat{E}_1 \hat{E}_2$
$C =$	$E_2 = AE_1 + BI_1$ $I_2 = CE_1 + DI_1$	$\frac{Y_{11}Y_{22} - Y_{12}^2}{Y_{12}}$	$-\frac{1}{Z_{12}}$	$Y_R + Y_S + ZY_R Y_R$	Y		
$D =$	$E_1 = DE_2 - BI_2$ $I_1 = CE_2 + AI_2$	$\frac{Y_{22}}{Y_{12}}$	$-\frac{Z_{11}}{Z_{12}}$	$1 + ZY_S$	$1 + Z_R Y$		
$Y_{11} =$	$\frac{A}{B}$	Admittance constants	$\frac{Z_{22}}{Z_{11}Z_{22} - Z_{12}^2}$	$Y_R + \frac{1}{Z}$	$\frac{1 + Z_S Y}{Z_R + Z_S + YZ_R Z_S}$	Admittance	$= \hat{Y}_{11} \bar{E}_1^2 - \hat{Y}_{12} \hat{E}_1 \hat{E}_2$
$Y_{12} =$	$\frac{1}{B}$		$\frac{Z_{12}}{Z_{11}Z_{22} - Z_{12}^2}$	$\frac{1}{Z}$	$\frac{1}{Z_R + Z_S + YZ_R Z_S}$		$= \hat{Y}_{22} \bar{E}_2^2 - \hat{Y}_{12} \hat{E}_1 \hat{E}_2$
$Y_{22} =$	$\frac{D}{E}$	$I_1 = Y_{11}E_1 - Y_{12}E_2$ $I_2 = Y_{22}E_2 - Y_{12}E_1$	$\frac{Z_{11}}{Z_{11}Z_{22} - Z_{12}^2}$	$Y_S + \frac{1}{Z}$	$\frac{1 + YZ_R}{Z_R + Z_S + YZ_R Z_S}$		
$Z_{11} =$	$\frac{D}{C}$	$\frac{Y_{22}}{Y_{11}Y_{22} - Y_{12}^2}$	Impedance constants	$\frac{1 + ZY_S}{Y_R + Y_S + ZY_R Y_S}$	$Z_R + \frac{1}{Y}$	Impedance	
$Z_{12} =$	$\frac{1}{C}$	$-\frac{Y_{12}}{Y_{11}Y_{22} - Y_{12}^2}$		$\frac{1}{Y_R + Y_S + ZY_R Y_S}$	$-\frac{1}{Y}$		

(Continued)

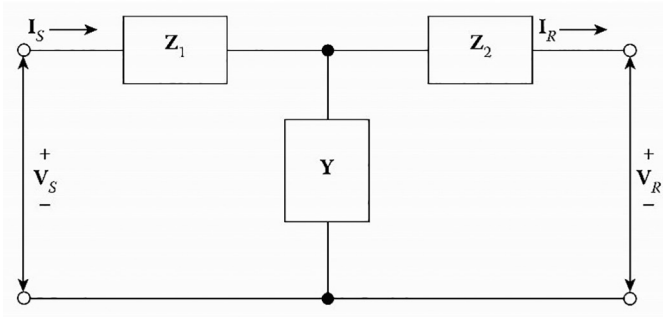
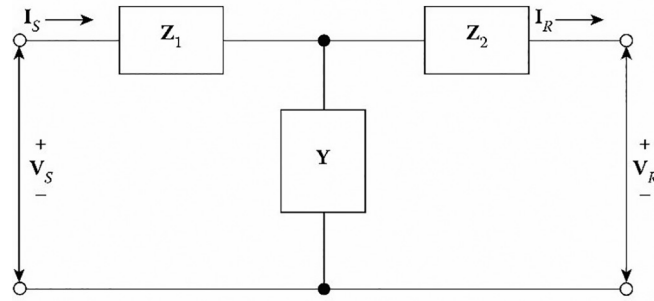
TABLE 4.4 (Continued)
Network Conversion Formulas

	To Convert from					To
	ABCD	Admittance	Impedance	Equivalent π	Equivalent T	
$Z_{22} =$	$\frac{A}{C}$	$\frac{Y_{11}}{Y_{11}Y_{22} - Y_{12}^2}$	$E_1 = Z_{11}I_1 - Z_{12}I_2$ $E_2 = Z_{22}I_2 - Z_{12}I_1$	$\frac{1 + ZY_R}{Y_R + Y_S + ZY_RY_S}$	$Z_S + \frac{1}{Y}$	
$Y_R =$	$\frac{A-1}{B}$	$Y_{11} - Y_{12}$	$\frac{Z_{22} + Z_{12}}{Z_{11}Z_{22} - Z_{12}^2}$	Equivalent π	$\frac{YZ_S}{Z_R + Z_S + YZ_RZ_S}$	Equivalent π
$Z =$	B	$\frac{1}{Y_{12}}$	$-\frac{Z_{11}Z_{22} - Z_{12}^2}{Z_{12}}$		$Z_R + Z_S + YZ_RZ_S$	$= Z_{11}I_1^2 - Z_{12}\hat{I}_1I_2$
$Y_S =$	$\frac{D-1}{B}$	$Y_{22} - Y_{12}$	$\frac{Z_{11} + Z_{12}}{Z_{11}Z_{22} - Z_{12}^2}$		$\frac{YZ_R}{Z_R + Z_S + YZ_RZ_S}$	$= Z_{22}I_2^2 - Z_{12}I_1\hat{I}_2$
$Z_R =$	$\frac{D-1}{C}$	$\frac{Y_{22} - Y_{12}}{Y_{11}Y_{22} - Y_{12}^2}$	$Z_{11} - Z_{12}$	$\frac{ZY_S}{Y_R + Y_S + ZY_RY_S}$	Equivalent T	Equivalent T
$Y =$	C	$\frac{Y_{11}Y_{22} - Y_{12}^2}{Y_{12}}$	$-\frac{1}{Z_{12}}$	$Y_R + Y_S + ZY_RY_S$		
$Z_S =$	$\frac{A-1}{C}$	$\frac{Y_{11} - Y_{12}}{Y_{11}Y_{22} - Y_{12}^2}$	$Z_{22} - Z_{12}$	$\frac{ZY_R}{Y_R + Y_S + ZY_RY_S}$		

Source: Wagner, C.F. and Evans, R.D., *Symmetrical Components*, McGraw-Hill, New York, 1933. With permission.

Note 1: P_1 and P_2 are positive in all cases for power flowing *into* the network from the point considered.

Note 2: P and Q of same sign indicate lagging PF; that is, $P + jQ = E\hat{I}$.

FIGURE 4.32 Transformer equivalent circuit *at no load*.FIGURE 4.33 Transformer equivalent circuit *at full load*.

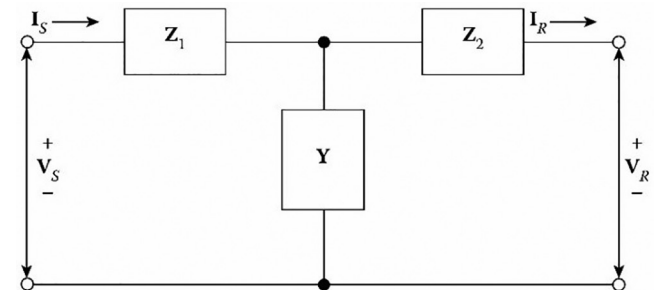
4.15.3 ASYMMETRICAL π AND T NETWORKS

Figure 4.34 shows an asymmetrical π network that can be thought of as a series (or *cascade*, or *tandem*) connection of a shunt admittance, a series impedance, and a shunt admittance.

The equivalent transfer matrix can be found by multiplying together the transfer matrices of individual components. Thus,

$$\begin{bmatrix} A & B \\ C & D \end{bmatrix} = \begin{bmatrix} 1 & 0 \\ Y_1 & 1 \end{bmatrix} \begin{bmatrix} 1 & Z \\ 0 & 1 \end{bmatrix} \begin{bmatrix} 1 & 0 \\ Y_2 & 1 \end{bmatrix} \quad (4.306)$$

$$= \begin{bmatrix} 1 + ZY_2 & Z \\ Y_1 + Y_2 + ZY_1Y_2 & 1 + ZY_1 \end{bmatrix}$$

FIGURE 4.34 Asymmetrical- π network.

When the π network is symmetrical,

$$Y_1 = Y_2 = \frac{Y}{2}$$

and the transfer matrix becomes

$$\begin{bmatrix} A & B \\ C & D \end{bmatrix} = \begin{bmatrix} 1 + \frac{ZY}{2} & Z \\ Y + \frac{ZY^2}{4} & 1 + \frac{ZY}{2} \end{bmatrix} \quad (4.307)$$

which is the same as Equation 4.215 for a nominal- π circuit of a medium-length transmission line.

Figure 4.35 shows an asymmetrical T network that can be thought of as a cascade connection of a series impedance, a shunt admittance, and a series impedance.

Again, the equivalent transfer matrix can be found by multiplying together the transfer matrices of individual components. Thus,

$$\begin{aligned} \begin{bmatrix} A & B \\ C & D \end{bmatrix} &= \begin{bmatrix} 1 & Z_1 \\ 0 & 1 \end{bmatrix} \begin{bmatrix} 1 & 0 \\ Y & 1 \end{bmatrix} \begin{bmatrix} 1 & Z_2 \\ 0 & 1 \end{bmatrix} \\ &= \begin{bmatrix} 1 + Z_1 Y & Z_1 + Z_2 + Z_1 Z_2 Y \\ Y & 1 + Z_2 Y \end{bmatrix} \end{aligned} \quad (4.308)$$

When the T network is symmetrical,

$$Z_1 = Z_2 = \frac{Z}{2}$$

and the transfer matrix becomes

$$\begin{bmatrix} A & B \\ C & D \end{bmatrix} = \begin{bmatrix} 1 + \frac{ZY}{2} & Z + \frac{Z^2 Y}{4} \\ Y & 1 + \frac{ZY}{2} \end{bmatrix} \quad (4.309)$$

which is the same as the equation for a nominal- T circuit of a medium-length transmission line.

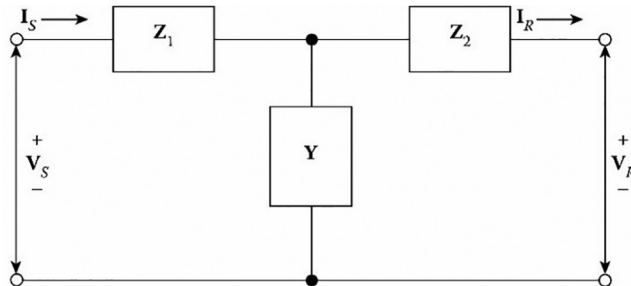


FIGURE 4.35 Asymmetrical T network.

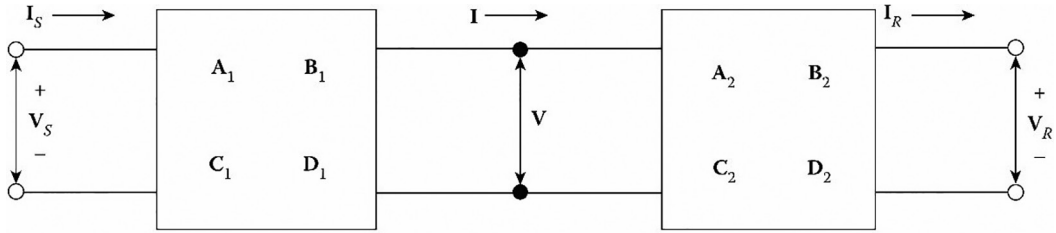


FIGURE 4.36 Transmission networks in series.

4.15.4 NETWORKS CONNECTED IN SERIES

Two four-terminal transmission networks may be connected in series, as shown in Figure 4.36, to form a new four-terminal transmission network. For the first four-terminal network,

$$\begin{bmatrix} \frac{V_S}{I_S} \end{bmatrix} = \begin{bmatrix} A_1 & B_1 \\ C_1 & D_1 \end{bmatrix} \begin{bmatrix} V \\ I \end{bmatrix} \quad (4.310)$$

and for the second four-terminal network,

$$\begin{bmatrix} V \\ I \end{bmatrix} = \begin{bmatrix} A_2 & B_2 \\ C_2 & D_2 \end{bmatrix} \begin{bmatrix} V_R \\ I_R \end{bmatrix} \quad (4.311)$$

By substituting Equation 4.311 into Equation 4.310,

$$\begin{aligned} \begin{bmatrix} V_S \\ I_S \end{bmatrix} &= \begin{bmatrix} A_1 & B_1 \\ C_1 & D_1 \end{bmatrix} \begin{bmatrix} A_2 & B_2 \\ C_2 & D_2 \end{bmatrix} \begin{bmatrix} V_R \\ I_R \end{bmatrix} \\ &= \begin{bmatrix} A_1 A_2 + B_1 C_2 & A_1 B_2 + B_1 D_2 \\ C_1 A_2 + D_1 C_2 & C_1 B_2 + D_1 D_2 \end{bmatrix} \begin{bmatrix} V_R \\ I_R \end{bmatrix} \end{aligned} \quad (4.312)$$

Therefore, the equivalent A , B , C , and D constants for two networks connected in series are

$$A_{eq} = A_1 A_2 + B_1 C_2 \quad (4.313)$$

$$B_{eq} = A_1 B_2 + B_1 D_2 \quad (4.314)$$

$$C_{eq} = C_1 A_2 + D_1 C_2 \quad (4.315)$$

$$D_{eq} = C_1 B_2 + D_1 D_2 \quad (4.316)$$

Example 4.9

Figure 4.37 shows two networks connected in cascade. Determine the equivalent A , B , C , and D constants.

Solution

For network 1,

$$\begin{bmatrix} A_1 & B_1 \\ C_1 & D_1 \end{bmatrix} = \begin{bmatrix} 1 & 10 \angle 30^\circ \\ 0 & 1 \end{bmatrix}$$

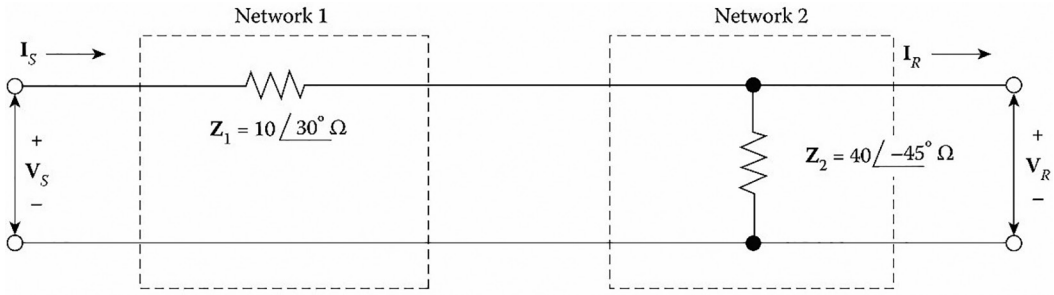


FIGURE 4.37 Network configurations for Example 4.17.

Network 2,

$$Y_2 = \frac{1}{Z_2} = \frac{1}{40 \angle -45^\circ} = 0.025 \angle 45^\circ \text{ S}$$

Then

$$\begin{bmatrix} A_2 & B_2 \\ C_2 & D_2 \end{bmatrix} = \begin{bmatrix} 1 & 0 \\ 0.025 \angle 45^\circ & 1 \end{bmatrix}$$

Therefore,

$$\begin{bmatrix} A_{\text{eq}} & B_{\text{eq}} \\ C_{\text{eq}} & D_{\text{eq}} \end{bmatrix} = \begin{bmatrix} 1 & 10 \angle 30^\circ \\ 0 & 1 \end{bmatrix} \begin{bmatrix} 1 & 0 \\ 0.025 \angle 45^\circ & 1 \end{bmatrix} \\ = \begin{bmatrix} 1.09 \angle 12.8^\circ & 10 \angle 30^\circ \\ 0.025 \angle 45^\circ & 1 \end{bmatrix}$$

4.15.5 NETWORKS CONNECTED IN PARALLEL

Two four-terminal transmission networks may be connected in parallel, as shown in Figure 4.38, to form a new four-terminal transmission network.

Since

$$\begin{aligned} V_S &= V_{S1} + V_{S2} \\ V_R &= V_{R1} + V_{R2} \end{aligned} \quad (4.317)$$

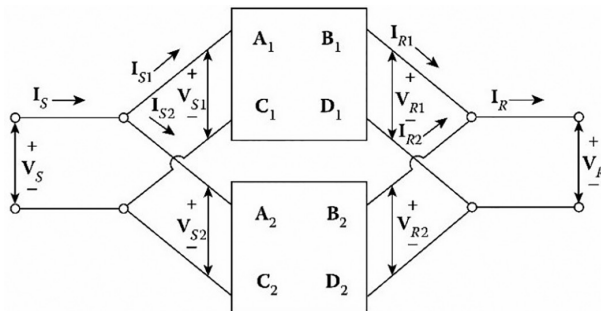


FIGURE 4.38 Transmission networks in parallel.

and

$$\begin{aligned} I_S &= I_{S1} + I_{S2} \\ I_R &= I_{R1} + I_{R2} \end{aligned} \quad (4.318)$$

for the equivalent four-terminal network,

$$\begin{bmatrix} V_S \\ I_S \end{bmatrix} = \begin{bmatrix} \frac{A_1 B_2 + A_2 B_1}{B_1 + B_2} & \frac{B_1 B_2}{B_1 + B_2} \\ C_2 + C_2 + \frac{(A_1 - A_2)(D_2 - D_1)}{B_1 + B_2} & \frac{D_1 B_2 + D_2 B_1}{B_1 + B_2} \end{bmatrix} \begin{bmatrix} V_R \\ I_R \end{bmatrix} \quad (4.319)$$

where the equivalent A , B , C , and D constants are

$$A_{eq} = \frac{A_1 B_2 + A_2 B_1}{B_1 + B_2} \quad (4.320)$$

$$B_{eq} = \frac{B_1 B_2}{B_1 + B_2} \quad (4.321)$$

$$C_{eq} = C_2 + C_2 + \frac{(A_1 - A_2)(D_2 - D_1)}{B_1 + B_2} \quad (4.322)$$

$$D_{eq} = \frac{D_1 B_2 + D_2 B_1}{B_1 + B_2} \quad (4.323)$$

Example 4.10

Assume that the two networks given in Example 4.17 are connected in parallel, as in Figure 4.39. Determine the equivalent A , B , C , and D constants.

Solution

Using the A , B , C , and D parameters found previously for networks 1 and 2, that is,

$$\begin{bmatrix} A_1 & B_1 \\ C_1 & D_1 \end{bmatrix} = \begin{bmatrix} 1 & 10\angle 30^\circ \\ 0 & 1 \end{bmatrix}$$

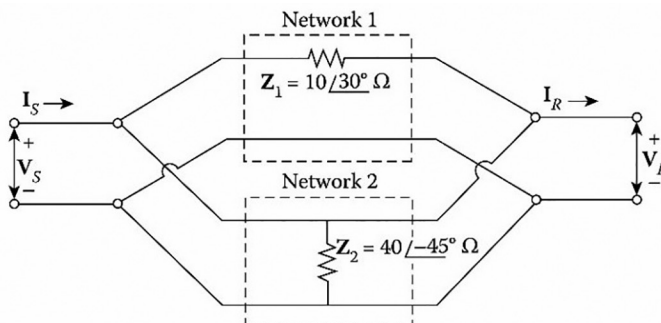


FIGURE 4.39 Transmission networks in parallel for Example 4.18.

and

$$\begin{bmatrix} A_2 & B_2 \\ C_2 & D_2 \end{bmatrix} = \begin{bmatrix} 1 & 0 \\ 0.025\angle 45^\circ & 1 \end{bmatrix}$$

the equivalent A , B , C , and D constants can be calculated as

$$\begin{aligned} A_{eq} &= \frac{A_1 B_2 + A_2 B_1}{B_1 + B_2} \\ &= \frac{1 \times 0 + 1 \times 10\angle 30^\circ}{10\angle 30^\circ + 0} = 1 \end{aligned}$$

$$\begin{aligned} B_{eq} &= \frac{B_1 B_2}{B_1 + B_2} \\ &= \frac{1 \times 0}{1 + 0} = 0 \end{aligned}$$

$$\begin{aligned} C_{eq} &= C_2 + C_2 + \frac{(A_1 - A_2)(D_2 - D_1)}{B_1 + B_2} \\ &= 0 + 0.025\angle 45^\circ + \frac{(1-1)(1-1)}{10\angle 30^\circ - 0} = 0.025\angle 45^\circ \end{aligned}$$

$$\begin{aligned} D_{eq} &= \frac{D_1 B_2 + D_2 B_1}{B_1 + B_2} \\ &= \frac{1 \times 0 + 1 \times 10\angle 30^\circ}{10\angle 30^\circ + 0} = 1 \end{aligned}$$

Therefore,

$$\begin{bmatrix} A_{eq} & B_{eq} \\ C_{eq} & D_{eq} \end{bmatrix} = \begin{bmatrix} 1 & 0 \\ 0.025\angle 45^\circ & 1 \end{bmatrix}$$

4.15.6 TERMINATED TRANSMISSION LINE

Figure 4.40 shows a four-terminal transmission network connected to (i.e., terminated by) a load Z_L .

For the given network,

$$\begin{bmatrix} V_S \\ I_S \end{bmatrix} = \begin{bmatrix} A & B \\ C & D \end{bmatrix} \begin{bmatrix} V_R \\ I_R \end{bmatrix} \quad (4.324)$$

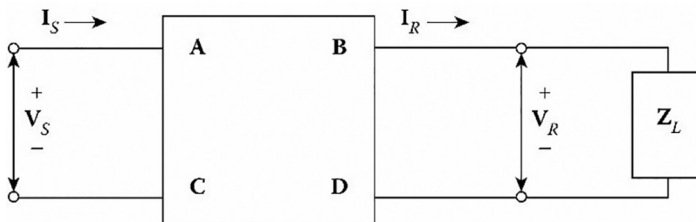


FIGURE 4.40 Terminated transmission line.

or

$$V_S = AV_R + BI_R \quad (4.325)$$

and

$$I_S = CV_R + DI_R \quad (4.326)$$

and also

$$V_R = Z_L I_R \quad (4.327)$$

Therefore, the input impedance is

$$\begin{aligned} Z_{in} &= \frac{V_S}{I_S} \\ &= \frac{AV_R + BI_R}{CV_R + DI_R} \end{aligned} \quad (4.328)$$

or by substituting Equation 4.325 into Equation 4.326,

$$Z_{in} = \frac{AZ_L + B}{CZ_L + D} \quad (4.329)$$

Since for the symmetrical and long transmission lines,

$$A = \cosh \sqrt{YZ} = \cosh \theta$$

$$B = \sqrt{\frac{Z}{Y}} \sinh \sqrt{YZ} = Z_C \sinh \theta$$

$$C = \sqrt{\frac{Y}{Z}} \sinh \sqrt{YZ} = Y_C \sinh \theta$$

$$D = A = \cosh \sqrt{YZ} = \cosh \theta$$

The input impedance, from Equation 4.329, becomes

$$Z_{in} = \frac{Z_L \cosh \theta + Z_C \sinh \theta}{Z_L Y_C \sinh \theta + \cosh \theta} \quad (4.330)$$

or

$$Z_{in} = \frac{Z_L [(Z_C/Z_L) \sinh \theta + \cosh \theta]}{(Z_L/Z_C) \sinh \theta + \cosh \theta} \quad (4.331)$$

If the load impedance is chosen to be equal to the characteristic impedance, that is,

$$Z_L = Z_C \quad (4.332)$$

the input impedance, from Equation 4.329, becomes

$$\mathbf{Z}_{\text{in}} = \mathbf{Z}_C \quad (4.333)$$

which is *independent* of θ and the line length. The value of the voltage is constant all along the line.

Example 4.11

Figure 4.41 shows a short transmission line that is terminated by a load of 200 kVA at a lagging PF of 0.866 at 2.4 kV. If the line impedance is $2.07 + j0.661 \, \Omega$, calculate the following:

- Sending-end current
- Sending-end voltage
- Input impedance
- Real and reactive power loss in the line

Solution

- From Equation 4.324,

$$\begin{bmatrix} V_S \\ I_S \end{bmatrix} = \begin{bmatrix} A & B \\ C & D \end{bmatrix} \begin{bmatrix} V_R \\ I_R \end{bmatrix} \\ = \begin{bmatrix} 1 & \mathbf{Z} \\ 0 & 1 \end{bmatrix} \begin{bmatrix} V_R \\ I_R \end{bmatrix}$$

where

$$\mathbf{Z} = 2.07 + j0.661 = 2.173 \angle 17.7^\circ \, \Omega$$

$$\mathbf{I}_R = \mathbf{I}_S = \mathbf{I}_L$$

$$\mathbf{V}_R = \mathbf{Z}_L \mathbf{I}_R$$

Since

$$\mathbf{S}_R = 200 \angle 30^\circ = 173.2 + j100 \, \text{kVA}$$

and

$$\mathbf{V}_L = 2.4 \angle 0^\circ \, \text{kV}$$

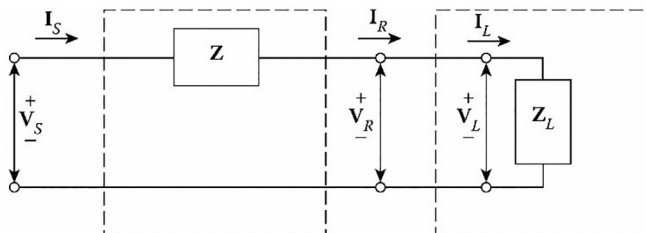


FIGURE 4.41 Transmission system for Example 4.19.

then

$$I_L^* = \frac{S_R}{V_L} = \frac{200 \angle 30^\circ}{2.4 \angle 0^\circ} = 83.33 \angle 30^\circ \text{ A}$$

or

$$I_L = 83.33 \angle -30^\circ \text{ A}$$

Hence,

$$I_S = I_R = I_L = 83.33 \angle -30^\circ \text{ A}$$

b.

$$Z_L = \frac{V_L}{I_L} = \frac{2.4 \times 10^3 \angle 0^\circ}{83.33 \angle -30^\circ} = 28.8 \angle 30^\circ \Omega$$

and

$$V_R = Z_L I_R = 28.8 \angle 30^\circ \times 83.33 \angle -30^\circ = 2404 \angle 0^\circ \text{ kV}$$

Thus,

$$\begin{aligned} V_S &= AV_R + BI_R \\ &= 2400 \angle 0^\circ + 2.173 \angle 17.7^\circ \times 83.33 \angle -30^\circ \\ &= 2576.9 - j38.58 \\ &= 2577.2 \angle -0.9^\circ \text{ V} \end{aligned}$$

c. The input impedance is

$$\begin{aligned} Z_{in} \frac{V_S}{I_S} &= \frac{AV_R + BI_R}{CV_R + DI_R} \\ &= \frac{2577.2 \angle -0.9^\circ}{83.33 \angle -30^\circ} = 30.93 \angle 29.1^\circ \Omega \end{aligned}$$

d. The real and reactive power loss in the line is

$$S_L = S_S - S_R$$

where

$$S_S = V_S I_S^* = 2,577.2 \angle -0.9^\circ \times 83.33 \angle 30^\circ = 214,758 \angle 29.1^\circ \text{ VA}$$

or

$$S_S = I_S \times Z_{in} \times I_S^* = 214,758 \angle 29.1^\circ \text{ VA}$$

Thus,

$$\begin{aligned} S_L &= 214,758 \angle 29.1^\circ - 200,000 \angle 30^\circ \\ &= 14,444.5 + j4,444.4 \text{ VA} \end{aligned}$$

that is, the active power loss is 14,444.5 W, and the reactive power loss is 4,444.4 vars.

4.16 BUNDLED CONDUCTORS

Bundled conductors are used at or above 345 kV. Instead of one large conductor per phase, two or more conductors of approximately the same total cross section are suspended from each insulator string. Therefore, by having two or more conductors per phase in close proximity compared with the spacing between phases, the voltage gradient at the conductor surface is significantly reduced. The bundles used at the EHV range usually have two, three, or four *subconductors*, as shown in Figure 4.42. The bundles used at the UHV range may also have 8, 12, and even 16 conductors.

Bundle conductors are also called *duplex*, *triplex*, and so on conductors, referring to the number of subconductors, and are sometimes referred to as grouped or multiple conductors. The advantages derived from the use of *bundled* conductors instead of single conductors per phase are (1) reduced line inductive reactance; (2) reduced voltage gradient; (3) increased corona critical voltage and, therefore, less corona power loss, Audible Noise (AN), and Ratio Interference (RI); (4) more power may be carried per unit mass of conductor; and (5) the amplitude and duration of high-frequency vibrations may be reduced. The disadvantages of bundled conductors include (1) increased wind and ice loading, (2) suspension is more complicated and duplex or quadruple insulator strings may be required, (3) the tendency to gallop is increased, (4) increased cost, (5) increased clearance requirements at structures, and (6) increased charging kilovolt-amperes.

If the subconductors of a bundle are transposed, the current will be divided exactly between the conductors of the bundle. The GMRs of bundled conductors made up of two, three, and four subconductors can be expressed, respectively, as

$$D_s^b = (D_s \times d)^{\frac{1}{2}} \quad (4.334)$$

$$D_s^b = (D_s \times d^2)^{\frac{1}{3}} \quad (4.335)$$

$$D_s^b = 1.09(D_s \times d_3)^{\frac{1}{4}} \quad (4.336)$$

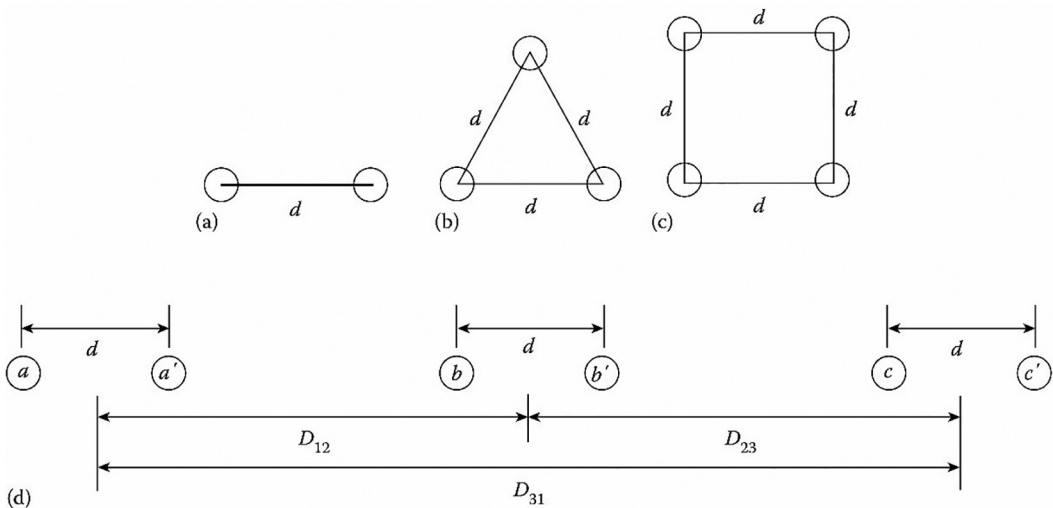


FIGURE 4.42 Bundle arrangements: (a) two-conductor bundle, (b) three-conductor bundle, (c) four-conductor bundle, and (d) cross section of bundled conductor three-phase line with horizontal tower configuration.

where

D_s^b is the GMR of bundled conductor

D_s is the GMR of subconductors

d is the distance between two subconductors

Therefore, the average inductance per phase is

$$L_a = 2 \times \frac{10^{-7} \ln \frac{D_{eq}}{D_s^b} H}{m} \quad (4.337)$$

and the inductive reactance is

$$X_L = \frac{0.1213 \ln \frac{D_{eq}}{D_s^b} \Omega}{\text{mi}} \quad (4.338)$$

where

$$D_{eq} \triangleq D_m = (D_{12} \times D_{23} \times D_{31})^{\frac{1}{3}} \quad (4.339)$$

The modified GMRs (to be used in capacitance calculations) of bundled conductors made up of two, three, and four subconductors can be expressed, respectively, as

$$D_{sC}^b = (r \times d)^{\frac{1}{2}} \quad (4.340)$$

$$D_{sC}^b = (r \times d^2)^{\frac{1}{3}} \quad (4.341)$$

$$D_{sC}^b = 1.09 (r \times d^3)^{\frac{1}{4}} \quad (4.342)$$

where

D_{sC}^b is the modified GMR of bundled conductor

r is the outside radius of subconductors

d is the distance between two subconductors

Therefore, the line-to-neutral capacitance can be expressed as

$$C_N = \frac{\frac{55.63 \times 10^{-12}}{\ln \left(\frac{D_{eq}}{D_{sC}^b} \right)} \text{ F}}{m} \quad (4.343)$$

or

$$C_N = \frac{\frac{2\pi \times 8.8538 \times 10^{-12}}{\ln \left(\frac{D_{eq}}{D_{sC}^b} \right)} \text{ F}}{m} \quad (4.344)$$

For a two-conductor bundle, the maximum voltage gradient at the surface of a subconductor can be expressed as

$$E_0 = \frac{V_0 \left(1 + \frac{2r}{d}\right)}{2r \ln \left(\frac{D}{\sqrt{r \times d}}\right)}$$

(4.345)

4.17 TYPE OF SUPPORTING STRUCTURES

4.17.1 POLE TYPES

There are basically four different pole types: (1) wood poles, (2) concrete poles, (3) steel poles, and (4) aluminum poles. In general, wood poles are preferred over others for OH distribution lines because of the abundance of the material, ease of handling, and cost. Concrete poles reinforced with steel have been used for street lighting because of their neat appearance. Steel poles have been used to support trolley OHs and street and parkway lighting. Both concrete and steel poles have been used to a limited extent for distribution. Aluminum poles are used basically for parkway lighting (Table 4.5).

The life of wood poles is materially extended by impregnation with wood preservatives. Wood that has been properly treated for the environment in which it will be used will resist decay and maintain its mechanical strength for many years. A minimum life expectancy of 35 years has been accepted by the wood industry [7]. Cedar, pine, and fir are best suited by their proportions and properties for use as distribution poles.

Besides their usage in distribution systems, wood structures have been utilized for many years as a means of supporting single- and double-circuit transmission lines at voltages of 115–230 kV and single circuit of 345 kV. As a result of developing technology, wood structures have recently been designed for applications up to 765 kV and tested for 500 kV [7].

Wood structure design is based on an assigned or calculated ultimate stress for the species used. The inherent flexibility of wood adds a certain degree of cushion when severe loadings are imposed.

TABLE 4.5
Horizontal Clearance at Supports between Line Conductor No. 2 AWG or Larger Based on Sags

Voltage between Conductors (kV)	Sag (in.)							But not Less than
	36	48	72	96	120	180	240	
	Horizontal Clearance (in.)							
2.4	14.6	16.7	20.2	23.3	26.0	31.7	36.5	12.0
4.16	15.1	17.3	20.8	23.8	26.5	32.2	37.0	12.0
12.47	17.6	19.7	23.6	26.3	29.0	34.7	39.5	13.5
13.2	17.8	20.0	23.5	26.5	29.2	34.9	39.7	13.8
13.8	18.0	23.7	26.7	29.4	35.1	39.9	14.0	
14.4	18.2	20.3	3.8	26.9	29.6	35.3	40.1	14.3
24.94	21.3	23.5	27.0	30.0	32.8	38.4	43.2	18.5
34.5	24.2	26.2	29.9	32.9	35.6	41.3	46.1	22.4
46	27.7	29.8	33.3	36.4	39.1	44.8	49.6	26.9

Source: American National Standards Institute, *National Electrical Safety Code*, 1984 edn., IEEE, New York, 1984.

This property provides wood construction the ability to absorb shock loads and longitudinal load capability not found in rigid structures.

Figure 4.43 shows some typical single-column wood structure designs used in distribution systems. Figure 4.44 shows typical single-column structure designs. Single wood column designs have been used for double-circuit lines through 230 kV and appear feasible for 345 kV. Structures using two columns, as shown in Figure 4.45, provide the basis for conventional H-frame designs with variations. Wood crossarms are normally used, although metal arms are sometimes specified. Double-circuit structures have been built using two columns for voltages through 230 kV and appear feasible for double circuits of 345 kV.

In distribution systems, single poles are widely used to support three transformer banks and their fused disconnects and surge arresters. A-frame poles are used where greater strength is required, and H-frame poles are used where it is necessary to support switching equipment and/or a transformer as well as the line.

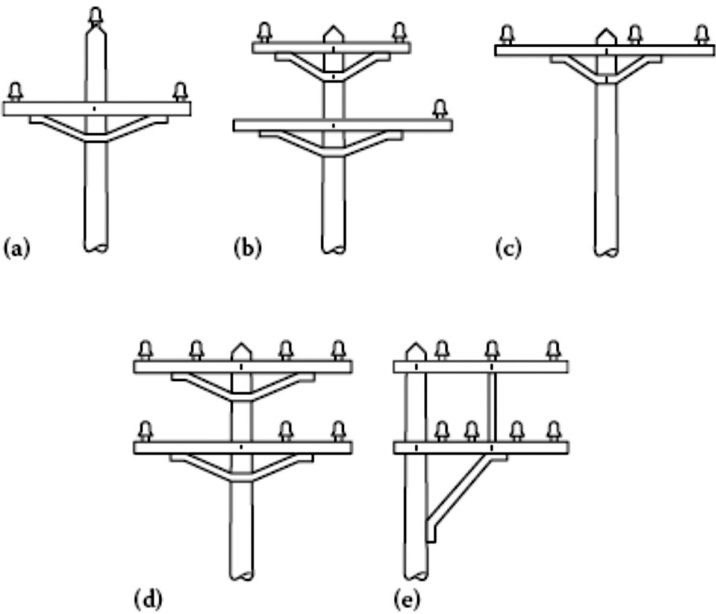


FIGURE 4.43 Typical single-pole designs used in distribution systems: (a) pole top, (b) two arms, (c) single arm, (d) line arms, and (e) side arms.

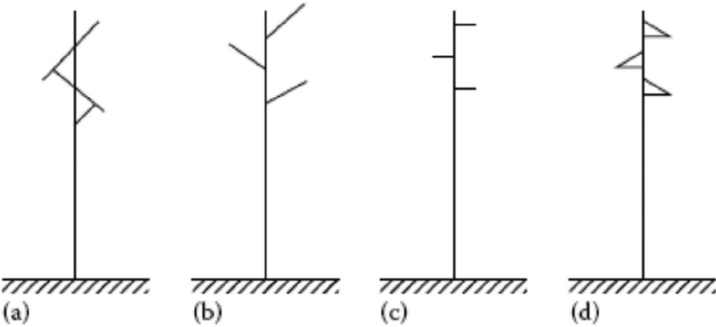


FIGURE 4.44 Typical single-column designs: (a) wishbone design, (b) unbraced upswept arms, (c) horizontal line post, and (d) braced horizontal arms.

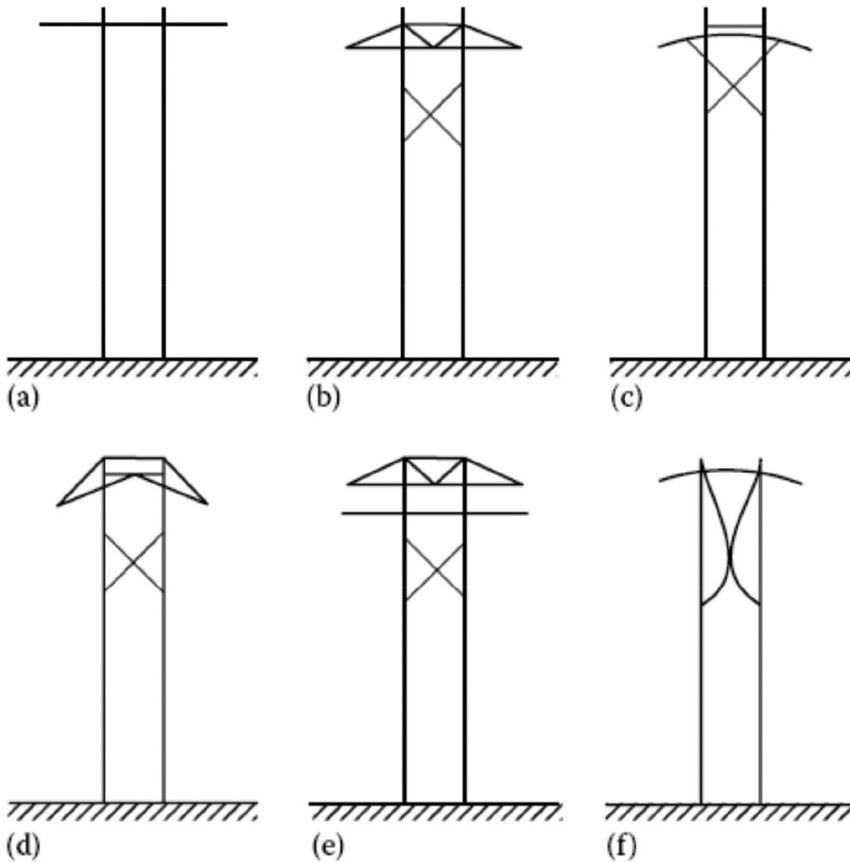


FIGURE 4.45 Typical two-column designs: (a) unbraced H-frame, (b) H-frame with wood (solid or laminated) crossarm, (c) H-frame with curved laminated crossarm, (d) K-frame, (e) double-circuit H-frame, and (f) Dreyfus design.

The poles must have sufficient height and be so located as to provide adequate ground clearance at either maximum loading or maximum temperature condition. The conductor ground clearance for railroad tracks and wire line crossings, as well as from buildings and other subjects, must meet the requirements of the NESC and other local rules and regulations. In essence, the height of a pole required for a particular location is determined by the following factors:

1. Length of vertical pole space required for wires and equipment
2. Clearance required above ground or obstructions for wires and equipment
3. Sag of conductors
4. Depth of pole to be set in ground

In distribution systems, the most commonly used pole is the 35 ft pole, and poles shorter than 30 ft are generally not used. The 30 ft pole may be used in alleys and on rear lot lines. The larger sizes are, of course, used for providing clearance over obstructions, for heavier leads, etc.

The size (i.e., class), or diameter, of the pole is determined by the strength required to endure the mechanical loading imposed upon it. The critical point of strength for an unguyed pole at or near the ground line, therefore, the circumference of the pole at this point, determines the resisting moment of the pole when bending as a cantilever. However, if a pole is guyed, the diameter of the pole at the point of attachment of the guy is the measure of its strength. The resisting moment at the point

of guy attachment must be sufficient to endure the bending stresses caused at that point. Also, the top of the pole must be of adequate circumference to permit the attachment of crossarms without excessively weakening the pole near the top.

The wood poles are divided into several classes according to top circumference and the circumference 6 ft from the butt end for each nominal length. The word *class* refers to the dimensional classifications set up by the American Standards Association. The classes are numbered from 1 to 10. Class 1 provides the largest ground circumference and class 7 the smallest. Classes 8–10 specify minimum top circumferences only.

All poles in a given class, regardless of length, have approximately the same strength against load applied horizontally at the top. Table 4.6 gives the standard pole dimensions for yellow pine, chestnut, and western cedar. In order to identify any particular wood pole, its class, pole length, and wood type should be given.

4.17.2 SOIL TYPES AND POLE SETTING

A stable pole must have sufficient setting depth. Table 4.7 provides the minimum depth of pole settings. However, the distribution engineer chooses the depth of settings as the situation dictates. For example, corner poles should have about 6 in. deeper settings. Of course, the stability or rigidity of the pole depends not only on the depth of setting but also on the type of earth, moisture content of soil, size of pole butt, and setting technique used. Figure 4.46 shows some of the setting techniques.

Earth can be classified into eight different groups, as given in Table 4.8, for the purpose of settings. Table 4.8 also gives the resistance S , as percentage of pole ultimate resisting moments, that the earth around the pole base shows displacement for various earth types [8]. The values given in the table are somewhat arbitrary, and based on the assumptions that the pole setting is standard, the hole diameter is minimum, and the backfilling is properly tamped.

4.18 EFFECT OF GROUND ON CAPACITANCE OF THREE-PHASE LINES

Consider three-phase line conductors and their images below the surface of the ground, as shown in Figure 4.44. Assume that the line is transposed and that conductors a , b , and c have the charges q_a , q_b , and q_c , respectively, and their images have the charges $-q_a$, $-q_b$, and $-q_c$. The line-to-neutral capacitance can be expressed as [3]

$$C_N = \frac{2\pi \times 8.8538 \times 10^{-12}}{\ln\left(\frac{D_{eq}}{r}\right) - \ln\left(\frac{l_{12}l_{23}l_{31}}{h_1h_{22}h_{33}}\right)} \text{ F/m} \quad (4.346)$$

If the effect of the ground is not taken into account, the line-to-neutral capacitance is

$$C_N = \frac{2\pi \times 8.8538 \times 10^{-12}}{\ln\left(\frac{D_{eq}}{r}\right) - \ln\left(\frac{l_{12}l_{23}l_{31}}{h_1h_{22}h_{33}}\right)} \text{ F/m} \quad (4.347)$$

As one can see, the effect of the ground increases the line capacitance. However, since the conductor heights are much larger than the distances between them, the effect of the ground is usually ignored for three-phase lines.

TABLE 4.6
Standard Wood Pole Dimensions

Class		1	2	3	4	5	6	7
Minimum Top Circumference (in.)		27	25	23	21	19	17	15
Minimum Top Diameter (in.)		8.6	8.0	7.3	6.7	6.1	5.4	4.8
Pole Length (ft)	Wood Type ^a	Minimum Circumference at Ground Level (in.)						
25	P	34.5	32.5	30.0	28.0	26.0	24.0	22.0
	C	37.0	34.5	32.5	30.0	28.0	25.5	24.0
	W	38.0	35.5	33.0	30.5	28.5	26.0	24.5
30	P	37.5	35.0	32.5	30.0	28.0	26.0	24.0
	C	40.0	37.5	35.0	32.5	30.0	28.0	26.0
	W	41.0	38.5	35.5	33.0	30.5	28.5	26.5
35	P	40.0	37.5	35.0	32.0	30.0	27.5	25.5
	C	42.5	40.0	37.5	34.5	32.0	30.0	27.5
	W	43.5	41.0	38.0	35.5	32.5	30.5	28.0
40	P	42.0	39.5	37.0	34.0	31.5	29.0	27.0
	C	45.0	42.5	39.5	36.5	34.0	31.5	29.5
	W	46.0	43.5	40.5	37.5	34.5	32.0	30.0
45	P	44.0	41.5	38.5	36.0	33.0	30.5	28.5
	C	47.5	44.5	41.5	38.5	36.0	33.0	31.0
	W	48.5	45.5	42.5	39.5	36.5	33.5	31.5
50	P	46.0	43.0	40.0	37.5	34.5	32.0	29.5
	C	49.5	46.5	43.5	40.0	37.5	34.5	32.0
	W	50.5	47.5	44.5	41.0	38.0	35.0	32.5
55	P	47.5	44.5	41.5	39.0	36.0	33.5	
	C	51.5	48.5	45.0	42.0	39.0	36.0	
	W	52.5	49.5	46.0	42.5	39.5	36.5	
60	P	49.5	46.0	43.0	40.0	37.0	34.5	
	C	53.5	50.0	46.5	43.0	40.0	37.5	
	W	54.5	51.0	47.5	44.0	41.0	38.5	
65	P	51.0	47.5	44.5	41.5	38.5		
	C	55.0	51.5	48.0	45.0	42.0		
	W	56.0	52.5	49.0	45.5	42.5		
70	P	52.5	49.0	46.0	42.5	39.5		
	C	56.5	53.0	48.5	45.5	43.5		
	W	57.5	54.0	50.5	47.0	45.0		
75	P	54.0	50.5	47.0	44.0			
	C	59.0	54.0	50.0	47.0			
	W	59.5	55.5	52.0	48.5			

^a Yellow pine, chestnut, and western cedar are denoted as P, C, and W, respectively.

TABLE 4.7
Minimum Required Setting Depths

Pole size (ft)	30	35	40	45	50	55	60	70
Setting depth (ft)	5	5.5	6	6.5	6.5	7	7	7.5

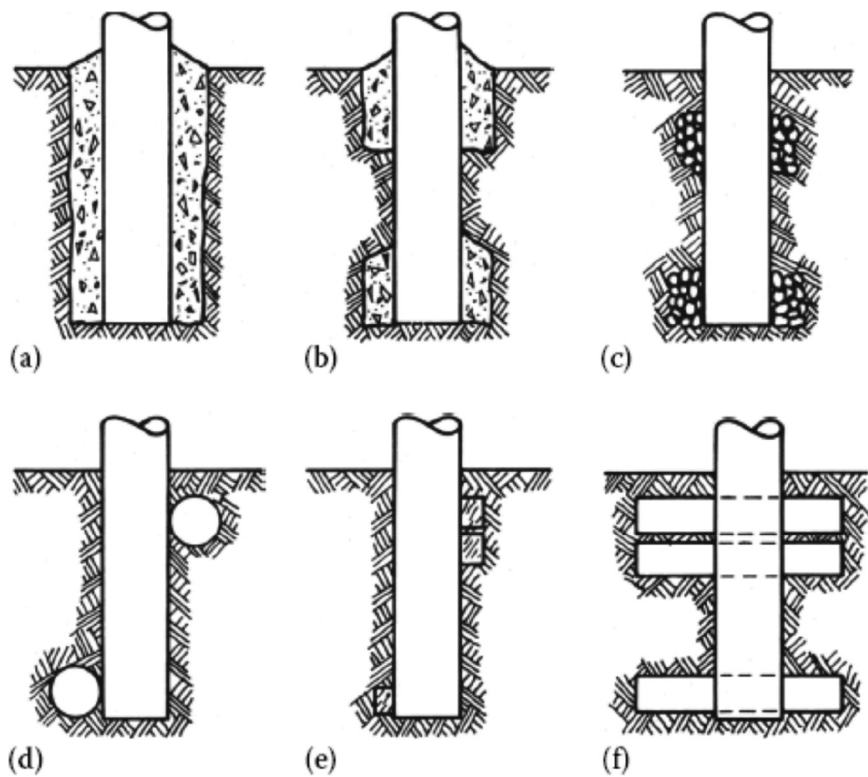


FIGURE 4.46 Setting techniques: (a) full-concrete setting, (b) concrete setting, (c) crushed stone setting, (d) plain earth setting, (e) heel-and-breast concrete blocks setting, and (f) bolted-timber setting.

TABLE 4.8
Various Earth Resistance to Displacement

Class	Earth Type	Percentage of Pole Resisting Moment, S_e
1	Hard rock	50
2	Shale, sandstone, or soft rock	50
3	Hard, dry hardpan	50
4	Crumbly, damp	40
5	Firm, moist	35
6	Plastic, wet	30
7	Loose, dry of loose, wet	25
8	Swamps, marshes	20

Source: Hubbard, A. and Watkins, W., *Electr. World*, 128, 94, 1947.

4.19 ADDITIONAL SOLVED NUMERICAL EXAMPLES FOR THE TRANSMISSION-LINE CALCULATIONS

Example 4.12: For Short Line

A 60 Hz, 30 MVA, 230 kV, 45 mi long, three-phase transmission line has 874.5 kcmil 54/3-strand ACSR conductors and is operating at 50°C. The conductors are spaced horizontally with $D_{ab}=20$ ft, $D_{bc}=20$ ft, and $D_{ac}=40$ ft. Determine the following:

- Inductive reactance in ohms per mile
- Capacitive reactance in ohms per mile
- Total line resistance in ohms
- Total impedance of the line in ohms
- Total capacitive reactance of the line in ohms
- Receiving-end current
- Sending-end current
- The line voltage drop
- The line-to-neutral sending-end voltage
- The line-to-line sending-end voltage
- The efficiency of the line
- The total power loss of the line
- The voltage regulation

Solution

Since the line length is 45 mi, the short-line model will be used in the calculations. From Table A.3, it can be found that

$$D_s = 0.0386 \text{ ft}, \quad r = 0.1228 \, \Omega/\text{mi},$$

$$X_a = 0.395 \, \Omega/\text{mi}, \quad X'_a = 0.0903 \, \Omega/\text{mi},$$

Thus, the equivalent spacing factor is

$$D_{eq} = (20 \text{ ft} \times 20 \text{ ft} \times 40 \text{ ft})^{1/3} = 25.198 \text{ ft}$$

- a. The inductive reactance of the line, in ohms per mile, can be determined, after linear interpolation of the spacing factor as

$$\begin{aligned} X_d &= 0.311 + \left(\frac{25.19 - 25.1}{25.2 - 25.1} \right) (0.3916 - 0.3911) \\ &= 0.39155 \\ &\cong 0.3916 \, \Omega/\text{mi}, \end{aligned}$$

Thus,

$$\begin{aligned} X_L &= X_a + X_d \\ &= 0.395 + 0.3916 \\ &= 0.7866 \, \Omega/\text{mi} \end{aligned}$$

b. The capacitive reactance of the line, in ohms per mile, is

$$\begin{aligned} X_C &= X'_a + X'_d \\ &= 0.0903 + 0.957 \\ &= 0.186 \text{ M}\Omega \cdot \text{mi} \end{aligned}$$

c. The total line resistance of the line, in ohms, is

$$\begin{aligned} R &= r \times l \\ &= (0.1228 \text{ }\Omega/\text{mi})(45 \text{ mi}) \\ &= 5.526 \text{ }\Omega \end{aligned}$$

d. The total impedance of the line, in ohms, is

$$\begin{aligned} \mathbf{Z} &= R + j(X_L \times l) \\ &= 5.526 + j(35.397 \text{ }\Omega/\text{mi})(45 \text{ mi}) \\ &= 5.526 + j35.397 \\ &\cong 35.826 \angle 81.13^\circ \Omega \end{aligned}$$

e. The total capacitive reactance of the line, in ohms, is

$$\begin{aligned} X_C &= \frac{X_C}{l} \\ &= \frac{0.186 \text{ M}\Omega \cdot \text{mi}}{45 \text{ mi}} \\ &= 0.00413 \text{ M}\Omega \\ &= 4.13 \text{ k}\Omega \end{aligned}$$

f. The receiving-end current is

$$\begin{aligned} I_R &= \frac{S_{3\phi}}{\sqrt{3}V_{R(L-L)}} \\ &= \frac{30 \text{ MVA}}{\sqrt{3}(230 \text{ kV})} \\ &= 75.31 \text{ A} \end{aligned}$$

where

$$V_{R(L-N)} = \frac{V_{R(L-L)}}{\sqrt{3}} = \frac{230 \text{ kV}}{\sqrt{3}} = 132.79 \text{ kV}$$

$$\mathbf{I}_R = I \angle \cos^{-1}(0.95) = 75.31 \angle 18.195^\circ \text{ A}$$

g. The sending-end current is

Since the line is a short line,

$$\mathbf{I}_S = \mathbf{I}_R = 75.31 \angle -18.925^\circ \text{ A}$$

h. The line voltage drop is

$$\begin{aligned} \text{VD} &= I_R \times Z \\ &= (75.31 \angle -18.195^\circ \text{ A})(35.826 \angle 81.13^\circ \Omega) \\ &= 2.698 \end{aligned}$$

i. The line-to-neutral sending-end voltage is

$$V_{s(L-N)} = V_R + \text{VD} = 134.04 \angle 1.03^\circ \text{ kV}$$

j. Since the line-to-line sending-end voltage is 30° ahead of line-to-neutral voltage and also $\sqrt{3}$ times greater than the line-to-neutral voltage,

$$\begin{aligned} V_{s(L-L)} &= \sqrt{3} V_{s(L-N)} \\ &= \sqrt{3} V_{s(L-N)} \angle \theta + 30^\circ \\ &= 134.04 \angle 1.03 + 30^\circ \\ &= 232.164 \angle 31.03^\circ \text{ kV} \end{aligned}$$

k. The efficiency of the line is

$$\begin{aligned} \% \mu &= \frac{\text{Output}}{\text{Input}} \times 100 \\ &= \frac{\sqrt{3} V_R I \cos \theta_R}{\sqrt{3} V_s I \cos \theta_s} \times 100 \\ &= \frac{132.79 \times \cos(18.195^\circ)}{134.04 \times \cos(18.195 + 1.03^\circ)} \times 100\% \\ &= 99.67\% \end{aligned}$$

l. The efficiency of the line is

m.

$$\begin{aligned} \sum P_{\text{loss}(3\phi)} &= 3I^2 R \\ &= 3 (75.31)^2 (55.26) \\ &= 94.015 \text{ kW} \end{aligned}$$

or

$$\begin{aligned} \sum P_{\text{loss}(3\phi)} &= I^2 R \text{ per phase} \\ &= (75.31)^2 (55.26) \\ &= \frac{94.015 \text{ kW}}{3} \\ &= 31.338 \text{ kW} \end{aligned}$$

n. The voltage regulation is

$$\begin{aligned}\%V_{\text{Reg}} &= \frac{232.164 - 230}{230} \times 100\% \\ &= 0.907\%\end{aligned}$$

PROBLEMS

- 4.1** Assume that the impedance of a line connecting buses 1 and 2 is $50\angle 90^\circ \Omega$ and that the bus voltages are $7,560\angle 10^\circ$ and $7,200\angle 0^\circ$ V per phase, respectively. Determine the following:
- Real power per phase that is being transmitted from bus 1 to bus 2
 - Reactive power per phase that is being transmitted from bus 1 to bus 2
 - Complex power per phase that is being transmitted
- 4.2** Solve Problem 4.1 assuming that the line impedance is $50\angle 26^\circ \Omega/\text{phase}$.
- 4.3** Verify the following equations:

$$V_{\text{pu}(L-N)} = V_{\text{pu}(L-L)}$$

$$VA_{\text{pu}(1\phi)} = VA_{\text{pu}(3\phi)}$$

$$Z_{\text{pu}(1\phi)} = Z_{\text{pu}(\Delta)}$$

- 4.4** Verify the following equations:
- Equation 4.24 for single-phase system
 - Equation 4.80 for three-phase system
- 4.5** Show that $Z_{B(\Delta)} = 3Z_{B(Y)}$
- 4.6** Consider two three-phase transmission lines with different voltage levels that are located side by side in close proximity. Assume that the bases of VA_B , $V_{B(1)}$, and $I_{B(1)}$ and the bases of VA_B , $V_{B(2)}$, and $I_{B(2)}$ are designated for the first and second lines, respectively. If the mutual reactance between the lines is $X_m \Omega$, show that this mutual reactance in per unit can be expressed as

$$X_{\text{pu}(m)} = (\text{Physical } X_m) \left[\frac{MVA_B}{kV_{B(1)}kV_{B(2)}} \right]$$

- 4.7** Consider Example 4.3 and assume that the transformer is connected in delta–wye. Use a 25 MVA base and determine the following:
- New line-to-line voltage of the LV side
 - New LV-side base impedance
 - Turns ratio of windings
 - Transformer reactance referred to as the LV side in ohms
 - Transformer reactance referred to as the LV side in per unit
- 4.8** Verify the following equations:
- Equation 4.92
 - Equation 4.93
 - Equation 4.94
 - Equation 4.96
- 4.9** Verify the following equations:
- Equation 4.100
 - Equation 4.102

4.10 Consider the one-line diagram given in Figure P4.1. Assume that the three-phase transformer T_1 has the nameplate ratings of 15,000 kVA, 7.97/13.8Y – 69A kV with leakage impedance of $0.01 + j0.08$ pu based on its ratings and that the three-phase transformer T_2 has the nameplate ratings of 1,500 kVA, 7.97A kV – 277/480Y V with leakage impedance of $0.01 + j0.05$ pu based on its ratings. Assume that the three-phase generator G_1 is rated 10/12.5 MW/MVA, 7.97/13.8Y kV with an impedance of $0 + j1.10$ pu based on its ratings and that the three-phase generator G_2 is rated 4/5 MW/MVA, 7.62/13.2Y kV with an impedance of $0 + j0.90$ pu based on its ratings. Transmission line TL_{23} has a length of 50 mi and is composed of 4/0 ACSR conductors with an equivalent spacing (D_m) of 8 ft and has an impedance of $0.445 + j0.976 \Omega/\text{mi}$. Its shunt susceptance is given as $5.78 \mu\text{S}/\text{mi}$. The line connects buses 2 and 3. Bus 3 is assumed to be an infinite bus, that is, the magnitude of its voltage remains constant at a given value, and its phase position is unchanged regardless of the power and PF demands that may be put on it. Furthermore, it is assumed to have a constant frequency equal to the nominal frequency of the system studied. Transmission line TL_{14} connects buses 1 and 4. It has a line length of 2 mi and an impedance of $0.80 + j0.80 \Omega/\text{mi}$.

Because of the line length, its shunt susceptance is assumed to be negligible. The load that is connected to bus 1 has a current magnitude $|I_1|$ of 523 A and a lagging PF of 0.707. The load that is connected to bus 5 is given as $8,000 + j6,000$ kVA. Use the arbitrarily selected 5,000 kVA as the three-phase kilovolt-ampere base and 39.84/69.00 kV as the line-to-neutral and line-to-line voltage base and determine the following:

- a. Complete Table P4.1 for the indicated values. Note the I_L means line current and $I\Phi$ means phase currents in delta-connected apparatus.

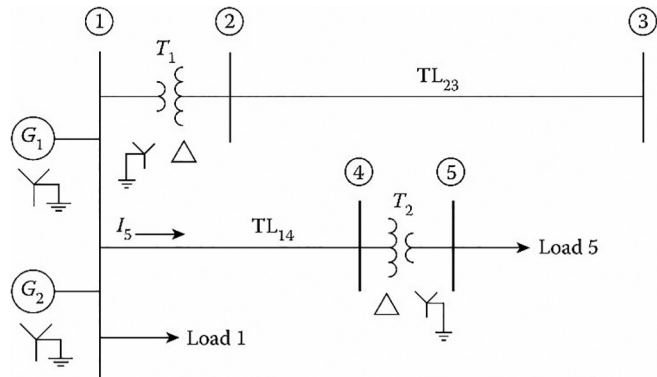


FIGURE P4.1 One-line diagram for Problem 4.10.

TABLE P4.1			
Table for Problem 4.10			
Quantity	Nominally 69 kV Circuits	Nominally 13 kV Circuits	Nominally 480V Circuits
kVA _{B(3φ)}	5,000 kVA	5,000 kVA	5,000 kVA
kV _{B(L – L)}	69 kV		
kV _{B(L – N)}	39.84 kV		
I _{B(L)}			
IB _(φ)			
Z _B			
Y _B			

- b. Draw a single-line positive-sequence network of this simple power system. Use the nominal- π circuit to represent the 69 kV line. Show the values of all impedances and susceptances in per unit on the chosen bases. Show all loads in per unit $P + jQ$.
- 4.11** Assume that a $500 + j200$ kVA load is connected to a load bus that has a voltage of $1.0 \angle 0^\circ$ pu. If the power base is 1,000 kVA, determine the per-unit R and X of the load:
- When load is represented by parallel connection
 - When load is represented by series connection
- 4.12** Assume that a three-phase transmission line is constructed of 700 kcmil, 37-strand copper conductors and the line length is 100 mi. The conductors are spaced horizontally with $D_{ab} = 10$ Ω , $D_{bc} = 8$ Ω , and $D_{ca} = 18$ Ω . Use 60 Hz and 25°C and determine the following line constants from tables in terms of
- Inductive reactance in ohms per mile
 - Capacitive reactance in ohms per mile
 - Total line resistance in ohms
 - Total inductive reactance in ohms
 - Total capacitive reactance in ohms
- 4.13** Redraw the phasor diagram shown in Figure 4.17 by using I as the reference vector and derive formulas to calculate the following:
- Sending-end phase voltage, V_s
 - Sending-end PF angle,
- 4.14** A three-phase, 60 Hz, 15 mi long transmission line provides 10 MW at a PF of 0.9 lagging at a line-to-line voltage of 34.5 kV. The line conductors are made of 26-strand 300 kcmil ACSR conductors that operate at 25°C and are equilaterally spaced 3 ft apart. Calculate the following:
- Source voltage
 - Sending-end PF
 - Transmission efficiency
 - Regulation of line
- 4.15** Repeat Problem 4.14 assuming the receiving-end PF of 0.8 lagging.
- 4.16** Repeat Problem 4.15 assuming the receiving-end PF of 0.8 leading.
- 4.17** A single-phase load is supplied by a $(34.5/\sqrt{3})$ kV feeder whose impedance is $95 + j340$ Ω and a $(34.5/\sqrt{3})/2.4$ kV transformer whose equivalent impedance is $0.24 + j0.99$ Ω referred to as its LV side. The load is 200 kW at a leading PF of 0.85 and 2.25 kV. Calculate the following:
- Calculate the sending-end voltage of feeder.
 - Calculate the primary-terminal voltage of transformer.
 - Calculate the real and reactive power input at the sending end of feeder.
- 4.18** A short three-phase line has a series reactance of 15 Ω per phase. Neglect its series resistance. The load at the receiving end of the transmission line is 15 MW per phase and 12 Mvar lagging per phase. Assume that the receiving-end voltage is given as $115 + j0$ kV per phase and calculate the following:
- Sending-end voltage
 - Sending-end current
- 4.19** A short 40 mi long three-phase transmission line has a series line impedance of $0.6 + j0.95$ Ω/mi per phase. The receiving-end line-to-line voltage is 69 kV. It has a full-load receiving-end current of $300 \angle -30^\circ$ A. Calculate the following:
- Calculate the percentage of voltage regulation.
 - Calculate the **ABCD** constants of the line.
 - Draw the phasor diagram of V_s , V_R , and I .

- 4.20** Repeat Problem 4.19 assuming the receiving-end current of $300\angle -45^\circ$ A.
- 4.21** A three-phase, 60 Hz, 12 MW load at a lagging PF of 0.85 is supplied by a three-phase, 138 kV transmission line of 40 mi. Each line conductor has a resistance of $41\ \Omega/\text{mi}$ and an inductance of $14\ \text{mH}/\text{mi}$. Calculate:
- Sending-end line-to-line voltage
 - Loss of power in transmission line
 - Amount of reduction in line power loss if load-PF were improved to unity
- 4.22** A three-phase, 60 Hz transmission line has a sending-end voltage of 39 kV and a receiving-end voltage of 34.5 kV. If the line impedance per phase is $18 + j57\ \Omega$, compute the maximum power receivable at the receiving end of the line.
- 4.23** A three-phase, 60 Hz, 45 mi long short line provides 20 MVA at a lagging PF of 0.85 at a line-to-line voltage of 161 kV. The line conductors are made of 19-strand 4/0 copper conductors that operate at 50°C . The conductors are equilaterally spaced with 4 ft spacing between them:
- Determine the percentage of voltage regulation of the line.
 - Determine the sending-end PF.
 - Determine the transmission-line efficiency if the line is single phase, assuming the use of the same conductors.
 - Repeat Part (c) if the line is three phase.

NOTES

- In this chapter, the emphasis has been placed on the LV and HV OH lines, including OH distribution lines.
- It is important to note that the material in this book, especially in this and the following chapters, illustrates only some selected requirements of the NESC. It is not advocated that the material in this book be used as the sole basis for line design in practice. Any line design must satisfy all applicable laws, ordinances, commission rules and orders, etc. While every precaution has been taken in the preparation of this book, the author and the publisher assume no responsibility for errors or omissions. Neither is any liability assumed for damages resulting from the use of information contained herein.
- For an excellent treatment of the subject, see Elgerd [1].
- It is defined as that impedance across which there is a voltage drop that is equal to the base voltage if the current through it is equal to the base current.
- For further information, see Anderson [4].
- This subject has been explained in greater depth in an excellent review by Stevenson [3].
- In Europe, it is called the *star configuration*.
- It is also the same as the positive and negative sequence of a line.
- Also called the *steady-state power limit*.
- For many decades, the electrical utility industry has declined to recognize two different kinds of reactive power, *leading* and *lagging vars*. Only *magnetizing vars* are recognized, printed on varmeter scale plates, bought, and sold. Therefore, in the following sections, the leading or lagging vars will be referred to as magnetizing vars.
- When dealing with high frequencies or with surges due to lightning, losses are often ignored [3].
- The application of series compensation on the new EHV lines has occasionally caused a problem known as *subsynchronous resonance*. It can be briefly defined as an oscillation due to the interaction between an SC-compensated transmission system in electrical resonance and a turbine generator mechanical system in torsional mechanical resonance. As a result of the interaction, a negative resistance is introduced into the electric circuit by the turbine generator. If the effective resistance magnitude is sufficiently large to make the net resistance of the circuit negative, oscillations can increase until mechanical failures take place in terms of flexing or even breaking of the shaft. The event occurs when the electrical subsynchronous resonance frequency is equal or close to 60 Hz minus the frequency of one of the natural torsional modes of the turbine generator. The most well-known subsynchronous resonance problem took place at Mojave Generating Station [8–11].

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5 Direct-Current Power Transmission

By all means marry. If you get a good wife, you'll be happy.

If you get a bad one, you'll become a philosopher.

Socrates

5.1 BASIC DEFINITIONS

Converter: A machine, device, or system for changing AC power to DC power or vice versa.

Rectifier: A converter for changing AC to DC.

Inverter: A converter for changing DC to AC.

Arc-back: A malfunctioning phenomenon in which a valve conducts in the reverse direction.

Pulse number (p): The number of pulsations (i.e., *cycles of ripple*) of the direct voltage per cycle of alternating voltage (e.g., pulse numbers for three-phase one-way and three-phase two-way rectifier bridges are 3 and 6, respectively).

Ripple: The AC component from DC power supply arising from sources within the power supply. It is expressed in peak, peak-to-peak, rms volts, or percent rms. Since high-voltage direct-current (HVDC) converters have large DC smoothing reactors, ~ 1 H, the resultant DC is constant (i.e., free from ripple). However, the direct voltage on the valve side of the smoothing reactor has ripple.

Ripple amplitude: The maximum value of the instantaneous difference between the average and instantaneous value of a pulsating unidirectional wave.

Reactor: An inductive reactor between the DC output of the converter and the load. It is used to smooth the ripple in the DC adequately, to reduce harmonic voltages and currents in the DC line, and to limit the magnitude of fault current. It is also called a *smoothing reactor*.

Commutation: The transfer of current from one valve to another in the same row.

Delay angle (α): The time, expressed in electrical degrees, by which the starting point of commutation is delayed. It cannot exceed 180° . It is also called *ignition angle* or *firing angle*.

Overlap angle (u): The time, expressed in degrees, during which the current is commutated between two rectifying elements. It is also called *commutation time*. In normal operation, it is less than 60° and is usually somewhere between 20° and 25° at full load.

Extinction angle (δ): The sum of the delay angle α and the overlap angle u of a rectifier and is expressed in degrees.

Ignition angle (β): The delay angle of an inverter and is equal to $\pi - \alpha$ electrical degrees.

Extinction (advance) angle (γ): The extinction angle of an inverter and is equal to $\pi - \gamma$ electrical degrees. It is defined as the time angle between the end of conduction and the reversal of the sign of the sinusoidal commutation voltage of the source.

Commutation margin angle (Z): The time angle between the end of conduction and the reversal of the sign of the nonsinusoidal voltage across the outgoing valve of an inverter. Under normal operating conditions, the commutation margin angle is equal to the extinction advance angle.

Equivalent commutating resistance (R_c): The ratio of drop of direct voltage to DC. However, it does not consume any power.

Thyristor (SCR): A thyristor (silicon-controlled rectifier) is a semiconductor device with an anode, a cathode terminal, and a gate for the control of the firing.

5.2 INTRODUCTION

For the most part, electric power is transmitted worldwide by means of AC. However, there are certain applications where DC transmission offers distinct economic and/or performance advantages. These applications include long-distance overhead transmission, underwater or underground transmission, and asynchronous ties between power systems. The first practical application of DC transmission was in Sweden in 1954. But, the wider applications of HVDC started after 1960.

Today, HVDC lines are used all over the world to transmit increasingly large amounts of energy over long distances. In the United States, one of the best-known HVDC transmission lines is the Pacific HVDC Intertie, which interconnects California with Oregon. Additionally, there are ± 400 kV Coal Creek-Dicken lines as a good example for HVDC system. In Canada, Vancouver Island is supplied through an HVDC cable. Another famous HVDC system is the interconnection between England and France, which uses underwater cables.

Typically, in an HVDC system, the AC voltage is rectified and a DC transmission line transmits the energy. An inverter that is located at the end of the DC transmission line converts the DC voltage to AC, for example, the Pacific HVDC Intertie that operates with ± 500 kV voltage and interconnects Southern California with the hydro station in Oregon. The bundled conductors are also used in HVDC transmission lines.

5.3 OVERHEAD HVDC TRANSMISSION

Figure 5.1 shows some of the typical circuit arrangements (*links*) for HVDC transmissions. In the monopolar arrangement, which is shown in Figure 5.1a, there is only one insulated transmission conductor (*pole*) installed and ground return is used. It is the least expensive arrangement but has certain disadvantages. For example, it causes the corrosion of buried pipes, cable sheaths, ground electrodes, etc., due to the electrolysis phenomenon caused by the ground return current. It is used in DC systems that have low power ratings, primarily with cable transmission. In order to eliminate the aforementioned electrolysis phenomenon, a metallic return (*conductor*) can be used, as shown in Figure 5.1b.

The bipolar circuit arrangement has two insulated conductors used as plus and minus poles. The two poles can be used independently if both neutrals are grounded. *Under normal operation*, the currents flowing in each pole are equal, and therefore, there is no ground current.

Under emergency operation, the ground return can be used to provide for increased transmission capacity. For example, if one of the two poles is out of order, the other conductor with ground return can carry up to the total power of the link. In that case, the transmission line losses are doubled. As shown in Figure 5.1c, the rated voltage of a bipolar arrangement is given as $\pm V_d$ (e.g., ± 500 kV, which is read as *plus and minus 500 kV*). Figure 5.2 shows a DC transmission system operating in the bipolar mode.

It is possible to have two or more poles all having the same polarity and always having a ground return. This arrangement is known as the *homopolar arrangement* and is used to transmit power in DC systems that have very large ratings. The DC tower normally carries only two insulated conductors, and the ground return can be used as the additional conductor.

5.4 COMPARISON OF POWER TRANSMISSION CAPACITY OF HVDC AND HVAC

Assume that there are two comparable transmission lines: one is the AC and the other is the DC line. Assume that both lines have the same length and are made of the same conductor sizes and that the loading of both lines is thermally limited so that current I_d equals the rms AC I_L . Also assume that the AC line has three phases and three wires and has a power factor of 0.945 and the DC line is a bipolar circuit arrangement with two conductors. Furthermore, assume that the AC and DC

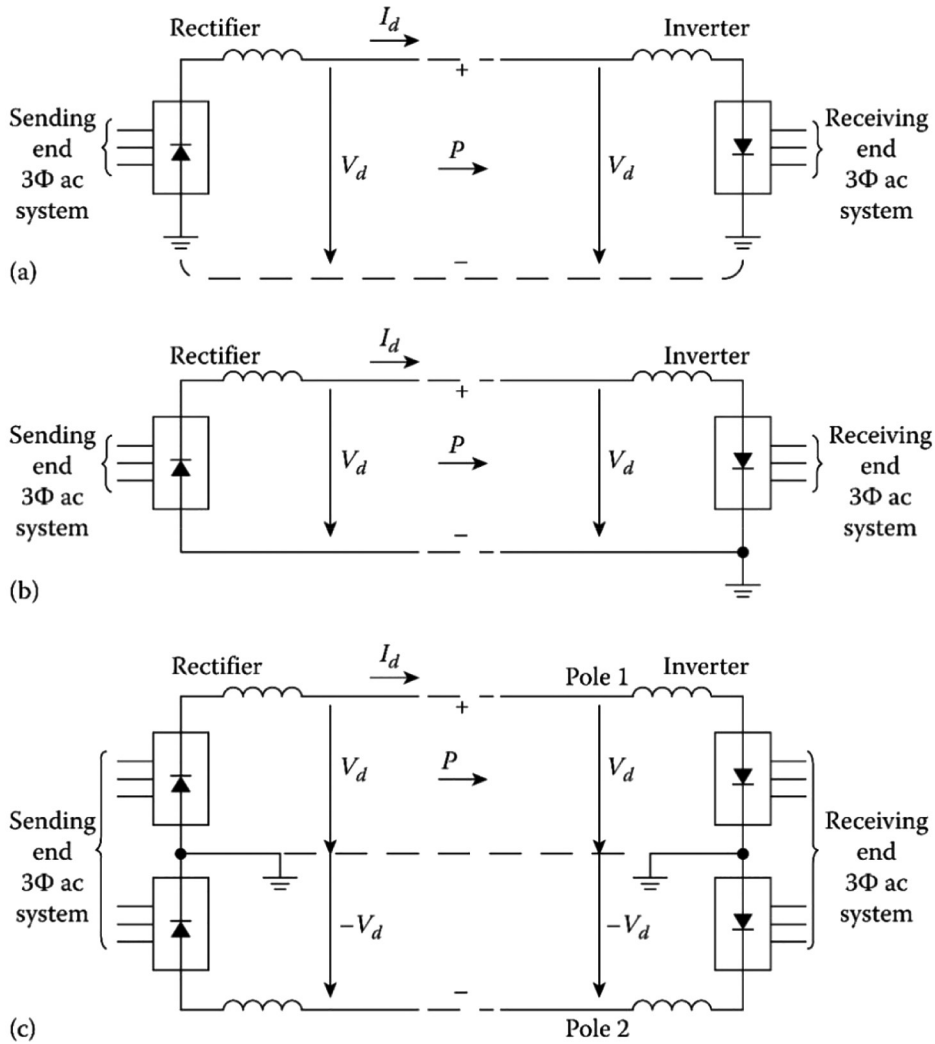


FIGURE 5.1 Typical circuit arrangements for HVDC transmissions: (a) monopolar arrangement with ground return, (b) monopolar arrangement with metallic return grounded at one end, and (c) bipolar arrangement.

insulators withstand the same crest voltage to ground so that the voltage V_d is equal to $\sqrt{2}$ times the rms AC voltage. Therefore, it can be shown that the DC power per conductor is

$$P_{(dc)} = V_d I_d \quad (5.1)$$

and the AC power per conductor is

$$P_{(dc)} = V_{(L-N)} I_L \cos \theta W / \text{conductor} \quad (5.2)$$

where

V_d is the line-to-ground DC voltage in volts

$V_{(L-N)}$ is the line-to-neutral AC voltage in volts

I_d is the DC line current in amperes

I_L is the AC line current in amperes

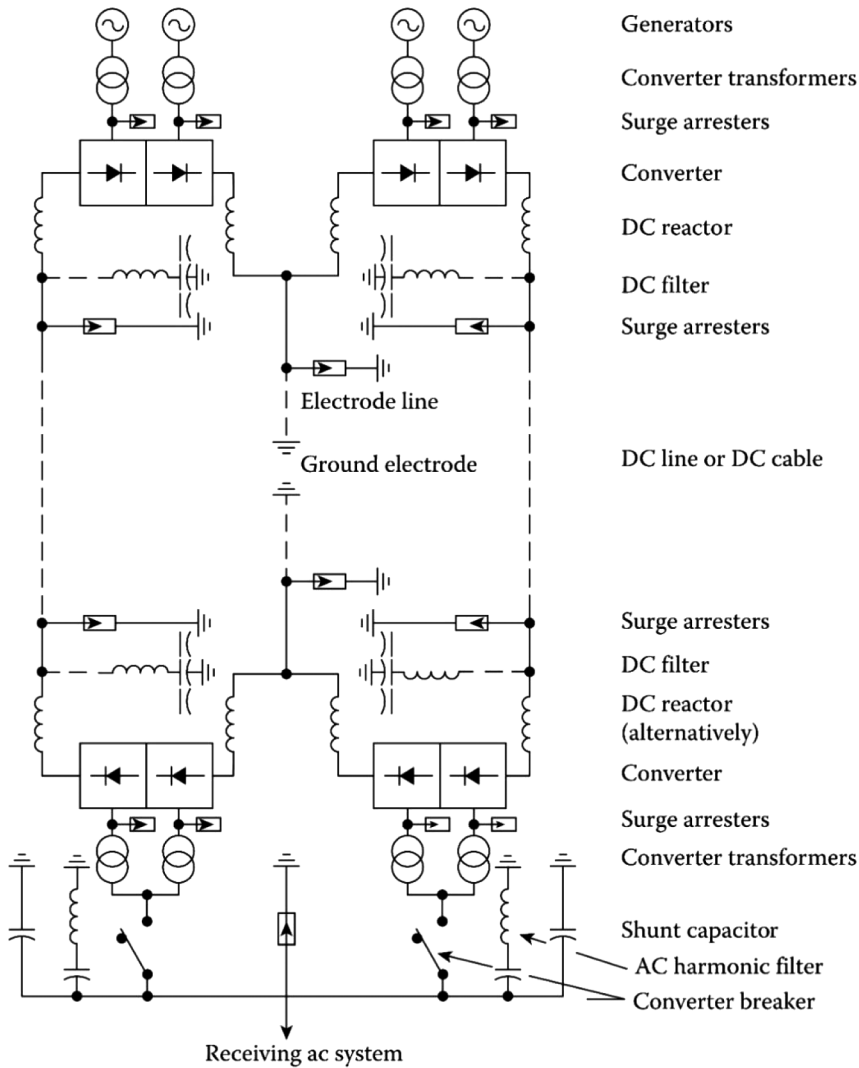


FIGURE 5.2 A DC transmission system operating in bipolar mode. (From Fink, D. G. and Beaty, H. W., *Standard Handbook for Electrical Engineers*, 11th edn., McGraw-Hill, New York, 1978.)

Therefore, the ratio of the DC power per conductor to the AC power per conductor (phase) can be expressed as

$$\frac{P_{(dc)}}{P_{(ac)}} = \frac{V_d I_d}{V_{(L-N)} I_L \cos \theta} \quad (5.3)$$

or

$$\frac{P_{(dc)}}{P_{(ac)}} = \frac{\sqrt{2}}{\cos \theta} \quad (5.4)$$

but since

$$\cos \theta = 0.945$$

then

$$\frac{P_{(dc)}}{P_{(ac)}} = 1.5 \quad (5.5)$$

or

$$P_{(dc)} = 1.5P_{(ac)} \text{ W/conductor} \quad (5.6)$$

Furthermore, the total power transmission capabilities for the DC and AC lines can be expressed as

$$P_{(dc)} = 2p_{(dc)} \text{ W} \quad (5.7)$$

and

$$P_{(ac)} = 3p_{(ac)} \text{ W} \quad (5.8)$$

Therefore, their ratio can be expressed as

$$\frac{P_{(dc)}}{P_{(ac)}} = \frac{2}{3} \times \frac{P_{(dc)}}{P_{(ac)}} \quad (5.9)$$

Substituting Equation 5.5 into Equation 5.9,

$$\frac{P_{(dc)}}{P_{(ac)}} = \frac{2}{3} \times \frac{3}{2} = 1$$

or

$$P_{(dc)} = P_{(ac)} \text{ W} \quad (5.10)$$

Thus, both lines have the same transmission capability and can transmit the same amount of power. However, the DC line has two conductors rather than three and thus requires only two-thirds as many insulators. Therefore, the required towers and rights of way are narrower in the DC line than in the AC line. Even though the power loss per conductor is the same for both lines, the total power loss of the DC line is only two-thirds that of the AC line.

Thus, studies indicate that a DC line generally costs about 33% less than an AC line of the same capacity. Furthermore, if a two-pole (homopolar) DC line is compared with a double-circuit three-phase AC line, the DC line costs would be about 45% less than the AC line. In general, the cost advantage of the DC line increases at higher voltages. The power losses due to the corona phenomena are smaller for DC than for AC lines.

The reactive powers generated and absorbed by a high-voltage alternating-current (HVAC) transmission line can be expressed as

$$Q_c = X_c V^2 \text{ var s/unit length} \quad (5.11)$$

or

$$Q_c = \omega C V^2 \text{ var s/unit length} \quad (5.12)$$

and

$$Q_L = X_L I^2 \text{ var s/unit length} \quad (5.13)$$

or

$$Q_L = \omega L I^2 \text{ var s/unit length} \quad (5.14)$$

where

X_c is the capacitive reactance of line in ohms per-unit length

X_L is the inductive reactance of line in ohms per-unit length

C is the shunt capacitance of line in farads per-unit length

L is the series inductance of line in farads per-unit length

V is the line-to-line operating voltage in volts

I is the line current in amperes

If the reactive powers generated and absorbed by the line are equal to each other,

$$Q_c = Q_L$$

or

$$\omega_c V^2 = \omega L I^2$$

from which the surge impedance of the line can be found as

$$Z_c = \frac{V}{I} = \sqrt{\frac{L}{C}} \Omega \quad (5.15)$$

Therefore, the power transmitted by the line at the surge impedance can be expressed as

$$\text{SIL} = \frac{V_{L-L}^2}{Z_c} \text{ W} \quad (5.16)$$

Note that this surge impedance loading (or natural load) is a function of the voltage and line inductance and capacitance. However, it is not a function of the line length. In general, the economical load of a given overhead transmission line is larger than its SIL. In this case, the net reactive power absorbed by the line must be provided from one or both ends of the line and from intermediate series capacitors.

Hence, the costs of necessary series capacitor and shunt reactor compensation should be taken into account in the comparison of AC versus DC lines. The DC line itself does not require any reactive power. However, the converters at both ends of the line require reactive power from the AC systems.

Underground cables used for AC transmission can also be used for DC, and they can normally carry more DC power than AC due to the absence of capacitive charging current and better utilization of insulation and less dielectric wear. However, an HVDC transmission cable is designed somewhat differently than that of an AC transmission cable. Since a power cable employed for DC power transmission does not have capacitive leakage currents, the power transmission is restricted by the $I^2 R$ losses only.

Furthermore, submarine or underground AC cables are always operated at a load that is far less than the surge impedance load in order to prevent overheating. As a result of this practice, the reactive power generated by charging the shunt capacitance is greater than that absorbed by the series inductance. Thus, compensating shunt reactors are to be provided at regular intervals (~20 mi). Contrarily, DC cables do not have such restrictions. Thus, the power transmission using DC cable is much cheaper than AC cable.

The major advantages of the DC transmission are summarized as follows:

1. If the high cost of converter stations is excluded, the DC overhead lines and cables are less expensive than AC overhead lines and cables. The break-even distance is about 500 mi for the overhead lines, somewhere between 15 and 30 mi for submarine cables and 30 and 60 mi for underground cables. Therefore, in the event that the transmission distance is less than the break-even distance, the AC transmission is less expensive than DC; otherwise, the DC transmission is less expensive. The exact break-even distance depends on local conditions, line performance requirements, and connecting AC system characteristics.
2. A DC link is asynchronous; that is, it has no stability problem in itself. Therefore, the two AC systems connected at each end of the DC link do not have to be operating in synchronism with respect to each other or even necessarily at the same frequency.
3. The corona loss and Radio Interference (RI) conditions are better in the DC than in the AC lines.
4. The power factor of the DC line is always unity, and therefore, no reactive compensation is needed.
5. Since the synchronous operation is not demanded, the line length is not restricted by stability.
6. The interconnection of two separate AC systems via a DC link does not increase the short circuit capacity, and thus the circuit breaker ratings, of either system.
7. The line loss is smaller than the comparable AC line.

The major disadvantages of the DC transmission are summarized as follows:

8. The converters generate harmonic voltages and currents on both AC and DC sides, and therefore, filters are required.
9. The converters consume reactive power.
10. The DC converter stations are expensive.
11. The DC circuit breakers have disadvantages with respect to the AC circuit breakers because the DC does not decrease to zero twice a cycle, contrary to the AC.

5.5 HVDC TRANSMISSION LINE INSULATION

The factors that affect the insulation of the HVDC overhead transmission lines are (1) steady-state operating voltages, (2) switching surge over voltages, and (3) lightning over voltages. The factors must be restricted to values that cannot cause puncture or flashover of the insulation. The steady-state operating voltage affects the selection of leakage distance, particularly when there is considerable pollution in the environment. The switching surge and lightning over voltages influence the required insulator chain length and strike distance [1].

Consider the transmission line conductor configurations shown in Figure 5.3 for the comparable AC and DC systems. For the steady-state operating voltages, it can be shown that the factor K given by the following equation relates the DC and AC voltages to ground that may be applied to a given insulation

$$K = \frac{V_d / 2}{E_p} \quad (5.17)$$

or

$$\frac{1}{2}V_d = KE_p \quad (5.18)$$

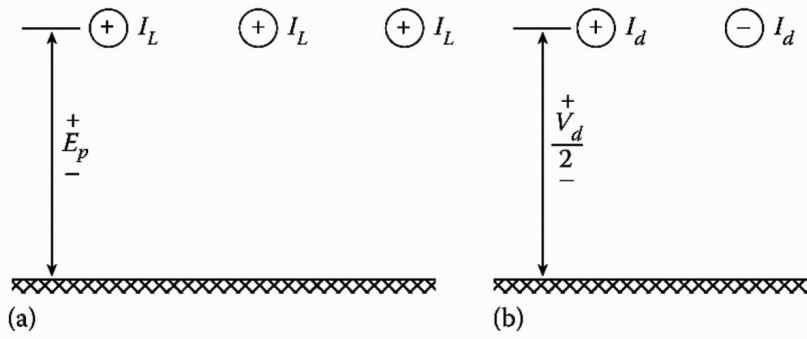


FIGURE 5.3 Transmission line conductor configuration for high voltage: (a) AC system and (b) DC system.

where

V_d is the line-to-line DC voltage in volts

$\frac{1}{2}V_d$ is the line-to-ground DC V_d voltage in volts

E_p is the line-to-neutral AC voltage in volts

Typical values of factor K are as follows:

$K = 42$ for indoor porcelain

$K = 1$ for outdoor porcelain

$2 < K < 6$ for insulated power cables

The given data for factor K imply that conventional insulators have inferior wet flashover performance when used in the high-voltage service. Therefore, the HVDC lines require special insulators.

Typically, the following approximate insulation levels are required to withstand switching surges on overhead lines:

For HVAC lines,

$$\begin{aligned} \text{ac insulation level} &= K_1 E_p \\ &\cong 2.5 E_p \end{aligned} \quad (5.19)$$

and for HVDC lines,

$$\begin{aligned} \text{dc insulation level} &= K_2 \left[\frac{1}{2} V_d \right] \\ &\cong 1.7 \left[\frac{1}{2} V_d \right] \end{aligned} \quad (5.20)$$

Therefore, for a fixed value of insulation level, the following operating voltages can be used from the standpoint of switching surge performance:

$$K_1 E_p = K_2 \left[\frac{1}{2} V_d \right] \quad (5.21)$$

If $K_1 = 2.5$ and $K_2 = 1.7$,

$$2.5 E_p = 1.7 \left[\frac{1}{2} V_d \right]$$

or

$$\left[\frac{1}{2} V_d \right] = 1.47 E_p \quad (5.22)$$

On overhead lines, the maximum steady-state operating voltage or the minimum conductor size is also restricted by the power losses and RI due to corona. But in cables, the restricting factor is usually the normal steady-state operating voltage.

Example 5.1

Assume that the overhead AC and DC lines shown in Figure 5.3 have the same line length and are made of the same size conductors that transmit the same amount of power and have the same total PR losses. Assume that the AC line is three phase, has three wires, and has a unity power factor and that the DC line has two wires plus ground return. Furthermore, assume that the factors K_1 and K_2 are 2.5 and 1.7, respectively, and determine the following:

- Line-to-line DC voltage of V_d in terms of line-to-neutral voltage E_p
- The DC line current I_d in terms of AC line current I_L
- Ratio of DC insulation level to AC insulation level

Solution

- Since the power losses are the same in either system,

$$P_{\text{loss}(\text{dc})} = P_{\text{loss}(\text{ac})}$$

or

$$2I_d^2 R_{(\text{dc})} = 3I_L^2 R_{(\text{ac})}$$

where, ignoring the skin effects,

$$R_{(\text{dc})} = R_{(\text{ac})}$$

so that

$$I_d = \sqrt{\frac{3}{2}} I_L$$

or

$$I_d = 1.225 I_L$$

- Since

$$P_{(\text{dc})} = P_{(\text{ac})}$$

or

$$V_d I_d = 3 E_p I_L$$

$$V_d = 2.45 E_p$$

c. The ratio is

$$\frac{\text{dc insulation level}}{\text{ac insulation level}} = \frac{K_2 (V_d / 2)}{K_1 E_p}$$

where

$$K_1 = 2.5 \quad K_2 = 1.7$$

Therefore,

$$\frac{\text{dc insulation level}}{\text{ac insulation level}} = 8.8328$$

or

$$\text{dc insulation level} = 0.8328 (\text{ac insulation level})$$

5.6 THREE-PHASE BRIDGE CONVERTER

The energy conversion from AC to DC is called *rectification* and the conversion from DC to AC is called *inversion*. A converter can operate as a rectifier or as an inverter provided that it has grid control. A valve, whether it is a mercury arc valve or a solid-state (*thyristor*) valve, can conduct in only one direction (*the forward direction*), from anode to cathode. The resultant arc voltage drop is <50 V. The valve can endure a considerably high voltage in the negative (*inverse*) direction without conducting. Any arc-back in mercury arc rectifiers can be stopped by grid control and by a bypass valve.

Presently, the thyristors have converter current ratings up to 2,000 A. Their typical voltage rating is 3,000 V. A solid-state valve has a large number of thyristors connected in series to provide proper voltage division among the thyristors. The thyristors are also connected in parallel, depending on the valve current rating. The thyristors are grouped in modules, each having two to ten thyristors with all auxiliary circuits. Some of the advantages of thyristors are as follows:

1. There is no possibility of arc-back.
2. They have lower maintenance requirements.
3. They have less space requirements.
4. They have shorter deionization time.
5. There is no need for degassing facilities.
6. There is no need for bypass valves.

In this chapter, the term *valve* includes the solid-state devices as well as the mercury arc valves.

5.7 RECTIFICATION

In a given bridge rectifier, the transfer of current from one valve to another in the same row is called *commutation*. The time during which the current is commutated between two rectifying elements is known as the *overlap angle* or *commutation time*. Therefore, if two valves conduct simultaneously, there is no overlap, that is, *commutation delay*. The time during which the starting point of commutation is delayed is called the *delay angle*. The delay angle is governed by the grid control setting. Neglecting overlap angle, the average direct voltage for a given delay angle α can be expressed as

$$V_d = \frac{3\sqrt{3}}{\pi} E_m \cos \alpha \quad (5.23)$$

or

$$V_d = V_{d0} \cos \alpha \quad (5.24)$$

Since

$$V_{d0} = \frac{3\sqrt{3}}{\pi} E_m \quad (5.25)$$

where

V_{d0} is the ideal no-load direct voltage

E_m is the maximum value of phase-neutral alternating voltage

α is the delay angle

However, if there is no delay, that is, $\alpha = 0$, the average direct voltage can be expressed as

$$V_{d0} = \frac{3\sqrt{3}}{\pi} E_m \quad (5.26)$$

or

$$\begin{aligned} V_{d0} &= \frac{3\sqrt{6}}{\pi} E_{(L-N)} \\ &= 2.34 E_{(L-N)} \end{aligned} \quad (5.27)$$

or

$$\begin{aligned} V_{d0} &= \frac{3\sqrt{2}}{\pi} E_{(L-L)} \\ &= 1.35 E_{(L-L)} \end{aligned} \quad (5.28)$$

where

$E_{(L-N)}$ is the rms line-to-neutral alternating voltage

$E_{(L-L)}$ is the rms line-to-line alternating voltage

From Equation 5.24, one can observe that the delay angle α can change the average direct voltage by the factor $\cos \alpha$. Since α can take values from 0 to almost 180° , the average direct voltage can take values from positive V_{d0} to negative V_{d0} . However, the negative direct voltage V_d with positive current I_d causes the power to flow in the opposite direction. Hence, the converter operates as an inverter rather than as a rectifier. Note that since the current can only flow from anode to cathode, the direction of current I_d remains the same.

It can be shown that the rms value of the fundamental-frequency component of AC is

$$I_{L1} = \frac{\sqrt{6}}{\pi} I_d \quad (5.29)$$

or

$$I_{L1} = 0.780 I_d \quad (5.30)$$

When losses are disregarded, the active AC power can be set equal to the DC power, that is,

$$P_{(ac)} = P_{(dc)} \quad (5.31)$$

where

$$P_{(ac)} = 3E_{(L-N)}I_{L1} \cos \theta \quad (5.32)$$

$$P_{(dc)} = V_d I_d \quad (5.33)$$

Substituting Equation 5.29 into Equation 5.32,

$$P_{(ac)} = \frac{3\sqrt{6}}{\pi} E_{(L-N)} I_d \cos \theta \quad (5.34)$$

Also substituting Equations 5.24 and 5.27 simultaneously into Equation 5.33,

$$P_{(ac)} = \frac{3\sqrt{6}}{\pi} E_{(L-N)} I_d \cos \alpha \quad (5.35)$$

Thus, by substituting Equations 5.34 and 5.35 into Equation 5.31, it can be shown that

$$\cos \theta = \cos \alpha \quad (5.36)$$

$$\Delta V_d = \frac{V_{d0}}{2} [\cos \alpha - \cos(\alpha + u)] \quad (5.37)$$

Thus, the associated average direct voltage can be expressed as

$$V_d = V_{d0} \cos \alpha - \Delta V_d \quad (5.38)$$

or

$$V_d = \frac{1}{2} V_{d0} [\cos \alpha - \cos(\alpha + u)] \quad (5.39)$$

Note that the extinction angle δ is

$$\delta \triangleq \alpha + u \quad (5.40)$$

Thus, substituting Equation 5.40 into Equations 5.37 and 5.39,

$$\Delta V_d = \frac{1}{2} V_{d0} (\cos \alpha - \cos \delta) \quad (5.41)$$

and

$$V_d = \frac{1}{2} V_{d0} (\cos \alpha + \cos \delta) \quad (5.42)$$

The overlap angle u is due to the fact that the AC supply source has inductance. Thus, the currents in it cannot change instantaneously. Therefore, the current transfer from one phase to another takes a certain time, which is known as the commutation time or overlap time (u/m). In normal operation, the overlap angle is $0^\circ < u < 60^\circ$. Whereas in the abnormal operation mode, it is $60^\circ < u < 120^\circ$. The commutation delay takes place when two phases of the supplying AC source are short-circuited. Therefore, it can be shown that at the end of the commutation,

$$I_d = I_{s2} [\cos \alpha - \cos(\alpha + u)] \quad (5.43)$$

but

$$I_{s2} = \frac{\sqrt{3}E_m}{2\omega L_c} \quad (5.44)$$

Substituting Equation 5.44 into Equation 5.43,

$$I_d = \frac{\sqrt{3}E_m}{2\omega L_c} [\cos \alpha - \cos(\alpha + u)] \quad (5.45)$$

where

I_{s2} is the maximum value of current in line-to-line short circuit on AC source

L_c is the series inductance per phase of AC source

By dividing Equations 5.37 and 5.43 side by side,

$$\frac{\Delta V_d}{I_d} = \frac{V_{d0} [\cos \alpha - \cos(\alpha + u)]}{2I_{s2} [\cos \alpha - \cos(\alpha + u)]}$$

or

$$\frac{\Delta V_d}{I_d} = \frac{V_{d0}}{2I_{s2}} \quad (5.46)$$

$$\Delta V_d = \frac{I_d}{2I_{s2}} V_{d0} \quad (5.47)$$

substituting Equation 6.47 into Equation 6.38,

$$V_d = V_{d0} \left(\cos \alpha - \frac{I_d}{2I_{s2}} \right) \quad (5.48)$$

or

$$V_d = V_{d0} \cos \alpha - R_c I_d \quad (5.49)$$

where R_c is the equivalent commutation resistance per phase (it does not consume any power and represents voltage drop due to commutation)

$$R_c = \frac{3}{\pi} X_c \quad (5.50)$$

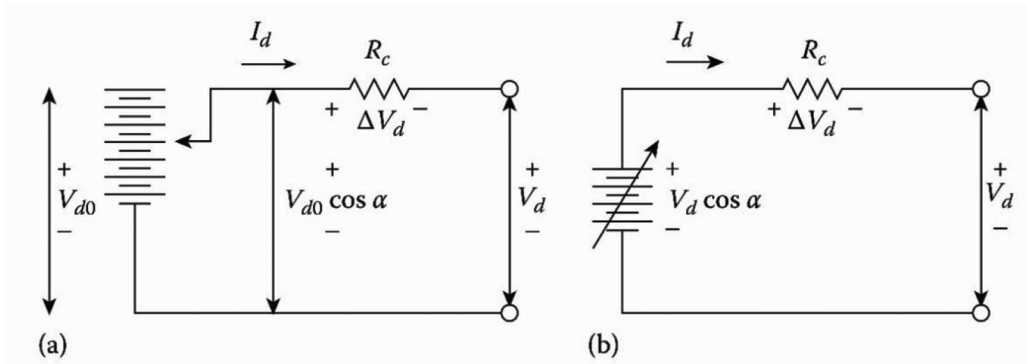


FIGURE 5.4 Equivalent circuit representations of bridge rectifier where the direct voltage V_d can be controlled: (a) by changing the delay angle or (b) by varying the no-load direct voltage using a transformer tap changer.

or

$$R_c = \frac{3}{\pi} \omega L_c \quad (5.51)$$

or

$$R_c = 6fL_c \quad (5.52)$$

Figure 5.4 shows two different representations of the equivalent circuit of a bridge rectifier based on Equation 5.49. The direct voltage V_d can be controlled by changing the delay angle α or by varying the no-load direct voltage using a transformer tap changer.

Example 5.2

Figure 5.5 shows that a rectifier transformer with a tap changer underload is connected to a large AC network. Assume that the Thevenin equivalent voltage of the AC network is given as 92.95/161Y kV and that the impedance of the rectifier transformer is 0.10 pu Q based on transformer ratings. The subtransient Thevenin impedances of the AC system are to be computed from the three-phase short circuit data given in the figure for the faults occurring at the bus.

Assume zero power factor faults in circuits of this size. The bridge rectifier ratings are given as 125 kV and 1,600 A for the maximum continuous no-load direct voltage (i.e., V_{d0}) and maximum continuous current (i.e., I_d), respectively. Use the given data and specify the rectifier transformer in terms of the following:

- Three-phase kilovolt-ampere rating
- Wye-side kilovolt rating

Solution

- The three-phase kilovolt-ampere rating of a rectifier transformer can be determined from

$$S_{(B)} = 1.047V_{d0}I_d$$

where

$$V_{(d0)} = V_{dr0} = 125 \text{ kV}$$

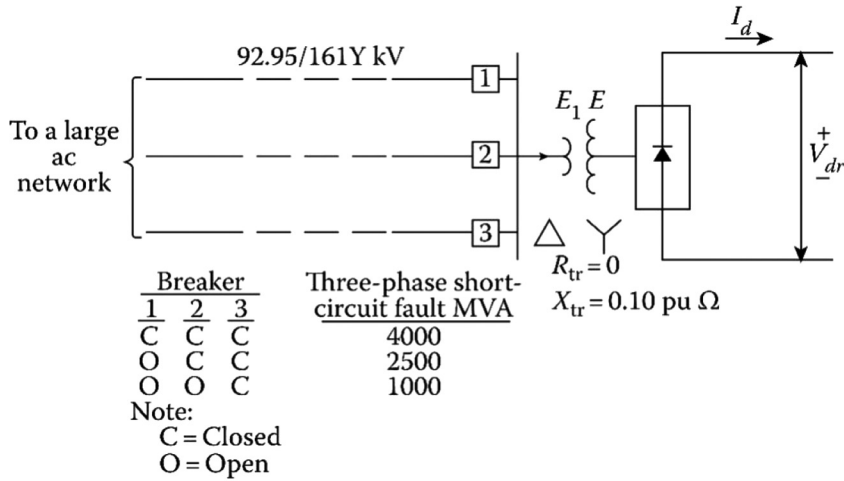


FIGURE 5.5 System for Example 5.2.

Therefore,

$$S_{(B)} = 1.047 (125 \text{ kV}) (1,600 \text{ A}) = 209,400 \text{ kVA}$$

(b) Since

$$V_{d0} = 2.34 E_{(L-N)}$$

then

$$\begin{aligned} E_{(L-N)} &= \frac{V_{d0}}{2.34} \\ &= \frac{125 \text{ kV}}{2.34} = 53.4188 \text{ kV} \end{aligned}$$

5.8 PER-UNIT SYSTEMS AND NORMALIZING

The per-unit value of any quantity is its ratio to the chosen base quantity of the same dimensions. Therefore, a per-unit quantity is a *normalized* quantity with respect to a selected base value. Figure 5.6 shows a one-line diagram of a single-bridge converter system connected to a transformer with a tap changer underload. The figure also shows the fundamental AC and DC system quantities. The base quantities are indicated by the subscript *B*.

All AC voltages indicated in Figure 5.6 are line-to-neutral voltages. Therefore,

$$\begin{aligned} E &= E_{(L-N)} \\ &= \frac{E_m}{\sqrt{2}} \end{aligned} \tag{5.53}$$

The ratio of base AC voltages is a fixed value and is defined as

$$a \triangleq \frac{E_{l(B)}}{E_{(B)}} = \frac{I_{(B)}}{I_{(B)}} \tag{5.54}$$

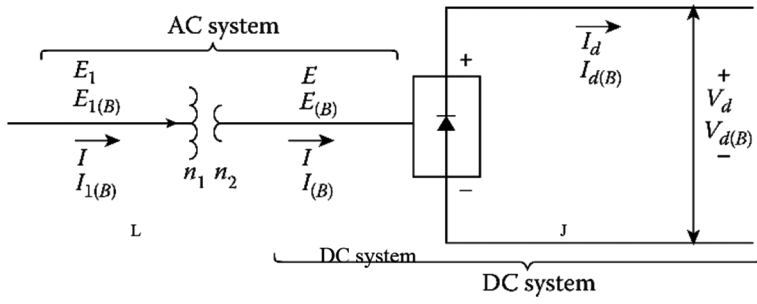


FIGURE 5.6 One-line diagram of a single-bridge converter system.

On the other hand, the turns ratio in use is a variable that is changeable by the load tap changers (LTC) position and is defined as

$$n \triangleq \frac{n_1}{n_2} = \frac{E_1}{E} = \frac{I}{I_1} \quad (5.55)$$

Therefore, the per-unit voltage on the AC side of the converter transformer is

$$E_{1(\text{pu})} = \frac{E_1}{E_{1(B)}} = \text{pu V} \quad (5.56)$$

and the per-unit voltage on the DC side of the converter transformer is

$$E_{(\text{pu})} = \frac{E}{E_{(B)}} = \text{pu V} \quad (5.57)$$

where

$$E = \frac{E_1}{n} \text{ V} \quad (5.58)$$

$$E_{(B)} = \frac{E_{1(B)}}{a} \text{ V} \quad (5.59)$$

Thus, Equation 5.57 can be expressed as

$$E_{(\text{pu})} = \left(\frac{a}{n} \right) E_1 \text{ pu V} \quad (5.60)$$

Note that when the LTC is on neutral,

$$n = a$$

and

$$E_{(\text{pu})} \left\langle E_{1(\text{pu})} n \right\rangle a$$

Thus, when the voltage on the DC side of the converter transformer is lowered with respect to the voltage on the AC side of the converter transformer by using the LTC of the transformer, the DC voltage V_d decreases.

5.8.1 AC SYSTEM PER-UNIT BASES

The per-unit bases for the quantities that are located on the AC side of the converter transformer are as follows:

$E_{1(B)}$ is the arbitrarily chosen voltage value

$S_{1(B)}$ is the arbitrarily chosen volt-ampere value

$$I_{1(B)} = \frac{S_{1(B)}}{E_{1(B)}} \text{ A} \quad (5.61)$$

$$Z_{1(B)} = \frac{E_{1(B)}}{I_{1(B)}} \Omega \quad (5.62)$$

$$L_{1(B)} = \frac{Z_{1(B)}}{\omega_{(B)}} \text{ H} \quad (5.63)$$

where

$$\omega_{(B)} = \omega = 377 \text{ if } f = 60 \text{ Hz}$$

On the other hand, the per-unit bases for the quantities that are located on the DC side of the converter transformer are

$$E_{(B)} = \frac{E_{1(B)}}{a} \text{ V} \quad (5.64)$$

$$\begin{aligned} S_{(B)} &= \text{Arbitrarily chosen volt-ampere value (same as before)} \\ &= S_{1(B)} \end{aligned}$$

$$I_{(B)} = a I_{1(B)} \text{ A} \quad (5.65)$$

$$Z_{(B)} = \frac{Z_{1(B)}}{a^2} \Omega \quad (5.66)$$

$$L_{(B)} = \frac{L_{1(B)}}{a^2} \text{ H} \quad (5.67)$$

5.8.2 DC SYSTEM PER-UNIT BASES

The DC system per-unit bases are constrained by the bridge circuit steady-state equations to be related to the chosen AC system per-unit bases. Note the analogy to the selection of AC bases on the two sides of a transformer, wherein such bases must be related by the transformer turns ratio.

When the firing angle α , overlap angle u , and DC I_d are zero, the DC voltage base is

$$V_{d(B)} \triangleq V_{d0}$$

or

$$V_{d(B)} = \frac{3\sqrt{6}}{\pi} E_{(B)} \quad (5.68)$$

substituting Equation 5.64 into Equation 5.68, the DC voltage base can be expressed as

$$V_{d(B)} = \frac{3\sqrt{6}}{\pi} \times \frac{E_{l(B)}}{a} \quad (5.69)$$

The DC base can be expressed as

$$I_{d(B)} = \sqrt{\frac{3}{2}} I_{(B)} \quad (5.70)$$

or substituting Equation 5.65 into Equation 5.70,

$$I_{d(B)} = \sqrt{\frac{3}{2}} (a I_{l(B)}) \quad (5.71)$$

which is exact only if $u = 0$. However, it is an approximate relation with a maximum error of 4.3% at $u = 60^\circ$ and only 1.1% at $u \leq 30^\circ$ (i.e., the *normal operating range*).

The DC resistance base in the DC system can be expressed as

$$R_{d(B)} = \frac{V_{d(B)}}{I_{d(B)}} \quad (5.72)$$

or substituting Equations 5.69 and 5.71 into Equation 5.72,

$$R_{d(B)} = \frac{6}{\pi} \times \frac{Z_{l(B)}}{a^2} \quad (5.73)$$

or

$$R_{d(B)} = \frac{6}{\pi} \times Z_{(B)} \quad (5.74)$$

Similarly, the DC inductance base in the DC system can be expressed as

$$L_{d(B)} = \frac{6}{\pi} \times L_{(B)} \text{ H} \quad (5.75)$$

$$L_{d(B)} = \frac{6}{\pi} \times \frac{L_{l(B)}}{a^2} \text{ H} \quad (5.76)$$

Example 5.3

Normalize the steady-state rectifier equation of

$$V_d = V_{d0} \cos \alpha - \frac{3}{\pi} \omega L_c I_d$$

Solution

Since

$$V_{d0} = \frac{3\sqrt{6}}{\pi} \times E_{(L-N)}$$

$$V_d = \frac{3\sqrt{6}}{\pi} E_{(L-N)} \cos \alpha - \frac{3}{\pi} \omega L_c I_d$$

Dividing both sides of the equation by $V_{d(B)}$,

$$\frac{V_d}{V_{d(B)}} = \frac{3\sqrt{6}}{\pi} \times \frac{E}{V_{d(B)}} \cos \alpha - \frac{3}{\pi} \frac{\omega L_c I_d}{V_{d(B)}}$$

Referring to Equation 5.52 and simplifying the resultant,

$$V_{d(\text{pu})} = \frac{a}{n} E_{l(\text{pu})} \cos \alpha - \frac{1}{2} L_{u(\text{pu})} I_{d(\text{pu})} \text{ pu V}$$

5.9 INVERSION

In a given converter, the current flow is always from anode to cathode, that is, the unidirectional inside a rectifying valve or thyristor, so that the cathode remains the positive terminal. Therefore, the current direction in the converter cannot be reversed. When it is required to operate the converter as an inverter in order to reverse the direction of power flow, the direction of the average direct voltage must be reversed. This can be obtained by using the grid control to change the delay angle a until the average direct voltage V_d becomes negative. If there is no overlap, the voltage V_d decreases as the delay angle a is advanced, and it becomes zero when a is 90° . With a further increase in the delay angle a , the average direct voltage becomes negative.

Therefore, it can be said that the rectification and inversion processes occur when $0^\circ < a < 90^\circ$ and $90^\circ < a < 180^\circ$, respectively. If there is an overlap, the inversion process may start at a value of the delay angle that is $< 90^\circ$. Therefore,

$$a = \pi - \delta \quad (5.77)$$

or

$$a = \frac{1}{2(\pi - u)} \quad (5.78)$$

where

a is the delay angle in electrical degrees

δ is the extinction angle in electrical degrees

u is the overlap angle in electrical degrees

Figure 5.7 shows relations among angles used in converter theory and the reason the curvature of the front of a current pulse of an inverter differs from that of a rectifier. Kimbark [2] gives the relations among the various inverter angles as

$$\beta = \pi - a \quad (5.79)$$

$$\gamma = \pi - \delta \quad (5.80)$$

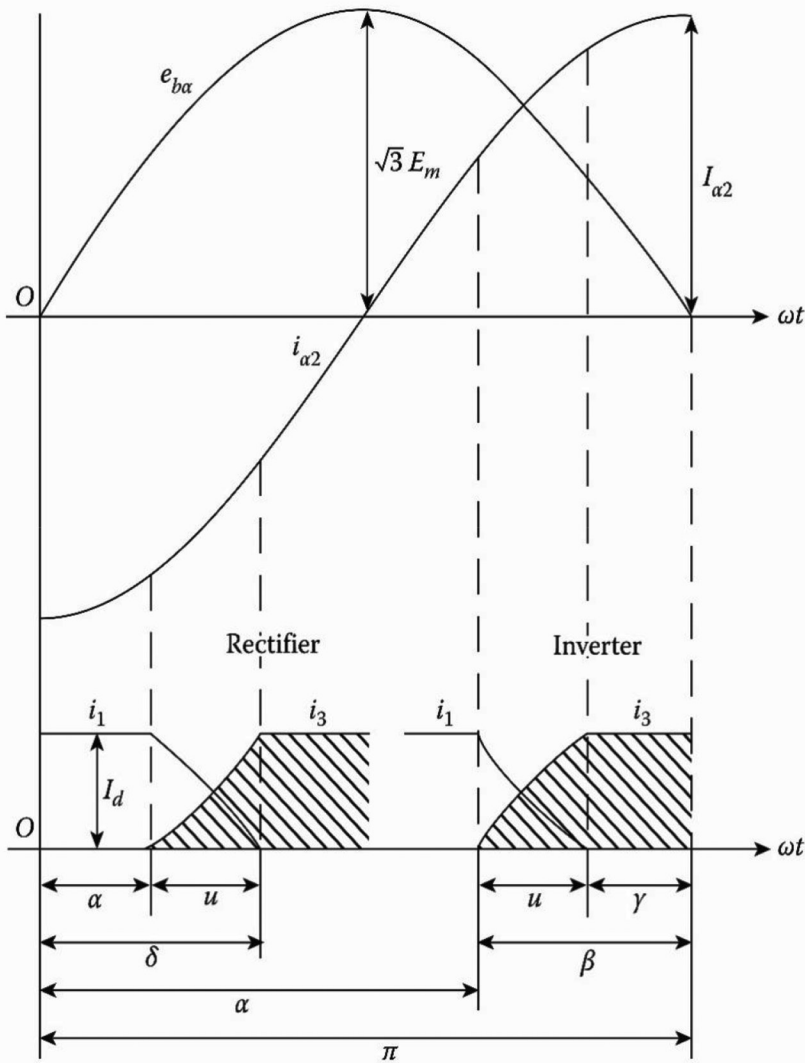


FIGURE 5.7 Relations among angles used in converter theory. (From Kimbark, E. W., *Direct Current Transmission*, vol. 1, Wiley, New York, 1971.)

$$u = \delta - a \quad (5.81)$$

$$u = \beta - \gamma \quad (5.82)$$

where

β is the inverter ignition angle in electrical degrees

γ is the inverter extinction angle in electrical degrees

In order to provide adequate time for the deionization of the arc for the appropriate valve, the minimum value of the inverter extinction angle γ_0 must be in the range of 1° – 8° . If the value of γ_0 is not adequate, the valve starts to conduct again. This is called *commutation failure*.

The rectifier equations can be used to describe the inverter operation by substituting a and δ by $\pi - \beta$ and $\beta - \gamma$, respectively. In order to differentiate the inverter equations from the rectifier equations, it is customary to use the subscripts i and r to signify the inverter and rectifier operations, respectively. Therefore, it can be expressed that

$$I_{di} = I_{s2} (\cos \gamma - \cos \beta) \quad (5.83)$$

or substituting Equation 5.44 into Equation 5.83,

$$I_{di} = \frac{\sqrt{3}E_m}{2\omega L_c} I_{s2} (\cos \gamma - \cos \beta) \quad (5.84)$$

In general, it is customary to express the inverter voltage as negative when it is used in conjunction with a rectifier voltage in a given equation. Otherwise, when it is used alone, it is customary to express it as positive. Therefore, it can be expressed that

$$V_{di} = \frac{V_{d0i}}{2} V (\cos \gamma + \cos \beta) \quad (5.85)$$

Furthermore, for inverters with constant-ignition-angle control,

$$V_{di} = V_{d0i} \cos \beta + R_c I_d \quad (5.86)$$

or

$$V_{di} = V_{d0i} \cos \beta + \frac{3}{\pi} X_c I_d \quad (5.87)$$

and for inverters with constant-extinction-angle (CEA) control,

$$V_{di} = V_{d0i} \cos \gamma - R_c I_d \quad (5.88)$$

or

$$V_{di} = V_{d0i} \cos \gamma - \frac{3}{\pi} X_c I_d \quad (5.89)$$

Note that it is preferable to operate inverters with CEA control rather than with constant-ignition-angle control. Figure 5.8 shows the corresponding equivalent inverter circuit representations.

It can be said that an inverter has a leading power factor, contrary to a rectifier, which has a lagging power factor. This is due to the fact that the lagging reactive power is provided to the inverter

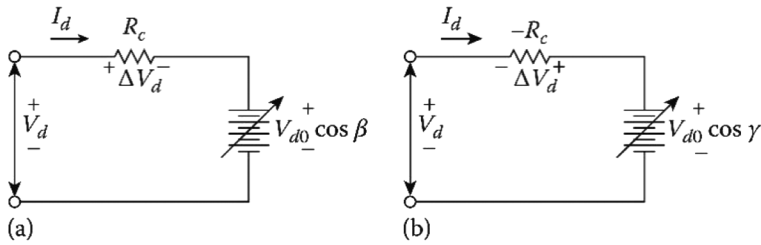


FIGURE 5.8 Equivalent circuits of inverter: (a) with constant P and (b) with constant Y .

by the AC system into which the inverter is feeding active power. Therefore, this is equivalent to the inverter feeding current to the AC system at a leading power factor. The required additional reactive power by the inverter is provided by the synchronous capacitors or by static shunt capacitors.

Furthermore, harmonic filters are needed on both AC and DC sides of converters in order to prevent the harmonics generated by the rectifier and inverter from entering into the AC and DC systems. The order of harmonics in the direct voltage is expressed by

$$N = pq$$

and the order of harmonics in the AC is given by

$$N = pq \pm 1$$

where

p is the pulse number

q is the integer number

Example 5.4

Consider a single-bridge inverter and do the following:

- Verify that the power factor of the fundamental component of the inverter AC line current can be expressed as

$$\cos \theta_{li} \equiv \frac{1}{2} (\cos \beta + \cos \gamma)$$

- Explain the approximation involved in part (a).
- Explain the effect of increasing the ignition advance angle β on the power factor in part (a).
- Explain the effect of increasing the extinction angle γ on the power factor in part (a).
- Explain whether or not the power factor that can be found using the equation given in part (a) is greater or less than the power factor that would be measured in terms of the readings of the switchboard wattmeter, voltmeter, and ammeter.

Solution

- From Equation 5.85, inverter voltage can be expressed as

$$V_{doi} = V_{d0i} \left[\frac{1}{2} (\cos \beta + \cos \gamma) \right]$$

where

$$V_{d0i} = \frac{3\sqrt{6}}{\pi} \times E_{(L-N)}$$

Therefore,

$$V_{di} = \frac{3\sqrt{6}}{\pi} \left[\frac{1}{2} (\cos \beta + \cos \gamma) \right] E_{(L-N)}$$

When losses are disregarded, the active AC power can be set equal to the DC power:

$$P_{(ac)} = P_{(dc)}$$

where

$$P_{(ac)} = 3E_{(L-N)} I_{L1} \cos \theta_{li}$$

and

$$P_{(dc)} = V_{di} I_d$$

or

$$P_{(dc)} = \frac{3\sqrt{6}}{\pi} \left[\frac{1}{2} (\cos \beta + \cos \gamma) \right] E_{(L-N)} I_d$$

Thus,

$$3E_{(L-N)} I_{L1} \cos \theta_{li} = \frac{3\sqrt{6}}{\pi} \left[\frac{1}{2} (\cos \beta + \cos \gamma) \right] E_{(L-N)}$$

or

$$I_{L1} \cos \theta_{li} = \frac{\sqrt{6}}{\pi} \left[\frac{1}{2} (\cos \beta + \cos \gamma) \right]$$

However,

$$I_{L1} \cong \frac{\sqrt{6}}{\pi} \times I_d$$

which is an approximation. Therefore,

$$\cos \theta_{li} \cong \frac{1}{2} (\cos \beta + \cos \gamma)$$

which is also an approximation.

Equations $I_{L1} \cong \frac{\sqrt{6}}{\pi} \times I_d$ and $\cos \theta_{li} \cong \frac{1}{2} (\cos \beta + \cos \gamma)$ would be exact only if $u = 0$. Otherwise, there will be some approximate values with a maximum error of 4.3% at $u = 60^\circ$. At normal operating range (i.e., $u < 30^\circ$), the error involved is $< 1.1\%$.

- b. An increase in the ignition advance angle β causes the power factor to decrease.
- c. An increase in the extinction angle γ causes the power factor to decrease.
- d. The power factor determined based on the readings can be expressed as

$$\cos \theta = \frac{W_{\text{reading}}}{\sqrt{3} (V_{(L-L)\text{reading}}) (I_{\text{reading}})}$$

Therefore, the calculated power factor $\cos \theta_{li}$ is greater than the power factor determined from the readings because of the harmonics involved.

Example 5.5

Consider the single-bridge inverter in Example 5.4 and verify that the power factor of the fundamental component of the inverter AC line current can be expressed as

$$\cos \theta_{li} \cong \frac{V_{di}}{V_{d0i}}$$

Solution

The inverter's direct voltage is

$$V_{di} = V_{d0i} \cos \beta - \Delta V_{di}$$

where

$$\Delta V_{di} = \frac{1}{2} V_{d0i} (\cos \beta - \cos \gamma)$$

Therefore,

$$V_{di} = V_{d0i} \cos \beta - \frac{1}{2} V_{d0i} (\cos \beta - \cos \gamma)$$

or

$$V_{di} = \frac{1}{2} V_{d0i} (\cos \beta + \cos \gamma)$$

Thus,

$$\frac{(\cos \beta + \cos \gamma)}{2} = \frac{V_{di}}{V_{d0i}}$$

$$\cos \theta_{li} = \frac{(\cos \beta + \cos \gamma)}{2}$$

Therefore,

$$\cos \theta_{li} = \frac{V_{di}}{V_{d0i}}$$

Alternatively,

$$V_{di} = V_{doi} \frac{(\cos \beta + \cos \gamma)}{2}$$

from which

$$\frac{(\cos \beta + \cos \gamma)}{2} = \frac{V_{di}}{V_{doi}}$$

Therefore,

$$\cos \theta_{li} \cong \frac{V_{di}}{V_{doi}}$$

5.10 MULTIBRIDGE (B-BRIDGE) CONVERTER STATIONS

Figure 5.9 shows 800 kV DC terminals of a converter station. Figure 5.10 shows a 800 kV disconnect switch on the AC side at the same converter station. Figure 5.11 shows 800 kV risers on the AC side at the same converter station.

Figure 5.12 shows a typical converter station layout. For such a station, the general arrangement of a converter station with 12-pulse converters is shown in Figure 5.13. Figure 5.14 shows a one-line diagram for a *B*-bridge converter (rectifier) station and the supplying AC network. The AC network system is represented by the Thevenin equivalent E_f voltage and $X_{l(sys)}$ reactance. The E_f voltage can be assumed to be sinusoidal due to the AC filter connected at the AC bus.

The converter bank is made of two or more three-phase bridges, and each bridge contains up to six mercury arc valves or thyristors. Note that there are *B*-bridges in the figure. The number of bridges required is dictated by the direct voltage level selected for economical transmission.

In order to eliminate certain harmonics, the transformer connections are arranged in a certain way so that one-half of the bridge transformers has 0° phase shift and the other half has 30° phase shift. This arrangement gives 12-pulse operation. The two sets of transformer banks are connected either one set in wye–wye and the other set in wye–delta with 30° phase shift or one set in delta–delta with 0° phase shift and the other in wye–delta with 30° phase shift (or from one three-winding bank connected wye–wye–delta).

As a result of this arrangement, the two halves of the bridges do not commute simultaneously. The current on the DC side of the converter is almost completely smoothed due to the DC reactors



FIGURE 5.9 800 kV DC terminals of a converter station.



FIGURE 5.10 An 800 kV disconnect switch on the AC side at the same converter station.

(I_d) connected. As can be seen from Figure 5.14, the B -bridges are connected in series on the DC side and in parallel on the AC side. Therefore, the direct voltage can be expressed as

$$V_d = \left(\frac{3\sqrt{6}}{\pi} \right) B \times n \times E_{(L-N)} \cos \theta \quad (5.90)$$

or

$$V_d = 2.34 B \times n \times E_{(L-N)} \cos \theta \quad (5.91)$$

or

$$V_d = 1.35 B \times n \times E_{(L-N)} \cos \theta \quad (5.92)$$

where

B is the number of bridges

n is the turns ratio in use

$E_{(L-N)}$ is the line-to-neutral voltage in volts

$E_{(L-L)}$ is the line-to-line voltage in volts

$\cos \theta$ is the power factor of fundamental component of AC line current

The fundamental component of the AC line current can be expressed as

$$I_{1(a)} = \frac{\sqrt{6}}{\pi} B \times n \times I_d \quad (5.93)$$



FIGURE 5.11 800 kV risers on the AC side at the same converter station.

or

$$I_{l(a)} = 0.78B \times n \times I_d \quad (5.94)$$

The active AC power is equal to DC power, ignoring losses:

$$P_{(ac)} = P_{(dc)} \text{ W}$$

where

$$P_{(dc)} = V_d I_d \text{ W} \quad (5.95)$$

and

$$P_{(ac)} = 3E_{(L-N)} I_{l(a)} \cos \Phi \text{ W} \quad (5.96)$$

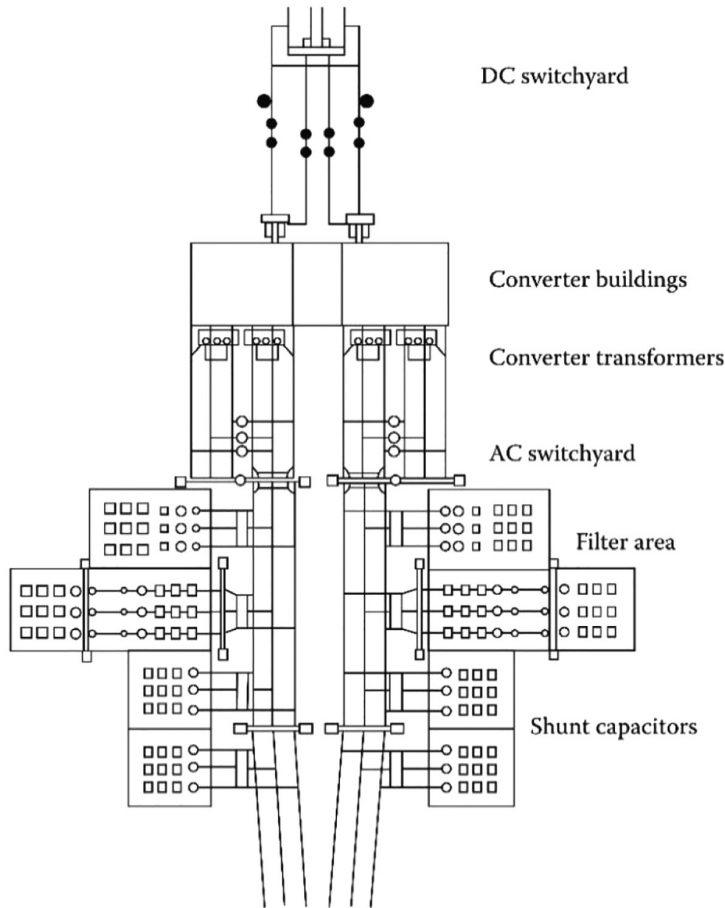


FIGURE 5.12 Typical converter station layout. (From Fink, D. G. and Beaty, H. W., *Standard Handbook for Electrical Engineers*, 11th edn., McGraw-Hill, New York, 1978.)

5.11 PER-UNIT REPRESENTATION OF *B*-BRIDGE CONVERTER STATIONS

Figure 5.15 shows a one-line diagram representation of two AC systems connected by a DC transmission link. The system has two *B*-bridge converter stations: the one on the left operates as a rectifier and the one on the right operates as an inverter. It is possible to reverse the direction of power flow by interchanging the functions of the converter stations.

In this section, only the first-mode operation is to be reviewed; that is, the overlap angle u is $<30^\circ$ so that the one-half of the bridges with 0° phase and the other half of the bridges with 30° phase shift do not commute simultaneously.

The notation that will be used is largely defined in the illustration. As before, the subscript *B* designates the base value. An additional subscript in terms of *r* or *i* may be added to define the rectifier or inverter operation involved, respectively. Assume that all AC voltages given are line-to-neutral voltages. The following notation is applicable for each transformer:

S_{tr} is the transformer nameplate rated in three-phase volt-amperes

a is the ratio of base AC voltages:

$$= \frac{E_{l(B)}}{E_{(B)}} = \frac{BI_{(B)}}{I_{l(B)}} \quad (5.97)$$

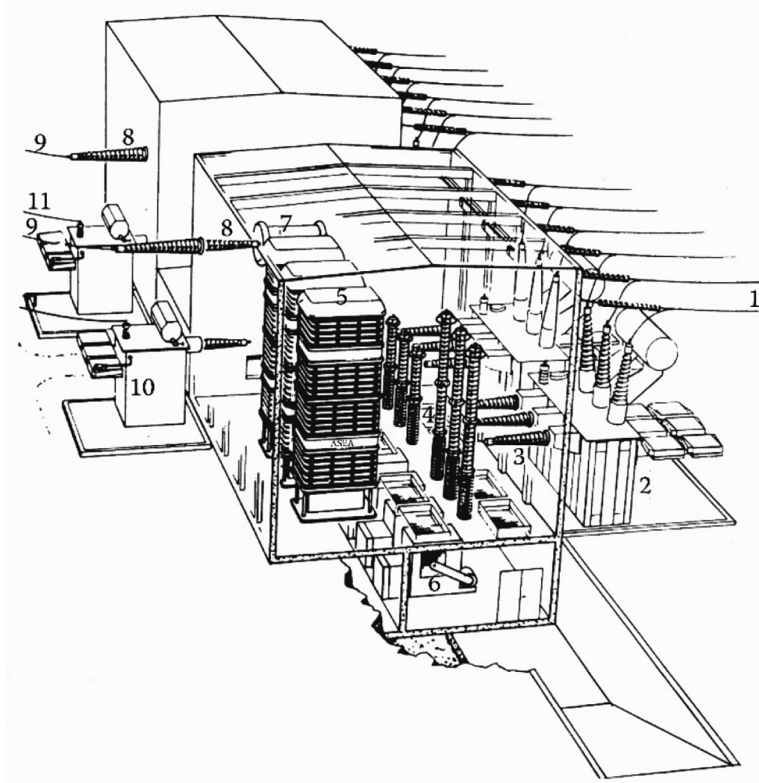


FIGURE 5.13 General arrangement of converter station with 12-pulse converters: (1) AC bus bar, (2) converter transformer, (3) valve-side bushing of converter transformer, (4) surge arresters, (5) quadruple valves, (6) valve-cooling fans, (7) air core reactor, (8) wall bushing, (9) outgoing DC bus work, (10) smoothing reactor, and (11) outgoing electrode line connection. (From Fink, D. G. and Beaty, H. W., *Standard Handbook for Electrical Engineers*, 11th edn., McGraw-Hill, New York, 1978.)

n is the turns ratio in use (variable changeable with LTC position):

$$\frac{n_1}{n_2} = \frac{E_1}{E} = \frac{I}{I_1} \quad (5.98)$$

X_{tr} is the leakage reactance referred to as the DC side in ohms:

$$= n^2 X_{tr} \quad (5.99)$$

$X_{l(tr)}$ is the leakage reactance referred to as the AC side in ohms:

$$= n^2 X_{tr}$$

L_{tr} is the leakage inductance referred to as the DC side in henries

$L_{l(tr)}$ is the inductance referred to as the AC side in henries:

$$= n^2 L_{(tr)} \quad (5.100)$$

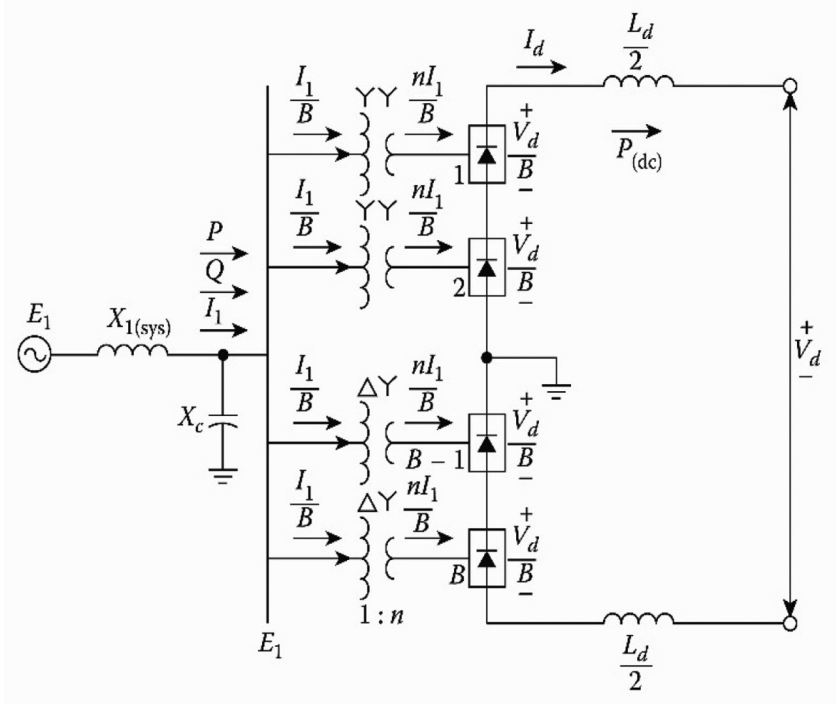


FIGURE 5.14 One-line diagram for B -bridge converter (rectifier) station.

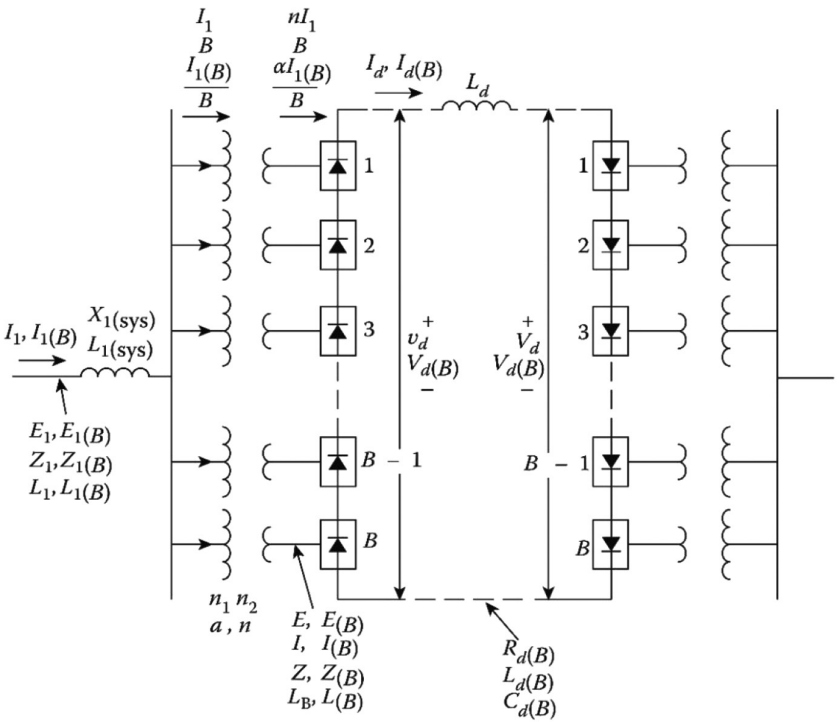


FIGURE 5.15 One-line diagram representation of two B -bridge converter stations connecting two AC systems over a DC transmission link.

$X_{tr(pu)}$ is the per-unit leakage reactance (when LTC is on neutral):

$$= \frac{X_{(tr)}}{Z_{(B)}} = \frac{a^2 X_{tr}}{a^2 Z_{(B)}} = \frac{X_{l(tr)}}{Z_{l(B)}} \quad (5.101)$$

$L_{tr(pu)}$ is the per-unit leakage inductance:

$$= X_{tr(pu)}$$

If there is a significant amount of AC system impedance, the following notation is applicable:

$X_{l(sys)}$ is the AC system reactance referred to as the AC side in ohms

X_{sys} is the AC system reactance referred to as the DC side in ohms:

$$= \frac{X_{l(sys)}}{n^2} \quad (5.102)$$

$L_{l(sys)}$ is the AC system inductance referred to as the AC side in henries

L_{sys} is the AC system inductance referred to as the DC side in henries:

$$= \frac{L_{l(sys)}}{n^2} \quad (5.103)$$

5.11.1 AC SYSTEM PER-UNIT BASES

The per-unit bases for the quantities located on the AC side of the converter transformer are as follows:

$E_{l(B)}$ is the arbitrarily chosen voltage value

$S_{l(B)}$ is the arbitrarily chosen volt-ampere value

$$I_{l(B)} = \frac{S_{l(B)}}{3E_{l(B)}} \text{ A} \quad (5.104)$$

$$Z_{l(B)} = \frac{E_{l(B)}}{I_{l(B)}} \Omega \quad (5.105)$$

$$L_{l(B)} = \frac{Z_{l(B)}}{\omega_{(B)}} \text{ H} \quad (5.106)$$

$$C_{l(B)} = \frac{1}{\omega_{(B)} Z_{l(B)}} \quad (5.107)$$

where

$$\omega_{(B)} = \omega = 377 \quad \text{if} \quad f = 60 \text{ Hz}$$

On the other hand, the per-unit bases for the quantities located on the DC side of the converter transformer are

$$E_B = \frac{E_{l(B)}}{a} \quad (5.108)$$

$$S_B = S_{l(B)} \quad (5.109)$$

$$I_{(B)} = a I_{l(B)} \quad (5.110)$$

$$Z_{(B)} = \frac{Z_{l(B)}}{a^2} \quad (5.111)$$

$$L_{(B)} = \frac{L_{l(B)}}{a^2} \quad (5.112)$$

$$C_{(B)} = a^2 C_{l(B)} \quad (5.113)$$

Note that the per-unit size of each transformer is

$$S_{tr(pu)} = \frac{1}{B} \text{ pu VA} \quad (5.114)$$

provided that

$$S_{(B)} = B S_{tr} \text{ VA} \quad (5.115)$$

is selected. For example, the per-unit size of each transformer of a four-bridge converter station is

$$\begin{aligned} S_{tr(pu)} &= \frac{S_{tr}}{S_{(B)}} \\ &= \frac{S_{tr}}{4 S_{tr}} \\ &= 0.25 \text{ pu VA} \end{aligned}$$

5.11.2 DC SYSTEM PER-UNIT BASES

The DC system per-unit bases for a B -bridge converter are selected somewhat differently than the previous bases used for a single-bridge converter in Section 5.7.

When the firing angle α , overlap angle u , and DC I_d are zero, the ratio of base AC voltages a and turns ratio in use n are equal, and

$$E_{(pu)} = E_{l(pu)} = 10 \text{ pu V}$$

the DC voltage base is

$$V_{d(B)} \triangleq V_{d0}$$

or

$$V_{d(B)} = \frac{3\sqrt{6}}{\pi} \times B \times E_{(B)} \quad (5.116)$$

or

$$V_{d(B)} = \frac{3\sqrt{6}}{\pi} \times \frac{B \times E_{l(B)}}{a} \quad (5.117)$$

By forcing the AC and DC power bases to be exactly equal,

$$3E_{(B)}I_{(B)} = V_{d(B)}I_{d(B)} \quad (5.118)$$

so that

$$I_{d(B)} = \frac{3E_{(B)}I_{(B)}}{V_{d(B)}} \quad (5.119)$$

Substituting Equations 5.116 and 5.117 into Equation 5.119 separately,

$$I_{d(B)} = \frac{\pi}{\sqrt{6}} \times \frac{I_{(B)}}{B} \quad (5.120)$$

and

$$I_{d(B)} = \frac{\pi}{\sqrt{6}} \times \frac{a \times I_{l(B)}}{B} \quad (5.121)$$

The fundamental component of the AC per line to a bridge having no overlap is

$$I_{l(a)} = \frac{\sqrt{6}}{\pi} \times I_d \quad (5.122)$$

or

$$I_{l(a)} = 0.78 \times I_d \quad (5.123)$$

whereas the total rms AC is

$$I_{(a)} = \sqrt{\frac{2}{3}} \times I_d \quad (5.124)$$

or

$$I_{(a)} = 0.8165 I_d \quad (5.125)$$

Note that, in the bases discussed in Section 5.7, the constant $43/2$ was in the definition of $I_{d(B)}$ and that $P_{d(B)}$ was not exactly equal to the AC power base. However, in the present bases, the constant $\sqrt{6}/\pi$ is in the definition of $I_{d(B)}$, and AC and DC power bases are exactly equal.

The DC resistance base in the DC system can be expressed as

$$R_{d(B)} = \frac{V_{d(B)}}{I_{d(B)}} \quad (5.126)$$

or

$$R_{d(B)} = \frac{18B^2 \times Z_{(B)}}{\pi^2} \quad (5.127)$$

or

$$R_{d(B)} = \frac{18B^2 \times Z_{l(B)}}{\pi^2 \times a^2} \quad (5.128)$$

The DC inductance base in the DC system can be expressed as

$$L_{d(B)} = \frac{V_{d(B)} t_B}{I_{d(B)}} \quad (5.129)$$

or

$$L_{d(B)} = \frac{R_{d(B)}}{\omega_{(B)}} \quad (5.130)$$

where

$$t_{(B)} = \frac{1}{\omega_{(B)}} \quad (5.131)$$

Similarly, the DC capacitance base in the DC system can be expressed as

$$C_{d(B)} = \frac{1}{R_{d(B)} \omega_{(B)}} F \quad (5.132)$$

5.12 OPERATION OF DC TRANSMISSION LINK

Figure 5.16 shows the equivalent circuit for a simple DC transmission link. Here, the DC link may be a transmission line, a cable, or a link with negligible length. The subscripts *r* and *i* signify rectifier and inverter, respectively.

The DC I_d that flows from the rectifier to the inverter can be expressed as

$$I_d = \frac{V_{dr} - V_{di}}{R_L} \quad (5.133)$$

and the sending-end power can be expressed as

$$P_{(dc)} = V_{dr} I_d \quad (5.134)$$

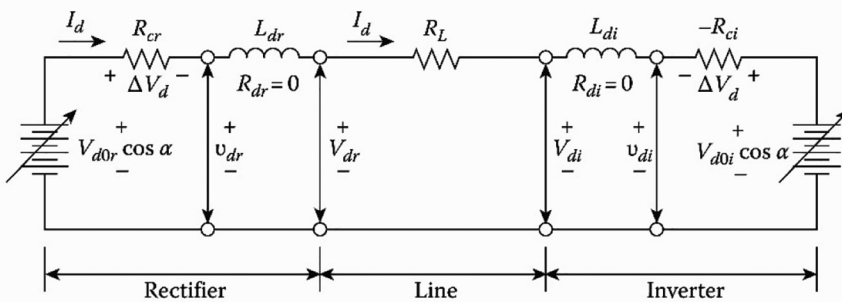


FIGURE 5.16 Equivalent circuit of DC link.

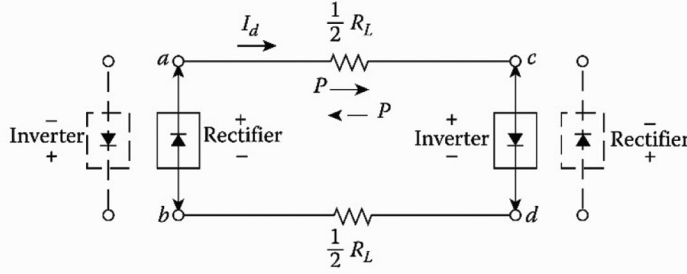


FIGURE 5.17 Illustration of reversion in the power flow direction.

Since it is possible for a converter to become a rectifier or an inverter by grid control, the direction of the power flow can be reversible. This can be accomplished by reversing the direct voltage, as previously explained. Figure 5.17 illustrates this reversion in power flow direction. It can be shown, from Kirchhoff's voltage law, that

$$V_{ab} = I_d R_L + V_{cd} \quad (5.135)$$

Therefore, when the V_{ab} and V_{cd} voltages represent the average direct voltages of a rectifier and an inverter, respectively, Equation 5.135 can be expressed as

$$V_{dr} = I_d R_L - V_{di} \quad (5.136)$$

Similarly, when the V_{ab} and V_{cd} voltages represent the average direct voltages of an inverter and a rectifier, respectively, Equation 5.135 can be expressed as

$$V_{di} = I_d R_L - V_{dr} \quad (5.137)$$

Therefore, it can be shown in either case that

$$I_d R_L = V_{dr} + V_{di} \quad (5.138)$$

where

$$V_{dr} = V_{d0r} \cos \alpha - \frac{3}{\pi} \omega L_{cr} I_d \quad (5.139)$$

$$V_{di} = -V_{d0i} \cos \alpha + \frac{3}{\pi} \omega L_{ci} I_d \quad (5.140)$$

Thus,

$$I_d = \frac{V_{d0r} \cos \alpha - V_{d0i} \cos \gamma}{R_L + \frac{3}{\pi} \omega L_{cr} - \frac{3}{\pi} \omega L_{ci}} \quad (5.141)$$

or

$$I_d = \frac{V_{d0r} \cos \alpha - V_{d0i} \cos \gamma}{R_L + R_{cr} - R_{ci}} \quad (5.142)$$

where

$$R_{cr} = \frac{3}{\pi} \omega L_{cr} \quad (5.143)$$

$$R_{ci} = \frac{3}{\pi} \omega L_{ci} \quad (5.144)$$

The value of the DC I_d can be controlled by changing either V_{d0r} and V_{d0i} values or delay angle α or extinction angle γ . The values of V_{d0r} and V_{d0i} can be governed by using the LTCs of the supply transformers to change the ratio between the DC and AC voltages. Unfortunately, this method is very slow to be practical, whereas the delay angle α can be controlled very fast by using the grid control system. However, this method causes the converter to consume an excessively large amount of reactive power. Therefore, it is usual to operate the rectifier with a minimum delay angle and the inverter with a minimum extinction angle in order to achieve the control with a minimum amount of reactive power consumption. Thus, it is a better practice to operate the rectifier with a constant-current (CC) characteristic and the inverter with a constant-voltage characteristic, as shown in Figure 5.18. As succinctly put by Kimbark [2], “the rectifier controls the direct current and the inverter controls the direct voltage.” In practice, the values of the delay angle α and the extinction angle γ are usually selected in the ranges of 12° – 18° and 15° – 18° , respectively. Since a converter can be operated as a rectifier or inverter depending on the direction of power flow, it is necessary that each converter has dual-control systems, as shown in Figure 5.19.

Note that, in Figure 5.18, the normal operation point is E , where the characteristics of rectifier and inverter intersect. The rectifier characteristic has two line segments: the AB segment, at which the minimum delay angle α is constant, and the BC segment, at which the rectifier current I_{d1} is constant. Similarly, the inverter characteristic has two segments: the DF segment, at which the minimum extinction angle γ is constant, and the FH segment, at which the inverter current I_{d2} is constant. Normally, the current regulator of the inverter is set at a lower current value than the one of the rectifier. Hence, the difference in currents is

$$\Delta I_d = I_{d1} - I_{d2} \quad (5.145)$$

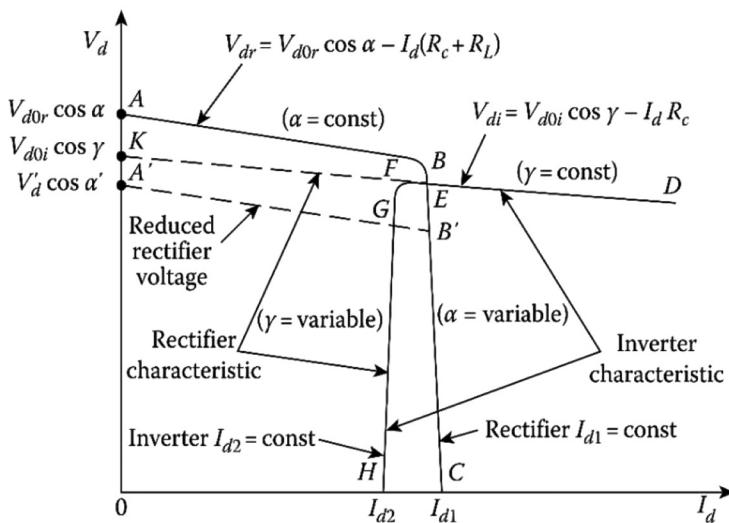


FIGURE 5.18 Inverter and rectifier operation characteristics with CC compounding.

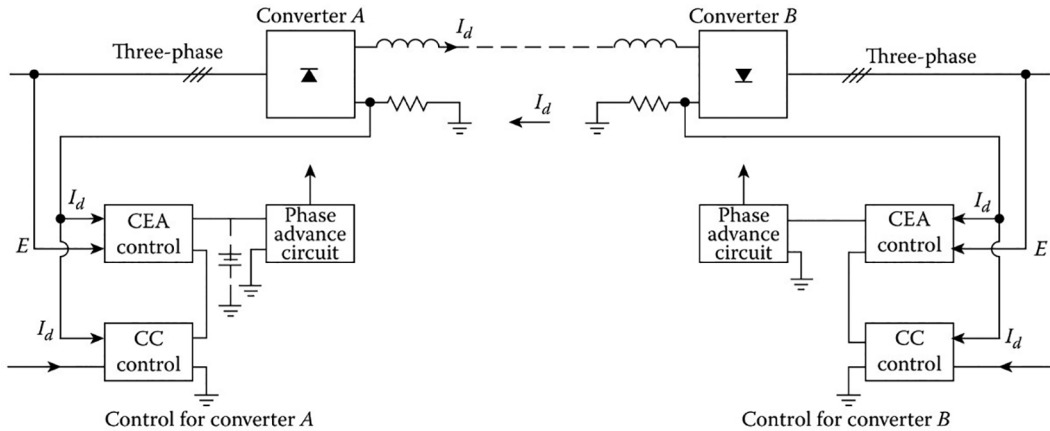


FIGURE 5.19 Schematic control diagram of HVDC system with CEA and CC controls. (From Weedy, B. M., *Electric Power Systems*, 3rd edn., Wiley, New York, 1979.)

where

ΔI_d is the current margin (usually 10%–15% of rated current)

I_{d1} is the CC of rectifier

I_{d2} is the CC of inverter

As aforementioned, under normal operating conditions, the operation point is E , at which the rectifier controls the DC and the inverter controls the direct voltage.

However, under emergency conditions, the operation point may change. For example, if the rectifier voltage characteristic is shifted down due to a large dip in rectifier voltage, it intersects the FH CC segment of the inverter characteristic at a new operation point G , where the inverter controls the DC and the rectifier controls the direct voltage.

Note that if the inverter were not equipped with the CC (control) regulator, it would have the characteristic DFK, as shown in Figure 5.18. Therefore, it can be seen that the shifted rectifier characteristic $A'B'$ would not have intersected the inverter characteristic. Consequently, the current and power would have decreased to zero.

Under normal operation, if the current is required to increase, the current setting is increased first at the rectifier and second at the inverter. On the other hand, if the current is required to decrease, the order of the operation is reversed; the current setting is decreased first at the inverter and second at the rectifier. This keeps the sign of the current margin the same and thus prevents any unexpected reversing in the direction of power flow.

Furthermore, the current margin between such points E and G shown in Figure 5.18 has to be adequate in order to prevent both inverter and rectifier current regulators operating at the same time. Note also that the voltage margin indicated by BE is due to a trade-off between minimum reactive compensations by holding the delay angle α as low as possible and preventing inverter control, which affects current.

5.13 STABILITY OF CONTROL

As aforementioned, the control system is made of CC control of the rectifier and CEA control of the inverter. An inappropriate control system can make oscillations by various disturbances, that is, converter faults and line-to-ground faults, and can cause *instability*. Kimbark [2] gives the following approximate method to study this phenomenon.

Figure 5.20 shows an equivalent circuit of a DC link for analysis of stability of control. Note that the rectifier on a CC control shows a large resistance $K + R_{c1}$ (where K is the gain of the CC regulator). But, the inverter on a CEA control shows a low negative resistance, $-R_{c2}$.

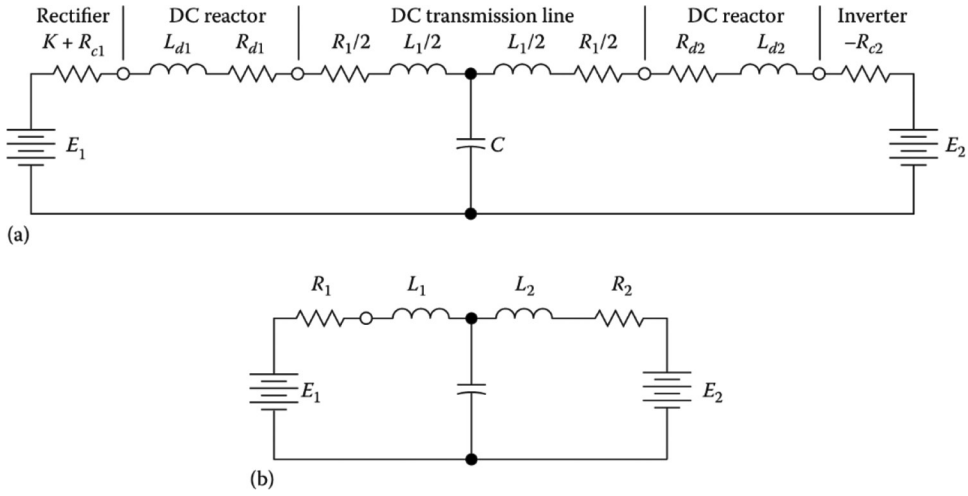


FIGURE 5.20 Equivalent circuit of DC link for analysis of stability of control: (a) before combination of line with terminal equipment and (b) after combination. (From Kimbark, E. W., *Direct Current Transmission*, vol. 1, Wiley, New York, 1971.)

Therefore, it can be written in the s domain that

$$E_{1(s)} = Z_{1(s)}I_{1(s)} - Z_{m(s)}I_{2(s)} \quad (5.146)$$

$$E_{2(s)} = Z_{m(s)}I_{1(s)} - Z_{2(s)}I_{2(s)} \quad (5.147)$$

or, in matrix notation,

$$\begin{bmatrix} Z_{1(s)} & -Z_{m(s)} \\ Z_{m(s)} & -Z_{2(s)} \end{bmatrix} \begin{bmatrix} I_{1(s)} \\ I_{2(s)} \end{bmatrix} = \begin{bmatrix} E_{1(s)} \\ E_{2(s)} \end{bmatrix} \quad (5.148)$$

Since the transient response is being studied,

$$\begin{bmatrix} Z_{1(s)} & -Z_{m(s)} \\ Z_{m(s)} & -Z_{2(s)} \end{bmatrix} \begin{bmatrix} I_{1(s)} \\ I_{2(s)} \end{bmatrix} = 0$$

But

$$\begin{bmatrix} I_{1(s)} \\ I_{2(s)} \end{bmatrix} \neq 0$$

Therefore,

$$\begin{bmatrix} Z_{1(s)} & -Z_{m(s)} \\ Z_{m(s)} & -Z_{2(s)} \end{bmatrix} = 0$$

Thus, the characteristic equation of the circuit can be expressed as

$$-Z_1(s)Z_2(s) + Z_m^2(s) = 0 \quad (5.149)$$

where

$$Z_1(s) = R_1 + L_1s + \frac{1}{C_s} \quad (5.150)$$

$$Z_2(s) = R_2 + L_2s + \frac{1}{C_s} \quad (5.151)$$

$$Z_m(s) = \frac{1}{C_s} \quad (5.152)$$

where

$$\begin{aligned} s &= \text{Complex frequency} \\ &= \sigma + j\omega \end{aligned}$$

Substituting Equations 5.150–5.152 into Equation 5.149,

$$-\left(R_1 + L_1s + \frac{1}{C_s}\right)\left(R_2 + L_2s + \frac{1}{C_s}\right) + \left(\frac{1}{C_s}\right)^2 = 0 \quad (5.153)$$

or

$$CL_1L_2s^3 + C(R_1L_2 + R_2L_1)s^2 + (L_1 + L_2 + R_1D_2C)s + (R_1 + R_2) = 0 \quad (5.154)$$

Assume that $R_1 \gg L_1s$ and that $L_1 = 0$. Thus, Equation 5.154 becomes

$$CR_1L_2s^2 + (L_2 + R_1R_2C)s + (R_1 + R_2) = 0 \quad (5.155)$$

or

$$s^2 + \left(\frac{1}{R_1C} + \frac{R_2}{L_2}\right)s + \frac{R_1 + R_2}{CR_1L_2} = 0 \quad (5.156)$$

However, since $R_1 \gg R_2$,

$$R_1 + R_2 \cong R_1 \quad (5.157)$$

substituting Equation 5.157 into Equation 5.156,

$$s^2 + \left(\frac{1}{R_1C} + \frac{R_2}{L_2}\right)s + \frac{1}{CL_2} = 0 \quad (5.158)$$

Comparing Equation 5.158 with the standard equation of

$$s^2 + 2\zeta\omega_n s + \omega_n^2 = 0 \quad (5.159)$$

the undamped natural frequency can be expressed as

$$\omega_n \cong \frac{1}{\sqrt{CL_2}} \quad (5.160)$$

Since

$$2\zeta\omega_n = \frac{1}{R_1C} + \frac{R_2}{L_2} \quad (5.161)$$

the damping coefficient can be expressed as

$$\begin{aligned} \sigma &= \zeta\omega_n \\ &= \frac{1}{2} \left(\frac{1}{R_1C} + \frac{R_2}{L_2} \right) \end{aligned} \quad (5.162)$$

from which the damping ratio can be found as

$$\zeta = \frac{1}{2R_1} \sqrt{\frac{L_2}{C}} + \frac{R_2}{2} \sqrt{\frac{C}{L_2}} \quad (5.163)$$

From Equation 5.163,

$$R_1 \cong \frac{L_2}{2\zeta\sqrt{L_2C} - R_{2C}} \quad (5.164)$$

In general, a positive, but less than critical, damping (i.e., $Z = 1$) is required. For example, when $\zeta = 0.7$,

$$R_1 \cong \frac{L_2}{14\sqrt{L_2C} - R_{2C}}$$

Note that at critical damping,

$$R_1 \cong \frac{L_2}{2\sqrt{L_2C} - R_{2C}} \quad (5.165)$$

Applying Routh's criterion to the characteristic equation of the HVDC link given by Equation 5.154 and assuming equal DC smoothing reactors (i.e., $L_{d1} = L_{d2} = L_d$), it can be found that

$$R_1 = \frac{L_d}{R_2C} \quad (5.166)$$

or

$$R_1 = -\frac{L_d}{(-R_2)C} \quad (5.167)$$

or since

$$L_2 \cong L_d$$

then

$$R_1 = -\frac{L_2}{(-R_2)C} \quad (5.168)$$

Therefore, in order to have a stable system or oscillations to be damped, the maximum value of R_1 must be

$$R_{1(\max)} < \frac{L_2}{|R_2|C} \quad (5.169)$$

But

$$R_{1(\max)} = K_{(\max)} + R_{c1} + R_{d1} + \frac{1}{2}R_1 \quad (5.170)$$

Therefore, there is a maximum value of K for which the system is stable. However, note that if

$$R_{1(\max)} > \frac{L_1}{L_2}|R_2| \quad (5.171)$$

5.14 LINE-COMMUTATED CONVERTER (LCC) TECHNOLOGY

5.14.1 INTRODUCTION

LCC is a kind of electronic converter for HVDC, which is made with electronic switches. Semiconductor devices are only required to have controllable turn-on as they naturally turn off when the current drops to zero due to turning on the next device on the same side of the converter [3]. This commutation process depends on the AC system's voltages and impedances, and hence these devices are also frequently referred to as LCC [4]. The function of LCC is to convert AC to DC or DC to AC. Among them, when LCC works in the state of alternating AC to DC, LCC can be regarded as a rectifier; On the contrary, if LCC operates in the state of alternating DC to AC, LCC can be considered an inverter.

Most of the HVDC systems in operation today are based on LCC. Although the HVDC converter can be constructed from diodes, such a converter can only be used in rectification mode and the lack of controllability of the DC voltage is a serious disadvantage. Consequently, in practice, all LCC HVDC systems used either grid-controlled mercury-arc valves until the 1970s or thyristors to the present day [5]. On the AC side of LCC, the converter behaves approximately as a current source, injecting both grid-frequency and harmonic currents into the AC network. That is the reason why LCC for HVDC can also be considered a current-source converter. However, the magnitude and direction of the DC in a LCC is almost constant.

In the HVDC transmission system, LCC usually adopts a three-phase bridge fully controlled circulation circuit as the basic unit. As shown in Figure 5.21a, the DC side rectifier voltage of the circuit has six wave heads in a power-frequency cycle, so the three-phase bridge full power converter circuit is also called the six-pulse converter. When the two 6-pulse converters are connected in series with DC terminals and parallel with AC terminals, the 12-pulse converters are formed, as shown in Figure 5.21b. Modern HVDC transmission projects basically use 12-pulse converter as the basic converter unit. Because the realization of 12-pulse converter needs to use converter transformer, the same phase voltage of each 6-pulse converter produces 30° of phase difference. In HVDC, LCC, converter transformer, AC/DC filter, control and protection equipment, and AC/DC switching equipment are generally defined as a basic converter unit. The converter transformers

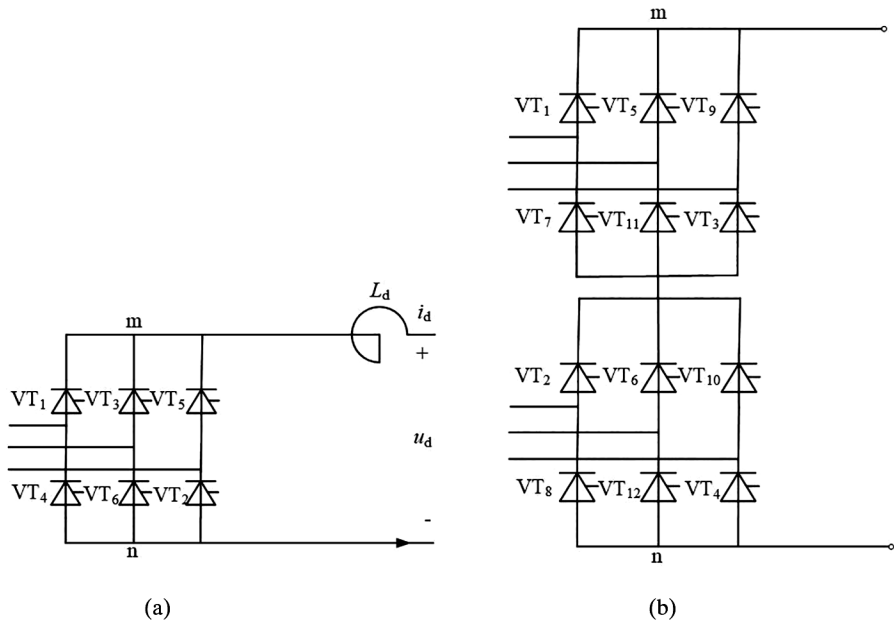


FIGURE 5.21 Schematic diagram of converters: (a) 6-pulse converter, (b) 12-pulse converter.

are designed to operate with high harmonic currents and to withstand AC and DC voltage stress. In most cases, converter transformers will have tap changers that enable optimization of HVDC operation. The AC/DC filter is mainly connected to the AC/DC bus and is used to suppress the harmonic generated by the converter, which is injected into the AC or DC system.

The converter station is composed of basic converter units, which also have 6-pulse converter unit (as shown in Figure 5.22) and 12-pulse converter unit (as shown in Figure 5.23). The converter transformer of the 6-pulse converter unit can adopt either three-phase or single-phase structure, and the wiring mode of the winding on the valve side can be star or triangle wiring. Six-pulse converter will generate $6K \pm 1$ and $6K$ (K is an integer) characteristic harmonics on the AC side and DC side, respectively. Therefore, the AC side needs to be equipped with $6K + 1$ AC filter; smoothing reactors are usually equipped on the DC side. The inductance of the smoothing reactor usually tends to be a large value, but not too large. This is because, when the inductance is too large, it is easy to produce overvoltage, which will reduce the response speed of the automatic regulation characteristic of the DC

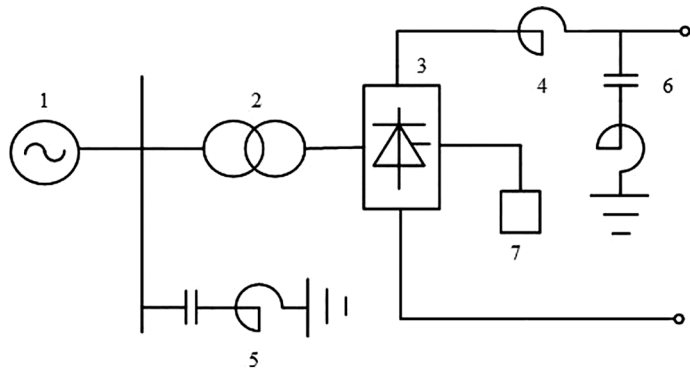


FIGURE 5.22 Six-pulse converter unit: 1-AC system; 2-converter transformer; 3-6-pulse converter; 4-smoothing reactor; 5-AC filter; 6-DC filter; 7-control protection device.

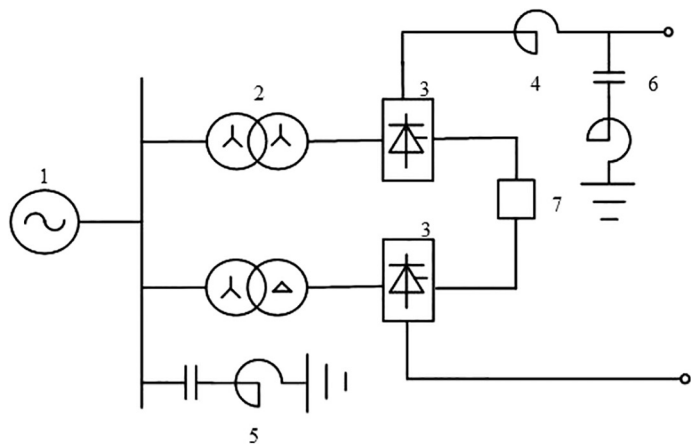


FIGURE 5.23 Twelve-pulse converter unit with double-winding transformer: 1-AC system; 2-converter transformer; 3-12-pulse converter; 4-smoothing reactor; 5-AC filter; 6-DC filter; 7-control protection device.

transmission system. The inductances of smoothing reactors are usually in the range of 0.27–1.5 H (for DC overhead lines) or 12–200 mH (for DC cable lines). For overhead lines, it is usually equipped with 6K DC filters. All modern HVDC transmission projects use 12-pulse converter units.

5.14.2 THYRISTORS

The thyristor is an essential component in LCC-HVDC valves and it is still one of the most common devices used in power-switching applications in all industries. Thyristor solves the problems of low reliability, high investment, and inconvenient operation and maintenance caused by mercury-arc valves in the early HVDC power transmission engineering.

Since thyristors were first used in HVDC engineering in 1972, thyristors have evolved from 3 in., 4 in. to 5 in. At present, it is possible to produce 6 in. thyristors. The thyristor is a four-layer, three-terminal device, as shown in Figure 5.24. The three connections are *A*-anode, *K*-cathode, and *G*-gate. When gate current is applied, the layer between *J2* and *J3* becomes *N* (negative) and the thyristor becomes a PN device similar to a diode. Functionally, it is similar to a diode but the start of conduction can be delayed using the gate circuit.

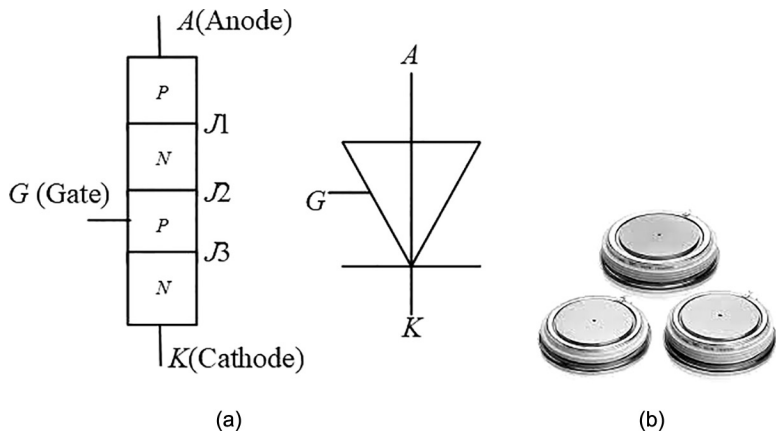


FIGURE 5.24 Structure and symbol for the thyristor: (a) thyristor electrical symbol, (b) thyristors of press-pack design.

When a trigger current signal is applied to the gate of the thyristor and the voltage between the anode and the cathode is positive, the thyristor will be triggered to conduct. Once the thyristor is turned on, the gate loses control function. The thyristor remains conduction even if the trigger current signal is removed. The thyristor voltage drop in the conduction state is very small (generally in 0.5–1.5 V). Control signals cannot be used to turn off the thyristor after it is turned on. The thyristor can only be turned off by an external circuit. When the current flowing through the thyristor is less than its holding current, the thyristor will be turned off naturally. Typical characteristics of thyristors are as follows:

5.14.2.1 Anodic Volt-Ampere Characteristics

The anodic volt-ampere characteristics are shown in Figure 5.25, and its reverse characteristic is similar to that of the diode [6]. When the reverse leakage current increases sharply to a specified value, the corresponding voltage is the breakdown voltage. If there is no trigger pulse on the control pole, the element is off-state when the anode voltage is not high. So, the forward and reverse properties are similar at this stage. However, when the forward voltage increases to a certain transition voltage, the element enters the on-state due to a sharp increase in current. The forward characteristic of the on-state is similar to that of the diode. At this point, there is only a small forward pressure drop between the anode and cathode.

5.14.2.2 Gate Volt-Ampere Characteristics

The gate forward voltage of the thyristor refers to the potential difference between the gate and the cathode, and the relationship between this forward voltage and forward current, known as the gate characteristics. There is a PN junction between the gate and the cathode, so the gate characteristics of thyristors are similar to those of a power diode, except that the forward and reverse resistance values of the thyristor are close. To ensure reliable and safe triggering, the trigger voltage, trigger current, and power generated by the thyristor trigger circuit should be limited to the reliable triggering region in the thyristor gate characteristic curve.

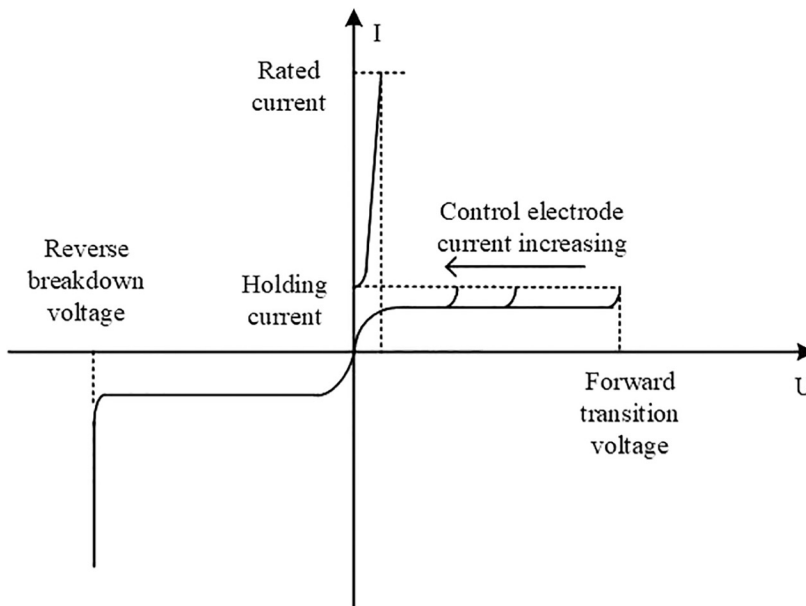


FIGURE 5.25 Volt-ampere characteristics of thyristors.

5.14.2.3 Dynamic Characteristics

The process of thyristor from on-state to off-state is called turn-off, and the process from off-state to on-state is called turn-on [7]. For the turn-on process, due to the positive feedback process inside the thyristor takes time, coupled with the limitation of external circuit inductance, the increase in anode current cannot be completed instantly. From the beginning of applying the gate current signal to the time when the anode current rises to the stable value of 10% is called the delay time. The time required for the anode current to rise from 10% to the stable value of 90% is called the rise time, and the turn-on time is the sum of the delay time and the rise time. The delay time decreases with the increase in gate current. The rise time not only reflects the characteristics of the thyristor itself, but also is greatly affected by the inductance of the external circuit. The higher the inductance, the longer the rise time; Conversely, the lower the inductance, the shorter the rise time. In addition, the delay time and rise time are also related to the anode voltage. Increasing the anode voltage can significantly shorten the delay time and rise time, thus reducing the turn-on time of the thyristor. The turn-off time of the thyristor is defined as the sum of the recovery time of the reverse blocking and the recovery time of the forward blocking. The turn-off time of the thyristor is generally 400 μ s, corresponding to 7.2° of the 50 Hz power frequency cycle. In the process of HVDC transmission, the thyristor valve of the inverter is easy to be turned on without control. This phenomenon is called commutation failure, which is a common fault of HVDC transmission systems. In order to reduce the probability of inverter thyristor valve commutation failure, the thyristor should be applied enough time to reverse voltage, so that the thyristor fully recovers its blocking ability to forward voltage.

5.14.3 WORKING PRINCIPLES

5.14.3.1 The Working Principle of the Six-Pulse Rectifier

Six-pulse rectifier is also called single bridge rectifier, and its working principle is shown in Figure 5.26 [7]. In Figure 5.26, VT₁–VT₆ are the first to the sixth valve arms, respectively, and numbers 1–6 represent the conduction sequence of the valve arms. Each valve arm consists of dozens to hundreds of thyristors in series. u_a , u_b , and u_c are the equivalent fundamental wave phase voltages of AC system, respectively. L_r is the equivalent commutation inductance per phase; L_d is the inductance value of the smoothing reactor; m and n are the common cathode and common anode points of the single-bridge rectifier, respectively. N is the reference potential of the AC system. Under ideal conditions, the three-phase system is considered to be symmetrical, the triggering pulses are equidistant, and the triggering angles α of the converter valves are equal. The rectifier's trigger pulses are spaced 60° apart.

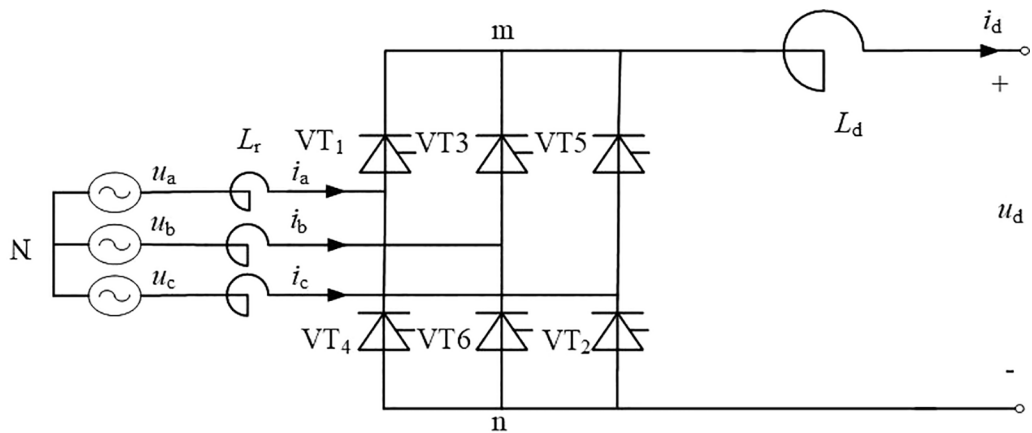


FIGURE 5.26 The principle diagram of the six-pulse rectifier.

The converter is assumed to consist of a controlled thyristor. Under the action of AC side electromotive force and trigger pulse, the converter switches on and off in sequence according to the turning-on and turning-off conditions of the thyristor valve, and changes the AC into DC. In general, the zero-crossing point c_i , where the line voltage changes from negative to positive, is the zero-crossing point of the trigger angle α_i of the converter valve VT_i (i is a positive integer ranging from 1 to 6, representing the valve conduction sequence). The triggering pulse P_i can make VT_i turn on only after the corresponding c_i arrives. For the thyristor valve, the original valve continues to operate before the arrival of P_i . Until the arrival of P_i , VT_i has two conduction conditions and be turned on, replacing the original conduction valve. VT_i has conduction conditions in the range of $0 < \alpha < 180^\circ$, and α of the rectifier has a possible operating range of $0 < \alpha < 90^\circ$. Under normal operating conditions, the range of α of the rectifier is relatively small. In order to ensure the simultaneity of the series thyristors in the converter valve, the minimum value of α is usually 5° . In addition, α needs to be adjusted to some extent during the operation state. When α increases, the operation characteristics of the rectifier may deteriorate, so α is usually between 5° and 20° .

5.14.3.2 The Working Principle of the Six-Pulse Inverter

The inverter is a converter that can convert DC to AC. In HVDC transmission projects, active inverters are mostly used at present, which requires the AC system connected to the inverter to provide commutation voltage and current. The principle diagram of the six-pulse inverter is shown in Figure 5.27. Like the rectifier, the inverter uses a three-phase bridge connection consisting of six converter valves. Because of the unidirectional conductivity of the converter valve, the direction of the inverter converter valve must be consistent with the rectifier to ensure the flow of DC [6].

VT_1 – VT_6 valve arms of the six-pulse inverter are also triggered, in turn, in the same order as the six-pulse rectifier, and the conduction interval between adjacent valve arms is 60° . The turn-off of the six-pulse inverter is also realized by commutation of the two-phase short circuit current in the valve side winding of the converter transformer. Therefore, the six-pulse inverter works in a similar way to the six-pulse rectifier, except that the range of trigger delay angle α is different. When $\alpha \leq 90^\circ - \mu/2$ (μ is the commutation overlap angle), the converter works in the rectification state; when $90^\circ - \mu/2 \leq \alpha < 180^\circ$, the inverter works in the inverter state; When commutation is excluded, the operating boundary between rectification and inverter is $\alpha = 90^\circ$.

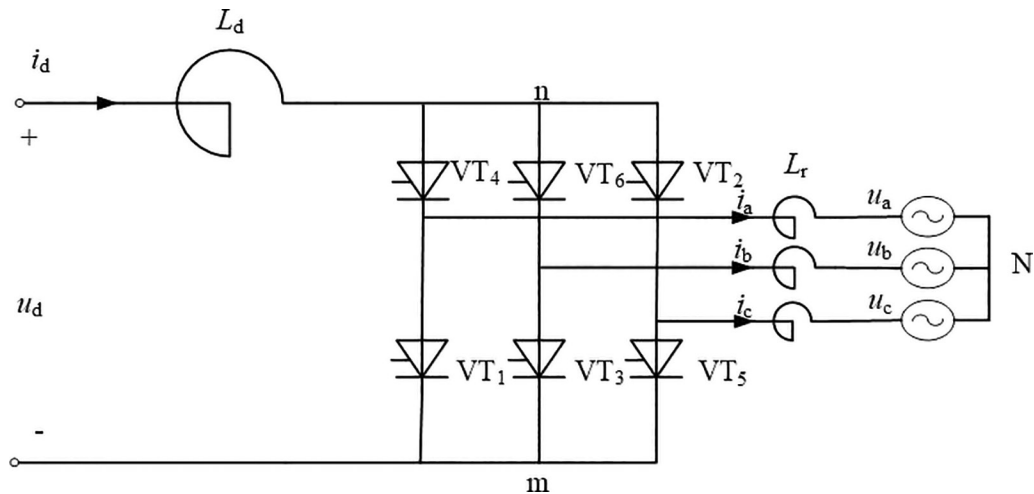


FIGURE 5.27 The principle diagram of the six-pulse inverter.

5.14.3.3 The Working Principle of the 12-Pulse Converter

The 12-pulse converter is composed of two 6-pulse converters in series on the DC side, and its AC side is connected in parallel through the network side winding of the converter transformer. 12-pulse converters can use either a two-winding converter transformer (as shown in Figure 5.28) or a three-winding converter transformer [7].

The converter consists of 12 converter valves (VT_1 – VT_{12}). In each power frequency cycle, the 12 converter valves will be turned on in sequence. In this process, 12 sequential trigger pulses (spaced 30° apart) synchronized with the AC system are required. The main advantages of 12-pulse converter are good quality of AC and DC voltage and less harmonic components.

The 12-pulse converter works on the same principle as the 6-pulse converter, which also uses the two-phase short-circuit current of the AC system for commutation. When the commutation angle $\mu < 30^\circ$, in the non-commutation period, only four valves (two valves in each bridge) are simultaneously turned on; When only one bridge is commutated, five valves (three valves in the commutated bridge and two valves in the non-commutated bridge) are turned on simultaneously. When $\mu = 30^\circ$, there are always five valves in the two bridges conducting at the same time. In one bridge, a pair of valves has just completed the commutation, and the other pair of valves in the other bridge starts the commutation immediately. When $30^\circ < \mu < 60^\circ$, one pair of valves in one bridge is not finished yet, and another pair of valves in the other bridge is started. When $\mu = 60^\circ$, the corresponding working condition ends.

Note that when the turn-off angle is too small, the 12-pulse inverter is prone to commutation failure, resulting in a short circuit on the DC side of the inverter (The DC will be high). If the continuous commutation fails, the DC will increase to a higher value, and the DC control protection system will take action. At this time, emergency phase shift control measures will be adopted, and the monopole or bipolar of the HVDC transmission system will stop running. If only one commutation failure occurs, the increase in DC is small, and the DC can be adjusted back to a predetermined value by controlling the DC on the rectifier side.

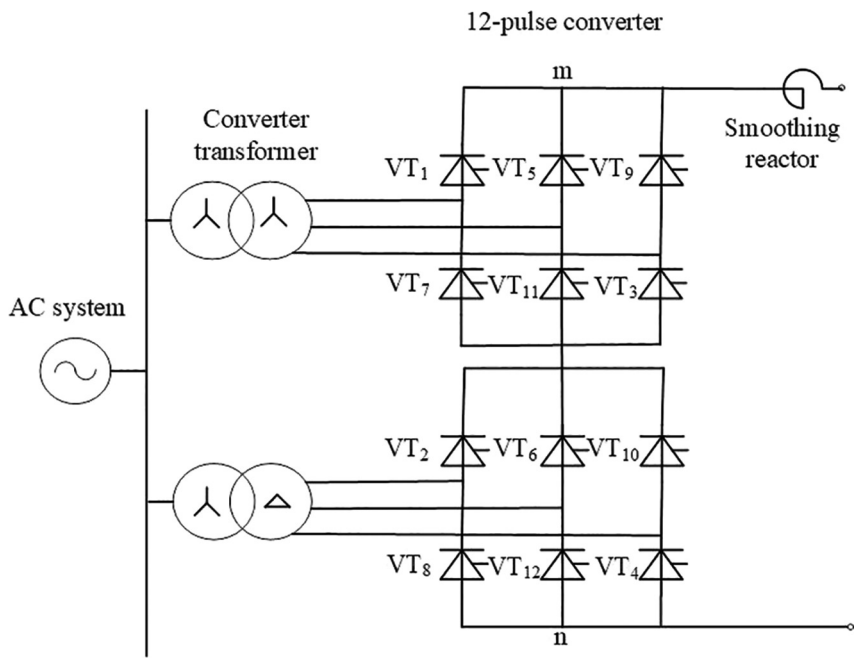


FIGURE 5.28 The principle diagram of the 12-pulse converter.

5.15 VOLTAGE SOURCED CONVERTER (VSC) TECHNOLOGY

In the 1990s, the commercial availability of high-power and high-voltage gate turn-off (GTO) and insulated gate bipolar transistor (IGBT) valves allowed VSCs to be used in HVDC schemes. In essence, a VSC's influence on the AC system may be estimated as the total of a traditional CSC and SVC running in parallel, but with the extra flexibility of safe commutation. The basic structure of VSC is shown in Figure 5.29.

In the basic structure of VSC shown in Figure 5.29, the major components include

- a. circuit breaker,
- b. line side harmonic filter,
- c. line side high-frequency filter,
- d. interface transformer,
- e. converter side harmonic filter,
- f. & g. converter side high-frequency filter,
- g. phase reactor,
- h. VSC unit,
- i. VSC DC capacitor,
- j. DC harmonic filter,
- k. neutral point grounding branch,
- l. DC reactor,
- m. common mode blocking reactor,
- n. DC side high-frequency filter,
- o. DC cable or overhead transmission line.

To operate the VSC in inverter mode and deliver a sinusoidal output to the AC system, many types of Pulse Width Modulation (PWM) methods can be used. The VSC has the following advantages:

1. Rapid control of active as well as reactive power,
2. Minimal environmental impact, and
3. Ability to connect to weak AC networks or even dead networks.

The technology lends itself to the following types of applications:

1. Low power (<250 MW) HVDC transmission (commercially referred to as “HVDC Light”),
2. VAR Computation (SVC and STATCOM), and
3. Active Filters.

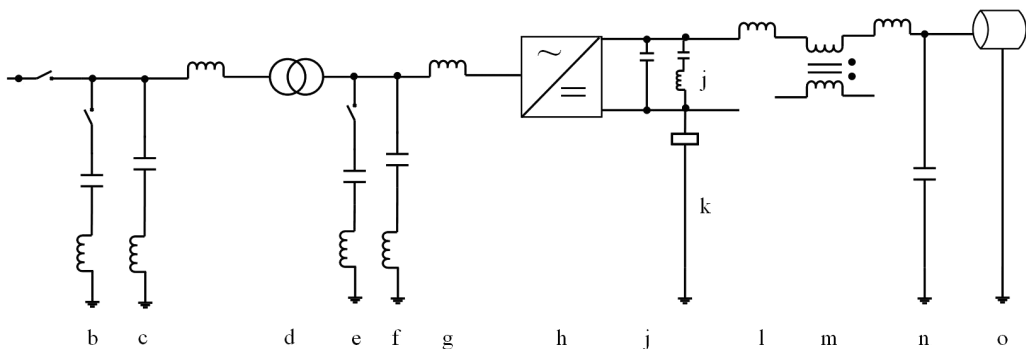


FIGURE 5.29 The basic structure of VSC.

VSCs utilize self-commutating switches (e.g., GTOs or IGBTs), which can be turned on or off at will. This is in contrast to traditional CSCs, which use line-commutated thyristor switches to operate. A force-commutated VSC valve can commute several times every cycle, but a line-commutated CSC can only commute once per cycle. This feature allows you to adjust the voltage/current in a VSC to generate a virtually sinusoidal output while also controlling the power factor. Furthermore, power reversal in a VSC may be accomplished on the DC side using either current or voltage reversal. With a CSC, however, only voltage reversal can cause power reversal.

For the specific VSC configurations, they contain:

1. Symmetrical monopole. The DC output voltages are of equal but opposite magnitude. The midpoint of the DC circuit is earthed, either by capacitors or by other means, which is shown in Figure 5.30a.
2. Asymmetric monopole with metallic return. The DC side output from the converter is asymmetrical with one side typically connected to earth. It is possible to operate the transmission system in metallic return or in earth return, which is shown in Figure 5.30b.

For the principles of active and reactive power control, the VSC may be compared to a synchronous generator without inertia that is capable of managing active and reactive power separately.

The active and reactive power can be controlled simultaneously and independently of each other. If U_{conv} is in phase with the line voltage U_L and its amplitude is equal to U_L , there is no AC current I_{conv} from the VSC. Under these conditions, the DC current I_d becomes zero and the DC capacitor voltage U_d becomes equal to the DC source voltage U_s .

Figure 5.31 shows the functioning principles of a VSC. The VSC's DC side capacitor and AC side inductor are both required components. The DC voltage is measured and compared to a reference value in order to create an error signal, which is used to regulate the PWM controller. The VSC operates as a rectifier when the DC is positive; the DC capacitor is depleted as it feeds the DC load, and the control system changes the firing angle to import power from the AC system. The VSC operates as an inverter when the DC is negative; the DC capacitor is charged from the DC source, and the control system modifies the firing angle to export power to the AC system.

The active and reactive power can be controlled simultaneously and independently of each other. If U_{conv} is in phase with the line voltage U_L and its amplitude is equal to U_L , there is no AC current I_{conv} from the VSC. Under these conditions, the DC current I_d becomes zero and the DC capacitor voltage U_d becomes equal to the DC source voltage U_s .

The PWM controller produces a voltage that has the same frequency as the AC system voltage. The converter may be made to operate in all four quadrants, that is, rectifier/inverter operation with lagging/leading power factor, by changing the amplitude of and its phasor interaction with it. Figure 5.32 depicts the phasor correlations for such an operation.

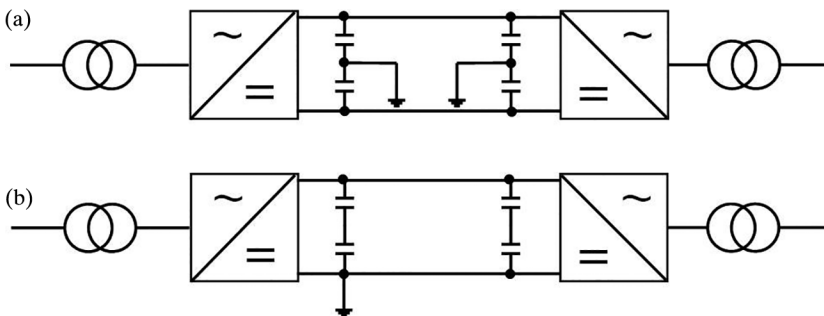


FIGURE 5.30 VSC transmission (a) with a symmetrical monopole and (b) with an asymmetric monopole with metallic return.

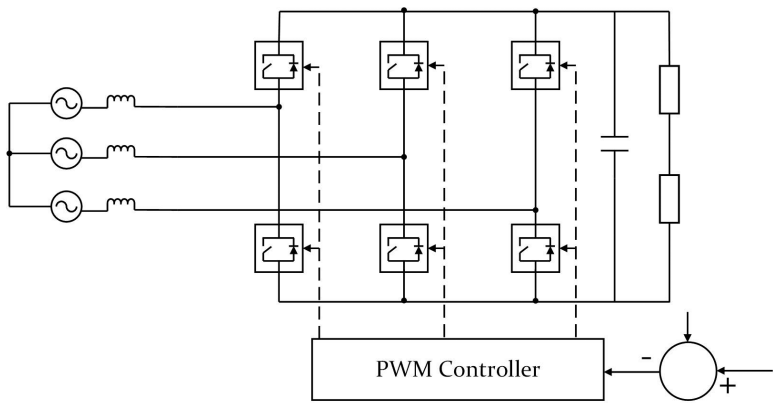


FIGURE 5.31 The basic structure of VSC.

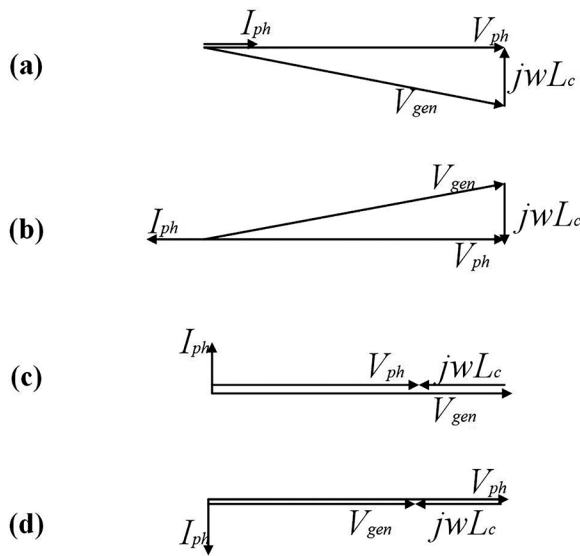


FIGURE 5.32 Four quadrant operation of the VSC: (a) rectifier operation at unity power factor, (b) inverter operation at unity power factor, (c) purely reactive with leading current, and (d) purely reactive with lagging current.

5.16 MODULAR MULTI-LEVEL CONVERTER (MMC) TECHNOLOGY

5.16.1 INTRODUCTION

The MMC was proposed by Rainer Marquardt from the University of Bundeswehr/Munich [8]. Its typical topology is shown in Figure 5.33. A phase unit of MMC consists of the upper arm and lower arm and each arm consists of multiple sub-modules (SMs) and an inductor connected in series. Each arm contains the same number of SMs and the same inductor. The phase output is drawn between the two bridge arms [9].

Different from the traditional VSC topology, the AC reactor is directly connected in series in the arms instead of being connected between the converter and the AC system. The inductor can suppress the interphase circulating current caused by the unequal instantaneous value of the DC voltage of each phase. It can also suppress the inrush current when the DC bus fails, and improve the reliability of the system [10].

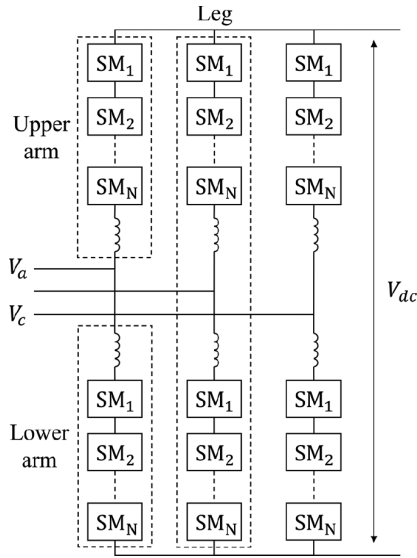


FIGURE 5.33 Topology of MMC.

Compared with traditional two-level and three-level VSC, MMC has the following advantages [11,12]:

1. *The output voltage waveform has higher quality:* MMC can realize the flexible change of voltage and power level by adjusting the number of SMs in series. Multi-level outputs can also be achieved and thus reduce electromagnetic interference as well as harmonic. Therefore, there is no need to install AC filters on the grid side. On the contrary, the output voltage of traditional two-level and three-level VSC can be seriously distorted. Thus, the installation of filters on the AC side is necessary.
2. *Faults at the DC side have a lower impact on the converter:* When a short-circuit fault occurs, the short-circuit current on the MMC arm should be less than the two-level and three-level VSC because of the inductor. Moreover, since the capacitors in the MMC are dispersed in each SM, the discharge process caused by faults has a much smaller impact on the SM. Therefore, the short-circuit fault on the DC side has less impact on the MMC than on the two-level and three-level VSC converters.
3. *Low requirements for switching devices:* The modular structure of MMC makes it less demanding on the identity of IGBT. It is also easy to package and expand. Traditional two-level and three-level VSC converters require each device to have the same characteristics because the IGBT connected in series are turned on and off at the same time, which is the main technical difficulty. Meanwhile, there is a protection switch in the SM that can bypass the fault module, so the MMC can still achieve the short-circuit failure mode by using the welded IGBT at a lower cost.
4. *Low switching loss.* The average switching frequency of MMC can be reduced to about 100–300 Hz. Compared with two-level and three-level VSC, MMC has lower switching loss and is more economical.

MMC has a wide range of application prospects. It can be used not only for MMC-HVDC but also for STATCOM, Static Synchronous Series Compensator, Unified Power Flow Controller, Unified Power Quality Controller, and other power electronic devices. Compared with traditional multi-level converter topologies, MMC not only inherits the structure and output characteristics of traditional multi-level converter topologies but also has significant technical advantages in system unbalanced operation and fault protection. Therefore, MMC has become the preferred topology for the HVDC converter station [13].

5.16.2 OPERATING STATES OF MMC SUB-MODULE

In MMC, SM is the basic part of its topology, which consists of a half-bridge IGBT in parallel with a capacitor. Figure 5.34 shows the topology of a SM. T_1 , T_2 stand for IGBT; VD_1 , VD_2 stand for anti-parallel diode; and C stands for the DC side capacitor. V_C is the voltage of the capacitor, V_{SM} is the voltage of the SM, and I_{SM} is the current flowing into the SM. According to the IGBT states and current direction, there are three operating states, as is shown in Table 5.1 [14].

State 1: Both T_1 and T_2 are switched off. There are two modes in state 1, namely, mode (a) and mode (d), depending on which diodes are turned on. For mode (a), VD_1 is on, and the current flows through VD_1 to charge the capacitor. For mode (d), VD_2 is on, and the current flows through VD_2 to charge the capacitor. These are abnormal operating modes, which are used for charging the SM capacitors when MMC starts or bypassing the SM capacitors when faults occur. State 1 is not allowed during normal operation.

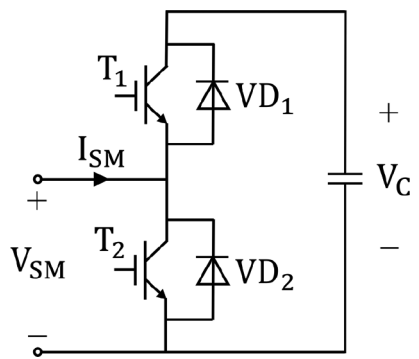


FIGURE 5.34 MMC SM topology.

TABLE 5.1
Operating States of MMC Sub-Module

State 1	State 2	State 3

State 2: T_1 is switched on and T_2 is switched off. VD_1 is also turned on and VD_2 is turned off.

There are two modes, namely, mode (b) and mode (e), depending on the direction of the current. For mode (b), T_1 is subjected to the inverse voltage and is switched off. The current flows through VD_1 to charge the capacitor. For mode (e), T_1 is switched on. VD_1 is subjected to the inverse voltage and is switched off. The current flow through T_1 to charge the capacitor. Thus, the capacitor at DC side is always charging or discharging and the output voltage of the SM is the capacitor voltage V_C .

State 3: T_2 is switched on and T_1 is switched off. There are also two modes, namely, mode (c) and mode (f). For mode (c), T_2 is switched on and VD_2 is subjected to the inverse voltage. The current flows through T_2 to bypass the capacitor. For mode (f), VD_2 is switched on and T_2 is switched off. The current flows through VD_2 to bypass the capacitor. In this state, the output voltage of SM is zero, that is, the SM is bypassed out of the main circuit.

The six operation modes are summarized in Table 5.2. For T_1 , T_2 , VD_1 , VD_2 , 1 corresponds to the on state, and 0 corresponds to the off state. It can be seen that only one of T_1 , T_2 , VD_1 , VD_2 is switched on in each mode. Therefore, it can be considered that only one of them is switched on during SM steady-state operation. Thus, SM can be turned on or off by controlling the on and off of T_1 and T_2 [10].

5.16.3 MMC MODULATION STRATEGY

The commonly used modulation methods for MMC include Staircase Modulation, Nearest Level Modulation, Level Stack Pulse Width Modulation, Space Vector Pulse Width Modulation, and Carrier Phase-Shifting Pulse Width Modulation. They are suitable for different occasions according to their characteristics [12]. The modulation method has a key influence on the performance of the VSC. Thus, a simple, efficient, and suitable modulation method needs to be selected for a specific VSC.

5.17 TWO-TERMINAL DIRECT-CURRENT TRANSMISSION SYSTEM AND ITS CONTROL

As a critical tool for long-distance bulk-power transmission, the two-terminal direction current transmission system plays an important role in point-to-point transmission scenarios. Compared with traditional AC transmission, one of the merits of DC transmission systems is the high performance of controllability and flexibility of the transmission power, whose value and direction could be rapidly regulated. In other words, the performance of DC transmission power is determined by its control system.

The control functions of the DC transmission system are included but not limited to

1. Start and stop of DC transmission systems.
2. Value and direction of DC transmission systems.
3. Suppress disturbances from interconnected AC systems.

TABLE 5.2
Six Operation Mode of MMC Sub-Module

Mode	T_1	T_2	VD_1	VD_2	i direction	U
(a)	0	0	On	Off	$A \rightarrow B$	V_C
(b)	0	0	On	Off	$A \rightarrow B$	V_C
(c)	0	1	Off	Off	$A \rightarrow B$	0
(d)	0	0	Off	On	$B \rightarrow A$	0
(e)	1	0	Off	Off	$B \rightarrow A$	V_C
(f)	0	0	Off	On	$B \rightarrow A$	0

With different devices and control philosophies, the control system of two-terminal LCC HVDC and two-terminal VSC HVDC is different and will be elaborated, respectively.

5.17.1 CONTROL SYSTEM OF TWO-TERMINAL LCC HVDC SYSTEMS

5.17.1.1 Hierarchical Control Structure

Generally, DC transmission employs a hierarchical way to achieve different levels of control and to achieve the following goals:

- 1. provide efficient and stable operation;
- 2. maximize flexibility in power control;
- 3. operate within equipment safety.

During operation, changes in various factors, including load changes, voltage fluctuations, and various disturbances, will cause changes in operating parameters. This requires various related control and adjustment components to be adjusted to bring the operating parameters back to the original or new values as required.

As shown in Figure 5.35, the hierarchical control structure of the two-terminal LCC HVDC system includes

- 1. *System control*: This is the highest control level. The control functions are as follows: (1) communication with the dispatch center with uploaded measurement data and downloaded command data; (2) power reversal control; (3) power and frequency modulation control for damping suppressing.
- 2. *Bi-pole control*: As shown in Figure 5.36, the control functions include the following: (1) allocation of DC transmission for each pole; (2) DC balance control; (3) reactive and voltage control; (4) voltage-dependent current limit control.
- 3. *Pole control*: As shown in Figure 5.37, when one of the two poles in a converter station fails, the other pole is required to operate independently and achieve the basic control target of power transmission. The control functions include the following: (1) DC control; (2) DC power control; (3) DC voltage control; (4) extinction angle control.

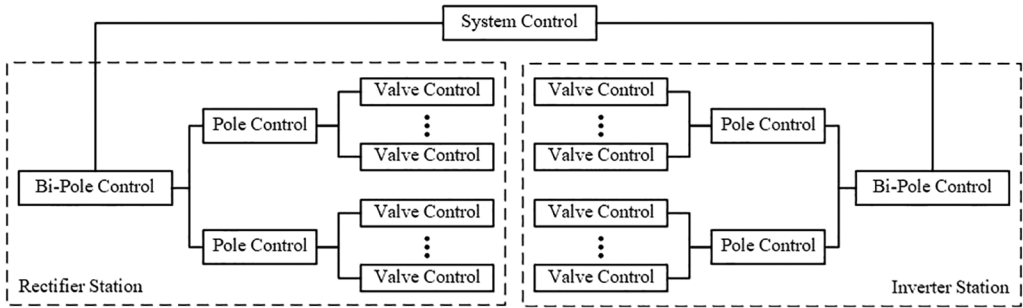


FIGURE 5.35 Hierarchical control structure of the two-terminal LCC HVDC system.

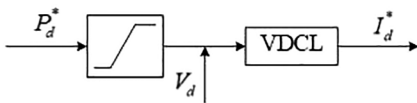


FIGURE 5.36 Bi-pole control.

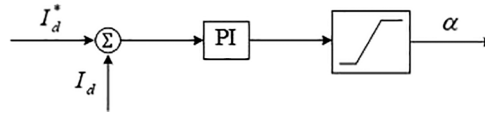


FIGURE 5.37 Pole control.

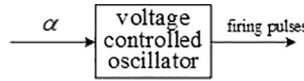


FIGURE 5.38 Valve control.

4. *Valve control:* As shown in Figure 5.38, this is the lowest control level. The order signal from the pole control to the valve control is used to generate the firing pulses. The control functions include a tap changer controller (in the time order to several hundreds of milliseconds), which maintains the tap position of the converter transformer and maintains the firing angle within a nominal range. This could help minimize the converter's reactive power consumption and provide sufficient margin for converter's dynamic operation.

Specifically, the above control functions are achieved by controllers within the rectifier station and inverter station and between the two stations. As shown in Figure 5.39, each station controls a DC voltage, and then the DC is determined according to Ohm's law:

$$I_d = (V_{dr} - V_{di})/R \quad (5.172)$$

where:

- V_{dr} : DC voltage of the rectifier station;
- V_{di} : DC voltage of the inverter station;
- R : DC line resistance.

Then, the DC transmission power of the two-terminal LCC HVDC system is given by

$$P_d = V_d I_d \quad (5.173)$$

Furthermore, considering the firing angles in each station, we have the equivalent circuit of the two-terminal LCC HVDC system in Figure 5.40.

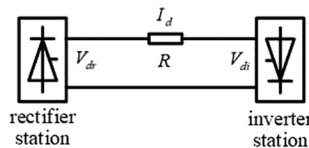


FIGURE 5.39 Illustration of a two-terminal LCC HVDC transmission system.

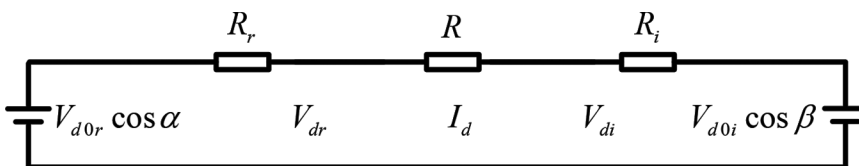


FIGURE 5.40 Equivalent circuit of a two-terminal LCC HVDC transmission system.

This leads to

$$V_{dr} = V_{d0r} \cos \alpha - R_r I_d \quad (5.174)$$

$$V_{di} = V_{d0i} \cos \beta + R_i I_d \quad (5.175)$$

where

α : firing angle of the rectifier station;

β : firing angle of the inverter station;

R_r : equivalent resistance of the rectifier station;

R_i : equivalent resistance of the inverter station;

Thus, the DC is actually determined by

$$I_d = (V_{d0r} \cos \alpha - V_{d0i} \cos \beta) / (R_r + R + R_i) \quad (5.176)$$

5.17.1.2 Coordination Control

As the most widely accepted control method of the two-terminal LCC HVDC system, the current margin control relies on the coordination between the two terminals, that is, the rectifier station and the inverter station.

The basic principle of the current margin control is depicted in Figure 5.41.

The intersection of the two characteristic curves determines the operation mode of the two-terminal LCC HVDC system. In order to operate at the desired operation point, the current margin should always be maintained. This requires a fast and reliable telecommunication channel for data transmission from one station to the other station. If a negative current margin is accidentally or purposely achieved, the corresponding characteristic curves are depicted in Figure 5.42.

This is also how the power reversal control works. Since in most two-terminal LCC HVDC systems, each converter could operate either as a rectifier station or as an inverter station. This facilitates the ability of rapid power reversal, which is important for emergency power support under extreme events. The power reversal control not only enhances the interconnection of the two AC systems, but also improves the reliability and flexibility of the whole power system.

Controllers in stations include constant DC control, constant DC voltage control, constant firing angle control, CEA control, and voltage-dependent current limit control.

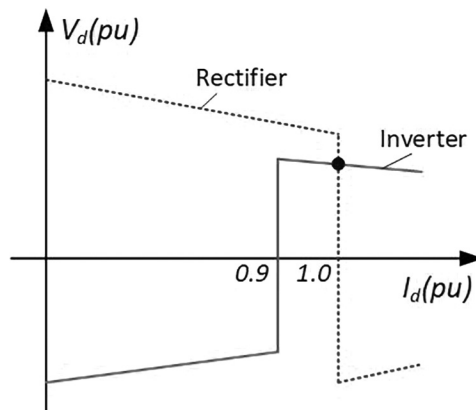


FIGURE 5.41 Current margin control.

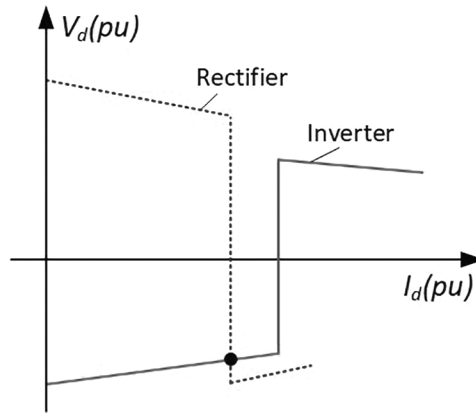


FIGURE 5.42 Power reversal control.

5.17.2 CONTROL SYSTEM OF TWO-TERMINAL VSC HVDC SYSTEMS

5.17.2.1 Basic Property of a VSC Station

As shown in Figure 5.43, the external characteristic of a VSC station can be described as the following equations:

$$P = \frac{U_s U_c \sin \theta}{X} \quad (5.177)$$

$$Q = \frac{U_s (U_s - U_c \sin \theta)}{X} \quad (5.178)$$

where

P : active power of the VSC station;

Q : reactive power of the VSC station;

θ : phase angle of the VSC station.

Hence, the active power is mainly determined by the θ . That is, when $\theta > 0$, the VSC station outputs active power and operates as an inverter station; when $\theta < 0$, the VSC station absorbs active power and operates as a rectifier station. As for the reactive power, it is mainly determined by the terminal voltage U_s .

Compared with the LCC technology, one major advantage of the VSC technology is that VSC has two degrees of control freedoms, while LCC only has one degree of control freedom. In other words, the active and reactive power are both controllable and can be adjusted independently.

As shown in Figure 5.44, the VSC station could operate as a generator or motor with zero inertia. That is, the VSC station could rapidly and independently adjust the active power and reactive power. The high performance of controllability and flexibility makes the VSC technology a promising solution for power systems.

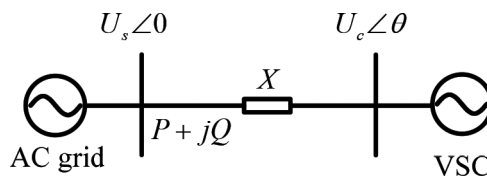


FIGURE 5.43 VSC system.

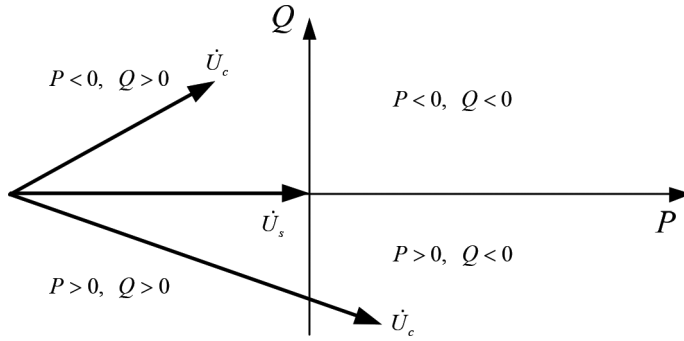


FIGURE 5.44 Operation of VSC station.

5.17.2.2 Vector Control of VSC Systems

There are two main control strategies for a VSC station, that is, the indirect current control and the direct current control (i.e., the vector control). The indirect current control is adopted in early times, where the magnitude and phase angle of the AC voltage are directly controlled and thus the phase current is indirectly controlled. The advantages of the indirect current control are the simple control philosophy and no current feedback is needed, while the disadvantages are the slow response to current dynamics and the inability to limit the overcurrent. To overcome the drawbacks of the indirect current control, the direct current control could quickly respond to the current dynamics and has become a widely applied control strategy.

In steady state, the q-axis component of the AC voltage is nearly zero, thus we have

$$P = 1.5 U_s i_d \quad (5.179)$$

$$Q = -1.5 U_s i_q \quad (5.180)$$

Hence, by adjusting the i_d and i_q , the active power and reactive power can be controlled, respectively. This is achieved by the outer control loop and inner control loop. Specifically, the inner control loop rapidly regulates the current i_d and i_q according to the current order from outer control loop and current measurement from current sensors.

As for the outer control loop, it generates the current order for inner control loop according to the power order or voltage order. There are four kinds of outer control loop designed for d-axis current or q-axis current, that is, active power controller, DC voltage controller, reactive power controller, and AC voltage controller.

In a two-terminal VSC HVDC transmission system, each station independently controls two variables. As shown in Figure 5.45, the intersection of the two control curves determines the operation point of the two-terminal VSC HVDC transmission system.

5.18 MULTI-TERMINAL DIRECT CURRENT TRANSMISSION SYSTEM AND ITS CONTROL

5.18.1 TOPOLOGY OF MULTI-TERMINAL TRANSMISSION SYSTEM

Multi-terminal HVDC (MTDC) transmission system is composed of at least three HVDC stations. Each of the HVDC stations interconnects an AC system. Compared with the two-terminal HVDC system, the MTDC system is more flexible and controllable for the following scenarios:

1. interconnection of multiple independent and asynchronous AC systems;
2. interconnection of multiple renewable energy bases;
3. interconnection of multiple load centers and power generations.

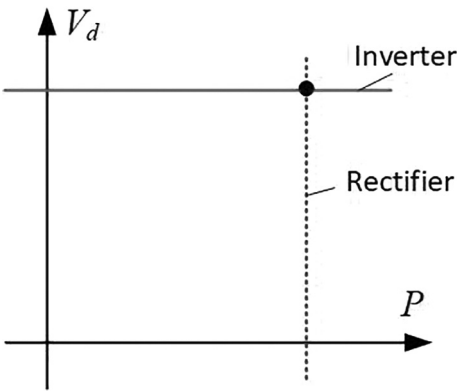


FIGURE 5.45 Coordination of a two-terminal VSC HVDC transmission system.

There are different topologies for MTDC transmission systems, which could be mainly divided into series-connected and parallel-connected, which are depicted in Figures 5.46 and 5.47, respectively.

5.18.2 CONTROL SYSTEM OF MULTI-TERMINAL LCC HVDC SYSTEM

Similar to the two-terminal LCC HVDC system, the multi-terminal LCC HVDC system is controlled by the coordination among all the participating HVDC stations. Specifically, one of the LCC station controls the DC voltage and the rest LCC stations control their DC independently.

For example, Figure 5.48 indicates the control curves of current margin control of a four-terminal LCC HVDC transmission system. Rectifier station 1 operates at a constant firing angle mode, while the rest three stations operate at a constant DC mode. Moreover, it is shown in Figure 5.49 that the current margin is still maintained to facilitate a feasible operation point.

5.18.3 CONTROL SYSTEM OF MULTI-TERMINAL VSC HVDC SYSTEM

Due to the high performance of controllability and flexibility of VSC technology, the VSC MTDC transmission system is more applicable than the LCC MTDC transmission system. There are mainly three kinds of control strategies, that is, the master/slave control, voltage margin control, and voltage droop control.

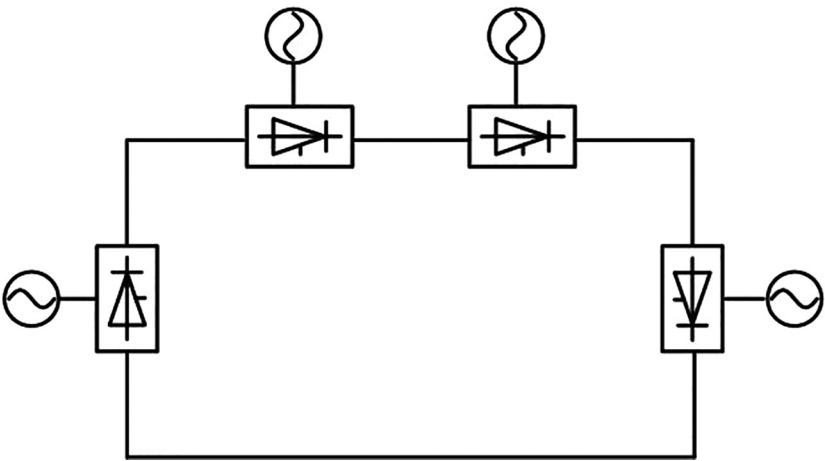


FIGURE 5.46 Series-connected topology of an MTDC transmission system.

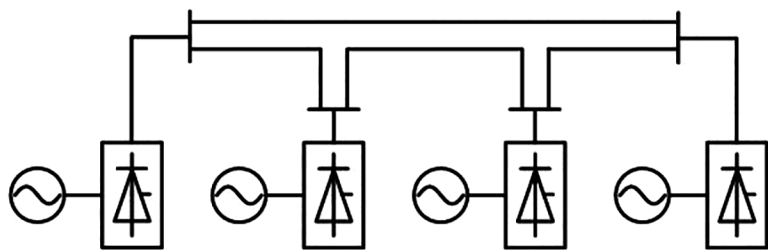


FIGURE 5.47 Parallel-connected topology of an MTDC transmission system.

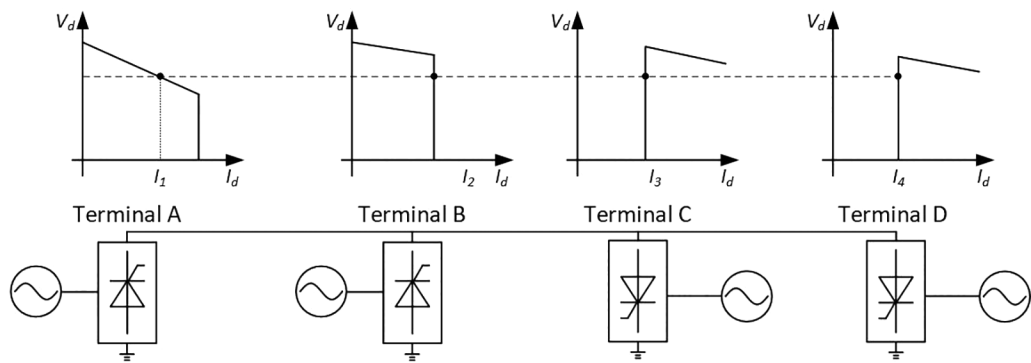


FIGURE 5.48 Current margin control of a four-terminal LCC HVDC transmission system.

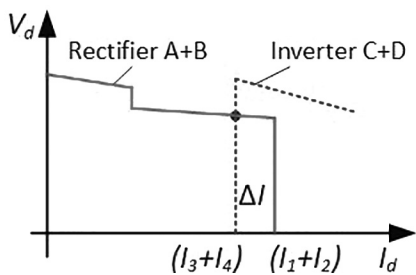


FIGURE 5.49 Current margin of a four-terminal LCC HVDC transmission system.

5.18.3.1 Master/Slave Control

As a simple and effective control strategy, the master/slave control is the most widely applied control strategy. The master station controls the DC voltage, while the rest slave stations control their own active power transmission. For example, Figure 5.50 indicates the control curves of master/slave control of a four-terminal VSC HVDC transmission system. Station 1 operates as the master station and controls the DC voltage, while the rest three stations operate as slave stations and control the active power.

Although the master/slave control is a simple and effective control strategy, it is vulnerable to the malfunction of the master station. That is, once the master station fails, one of the slave stations needs to operate as the new master station immediately. This requires reliable and rapid telecommunication among these VSC stations.

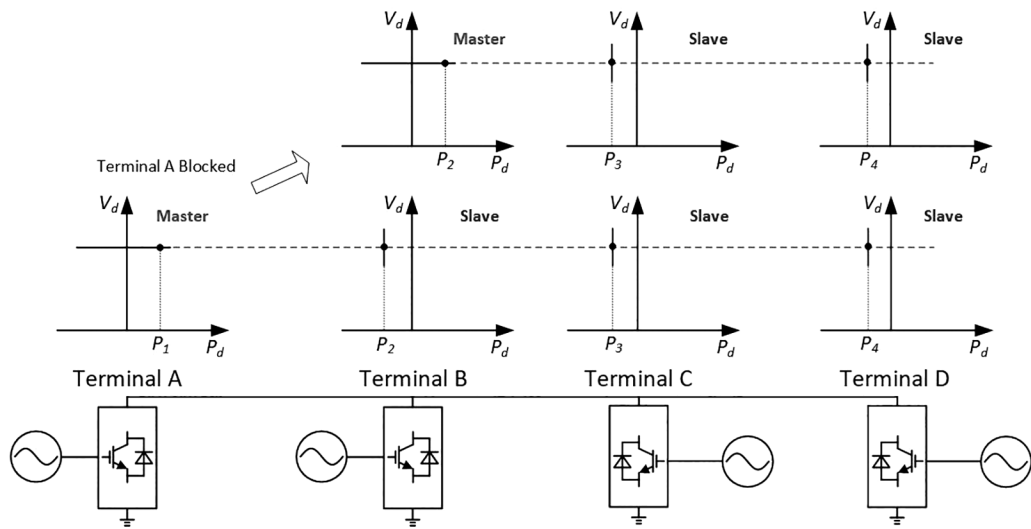


FIGURE 5.50 Master/slave control of a four-terminal VSC HVDC transmission system.

5.18.3.2 Voltage Margin Control

To overcome the drawback of dependence on the telecommunication of the master/slave control, the voltage margin control is proposed as a control strategy that could operate without communication. As a dual form of the current margin control, the voltage margin control is designed to set a slave station as a standby master station. The DC voltage order of the standby master station and the present master station is different and thereby leads to a voltage margin. Once the present master station fails, the standby master station will automatically operate as the master station.

For example, Figure 5.51 indicates the control curves of voltage margin control of a four-terminal VSC HVDC transmission system. Station 1 is the present master station and controls the DC voltage, station 2 is the standby master station which controls the active power but with different DC voltage order, and stations 3 and 4 control the active power.

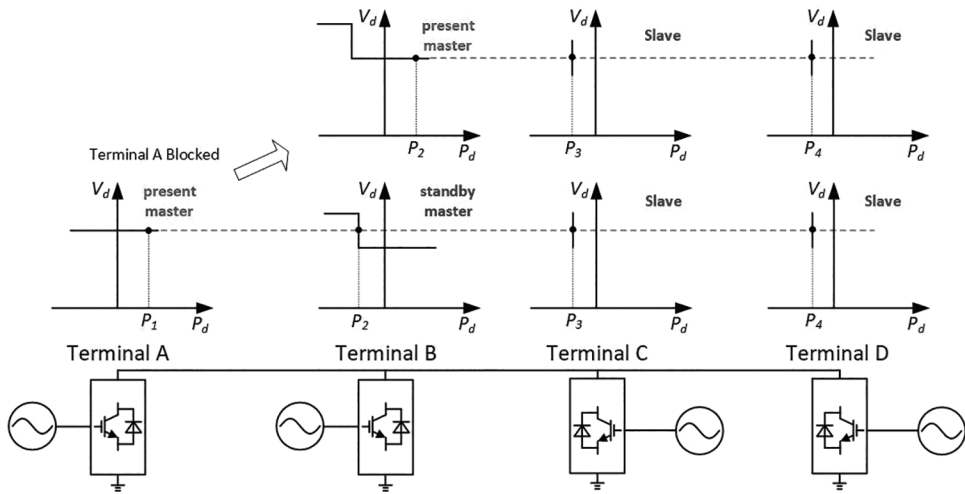


FIGURE 5.51 Voltage margin control of a four-terminal VSC HVDC transmission system.

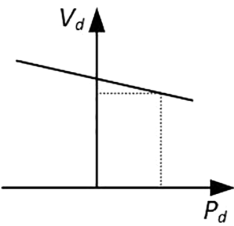


FIGURE 5.52 Voltage droop control of a VSC MTDC transmission system.

5.18.3.3 Voltage Droop Control

The former two control strategies both rely on one station to respond to the active power fluctuations of the whole system, leading to a single-point DC voltage regulation manner. Hence, the voltage droop control is proposed to select multiple stations as master stations to respond, leading to a multi-point DC voltage regulation manner. In each VSC station, the control diagram is designed as a combination of DC voltage controller and active power controller.

The corresponding control curve is depicted in Figure 5.52, which clearly indicates a DC voltage droop characteristic.

PROBLEMS

Problem 5.1

Assume that the following data are given for the overhead AC line discussed in Example 5.1:

- Steady-state operating voltage = 200/346 kV
- Line current = 1,000 A
- Power = 600 MVA
- Insulation level = 500 kV

Use the assumptions and results given in the example and determine the following for the comparable DC line:

- a. Line-to-line DC voltage in kilovolts
- b. Line-to-ground DC voltage in kilovolts
- c. The DC line current in amperes
- d. Associated DC power in megavolt-amperes
- e. The DC line power loss in kilowatts
- f. The DC insulation level

Problem 5.2

A three-conductor DC overhead line with equal conductor sizes is considered to be employed to transmit three-phase, three-conductor AC energy at a 0.92 power factor (see Figure P5.1). If maximum voltages to ground line and transmission efficiencies are the same for both DC and AC and the load is balanced, determine the change in the power transmitted in percent.

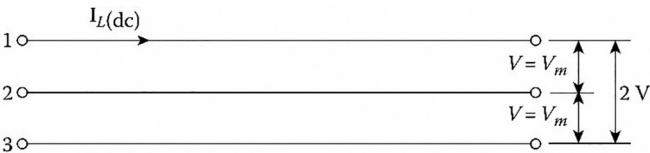


FIGURE P5.1 For Problem 5.2.

Problem 5.3

Derive Equations 5.127, 5.128, and 5.132.

Problem 5.4

Consider a B -bridge converter station and use the angles α and δ , which imply rectifier action. Consider only the first-mode operation, ($u < 30^\circ$). Apply the following equation:

$$I_d = \frac{\sqrt{3}E_m}{2\omega L_c}(\cos \alpha - \cos \delta)$$

which gives the average DC in any one bridge if E_m is properly interpreted. Also apply the following equation:

$$V_d = V_{d0} \cos \alpha - \Delta V_d$$

which gives the average DC terminal voltage of one bridge if $B = 1$ bridge is being analyzed.

- a. Redefine V_d , V_{d0} , and ΔV_d to designate total voltages for B -bridges in series on the DC sides and show that

$$V_d = V_{d0} \cos \alpha - \frac{3}{\pi} \omega B L_c I_d$$

is valid for the pole-to-pole voltage of the B -bridge station.

- b. Define V_d , in part (a), in terms of B , E , and E_1 .

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6 Underground Power Transmission and Gas-Insulated Transmission Lines

A person is never happy except at the price of some ignorance.

Anatole France

6.1 INTRODUCTION

In the United States, a large percentage of transmission systems was installed during World War II between the mid-1950s and the mid-1970s, with limited construction in the past few decades. The equipment installed in the postwar period is now between 30 and 50 years old and is at the end of its expected life. For example, 70% of transmission lines and power transformers in this country are 25 years old or even older. Similarly, 60% of high-voltage (HV) circuit breakers are 30 years old or older.

Even at a local level, transmission benefits are in danger. For the past 20 years, the growth of electricity demand has far exceeded the growth of transmission capacity. With limited new transmission capacity available, the loading of existing transmission lines has dramatically increased.

At present, the electric power industry is finally starting to invest more money on new transmission lines. This accomplished by upgrading is usually increasing the voltage levels, or by adding more wires, in terms of bundled conductors, to increase the current ratings. It is important that the new transmission construction be planned well so that the existing electric power grid can be systematically transformed into a modern and adequate system rather than becoming a patchwork of incremental and isolated decisions and uncoordinated subsystems.

Today, ten major metropolitan areas in the United States create almost 25% of the total electricity demand of the country. Because demand will continue to grow and become in remote sites, it becomes increasingly difficult to run overhead (OH) power transmission lines through urban or heavily populated suburban areas. These considerations, in addition to the delay and cost complications associated with acquiring right-of-way, emphasize the need for advanced high-capacity underground power transmission systems.

This underground power transmission solution has the advantages of possible usage of existing rights-of-way of present OH transmission lines and a decrease in waiting times for getting the necessary permissions. It goes without saying that the cost of building underground lines is much greater than building OH transmission lines.

Today, there are four main technical methods for underground transmission, namely, (1) using solidly insulated underground cables, (2) using gas-insulated lines, (3) using superconductive cables, and (4) using cryogenic cables.

The solidly insulated cables have been used for underground power transmission since the very beginning of the installation of the transmission network. They are mostly used in cities or other applications where OH lines cannot be used. The use of solidly insulated cables is limited in length as well as in current rating, even though these values have been increased recently. The solidly insulated underground cables and their usage are further discussed extensively starting from the next section in this chapter.

The gas-insulated lines have been used for more than 30 years worldwide. They have been used in many projects providing a very high-power transmission capability similar to the OH lines and are practically not limited in length.

The *superconductive cable* applications are still in their preliminary stages. The use of superconductive cable has been implemented so far only to a relatively few projects in the United States.

However, short experimental *superconducting lines* have been constructed and operated. It remains economical to implement. However, superconducting alternators have been built and operated. It is known that alternators with superconducting fields can be made 40% smaller in size, 1% more efficient, and up to 30% less expensive than typical alternators. The superconducting rotor is the reason for the low cost, size, and greater efficiency. It is interesting to note that the magnetic field from the superconducting rotor windings is so strong that no magnetic core is required, even though a magnetic shield is needed to help contain the coolant and hold AC electricity and magnetic fields, from the stator, from reaching the rotor. Today, several superconducting alternators that are in the range of 20–50 MVA are in operation in the United States and abroad. However, larger superconducting alternators have been economically found to be less attractive.

It is important to note that *a cryogenic cable is not superconducting*. The conductor of such cable possesses a higher electrical conductivity at very low temperature than at ambient temperature. Because of this fact, a cryogenic conductor has a lower resistive loss. For example, at the temperature of liquid nitrogen, the conductivity of aluminum and copper improves by a factor of 10. However, it is usually aluminum that is used in such cables due to its low cost.

The technical feasibility of resistive cryogenic cable systems is large based on insulation performance under HV conditions at low temperature. Based on operational, technical, and economical reasons, the cable that is usually selected is a liquid nitrogen-cooled flexible cable.

A cryogenic cable has a hollow former supporting a helically wound, stranded, transposed conductor made of aluminum. The conductor is taped with a suitable electrical insulation impregnated with liquid nitrogen. An evacuated thermal insulation that is put on the cryogenic pipe reduces heat leak from the environment. Its refrigeration is facilitated by using a system of turbomachinery and neon as the cooling fluid. The ratio of refrigerator input power to refrigeration increases as the cryogenic refrigeration temperature decreases. Today, it is feasible to have an electrical insulation system for a cryogenic cable that is operating at a typical EHV voltage. For example, recent research results indicate successful performance in a liquid nitrogen environment at voltages up to the equivalent of 150% of a 500 kV system having a measured dielectric cable loss that is 300 times less than a typical EHV oil-filled underground cable.

6.2 UNDERGROUND CABLES

Underground cables may have one or more conductors within a protective sheath. The protective sheath is an impervious covering over insulation, and it usually is lead. The conductors are separated from each other and from the sheath by insulating materials. The insulation materials used are (1) rubber and rubberlike compounds, (2) varnished cambric, and (3) oil-impregnated paper.

Rubber is used in cables rated 600 V to 35 kV, whereas polyethylene (PE), propylene (PP), and polyvinyl chloride (PVC) are used in cables rated 600 V to 138 kV. The high-moisture resistance of rubber makes it ideal for submarine cables. Varnished cambric is used in cables rated 600 V to 28 kV. Oil-impregnated paper is used in solid-type cables up to 69 kV and in pressurized cables up to 345 kV. In the solid-type cables, the pressure within the oil-impregnated cable is not raised above atmospheric pressure. In the pressurized cables, the pressure is kept above atmospheric pressure either by gas in gas-pressure cables or by oil in oil-filled cables. Impregnated paper is used for higher voltages because of its low dielectric losses and lower cost. Cables used for 59 kV and below are either (1) low pressure, not over 15 psi, or (2) medium pressure, not over 45 psi. High-pressure cables, up to 200 psi, installed pipes are not economical for voltages of 69 kV and below.

Voids or cavities can appear as a result of faulty products or during the operation of the cable under varying loads. Bending the cable in handling and on installation, and also the different thermal expansion coefficients of the insulating paper, the impregnating material and the lead sheath result in voids in the insulation of cable not under pressure. The presence of higher electrical field strength ionization that appears in the voids in the dielectric leads to the destruction of the insulation. The presence of ionization can be detected by means of the power factor change as a test voltage is applied. The formation of voids is avoided in the case of the oil-filled cable. With the gas-filled cable, the pressure in the insulation is increased to such a value that existing voids or cavities are ionization free. Ionization increases with temperature and decreases with increasing pressure.

The conductors used in underground cables can be copper or aluminum. Aluminum dictates larger conductor sizes to carry the same current as copper. The need for mechanical flexibility requires stranded conductors to be used. The equivalent aluminum cable is lighter in weight and larger in diameter in comparison to copper cable. Stranded conductors can be in various configurations, for example, concentric, compressed, compact, and rope.

Cables are classified in numerous ways. For example, they can be classified as (1) underground, (2) submarine, and (3) aerial, depending on the location. They can be classified according to the type of insulation, such as (1) rubber and rubberlike compounds, (2) varnished cambric, and (3) oil-impregnated paper. They can be classified as a single conductor, two conductors (duplex), three conductors, etc., depending on the number of conductors in a given cable. Also, they can be classified as shielded (as in the Hochstadter or type H cable) or unshielded (belted), depending on the presence or absence of metallic shields over the insulation. Shielded cables can be solid, oil-filled, or gas-filled. Further, they can be classified by their protective finish such as (1) metallic (e.g., a steel sheath) or (2) nonmetallic (e.g., plastic).

Insulation shields help to (1) confine the electric field within the cable; (2) protect the cable better from induced potentials; (3) limit electromagnetic or electrostatic interference; (4) equalize voltage stress within the insulation, minimizing surface discharges; and (5) reduce shock hazard (when properly grounded) [1].

In general, shielding should be considered for nonmetallic covered cables operating at a circuit voltage over 2 kV and where any of the following conditions exist [2]:

1. Transition from conducting to nonconducting conduit
2. Transition from moist to dry earth
3. In dry soil, such as in the desert
4. In damp conduits
5. Connections to aerial lines
6. Where conducting pulling compounds are used
7. Where the surface of the cable collects conducting materials, such as soot, salt, and cement deposits
8. Where electrostatic discharges are of low enough intensity not to damage cable but are sufficient in magnitude to interface with radio or television reception

In general, cables are pulled into underground ducts. However, if they have to be buried directly in the ground, the lead sheath (i.e., the covering over insulation) has to be protected mechanically by armor. The armor is to be made of two tapes overlapping each other or heavy steel wires.

Where heavy loads are to be handled, the usage of single-conductor cables is advantageous since they can be made in conductor sizes up to 3.5 kcmil or larger. They are also used where phase isolation is required or where balanced single-phase transformer loads are supplied. They are often used to terminate three-conductor cables in single-conductor potheads, such as at pole risers, to provide training in small manholes. They can be supplied triplexed or wound three in parallel on a reel, permitting the installation of three-conductor cables in a single duct. Figure 6.1 shows a single-conductor, paper-insulated power cable.

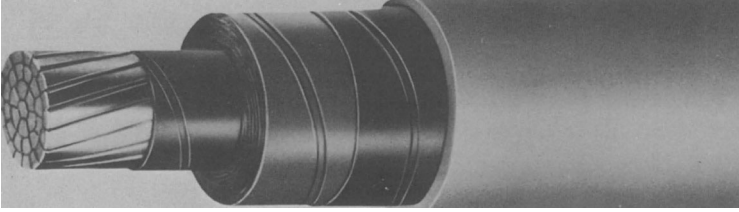


FIGURE 6.1 Single-conductor, paper-insulated power cable. (Courtesy Okonite Company, Ramsey, NJ.)

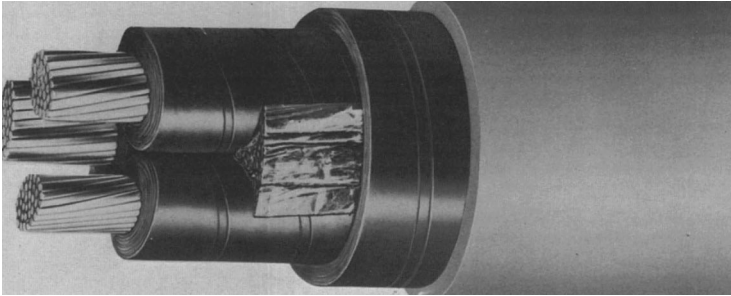


FIGURE 6.2 Three-conductor, belted compact sector, paper-insulated cable. (Courtesy Okonite Company, Ramsey, NJ.)

The belted cable construction is generally used for three-phase low-voltage operation, up to 5 kV, or with the addition of conductor and belt shielding, in the 10–15 kV voltage range. It receives its name from the fact that a portion of the total insulation is applied over partially insulated conductors in the form of an insulating belt, which provides a smooth *cushion* for the lead sheath.

Even though this design is generally more economical than the shielded (or type H) construction, the electrical field produced by three-phase AC voltage is asymmetrical, and the fillers are also under electric stress. These disadvantages restrict the usage of this cable to voltages below 15 kV. Figure 6.2 shows a three-conductor, belted, compact sector, paper-insulated cable. They can have concentric round, compact round, or compact sector conductors.

The three-conductor shielded, or type H, construction with compact sector conductors is the design most commonly and universally used for three-phase applications at the 5–46 kV voltage range. Three-conductor cables in sizes up to 1 kcmil are standard, but for larger sizes, if overall size and weights are important factors, single-conductor cables should be preferred.

It confines the electric stress to the primary insulation, which causes the voltage rating (radial stress) to be increased and the dielectric losses to be reduced. The shielded paper–oil dielectric has the greatest economy for power cables at HVs where reliability and performance are of prime importance. Figure 6.3 shows a three-conductor, shielded (type H) compact sector, paper-insulated cable.

Figure 6.4 presents various protective outer coverings for solid-type cables, depending on installation requirements. Figure 6.5 shows the recommended voltage ranges for various types of paper-insulated power cables.

Most cable insulations are susceptible to deterioration by moisture to varying degrees. Paper and oil, which have had all the moisture completely extracted in the manufacture of a paper cable, will reabsorb moisture when exposed to the atmosphere, and prolonged exposure will degrade the exceptionally high electrical quantities. Because of this, it is mandatory in all paper cable splices and terminations to reduce exposure or the insulation to moisture and to construct and seal the accessories to ensure the complete exclusion of moisture for a long and satisfactory service life.

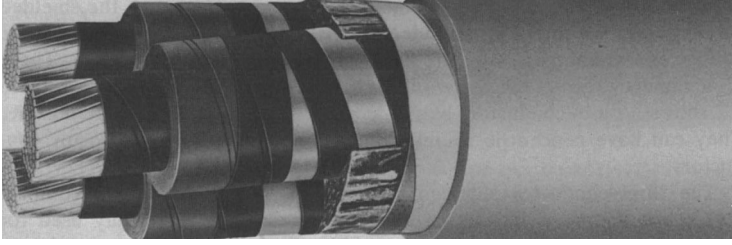


FIGURE 6.3 Three-conductor shielded (type H), compact sector, paper-insulated cable. (Courtesy Okonite Company, Ramsey, NJ.)

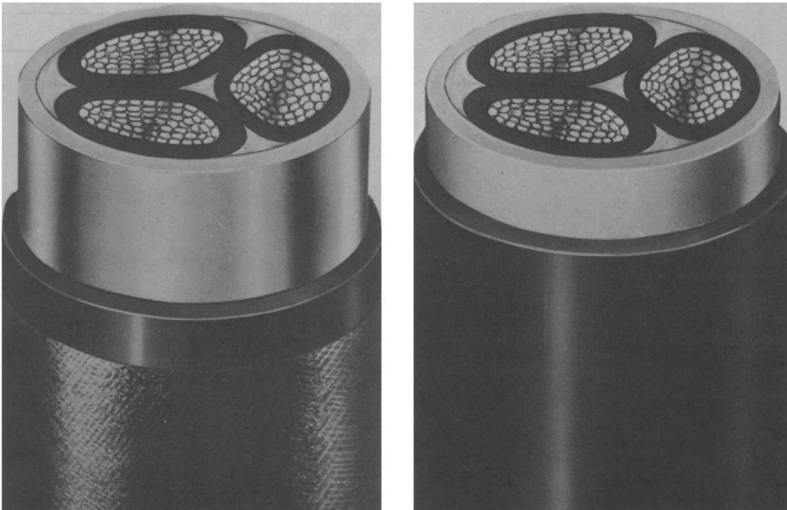
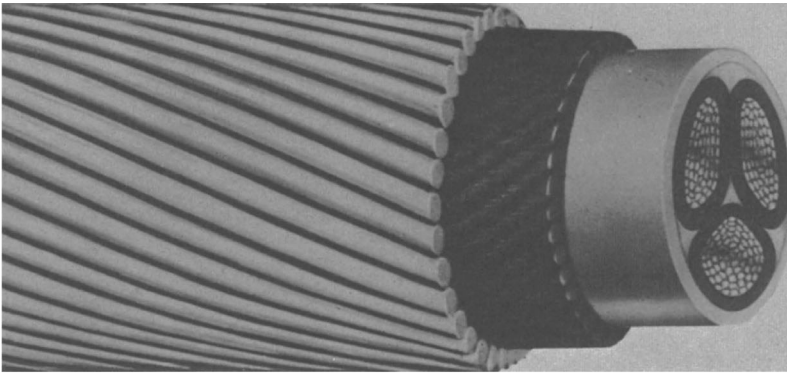


FIGURE 6.4 Various protective outer coverings for solid-type insulated cables. (Courtesy Okonite Company, Ramsey, NJ.)

Therefore, it is important that all cable ends are tested for moisture before splicing or potheading. The most reliable procedure is to remove rings of insulating paper from the section cut for the connector at the sheath, at the midpoint, and nearest the conductor and immerse the tape *loops* in clean oil or flushing compound heated to 280°F–300°F. If any traces of moisture are present, minute bubbles will be excluded from the tape and form *froth* in the oil.

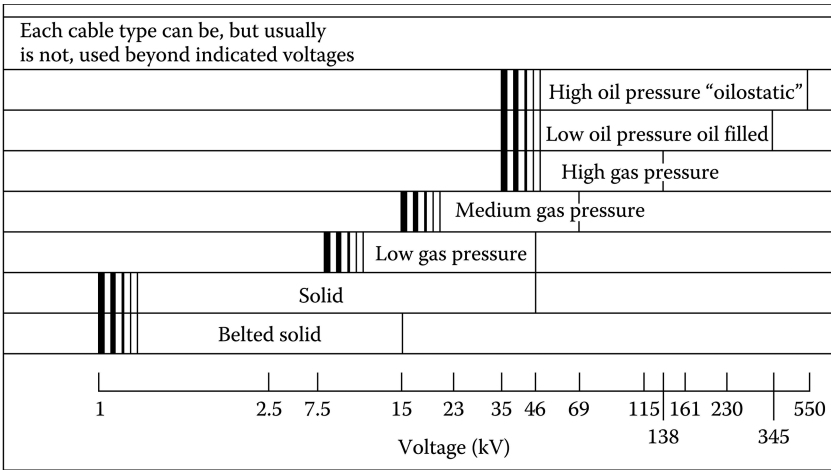


FIGURE 6.5 Recommended voltage ranges for various paper-insulated cables. (Courtesy Okonite Company, Ramsey, NJ.)

The shields and metallic sheaths of power cables must be grounded for safety and reliable operation. Without such grounding, shields would operate at a potential considerably above the ground potential. Therefore, they would be hazardous to touch and would incur rapid degradation of the jacket or other material that is between the shield and the ground. The grounding conductor and its attachment to the shield or metallic sheath, normally at a termination or splice, need to have an ampacity no lower than that of the shield. In the case of a lead sheath, the ampacity must be large enough to carry the available fault current and duration without overheating. Usually, the cable shield lengths are grounded at both ends such that the fault current would divide and flow to both ends, reducing the duty on the shield and therefore the chance of damage.

The capacitive charging current of the cable insulation, which is on the order of 1 mA/ft of conductor length, normally flows, at power frequency, between the conductor and the earth electrode of the cable, normally the shield. The shield, or metallic sheath, provides the fault return path in the event of insulation failure, permitting rapid operation of the protection devices [1].

6.3 UNDERGROUND CABLE INSTALLATION TECHNIQUES

There are a number of ways to install the underground cables such as the following:

- 1. Direct burial in the soil, as shown in Figure 6.6. The cable is laid in a trench that is usually dug by a machine.

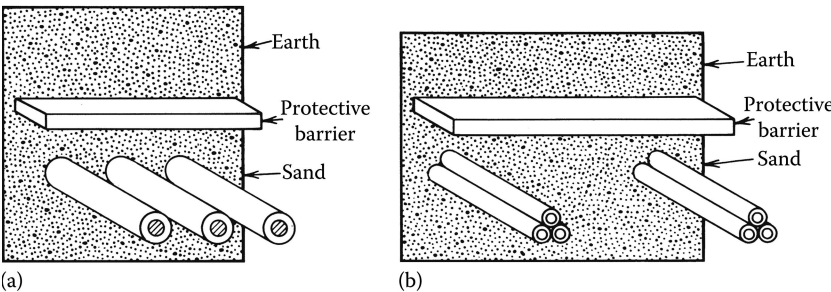


FIGURE 6.6 Direct burial (a) for single-conductor cables and (b) for triplexed cables.

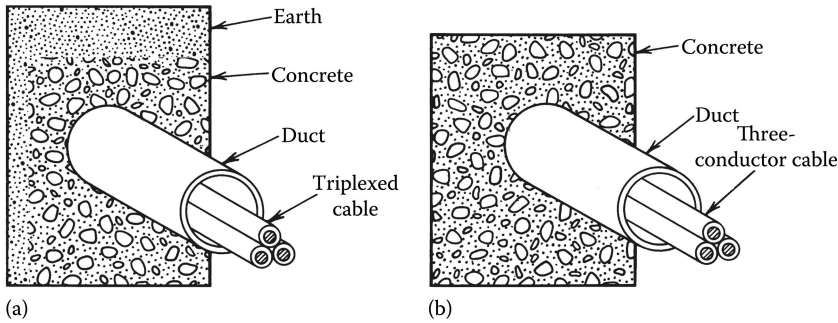


FIGURE 6.7 Burial in underground cuts (or duct bank) (a) for three single-conductor or triplexed cables and (b) for three-conductor cables.

2. In ducts or pipes with concrete sheath, as shown in Figure 6.7. For secondary network systems, duct lines may have 6–12 ducts.
3. Wherever possible, in tunnels built for other purposes, for example, sewer lines, water mains, gas pipes, and duct lines for telephone and telegraph cables.

In general, manholes are built at every junction point and corner. The spacing of manholes is affected by the types of circuits installed, allowable cable-pulling tensions, and utility company's standards and practices. Manholes give easily accessible and protected space in which cables and associated apparatus can be operated properly. For example, they should provide enough space for required switching equipment, transformers, and splices and terminations. Figure 6.8 shows a straight-type manhole. Figure 6.9 shows a typical street cable manhole, which is usually used to route cables at street intersections or other locations where cable terminations are required.

6.4 ELECTRICAL CHARACTERISTICS OF INSULATED CABLES

6.4.1 ELECTRIC STRESS IN SINGLE-CONDUCTOR CABLES

Figure 6.10 shows a cross section of a single-conductor cable. Assume that the length of the cable is 1 m. Let the charge on the conductor surface be q coulomb per meter of length. Assume that the cable has a perfectly homogeneous dielectric and perfect symmetry between conductor and insulation. Therefore, according to Coulomb's law, the electric flux density at a radius of x is

$$D = \frac{q}{2\pi x} \text{ C/m}^2 \quad (6.1)$$

where

- D is the electric flux density at radius x in Coulombs per square meter
- q is the charge on the conductor surface in Coulombs per square meter
- x is the distance from the center of the conductor in meters, where $r < x < R$

Since the absolute permittivity of the insulation is

$$\epsilon = \frac{D}{E} \quad (6.2)$$

the electric field or potential gradient or electric stress or the so-called dielectric stress E at radius x is

$$E = \frac{q}{2\pi\epsilon x} \text{ V/m} \quad (6.3)$$

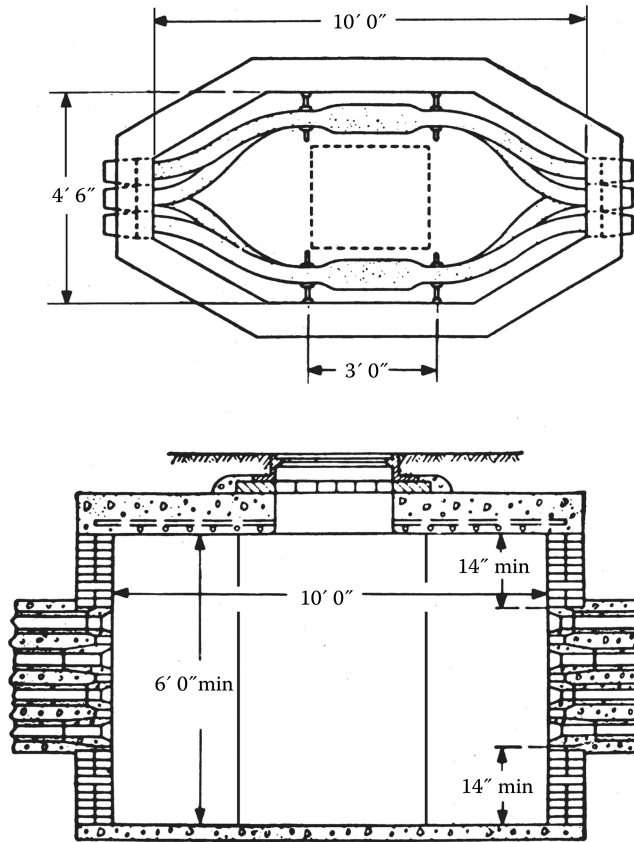


FIGURE 6.8 Straight-type manhole. (From Fink and Beaty [3].)

If the potential gradient at radius x is dV/dx , the potential difference V between the conductor and the lead sheath is

$$V = \int_r^R E \times dx \quad (6.4)$$

or

$$V = \int_r^R \frac{q}{2\pi\epsilon x} \times dx \quad (6.5)$$

or

$$V = \frac{q}{2\pi\epsilon} \times \ln \frac{R}{r} \quad (6.6)$$

From Equation 6.3,

$$\frac{q}{2\pi\epsilon} = E \times x \quad (6.7)$$

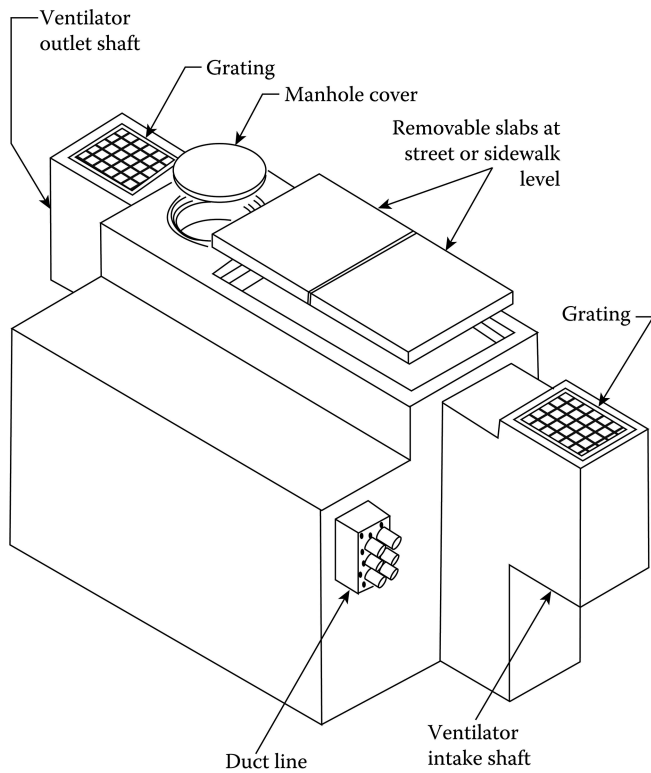


FIGURE 6.9 Street cable manhole. (From Skrotzki [4].)

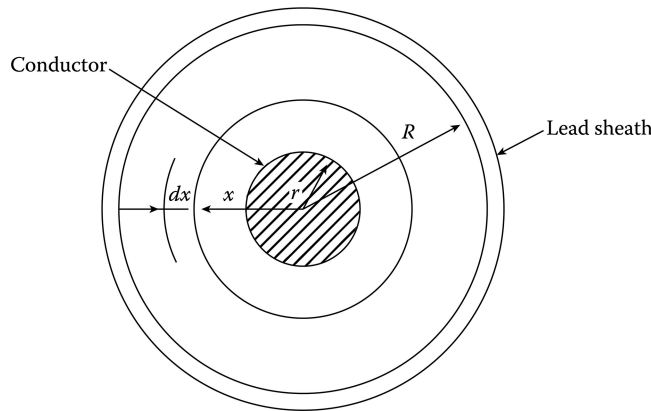


FIGURE 6.10 Cross section of a single-conductor cable.

Substituting it into Equation 6.6,

$$V = E \times x \times \ln \frac{R}{r} \text{ V} \tag{6.8}$$

Therefore,

$$E = \frac{V}{x \times \ln(R/r)} \text{ V/m} \tag{6.9}$$

where

E is the electric stress of cable in volts per meter

V is the potential difference between conductor and lead sheath in volts

x is the distance from the center of the conductor in meters

R is the outside radius of insulation or inside radius of lead sheath in meters

r is the radius of the conductor in meters

Dielectric strength is the maximum voltage that a dielectric can stand in a uniform field before it breaks down. It represents the permissible voltage gradient through the dielectric. Average stress is the amount of voltage across the insulation material divided by the thickness of the insulation.

The maximum stress in a cable usually occurs at the surface of the conductor, while the minimum stress occurs at the outer surface of the insulation. Average stress is the amount of voltage across the insulation material divided by the thickness of the insulation. Therefore, the maximum electric stress in the cable shown in Figure 6.10 occurs at $x=r$; thus,

$$E_{\max} = \frac{V}{r \times \ln(R/r)} \text{ V/m} \quad (6.10)$$

and the minimum electric stress occurs at $x=R$; hence,

$$E_{\min} = \frac{V}{R \times \ln(R/r)} \text{ V/m} \quad (6.11)$$

Thus, for a given V and R , there is one particular radius that gives the minimum stress at the conductor surface. In order to get the smallest value of $E_{\max}$, let

$$\frac{dE_{\max}}{dr} = 0 \quad (6.12)$$

from which

$$\ln \frac{R}{r} = 1 \quad (6.13)$$

or

$$\frac{R}{r} = e \quad (6.14)$$

Thus,

$$R = 2.178r \quad (6.15)$$

and the insulation thickness is

$$R - r = 1.78r \quad (6.16)$$

and the actual stress at the conductor stress is

$$E_{\max} = \frac{V}{r} \quad (6.17)$$

where r is the optimum conductor radius that satisfies Equation 6.15.

Example 6.1

A single-conductor belted cable of 5 km long has a conductor diameter of 2 cm and an inside diameter of lead sheath of 5 cm. The cable is used at 24.9 kV line-to-neutral voltage and 60 Hz frequency. Calculate the following:

- Maximum and minimum values of electric stress
- Optimum value of conductor radius that results in the smallest (minimum) value of maximum stress

Solution

- From Equation 6.10,

$$E_{\max} = \frac{V}{r \times \ln(R/r)} = \frac{24.9}{1 \times \ln 2.5} = 27.17 \text{ kV/cm}$$

and from Equation 6.11,

$$E_{\min} = \frac{V}{r \times \ln(R/r)} = \frac{24.9}{2.5 \times \ln 2.5} = 10.87 \text{ kV/cm}$$

- From Equation 6.15, the optimum conductor radius is

$$r = \frac{R}{2.718} = \frac{2.5}{2.718} = 0.92 \text{ cm}$$

Therefore, the minimum value of the maximum stress is

$$E_{\max} = \frac{24.9}{0.92 \ln(2.5/0.92)} = 27.07 \text{ kV/cm}$$

Example 6.2

Assume that a single-conductor belted cable has a conductor diameter of 2 cm and has insulation of two layers of different materials each 2 cm thick, as shown in Figure 6.11. The dielectric constants for the inner and the outer layers are 4 and 3, respectively. If the potential difference between the conductor and the outer lead sheath is 19.94 kV, calculate the potential gradient at the surface of the conductor.

Solution

$$R = 1 \text{ cm}$$

$$r_1 = r + t_1 = 3 \text{ cm}$$

$$R = r_1 + r_2 = 5 \text{ cm}$$

Since

$$E_1 = \frac{2q}{r \times K_1} \text{ and } E_2 = \frac{2q}{r_1 \times K_2}$$

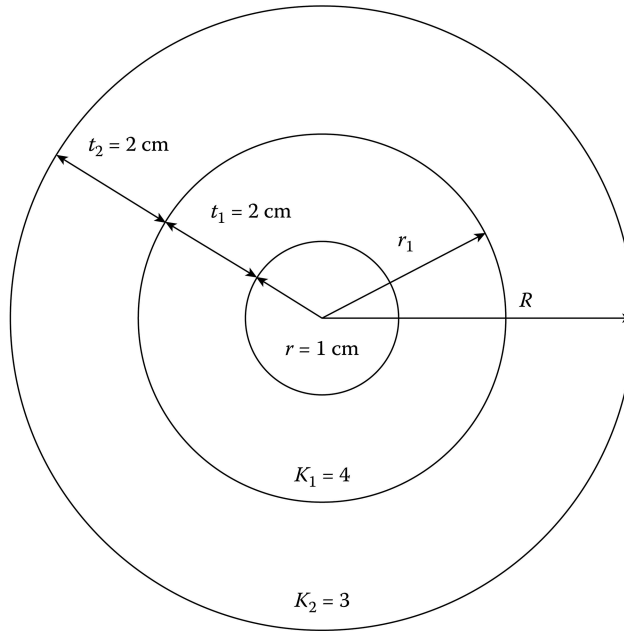


FIGURE 6.11 For Example 6.2.

their division gives

$$\begin{aligned}\frac{E_1}{E_2} &= \frac{r_1 \times t_2}{r \times t_1} \\ &= \frac{3 \times 3}{1 \times 4} = 2.25\end{aligned}$$

In addition,

$$\begin{aligned}E_1 &= \frac{V_1}{r \times \ln(r_1/r)} \\ &= \frac{V_1}{1 \times \ln(3/1)}\end{aligned}$$

and

$$\begin{aligned}E_2 &= \frac{V_2}{r_1 \times \ln(R/r_1)} \\ &= \frac{19.94 - V_1}{3 \times \ln(5/3)}\end{aligned}$$

or

$$\frac{E_1}{E_2} = \frac{V_1}{1 \times \ln(5/3)} \times \frac{3 \times \ln(5/3)}{19.94 - V_1}$$

or

$$\frac{E_1}{E_2} = \frac{1.532V_1}{21.906 - 1.099V_1}$$

but it was found previously that

$$\frac{E_1}{E_2} = 2.25$$

Therefore,

$$\frac{1.532V_1}{21.906 - 1.099V_1} = 2.25$$

from which

$$V_1 = 12.308 \text{ kV}$$

Hence,

$$\begin{aligned} E_1 &= \frac{V_1}{1 \times \ln 3} \\ &= \frac{12.308}{\ln 3} \\ &= 11.20 \text{ kV/cm} \end{aligned}$$

6.4.2 CAPACITANCE OF SINGLE-CONDUCTOR CABLES

Assume that the potential difference is V between the conductor and the lead sheath of the single-conductor cable as shown in Figure 6.10. Let the charges on the conductor and sheath be $+q$ and $-q$ C/m of length. From Equation 6.6,

$$V = \frac{q}{2\pi\epsilon} \times \ln \frac{R}{r} \text{ V} \quad (6.6)$$

where

V is the potential difference between the conductor and the lead sheath in volts

ϵ is the absolute permittivity of insulation

R is the outside radius of insulation in meters

r is the radius of the conductor in meters

Therefore, the capacitance between the conductor and the sheath is

$$C = \frac{q}{V} \quad (6.18)$$

or

$$C = \frac{2\pi\epsilon}{\ln(R/r)} \text{ F/m} \quad (6.19)$$

Since

$$\epsilon = \epsilon_0 \times K \quad (6.20)$$

thus,

$$C = \frac{2\pi\epsilon_0 \times K}{\ln(R/r)} \text{ F/m} \quad (6.21)$$

where

$$\epsilon_0 = \frac{1}{36\pi \times 10^9} \text{ F/m for air} \quad (6.22)$$

or

$$\epsilon_0 = 8.85 \times 10^{-12} \text{ F/m} \quad (6.23)$$

and

K = Dielectric constant of cable insulation

Substituting Equation 6.22 into Equation 6.21,

$$C = \frac{10^{-9} K}{18 \ln(R/r)} \text{ F/m} \quad (6.24)$$

or

$$C = \frac{K}{18 \ln(R/r)} \mu\text{F/m} \quad (6.25)$$

or

$$C = \frac{0.0345K}{\ln(R/r)} \mu\text{F/m} \quad (6.26)$$

or

$$C = \frac{0.0065K}{10^6 \ln(R/r)} \text{ F/1,000 ft} \quad (6.27)$$

or

$$C = \frac{0.0241K}{\log_{10}(R/r)} \mu\text{F/km} \quad (6.28)$$

or

$$C = \frac{0.0388K}{\log_{10}(R/r)} \mu\text{F/mi} \quad (6.29)$$

or

$$C = \frac{0.0073K}{10^6 \times \log_{10}(R/r)} \mu\text{F/1,000 ft} \quad (6.30)$$

6.4.3 DIELECTRIC CONSTANT OF CABLE INSULATION

The dielectric constant of any material is defined as the ratio of the capacitance of a condenser with the material as a dielectric to the capacitance of a similar condenser with air as the dielectric. It is also called the *relative permittivity* or *specific inductive capacity*. It is usually denoted by K . (It is also represented by ϵ_r or SIC.) Table 6.1 gives the typical values of the dielectric constants for various dielectric materials.

Using the symbol K , for example, in Equation 6.30, the formula for calculating the capacitance of a shielded or concentric neutral single-conductor cable becomes

$$C = \frac{0.0073K}{10^6 \log_{10}(D/d)} \text{ F/1,000 ft} \quad (6.31)$$

TABLE 6.1
Typical Values of Various

Dielectric Materials	K
Air	1
Impregnated paper	3.3
PVC	3.5–8.0
Ethylene PP insulation	2.8–3.5
PE insulation	2.3
Cross-linked PE	2.3–6.0

where

C is the capacitance in farads per 1,000 ft

K is the dielectric constant of cable insulation

D is the diameter over insulation in unit length

d is the diameter over the conductor shield in unit length

6.4.4 CHARGING CURRENT

By definition of susceptance,

$$b = \omega C \text{ S} \quad (6.32)$$

or

$$b = 2\pi f C \text{ S} \quad (6.33)$$

Then, the admittance Y corresponding to C is

$$Y = jb$$

or

$$Y = j2\pi f C \text{ S} \quad (6.34)$$

Therefore, the charging current is

$$I_C = YV_{(L-N)} \quad (6.35)$$

or, ignoring j ,

$$I_C = 2\pi f C V_{(L-N)} \quad (6.36)$$

For example, substituting Equation 6.31 into Equation 6.36, the charging current of a single-conductor cable is found as

$$I_C = \frac{2\pi f \times 0.0073 \times K \times V_{(L-N)}}{10^6 \times \log_{10}(D/d)} \quad (6.37)$$

or

$$I_C = \frac{0.0459 \times f \times K \times V_{(L-N)}}{10^3 \times \log_{10}(D/d)} \text{ A/1,000 ft} \quad (6.38)$$

where

f is the frequency in hertz

D is the diameter over insulation in unit length

d is the diameter over the conductor shield in unit length

K is the dielectric constant of cable insulation

V is the line-to-neutral voltage in kilovolts

At 60 Hz frequency,

$$I_C = \frac{2.75 \times K \times V_{(L-N)}}{10^3 \times \log_{10}(D/d)} \text{ A/1,000 ft} \quad (6.39)$$

The charging current and the capacitance are relatively greater for insulated cables than in OH circuits because of closer spacing and the higher dielectric constant of the insulation of the cable. In general, the charging current is negligible for OH circuits at distribution voltages, contrary to HV transmission circuits.

6.4.5 DETERMINATION OF INSULATION RESISTANCE OF SINGLE-CONDUCTOR CABLES

Assume that the cable shown in Figure 6.12 has a length of 1 m. Then the incremental insulation resistance of the cylindrical element in the radial direction is

$$\Delta R_i = \frac{\rho}{2\pi \times x \times l} \times dx \quad (6.40)$$

Therefore, the total insulation resistance between the conductor and the lead sheath is

$$R_i = \int_r^R \frac{\rho}{2\pi \times l} \times \frac{dx}{x}$$

or

$$R_i = \frac{\rho}{2\pi \times l} \ln\left(\frac{R}{r}\right) \quad (6.41)$$

where

R_i is the total insulation resistance in ohms

ρ is the insulation (dielectric) resistivity in ohm meters

l is the total length of cable in meters

R is the outside radius of insulation or inside radius of lead sheath in meters

r is the radius of the conductor in meters

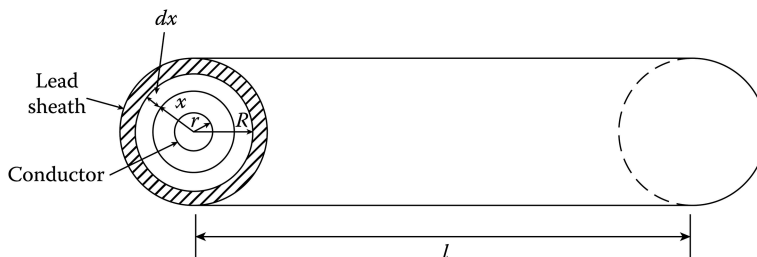


FIGURE 6.12 Cross section of a single-conductor cable.

A more practical version of Equation 6.41 is given by the Okonite Company as

$$R_i = r_{si} \times \log_{10} \left(\frac{D}{d} \right) \text{ M}\Omega / 1,000 \text{ ft} \tag{6.42}$$

where

- R_i is the total insulation resistance in megohms per 1,000 ft for a particular cable construction
- r_{si} is the specific insulation resistance in megohms per 1,000 ft at 60°F
- D is the inside diameter of the sheath
- d is the outside diameter of the conductor

Table 6.2 gives typical r_{si} values of various insulation materials. Equation 6.19 indicates that the insulation resistance is inversely proportional to the length of the insulated cable. An increase in insulation thickness increases the disruptive critical voltage of the insulation but does not give a proportional decrease in the voltage gradient at the conductor surface. Therefore, it does not permit a proportional increase in voltage rating.

Example 6.3

A 250 kcmil, single-conductor, synthetic rubber, belted cable has a conductor diameter of 0.575 in. and an inside diameter of sheath of 1.235 in. The cable has a length of 6,000 ft and is going to be used at 60 Hz and 115 kV. Calculate the following:

- a. Total insulation resistance in megohms at 60°F
- b. Power loss due to leakage current flowing through insulation resistance

Solution

- a. By using Equation 6.42,

$$R_i = r_{si} \times \log_{10} \left(\frac{D}{d} \right)$$

From Table 6.2, the specific insulation resistance r_{si} is 2,000 MΩ/1,000 ft. Therefore, the total insulation resistance is

$$\begin{aligned} R_i &= 6 \times 2,000 \log \left(\frac{1.235}{0.575} \right) \\ &= 3.984 \text{ M}\Omega \end{aligned}$$

TABLE 6.2
Typical Values of r_{si}

Insulation Material	r_{si} (MΩ/1,000 ft)
Synthetic rubber	2,000
Ethylene PP insulation	20,000
PE	50,000
PVC	2,000
Cross-linked PE	20,000

b. The power loss due to the leakage current is

$$\begin{aligned}\frac{V^2}{R_l} &= \frac{115,000^2}{3,984 \times 10^6} \\ &= 3.3195 \text{ W}\end{aligned}$$

6.4.6 CAPACITANCE OF THREE-CONDUCTOR BELTED CABLE

As shown in Figure 6.13, two insulation thicknesses are to be considered in belted cables: (1) the conductor insulation of thickness T and (2) the belt insulation of thickness t . The belt insulation is required because with line voltage V_L between conductors, the conductor insulation is only adequate for $V_L/2$ voltage, whereas the voltage between each conductor and ground (or earth) is $V_L/\sqrt{3}$.

In the three-conductor belted cable, there are capacitances of C_c between conductors and capacitances of C_s between each conductor and the sheath, as shown in Figure 6.14. The arrangement of the capacitors, representing these capacitances per-unit length, is equivalent to a delta system connected in parallel with a wye system, as shown in Figure 6.15. Further, the delta system, representing the capacitances C_c , can be represented by an equivalent wye system of capacitance C_1 , as shown in Figure 6.16. In the delta system, the capacitance between, say, conductors 1 and 2 is

$$C_c + \frac{C_c}{2} = \frac{3C_c}{2} \quad (6.43)$$

In the wye system, it is

$$\frac{C_1}{2} \quad (6.44)$$

Since the delta and wye systems are equivalent, the capacitance between the conductors must be the same:

$$\frac{3C_c}{2} = \frac{C_1}{2} \quad (6.45)$$

or

$$C_1 = 3C_c \quad (6.46)$$

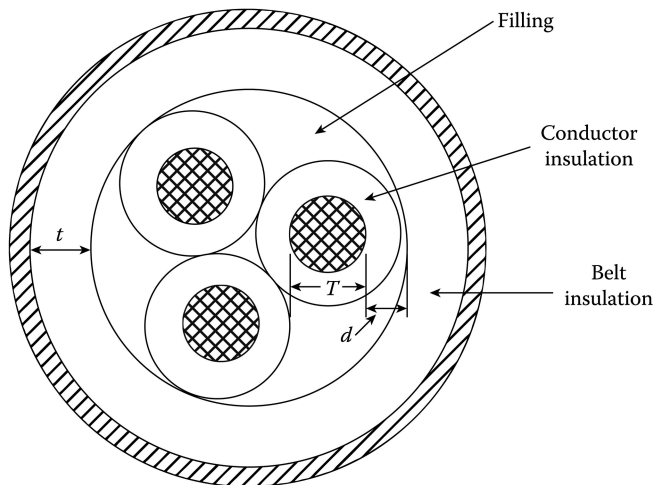


FIGURE 6.13 Three-conductor belted cable cross section.

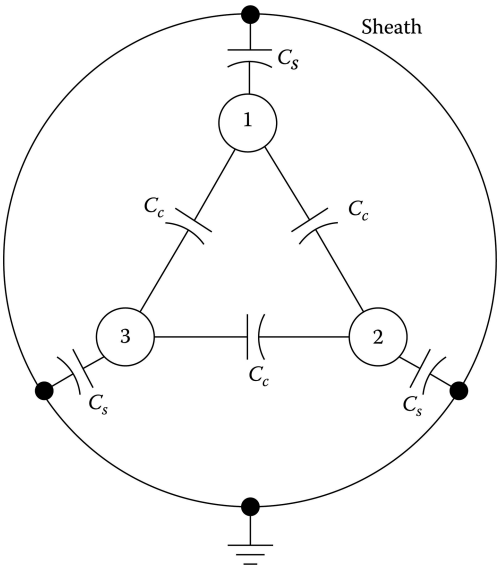


FIGURE 6.14 Effective capacitances.

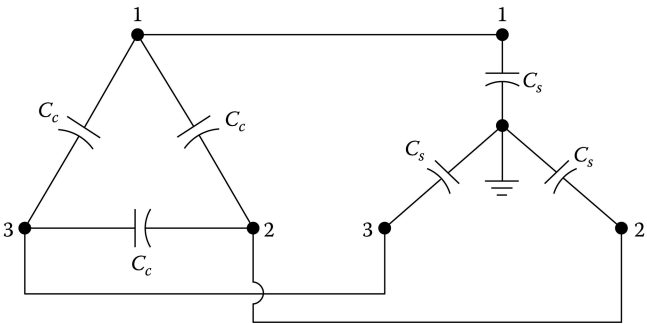


FIGURE 6.15 Equivalent circuit.

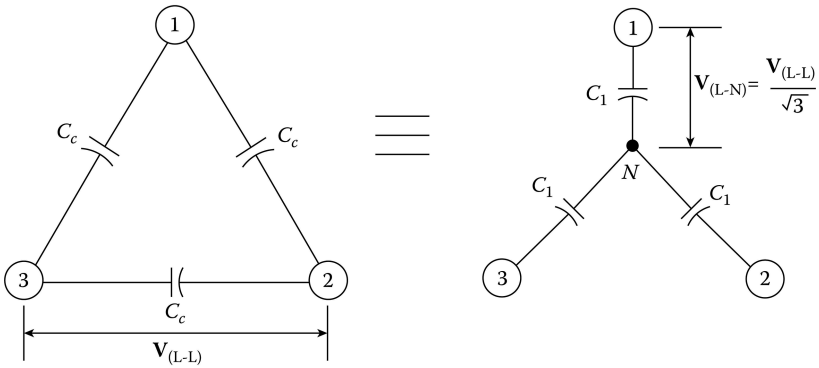


FIGURE 6.16 Equivalent circuit.

Alternatively, let the voltage across capacitor C_c in the delta system be $V_{(L-L)}$, the line-to-line voltage. Therefore, the phase current through the capacitor is equal to $\omega C_c V_{(L-L)}$, and the line current is

$$I_L = 3\omega C_c V_{(L-L)} \quad (6.47)$$

On the other hand, in the equivalent wye systems, the line-to-neutral voltage is

$$V_{(L-N)} = \frac{V_{(L-L)}}{\sqrt{3}} \quad (6.48)$$

and the phase current and the line current are the same. Therefore,

$$I_L = \omega C_1 \times \frac{V_{(L-L)}}{\sqrt{3}} \quad (6.49)$$

Thus, for equivalent delta and wye systems, by equating Equations 6.47 and 6.49,

$$3\omega C_c V_{(L-L)} = \omega C_1 \times \frac{V_{(L-L)}}{3}$$

or

$$C_1 = 3C_c \quad (6.50)$$

which is as same as Equation 6.46. Therefore, the delta system is converted to the wye system, as shown in Figure 6.16. All C_s capacitors are in wye connection with respect to the sheath, and all C_1 capacitors are in wye connection and in parallel with the first wye system of capacitors. The effective capacitance of each conductor to the grounded neutral is therefore

$$C_N = C_s + 3C_c \quad (6.51)$$

The value of C_N can be calculated with usually acceptable accuracy by using the formula

$$C_N = \frac{0.048K}{10g_{10} \left\{ 1 + \left[\frac{T+t}{d} \right] \left[3.84 - \frac{1.7t}{T} + \frac{0.52t^2}{T^2} \right] \right\}} \mu\text{F/mi} \quad (6.52)$$

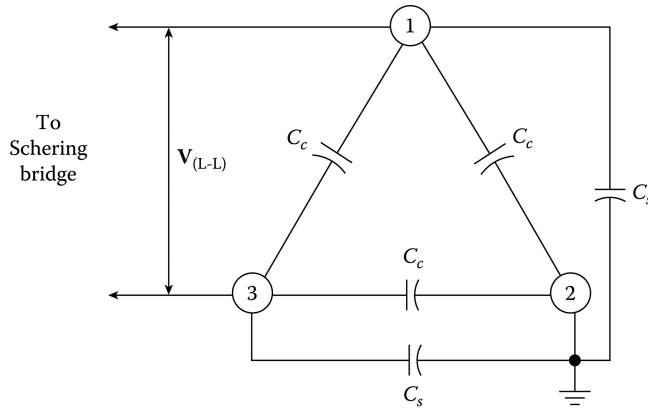
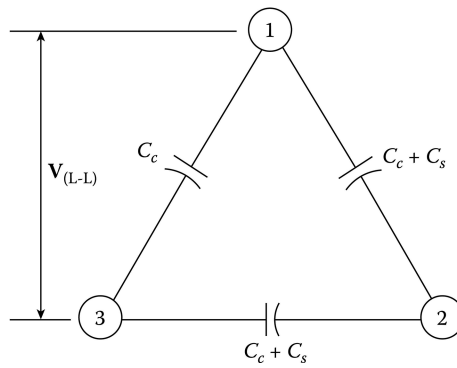
where

- K is the dielectric constant of insulation
- T is the thickness of conductor insulation
- t is the thickness of belt insulation
- d is the diameter of the conductor

In general, however, since the conductors are not surrounded by isotropic homogeneous insulation of one known permittivity, the C_c and C_s are not easily calculated and are generally obtained by measurements. The tests are performed at the working voltage, frequency, and temperature. In determining the capacitances of this type of cable, the *common tests* are the following:

1. Measure the capacitance C_a between two conductors by means of a Schering bridge connecting the third conductor to the sheath to eliminate one of the C_s 's, as shown in Figures 6.17 and 6.18. Therefore,

$$C_a = C_c + \frac{C_c + C_s}{2} \quad (6.53)$$

FIGURE 6.17 Measuring the capacitance C_a .FIGURE 6.18 Measuring the capacitance C_a .

or

$$C_a = \frac{C_s + 3C_c}{2} \quad (6.54)$$

Substituting Equation 6.51 into Equation 6.54,

$$C_a = \frac{C_N}{2} \quad (6.55)$$

or

$$C_N = 2C_a \quad (6.56)$$

2. Measure the capacitance C_b between the sheath and all three conductors joined together to eliminate (or to short out) all three C_s 's and to parallel all three C_s 's, as shown in Figure 6.19. Therefore,

$$C_b = 3C_s \quad (6.57)$$

or

$$C_s = \frac{C_b}{3} \quad (6.58)$$

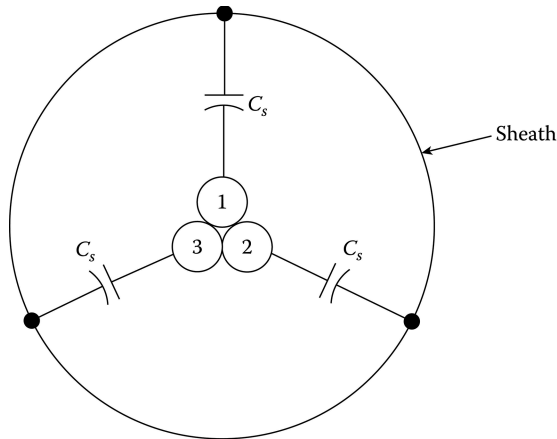


FIGURE 6.19 Measuring the capacitance C_b .

3. Connect two conductors to the sheath, as shown in Figure 6.20. Measure the capacitance C_d between the remaining single conductor and the two other conductors and the sheath. Therefore,

$$C_d = C_s + 2C_c \quad (6.59)$$

or

$$2C_c = C_d - C_s \quad (6.60)$$

Substituting Equation 6.58 into Equation 6.60,

$$C_c = \frac{C_d - \frac{C_b}{3}}{2} \quad (6.61)$$

Substituting this equation and Equation 6.58 into Equation 6.51, the effective capacitance to neutral is

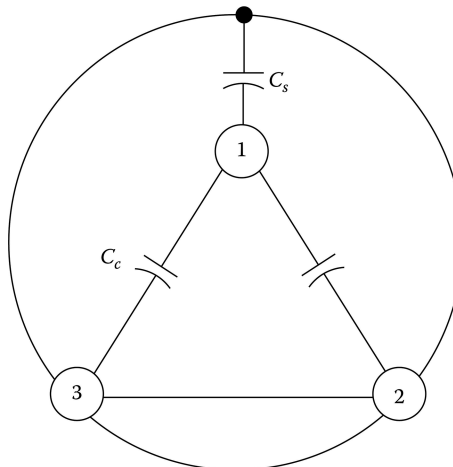


FIGURE 6.20 Connecting two conductors to the sheath.

$$C_N = \frac{9C_d - C_d}{6} \quad (6.62)$$

Example 6.4

A three-conductor three-phase cable has 2 mi of length and is being used at 34.5 kV, three phases, and 60 Hz. The capacitance between a pair of conductors on a single phase is measured to be 2 pF/mi. Calculate the charging current of the cable.

Solution

The capacitance between two conductors is given as

$$C_a = 2 \mu\text{F/mi}$$

or for total cable length,

$$C_a = (2 \mu\text{F/mi}) \times (2 \text{ mi}) = 4 \mu\text{F}$$

The capacitance of each conductor to neutral can be found by using Equation 4.56,

$$\begin{aligned} C_N &= 2C_a \\ &= 8 \mu\text{F} \end{aligned}$$

Therefore, the charging current is

$$\begin{aligned} I_C &= \omega C_N \times V_{(L-N)} \\ &= 27\pi \times 60 \times 8 \times 10^{-6} \times 19,942 \\ &= 60.14 \text{ A} \end{aligned}$$

Example 6.5

A three-conductor belted cable 4 mi long is used as a three-phase underground feeder and connected to a 13.8 kV, 60 Hz substation bus. The load, at the receiving end, draws 30 A at 0.85 lagging power factor. The capacitance between any two conductors is measured to be 0.45 pF/mi. Ignoring the power loss due to leakage current and also the line voltage drop, calculate the following:

- Charging current of feeder
- Sending-end current
- Sending-end power factor

Solution

The current phasor diagram is shown in Figure 6.21.

- The capacitance between two conductors is given as

$$C_a = 0.45 \mu\text{F/mi}$$

or for total feeder length,

$$C_a = 0.45 \mu\text{F/mi} \times 4 \text{ mi} = 1.80 \mu\text{F}$$

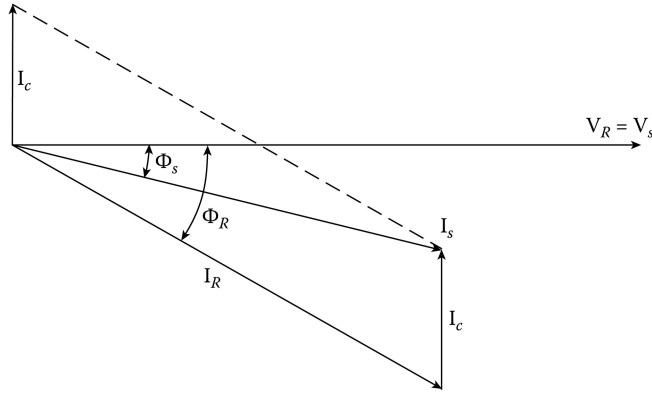


FIGURE 6.21 Current phasor diagram for Example 6.5.

The capacitance of each conductor to neutral can be found by using Equation 4.56,

$$\begin{aligned} C_N &= 2C_a \\ &= 3.6 \mu\text{F} \end{aligned}$$

Thus, the charging current is

$$\begin{aligned} I_c &= \omega \times C_N \times V_{(L-N)} \\ &= 2\pi \times 3.6 \times 10^{-6} \times 13,800 \times \frac{1}{\sqrt{3}} \\ &= 10.83 \text{ A} \end{aligned}$$

or, in complex form,

$$I_c = +j10.83 \text{ A}$$

b. The receiving-end current is

$$\begin{aligned} I_r &= 30(\cos \phi_r - j \sin \phi_r) \\ &= 30(0.85 - j0.5268) \\ &= 25.5 - j15.803 \text{ A} \end{aligned}$$

Therefore, the sending-end current is

$$\begin{aligned} I_s &= I_r + I_c \\ &= 25.5 - j15.803 + j10.83 \\ &= 25.5 - j4.973 \\ &= 25.98 \angle -11.04^\circ \text{ A} \end{aligned}$$

c. Hence, the sending-end power factor is

$$\cos \phi_s = \cos 11.04 = 0.98$$

and it is a lagging power factor.

6.4.7 CABLE DIMENSIONS

The overall diameter of a cable may be found in the following equations. They apply to conductors of a circular cross section.

For a single-conductor cable,

$$D = d + 2T + 2S \quad (6.63)$$

For a two-conductor cable,

$$D = 2(d + 2T + t + S) \quad (6.64)$$

For a three-conductor cable,

$$D = 2.155(d + 2T) + 2(t + S) \quad (6.65)$$

For a four-conductor cable,

$$D = 2.414(d + 2T) + 2(t + S) \quad (6.66)$$

For a sector-type three-conductor cable,

$$D_{3s} = D - 0.35d \quad (6.67)$$

where

D is the overall diameter of cable with circular cross-sectional conductors

D_{3s} is the overall diameter of cable with sector-type three conductors

d is the diameter of the conductor

S is the metal sheath thickness of cable

t is the belt insulation thickness of cable

T is the thickness of conductor insulation in inches

6.4.8 GEOMETRIC FACTORS

The geometric factor is defined as the relation in space between the cylinders formed by the sheath internal surface and the conductor external surface in a single-conductor belted cable. For a three-conductor belted cable, this relation (i.e., *geometric factor*) is sector-shaped and by relative thicknesses of conductor insulation T and belt insulation t . For a single-conductor cable, the geometric factor G is given by

$$G = 2.303 \log_{10} \frac{D}{d} \quad (6.68)$$

where

D is the inside diameter of sheath

d is the outside diameter of the conductor

Table 6.3 presents geometric factors for single-conductor and three-conductor belted cables. In this table, G indicates the geometric factor for a single-conductor cable, G_0 indicates the zero-sequence geometric factor, and G_1 indicates the positive-sequence geometric factor for three-conductor belted cables. Also, Figures 6.22 and 6.23 give geometric factors for single-conductor and three-conductor belted cables. In Figure 6.24, G_0 indicates the zero-sequence geometric factor, and G_1 indicates the positive-sequence geometric factor. In Table 6.3 and Figures 6.22 and 6.23,

T is the thickness of conductor insulation in inches

t is the thickness of belt insulation in inches

TABLE 6.3
Geometric Factors of Cables

Ratio $T + \frac{t}{d}$	Single Conductor, G	Sector Factor	Three-Conductor Cables					
			G_0 at Ratio t/T			G_1 at Ratio t/T		
			0	0.5	1.0	0	0.5	1.0
0.2	0.34		0.85	0.85	0.85	1.2	1.28	1.4
0.3	0.47	0.690	1.07	1.075	1.03	1.5	1.65	1.85
0.4	0.59	0.770	1.24	1.27	1.29	1.85	2.00	2.25
0.5	0.69	0.815	1.39	1.43	1.46	2.10	2.30	2.60
0.6	0.79	0.845	1.51	1.57	1.61	2.32	2.55	2.95
0.7	0.88	0.865	1.62	1.69	1.74	2.35	2.80	3.20
0.8	0.96	0.880	1.72	1.80	1.86	2.75	3.05	3.45
0.9	1.03	0.895	1.80	1.89	1.97	2.96	3.25	3.70
1.0	1.10	0.905	1.88	1.98	2.07	3.13	3.44	3.87
1.1	1.16	0.915	1.95	2.06	2.15	3.30	3.60	4.03
1.2	1.22	0.921	2.02	2.13	2.23	3.45	3.80	4.25
1.3	1.28	0.928	2.08	2.19	2.29	3.60	3.95	4.40
1.4	1.33	0.935	2.14	2.26	2.36	3.75	4.10	4.60
1.5	1.39	0.938	2.20	2.32	2.43	3.90	4.25	4.75
1.6	1.44	0.941	2.26	2.38	2.49	4.05	4.40	4.90
1.7	1.48	0.944	2.30	2.43	2.55	4.17	4.52	5.05
1.8	1.52	0.946	2.35	2.49	2.61	4.29	4.65	5.17
1.9	1.57	0.949	2.40	2.54	2.67	4.40	4.76	5.30
2.0	1.61	0.952	2.45	2.59	2.72	4.53	4.88	5.42

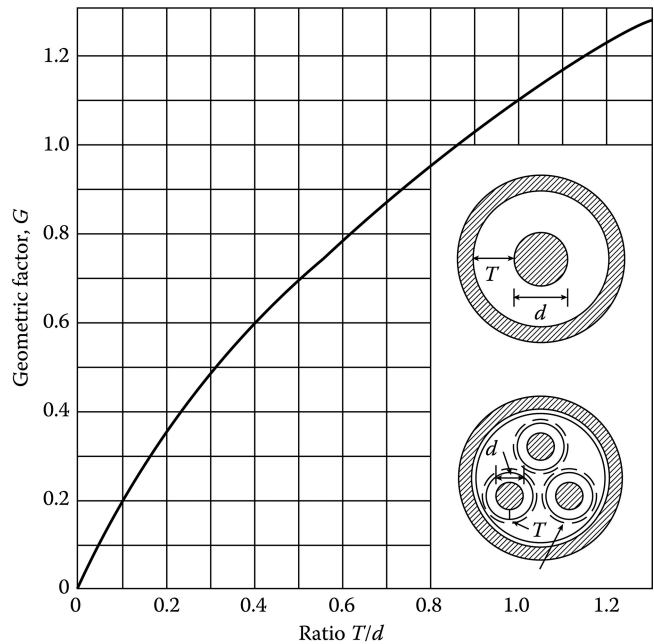


FIGURE 6.22 Geometric factor for single-conductor cables or three-conductor shielded cables having round conductors. (From Westinghouse Electric Corporation [2].)

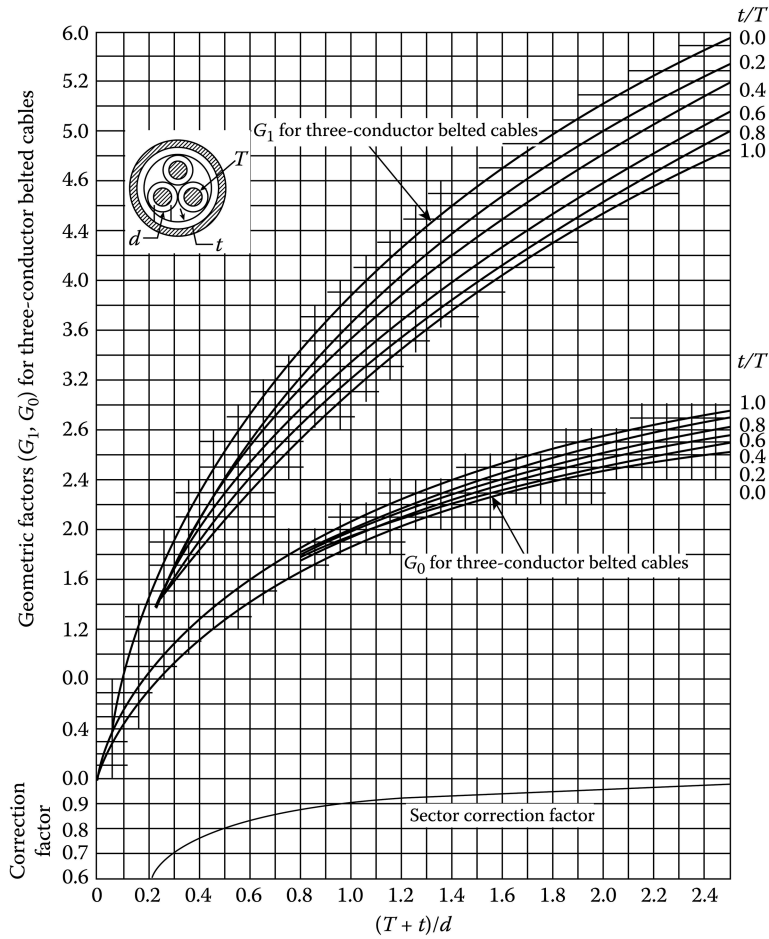


FIGURE 6.23 Geometric factor for three-conductor belted cables having round or sector conductors.

d is the outside diameter of the conductor in inches

For single-conductor cables,

$$t = 0$$

Thus,

$$\frac{T+t}{d} = \frac{T}{d} \quad (6.69)$$

which is used to find the value of geometric factor G for a single-conductor cable.

The geometric factor can be useful to calculate various cable characteristics such as capacitance, charging current, dielectric loss, leakage current, and heat transfer. For example, the general capacitance equation is given as [1]

$$C = \frac{0.0169 \times n \times K}{G} \mu\text{F}/1,000 \text{ ft} \quad (6.70)$$

where

K is the dielectric constant of insulation

n is the number of conductors

G is the geometric factor

Also, the charging current of a three-conductor three-phase cable is given as [5]

$$I_c = \frac{3 \times 0.106 \times f \times K \times V_{(L-N)}}{1,000 \times G_1} \text{ A/1,000 ft} \quad (6.71)$$

where

f is the frequency in hertz

K is the dielectric constant of insulation

$V_{(L-N)}$ is the line-to-neutral voltage in kilovolts

G_1 is the geometric factor for three-conductor cables from Table 6.3

Example 6.6

A 60 Hz, 138 kV, three-conductor, paper-insulated, belted cable is going to be installed at 138 kV and used as a three-phase underground feeder. The cable has three 250 kcmil sector-type conductors each with 11/64 in. of conductor insulation and 5/64 in. of belt insulation. Calculate the following:

- Geometric factor of cable using Table 6.3
- Charging current in amperes per 1,000 ft

Solution

a.

$$T = 0.172 \text{ mi}, \quad t = 0.078, \quad d = 0.575, \quad \frac{t}{T} = 0.454$$

$$\frac{t}{T} = 0.454$$

and

$$\frac{T+t}{d} = \frac{0.172+0.078}{0.575} = 0.435$$

From Table 6.3, by interpolation,

$$G_1 = 2.09$$

Since the cable has sector-type conductors, to find the real geometric factor G'_1 , G_1 has to be multiplied by the sector factor obtained for $(T+t)/d=0.435$ from Table 6.3, by interpolation,

$$\begin{aligned} G'_1 &= G_1 \times (\text{sector factor}) \\ &= 2.09 \times 0.7858 \\ &= 1.642 \end{aligned}$$

b.

$$V_{(L-N)} = \frac{V_{(L-L)}}{\sqrt{3}}$$

$$\frac{138 \text{ kV}}{\sqrt{3}} = 79.6743 \text{ kV}$$

For impregnated paper cable, K is 3.3. Therefore, using Equation 6.71, the charging current is

$$\begin{aligned} I_c &= \frac{3 \times 0.106 \times f \times K \times V_{(L-N)}}{1,000 \times G_1} \\ &= \frac{3 \times 0.106 \times 60 \times 3.3 \times 79.6743}{1,000 \times 1.642} \\ &= 3.055 \text{ A/1,000 ft} \end{aligned}$$

6.4.9 DIELECTRIC POWER FACTOR AND DIELECTRIC LOSS

When a voltage is applied across a perfect dielectric, there is no dielectric loss because of the existence of an induced capacitance current I_c located 90° ahead of the voltage V . However, in practice, since a perfect dielectric cannot be achieved, there is a small current component I_v that is in phase with voltage V . Therefore, the summation of these two current vectors gives the current vector $\mathbf{I}$ that leads the voltage V by $<90^\circ$, as shown in Figure 6.24. The cosine of the angle ϕ_d is the power factor of the dielectric, which provides a useful measure of the quality of the cable dielectric. The power factor of a dielectric is

$$\cos \phi_d = \frac{\text{Losses in dielectric (W)}}{\text{Apparent power (VA)}} \quad (6.72)$$

The power factor of an impregnated paper dielectric is very small, approximately 0.003. The *dielectric power factor* should not be confused with the regular (supply) power factor. The dielectric power factor represents loss and, therefore, an attempt to reduce it should be made. Conversely, an

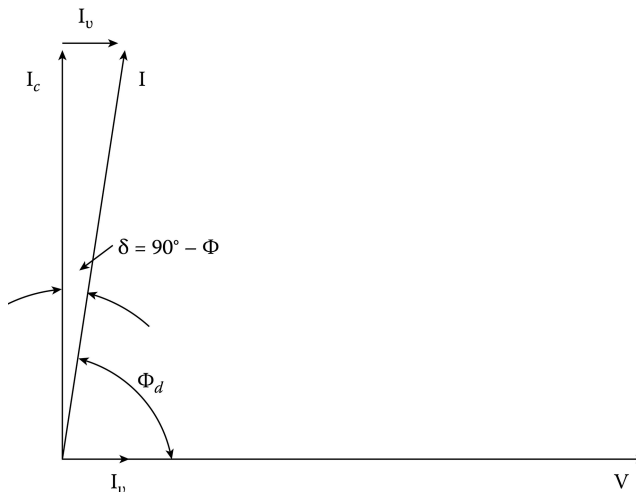


FIGURE 6.24 Phasor diagram for cable dielectric.

attempt should be made to increase the supply power factor toward unity. Since for a good dielectric insulation, ϕ_d is close to 90° , δ is sometimes called the *dielectric loss angle*. Therefore, δ is, in radians,

$$\delta \approx \tan \delta = \sin \delta = \cos \phi_d \quad (6.73)$$

since $\delta = 90^\circ - \phi_d$ and $\delta < 0.5^\circ$ for most cables.

Here, $\cos \phi_d$ should be held very small under all operating conditions. If it is large, the power loss is large, and the insulation temperature T rises considerably. The rise in temperature causes a rise in power loss in the dielectric, which again results in an additional temperature rise. If the cable is to operate under conditions where $\partial(\cos \phi_d)/\partial T$ is significantly large, the temperature continues to increase until the insulation of the cable is damaged.

When an AC $V_{(L-N)}$ voltage is applied across the effective cable capacitance C , the power loss in the dielectric, P_{dl} , is

$$P_{dl} = \omega \times C \times V_{(L-N)}^2 \times \cos \phi_d \quad (6.74)$$

This is larger than the dielectric power loss if the applied voltage is DC. The increase in the power loss is due to dielectric hysteresis, and it usually is much greater than leakage loss. The dielectric hysteresis loss cannot be measured separately. The total dielectric loss, consisting of dielectric hysteresis loss and the power loss due to leakage current flowing through the insulation resistance, can be measured by means of the Schering bridge. These losses depend on voltage, frequency, and the state of the cable dielectric. Therefore, the test has to be made at a rated voltage and frequency for a given cable.

For a balanced three-phase circuit, the dielectric loss at rated voltage and temperature is

$$P_{dl} = \omega \times C \times V_{(L-N)}^2 \times \cos \phi_d \quad \text{W/1,000 ft} \quad (6.75)$$

where

P_{dl} is the cable dielectric loss in watts per 1,000 ft

$$\omega = 2\pi f$$

C is the positive-sequence capacitance to neutral in farads per 1,000 ft

$V_{(L-N)}$ is the line-to-neutral voltage in kilovolts

$\cos \phi_d$ is the power factor of dielectric (insulation) at a given temperature

Example 6.7

A single-conductor belted cable has a conductor diameter of 0.814 in., an inside diameter of sheath of 2.442 in., and a length of 3.5 mi. The cable is to be operated at 60 Hz and 7.2 kV. The dielectric constant is 3.5, the power factor of the dielectric on the open circuit at a rated frequency and temperature is 0.03, and the dielectric resistivity of the insulation is $1.3 \times 10^7 \text{ M}\Omega\text{-cm}$. Calculate the following:

- Maximum electric stress occurring in cable dielectric
- Capacitance of cable
- Charging current of cable
- Insulation resistance
- Power loss due to leakage current flowing through insulation resistance
- Total dielectric loss
- Dielectric hysteresis loss

Solution

a. By using Equation 6.10,

$$\begin{aligned} E_{\max} &= \frac{V}{r \times \ln\left(\frac{R}{r}\right)} \\ &= \frac{7.2}{0.407 \times 2.54 \ln 3} \\ &= 6.34 \text{ kV/cm} \end{aligned}$$

b. From Equation 6.29,

$$\begin{aligned} C &= \frac{0.0388K}{\log_{10}\left(\frac{R}{r}\right)} \\ &= \frac{0.0388 \times 3.5}{\log_{10} 3} \\ &= 0.2846 \mu\text{F/mi} \end{aligned}$$

or the capacitance of the cable is

$$0.2846 \mu\text{F/mi} \times 3.5 \text{ mi} = 0.9961 \mu\text{F}$$

c. By using Equation 6.36,

$$\begin{aligned} I_c &= 2\pi \times f \times C \times V_{(L-N)} \\ &= \frac{2\pi \times 60 \times 0.9961 \times 7.2}{10^3} \\ &= 2.704 \text{ A} \end{aligned}$$

d. From Equation 6.41,

$$\begin{aligned} R_i &= \frac{\rho}{2\pi \times I} \times \ln\left(\frac{R}{r}\right) \\ &= \frac{1.3 \times 10^7}{2\pi \times 3.5 \times 5280 \times 12 \times 2.54} \times \ln 3 \\ &= 4 \text{ M}\Omega \end{aligned}$$

e. The power loss due to leakage current flowing through the insulation is

$$P_{lc} = \frac{V^2}{R_i} = \frac{7,200^2}{4 \times 10^6} = 12.85 \text{ W}$$

f. The total dielectric loss is

$$P_{dl} = V_{(L-N)} I \cos \phi_d$$

or

$$P_{dl} = V_{(L-N)} I \sin \delta$$

or

$$P_{dl} = \omega \times C \times V_{(L-N)}^2 \times \sin \delta$$

or

$$\begin{aligned} P_{dl} &= \omega \times C \times V_{(L-N)}^2 \times \delta \\ &= 2\pi \times 60 \times 0.996 \times 7,200^2 \times 0.03 \\ &= 584.01 \text{ W} \end{aligned}$$

g. The dielectric hysteresis loss is

$$\begin{aligned} P_{dh} &= P_{dl} - P_{lc} \\ &= 584.01 - 12.85 \\ &= 571.16 \text{ W} \end{aligned}$$

6.4.10 EFFECTIVE CONDUCTOR RESISTANCE

The factors that determine the effective AC resistance R_{eff} of each conductor of a cable are DC resistance, skin effect, proximity effect, sheath losses, and armor losses if there is any armor. Therefore, the effective resistance R_{eff} in AC resistance can be given as

$$R_{\text{eff}} = (\lambda_1 + \lambda_2 + \lambda_3 + \lambda_4) R_{\text{dc}} \quad (6.76)$$

where

R_{dc} is the DC resistance of the conductor

λ_1 is the constant (or resistance increment) due to the skin effect

λ_2 is the constant (or resistance increment) due to the proximity effect

λ_3 is the constant (or resistance increment) due to sheath losses

λ_4 is the constant (or resistance increment) due to armor losses

For example, λ_3 constant can be calculated as follows; since

$$\text{Sheath loss} = \lambda_3 \times (\text{conductor loss})$$

$$\lambda_3 = \frac{\text{Sheath loss}}{\text{Conductor loss}}$$

Similarly, since

$$\text{Armor loss} = \lambda_4 \times (\text{conductor loss})$$

then

$$\lambda_4 = \frac{\text{Armor loss}}{\text{Conductor loss}}$$

6.4.11 DC RESISTANCE

The DC resistance R_{dc} of a conductor is where

$$R_{\text{dc}} = \frac{\rho l}{A}$$

where

- ρ is the resistivity of the conductor
- l is the conductor length
- A is the cross-sectional area

The units used must be of a consistent set. In practice, several different sets of units are used in the calculation of resistance. For example, in the SI units, l is in meters, A is in square meters, and ρ is in ohms per meter. Whereas in power systems in the United States, ρ is in ohm-circular mils per foot (Ω -cmil/ft), or ohms per circular mil-foot, l is usually in feet, and A is in circular mils (cmil). Resistivity ρ is 10.66 Ω -cmil/ft, or 1.77×10^{-8} Ω -m, at 20°C for hard-drawn copper and 10.37 Ω -cmil/ft at 20°C for standard annealed copper. For hard-drawn aluminum at 20°C, ρ is 17.00 Ω -cmil/ft or 2.83×10^{-8} Ω -m. The DC resistance of a conductor in terms of temperature is given by

$$\frac{R_2}{R_1} = \frac{T_0 + t_2}{T_0 + t_1}$$

where

- R_1 is the conductor resistance at temperature t_1
- R_2 is the conductor resistance at temperature t_2
- t_1, t_2 is the conductor temperatures in degrees Celsius

$$\begin{aligned} T_0 &= \text{Constant varying with conductor material} \\ &= 234.5 \text{ for annealed copper} \\ &= 241 \text{ for hard-drawn copper} \\ &= 228 \text{ for hard-drawn aluminum} \end{aligned}$$

The *maximum allowable conductor temperatures* are given by the Insulated Power Cable Engineers Association (IPCEA) for PE and cross-linked PE-insulated cables as follows:

- Under normal operation
 - PE-insulated cables: 75°C
 - Cross-linked PE-insulated cables: 90°C
- Under emergency operation
 - PE-insulated cables: 90°C
 - Cross-linked PE-insulated cables: 130°C

The maximum conductor temperatures for impregnated paper-insulated cables are given in Table 6.4.

6.4.12 SKIN EFFECT

For DC currents, a uniform current distribution is assumed throughout the cross section of a conductor. This is not true for AC. As the frequency of AC current increases, the nonuniformity of the current becomes greater. The current tends to flow more densely near the outer surface of the conductor than near the center. The phenomenon responsible for this nonuniform distribution is called the *skin effect*.

Skin effect is present because the magnetic flux linkages of current near the center of the conductor are relatively greater than the linkages of current flowing near the surface of the conductor. Since the inductance of any element is proportional to the flux linkages per ampere, the inner areas of the conductor offer greater reactance to current flow. Therefore, the current follows the outer paths of lower reactance, which in turn reduces the effective path area and increases the effective resistance of the cable.

TABLE 6.4
Maximum Conductor Temperatures for Impregnated Paper-Insulated Cable

Rated Voltage (kV)	Conductor Temperature (°C)	
	Normal Operation	Emergency Operation
Solid-Type Multiple Conductor Belted		
1	85	105
2–9	80	100
10–15	75	95
Solid-Type Multiple Conductor Shielded and Single Conductor		
1–9	85	105
10–17	80	100
18–29	75	95
30–39	70	90
40–49	65	85
50–59	60	75
60–69	55	70
Low-Pressure Gas Filled		
8–17	80	100
18–29	75	95
30–39	70	90
40–46	65	85
Low-Pressure Oil Filled and High-Pressure Pipe Type		
		100h 300h
15–17	85	105 100
18–39	80	100 95
40–162	75	95 90
163–230	70	90 85

Sources: Fink and Beaty [3] and Insulated Power Cable Engineers Association [6].

Skin effect is a function of conductor size, frequency, and the relative resistance of the conductor material. It increases as the conductor size and the frequency increase. It decreases as the material’s relative resistance decreases. For example, for the same size conductors, the skin effect is larger for copper than for aluminum.

The effective resistance of a conductor is a function of power loss and the current in the conductor. Thus,

$$R_{\text{eff}} = \frac{P_{\text{loss in conductor}}}{|I|^2}$$

where

$P_{\text{loss in conductor}}$ is the power loss in conductor in watts
 I is the current in the conductor in amperes

Skin effect increases this effective resistance. Also, it can decrease reactance as internal flux linkages decrease. Stranding the conductor considerably reduces the skin effect. In an underground

cable, the central conductor strands are sometimes omitted since they carry small current. For example, some large cables are sometimes built over a central core of nonconducting material.

6.4.13 PROXIMITY EFFECT

The proximity effect is quite similar in nature to the skin effect. An increase in resistance is present due to nonuniformity in current density over the conductor section caused by the magnetic flux linkages of current in the other conductors. The result, as in the case of skin effect, is a crowding of the current in both conductors toward the portions of the cross sections that are immediately adjacent to each other. It can cause a significant change in the effective AC resistance of multiconductor cables or cables located in the same duct.

This phenomenon is called the *proximity effect*. It is greater for a given size conductor in single-conductor cables than in three-conductor belted cables. Table 6.5 gives the DC resistance and skin effect and proximity effect multipliers for copper and aluminum conductors at 25°C. Additional tables of electrical characteristics are supplied by the manufacturers for their cables.

TABLE 6.5
DC Resistance and Correction Factors for AC Resistance

Conductor Size (AWG or kcmil)	AC Resistance Multiplier					
	DC Resistance Ω/1,000 ft at 25°C ^a		Single-Conductor Cables ^b		Multiconductor Cables ^c	
	Copper	Aluminum	Copper	Aluminum	Copper	Aluminum
8	0.6532	1.071	1.000	1.000	1.00	1.00
6	0.4110	0.6741	1.000	1.000	1.00	1.00
4	0.2584	0.4239	1.000	1.000	1.00	1.00
2	0.1626	0.2666	1.000	1.000	1.01	1.00
1	0.1289	0.2114	1.000	1.000	1.01	1.00
10	0.1022	0.1676	1.000	1.000	1.02	1.00
20	0.08105	0.1329	1.000	1.001	1.03	1.00
30	0.06429	0.1054	1.000	1.001	1.04	1.01
40	0.05098	0.08361	1.000	1.001	1.05	1.01
250	0.04315	0.07077	1.005	1.002	1.06	1.02
300	0.03595	0.05897	1.006	1.003	1.07	1.02
350	0.03082	0.05055	1.009	1.004	1.08	1.03
500	0.02157	0.03538	1.018	1.007	1.13	1.06
750	0.01438	0.02359	1.039	1.015	1.21	1.12
1000	0.01079	0.01796	1.067	1.026	1.30	1.19
1500	0.00719	0.01179	1.142	1.058	1.53	1.36
2000	0.00539	0.00885	1.233	1.100	1.82	1.56

Source: Adapted from Fink and Beaty [3], with permission.

^a To correct to other temperatures, use the following:

For copper: $R_T = R_{25} \times (234.5 + T)/259.5$

For aluminum: $R_T = R_{25} \times (228 + T)/253$

where R_T is the new resistance at temperature T and R_{25} is the tabulated resistance.

^b Includes only the skin effect (use for cables in separate ducts).

^c Includes the skin effect and the proximity effect (use for triplex, multiconductor, or cables in the same duct).

Example 6.8

A single-conductor, paper-insulated, belted cable will be used as an underground feeder of 3 mi. The cable has a 2,000 MCM (2,000 kcmil) copper conductor:

- Calculate the total DC resistance of the conductor at 25°C.
- Using Table 6.5, determine the effective resistance and the skin effect on the effective resistance in percent if the conductor is used at 60 Hz AC.
- Calculate the percentage of reduction in cable ampacity in part (b).

Solution

- From Table 6.5, the DC resistance of the cable is

$$R_{dc} = 0.00539 \Omega/1,000 \text{ ft}$$

or the total DC resistance is

$$R_{dc} = 0.00539 \times 5280 \times 3 = 0.0854 \Omega$$

- From Table 6.5, the skin effect coefficient is 1.233; therefore, the effective resistance at 60 Hz is

$$\begin{aligned} R_{\text{eff}} &= (\text{Skin effect coefficient}) \times R_{dc} \\ &= (1.233) \times 0.0854 \\ &= 0.1053 \Omega \end{aligned}$$

or it is 23.3% greater than for DC.

- The reduction in the cable ampacity is also 23.3%.

6.5 SHEATH CURRENTS IN CABLES

The flow of AC current in the conductors of single-conductor cables induces AC voltages in the cable sheaths. When the cable sheaths are bonded together at their ends, the voltages induced give rise to sheath (*eddy*) currents, and therefore, additional I^2R losses occur in the sheath. These losses are taken into account by increasing the resistance of the relevant conductor. For a single-conductor cable with bonded sheaths operating in three-phase and arranged in an equilateral triangular formation, the increase in conductor resistance is

$$\Delta r = r_s \times \frac{X_m^2}{r_s^2 + X_m^2} \quad (6.77)$$

where

X_m is the mutual reactance between conductors and sheath per phase in ohms per mile

r_s is the sheath resistance per phase in ohms per mile

The mutual reactance between conductors and sheath can be calculated from

$$X_m = 0.2794 \left(\frac{f}{60} \right) \log_{10} \left(\frac{2S}{r_0 + r_i} \right) \quad (6.78)$$

and the sheath resistance of a metal sheath cable can be determined from

$$r_s = \frac{0.2}{(r_0 + r_i)(r_0 - r_i)} \quad (6.79)$$

where

f is the frequency in hertz

S is the spacing between conductor centers in inches

r_0 is the outer radius of the metal sheath in inches

r_i is the inner radius of the metal sheath in inches

In Equation 6.78,

$$\text{GMR} = D_s = \frac{r_0 + r_i}{2} \quad (6.80)$$

and

$$\text{GMD} = D_m = S$$

Therefore, for other conductor arrangements, that is, other than equilateral triangular formation,

$$X_m = 0.2794 \left(\frac{f}{60} \right) \log_{10} \left(\frac{D_m}{D_s} \right) \Omega/\text{mi}/\text{phase} \quad (6.81)$$

frequency used is 60 Hz,

$$X_m = 0.2794 \times \log_{10} \left(\frac{D_m}{D_s} \right) \quad (6.82)$$

or

$$X_m = 0.1213 \times \ln \left(\frac{D_m}{D_s} \right) \quad (6.83)$$

Hence, in single-conductor cables, the total resistance to positive- or negative-sequence current flow, including the effect of sheath current, is

$$r_a = r_c + \frac{r_s X_m^2}{r_s^2 + X_m^2} \Omega/\text{mi}/\text{phase} \quad (6.84)$$

where

r_a is the total positive- or negative-sequence resistance, including sheath current effects

r_c is the AC resistance of conductor, including the skin effect

The sheath loss due to sheath currents is

$$P_s = I^2 \Delta r \quad (6.85)$$

$$P_s = I^2 \left(\frac{r_s X_m^2}{r_s^2 + X_m^2} \right) \quad (6.86)$$

or

$$P_s = r_s \left(\frac{I^2 X_m^2}{r_s^2 + X_m^2} \right) \text{W}/\text{mi}/\text{phase} \quad (6.87)$$

r_s is the sheath resistance per phase in ohms per mile

I is the current in one conductor in amperes

X_m is the mutual reactance between conductors and sheath per phase in ohms per mile

For a *three-conductor cable with round conductors*, the increase in conductor resistance due to sheath currents is

$$\Delta r = 0.04416 \left(\frac{S^2}{r_s (r_o + r_i)^2} \right) \Omega/\text{mi/phase} \quad (6.88)$$

where

$$S = \frac{d + 2T}{\sqrt{3}} \quad (6.89)$$

and

r_s is the sheath resistance, from Equation 6.79

r_o is the outer radius of the lead sheath in inches

r_i is the inner radius of the lead sheath in inches

S is the distance between conductor center and sheath center for three-conductor cables made of round conductors

d is the conductor diameter in inches

T is the conductor insulation thickness in inches

For *sector-shaped conductors*, use Equations 6.88 and 6.82 but conductor diameter is $d = 82\% - 86\%$ of diameter of round conductor having the same cross-sectional area.

Sheaths of single-conductor cables may be operated short-circuited or open-circuited. If the sheaths are short-circuited, they are usually bonded and grounded at every manhole. This decreases the sheath voltages to zero but allows the flow of sheath currents. There are various techniques for operating with the sheaths open-circuited:

1. When a ground wire is used, one terminal of each sheath section is bound to the ground wire. The other terminal is left open so that no current can flow in the sheath.
2. With cross bonding, at each section, connections are made between the sheaths of cables *a*, *b*, and *c*, as shown in Figure 6.25, so that only the sheaths are transposed electrically. The sheaths are bonded together and grounded at the end of each complete transposition. Thus, the sum of sheath voltages induced by the positive-sequence currents becomes zero.
3. With impedance bonding, impedances are added in each cable sheath to limit sheath currents to predetermined values without eliminating any sequence currents.
4. With bonding transformers [5].

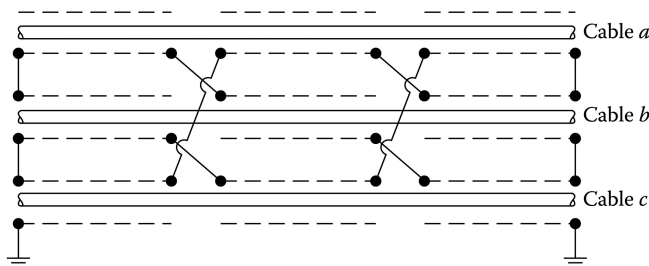


FIGURE 6.25 Cross bonding of single-conductor cables.

Example 6.9

Assume that three 35 kV, 350 kcmil, single-conductor belted cables are located in touching equilateral formation with respect to each other and the sheaths are bounded to ground at several points. The cables are operated at 34.5 kV and 60 Hz. The cable has a conductor diameter of 0.681 in., an insulation thickness of 345 cmil, a metal sheath thickness of 105 cmil, and a length of 10 mi. Conductor AC resistance is 0.190 Ω /mi per phase at 50°C. Calculate the following:

- Mutual reactance between conductors and sheath
- Sheath resistance of cable
- Increase in conductor resistance due to sheath currents
- Total resistance of conductor including sheath loss
- Ratio of sheath loss to conductor loss
- Total sheath losses of feeder in watts if current in conductor is 400 A

Solution

- a. By using Equation 6.78,

$$X_m = 0.2794 \left(\frac{f}{60} \right) \log_{10} \left(\frac{D_m}{D_s} \right) \Omega/\text{mi/phase} \quad (6.81)$$

where

$$r_i = \frac{0.681}{2} + 0.345 = 0.686 \text{ in.}$$

$$r_o = r_i + 0.105 = 0.791 \text{ in.}$$

$$S = 1.582 \text{ in.}$$

Therefore,

$$\begin{aligned} X_m &= \log_{10} \left(\frac{2 \times 1.582}{0.791 + 0.686} \right) \\ &= 0.09244 \quad \Omega/\text{mi} \end{aligned}$$

or

$$X_m = 0.9244 \Omega/\text{phase}$$

- b. By using Equation 6.79,

$$\begin{aligned} r_s &= \frac{0.2}{(r_o + r_i)(r_o - r_i)} \\ &= \frac{0.2}{(0.791 + 0.686)(0.791 - 0.686)} \end{aligned}$$

or

$$r_s = 12.896 \Omega/\text{phase}$$

c. Using Equation 6.77,

$$\begin{aligned}\Delta r &= r_s \times \frac{X_m^2}{r_s^2 + X_m^2} \\ &= 1.2896 \times \frac{0.09244^2}{1.2896^2 + 0.09244^4} \\ &= 0.0659 \text{ } \Omega/\text{phase}\end{aligned}$$

or

$$\Delta_r = 0.0659 \text{ } \Omega/\text{phase}$$

Using Equation 6.84,

$$\begin{aligned}r_a &= r_c \times \frac{r_s X_m^2}{r_s^2 + X_m^2} \\ &= 0.190 + 0.00659 \\ &= 0.19659 \text{ } \Omega/\text{mi}\end{aligned}$$

or

$$r_a = 1.9659 \text{ } \Omega/\text{phase}$$

$$\begin{aligned}\frac{\text{Sheath loss}}{\text{Conductor loss}} &= \frac{I^2 r_s X_m^2}{r_s^2 + X_m^2} \times \frac{1}{I^2 r_c} \\ &= \frac{0.00659}{0.190} \\ &= 0.0347\end{aligned}$$

That is,

$$\text{Sheath loss} = 3.47\% \times \text{conductor loss}$$

f. Using Equation 6.87,

$$P_s = r_s \left(\frac{r_s X_m^2}{r_s^2 + X_m^2} \right) \text{ W/mi}$$

or, for three-phase loss,

$$\begin{aligned}P_s &= 3I^2 \left(\frac{r_s X_m^2}{r_s^2 + X_m^2} \right) \\ &= 3 \times 400^2 \times 0.00659 \\ &= 3163.2 \text{ W/mi}\end{aligned}$$

or, for total feeder length,

$$P_s = 31,632 \text{ W/mi}$$

6.5.1 SINGLE-CONDUCTOR CABLES

The positive- and negative-sequence reactances for single-conductor cables, when sheath currents are present, can be determined as

$$X_1 = X_2 = 0.1213 \left(\frac{f}{60} \right) \times \ln \left(\frac{D_m}{D_s} \right) - \frac{X_m^3}{X_m^2 + r_s^2} \Omega/\text{mi} \quad (6.90)$$

or

$$X_1 = X_2 = 0.2794 \left(\frac{f}{60} \right) \times \log_{10} \left(\frac{D_m}{D_s} \right) - \frac{X_m^3}{X_m^2 + r_s^2} \Omega/\text{mi} \quad (6.91)$$

or

$$X_1 = X_2 = 0.2794 \left(\frac{f}{60} \right) \times \log_{10} \left(\frac{D_m}{0.7788 r} \right) - \frac{X_m^3}{X_m^2 + r_s^2} \Omega/\text{mi} \quad (6.92)$$

where r is the outside of the radius of the conductors. For cables, it is convenient to express D_m , D_s , and r in inches. In Equation 6.91,

X_1 is the positive-sequence reactance per phase in ohms per mile

X_2 is the negative-sequence reactance per phase in ohms per mile f is the frequency in hertz

D_m is the geometrical mean distance (GMD) among conductors

D_s is the geometrical mean radius (GMR), or self-GMD, of one conductor

X_m is the mutual reactance between conductors and sheath per phase in ohms per mile

r_s is the sheath resistance per phase in ohms per mile

Equation 6.91 can be also expressed as

$$X_1 = X_2 = X_a + X_d - \frac{X_m^3}{X_m^2 + r_s^2} \Omega/\text{mi} \quad (6.93)$$

where

$$X_a = 0.2794 \left(\frac{f}{60} \right) \times \log_{10} \left(\frac{12}{D_s} \right) \quad (6.94)$$

and

$$X_d = 0.2794 \left(\frac{f}{60} \right) \times \log_{10} \left(\frac{D_m}{12} \right) \quad (6.95)$$

Here, X_a and X_d are called *conductor component of reactance* and *separation component of reactance*, respectively. If the frequency is 60 Hz, Equations 6.94 and 6.95 may be written as

$$X_a = 0.2794 \times \log_{10} \left(\frac{12}{D_s} \right) \Omega/\text{mi} \quad (6.96)$$

or

$$X_a = 0.1213 \times \ln \left(\frac{12}{D_s} \right) \Omega/\text{mi} \quad (6.97)$$

and

$$X_d = 0.2794 \times \log_{10} \left(\frac{D_m}{12} \right) \Omega/\text{mi} \quad (6.98)$$

or

$$X_d = 0.1213 \times \log_{10} \left(\frac{D_m}{12} \right) \Omega/\text{mi} \quad (6.99)$$

In Equation 6.93, the last term symbolizes the correction for the existence of sheath currents. The negative sign is there because the current in the sheath is in a direction opposite to that in the conductor, therefore inclining to restrict the flux to the region between the conductor and the sheath. The last term is taken from Equation 6.77, with X_m substituted for r_s , and is derived by considering the current in the sheath and the component of voltage it induces in the conductor in quadrature to the conductor current.

6.5.2 THREE-CONDUCTOR CABLES

The positive- and negative-sequence reactances for three-conductor cables can be determined as

$$X_1 = X_2 = 0.2794 \left(\frac{f}{60} \right) \times \log_{10} \left(\frac{D_m}{D_s} \right) \Omega/\text{mi} \quad (6.100)$$

or

$$X_1 = X_2 = X_a + X_d \quad (6.101)$$

where D_m is the GMD among the three conductors. If the frequency is 60 Hz, X_a and X_d can be calculated from Equations 6.96 or 6.97 and 6.98 or 6.99, respectively. Equations 6.100 and 6.101 can be used for both shielded and unshielded cables because of negligible sheet current effects.

6.6 ZERO-SEQUENCE RESISTANCE AND REACTANCE

The return of the zero-sequence currents flowing along the phase conductors of a three-phase cable is in either the ground, or the sheaths, or the parallel combination of both ground and sheaths.

6.6.1 THREE-CONDUCTOR CABLES

Figure 6.26 shows an actual circuit of a single-circuit three-conductor cable with solidly bonded and grounded sheath. It can be observed that

$$(I_{a0} + I_{b0} + I_{c0}) + (I_{0(s)} + I_{0(g)}) = 0 \quad (6.102)$$

Figure 6.27 shows the equivalent circuit of this actual circuit in which Z_c represents the impedance of a composite conductor consisting of three single conductors. The zero-sequence current $I_{0(a)}$ in the composite conductor can be expressed as [7]

$$I_{0(a)} = 3I_{a0} \quad (6.103)$$

First, assume that there is no return (zero-sequence) current flowing in the sheath, and therefore, it is totally in the ground. Hence, the zero-sequence impedance of the composite conductor can be written as

$$Z_{0(a)} = (r_a + r_e) + j0.36396 \left(\frac{f}{60} \right) \times \ln \left(\frac{D_e}{D_{aa}} \right) \Omega/\text{mi}/\text{phase} \quad (6.104)$$

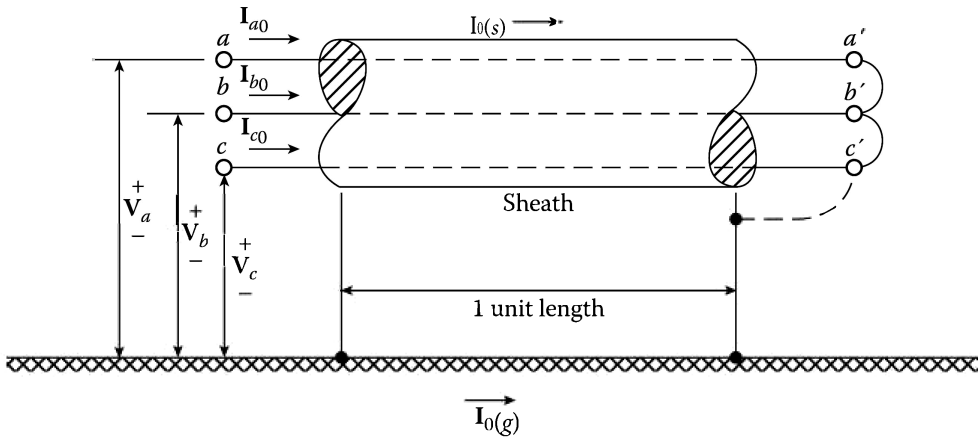


FIGURE 6.26 Actual circuit of three-conductor lead-sheathed cables.

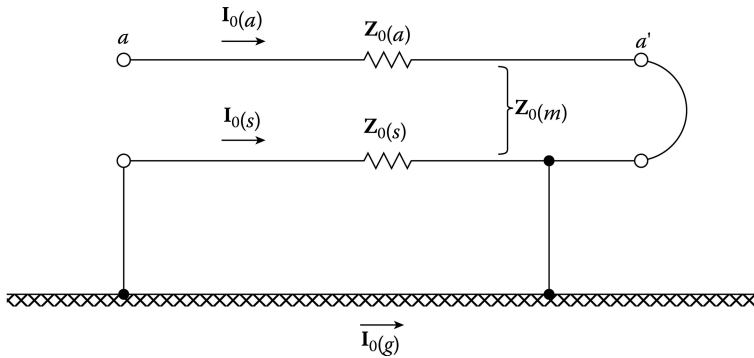


FIGURE 6.27 Equivalent circuit of three-conductor cables.

$$Z_{0(a)} = (r_a + r_e) + j0.8382 \left(\frac{f}{60} \right) \times \log_{10} \left(\frac{D_e}{D_{aa}} \right) \Omega/\text{mi}/\text{phase} \quad (6.105)$$

since the GMR, or the self-GMD, of this composite conductor is

$$D_{aa} = D_s^{1/3} \times D_{eq}^{2/3} \quad (6.106)$$

and since three-conductor cables are made of round conductors,

$$D_{eq} = D_m = d + 2T \quad (6.107)$$

where

d is the conductor diameter in inches

T is the conductor insulation thickness in inches

Equations 6.104 and 6.105 for 60Hz frequency can be expressed as

$$Z_{0(a)} = (r_a + r_e) + j0.36396 \ln \frac{D_e}{D_s^{1/3} \times D_{eq}^{2/3}} \Omega/\text{mi}/\text{phase} \quad (6.108)$$

and

$$\mathbf{Z}_{0(a)} = (r_a + r_e) + j0.8382 \left(\frac{f}{60} \right) \ln \frac{D_e}{D_s^{1/3} \times D_{eq}^{2/3}} \Omega/\text{mi/phase} \quad (6.109)$$

Equations 6.108 and 6.109 are sometimes written as

$$\mathbf{Z}_{0(a)} = (r_a + r_e) + j0.1213 \ln \frac{D_e^3}{D_s^{1/3} \times D_{eq}^{2/3}} \Omega/\text{mi/phase} \quad (6.110)$$

and

$$\mathbf{Z}_{0(a)} = (r_a + r_e) + j0.2794 \left(\frac{f}{60} \right) \log_{10} \frac{D_e^3}{D_s \times D_{eq}^2} \Omega/\text{mi/phase} \quad (6.111)$$

or

$$\mathbf{Z}_{0(a)} = (r_a + r_e) + j(X_a + X_e - 2X_d) \Omega/\text{mi/phase} \quad (6.112)$$

where

$$X_a = 0.1213 \ln \left(\frac{12}{D_s} \right) \Omega/\text{mi} \quad (6.113)$$

$$X_e = 3 \times 0.1213 \ln \left(\frac{D_e}{12} \right) \Omega/\text{mi} \quad (6.114)$$

$$X_d = 0.1213 \ln \left(\frac{D_{eq}}{12} \right) \Omega/\text{mi} \quad (6.115)$$

where

r_a is the AC resistance of one conductor in ohms per mile

r_e is the AC resistance of earth return

$$= 0.00476 \times f \Omega/\text{mi}$$

D_e is the equivalent depth of earth return path

$$= 2,592 \sqrt{\rho/f} \text{ in.}$$

D_{eq} is the equivalent, or geometric, mean distance among conductor centers in inches

D_s is the GMR, or self-GMD, of one conductor in inches

X_a is the reactance of individual phase conductor at 12 in. spacing in ohms per mile

Second, consider only ground return path and sheath return path but not the composite conductor. Hence, the *zero-sequence impedance of the sheath* to zero-sequence currents is

$$\mathbf{Z}_{0(s)} = (3r_s + r_3) + j0.36396 \times \left(\frac{f}{60} \right) \times \ln \left(\frac{2D_e}{r_0 + r_i} \right) \Omega/\text{mi/phase} \quad (6.116)$$

or

$$\mathbf{Z}_{0(s)} = (3r_s + r_3) + j0.8382 \times \left(\frac{f}{60} \right) \times \log_{10} \left(\frac{2D_e}{r_0 + r_i} \right) \Omega/\text{mi/phase} \quad (6.117)$$

or, at 60 Hz frequency,

$$Z_{0(s)} = (3r_s + r_3) + j0.36396 \times \ln\left(\frac{2D_e}{r_o + r_i}\right) \Omega/\text{mi/phase} \quad (6.118)$$

or

$$Z_{0(s)} = (3r_s + r_3) + j0.8382 \times \log_{10}\left(\frac{2D_e}{r_o + r_i}\right) \Omega/\text{mi/phase} \quad (6.119)$$

or

$$Z_{0(s)} = (3r_s + r_3) + j(3X_s + X_e + X_e) \Omega/\text{mi/phase} \quad (6.120)$$

where

$$r_s = \frac{0.2}{(r_o + r_i)(r_o - r_i)} \text{ for lead sheaths, } \Omega/\text{mi} \quad (6.121)$$

$$X_s = 0.1213 \ln\left(\frac{24}{r_o + r_i}\right) \Omega/\text{mi} \quad (6.122)$$

$$X_s = 3 \times 0.1213 \ln\left(\frac{D_e}{12}\right) \Omega/\text{mi} \quad (6.123)$$

where

r_s is the sheath resistance of the metal sheath cable in ohms per mile

r_e is the AC resistance of earth return in ohms per mile

r_o is the outer radius of the metal sheath in inches

r_i is the inner radius of the metal sheath in inches

X_s is the reactance of the metal sheath in ohms per mile

The *zero-sequence mutual impedance between the composite conductor and sheath* can be expressed as

$$\mathbf{Z}_{0(m)} = r_e + j0.36396 \times \left(\frac{f}{60}\right) \times \ln\left(\frac{2D_e}{r_o + r_i}\right) \Omega/\text{mi/phase} \quad (6.124)$$

or

$$\mathbf{Z}_{0(m)} = r_e + j0.8382 \times \left(\frac{f}{60}\right) \times \log_{10}\left(\frac{2D_e}{r_o + r_i}\right) \Omega/\text{mi/phase} \quad (6.125)$$

or, at 60 Hz frequency,

$$\mathbf{Z}_{0(m)} = r_e + j0.36396 \times \ln\left(\frac{2D_e}{r_o + r_i}\right) \Omega/\text{mi/phase} \quad (6.126)$$

or

$$\mathbf{Z}_{0(m)} = r_e + j0.8382 \times \log_{10}\left(\frac{2D_e}{r_o + r_i}\right) \Omega/\text{mi/phase} \quad (6.127)$$

or

$$\mathbf{Z}_{0(m)} = r_e + j(3X_s + X_e) \quad (6.128)$$

The equivalent circuit shown in Figure 6.27 can be modified as shown in Figure 6.28. *Total zero-sequence impedance* can be calculated for three different cases as follows:

1. When both ground and sheath return paths are present,

$$\mathbf{Z}_{00} = \mathbf{Z}_0 = \left(\mathbf{Z}_{0(a)} - \mathbf{Z}_{0(m)} \right) + \frac{\left(\mathbf{Z}_{0(s)} - \mathbf{Z}_{0(m)} \right) \mathbf{Z}_{0(m)}}{\mathbf{Z}_{0(s)}} \quad (6.129)$$

or

$$\mathbf{Z}_{00} = \mathbf{Z}_{0(a)} + \frac{\mathbf{Z}_{0(m)}^2}{\mathbf{Z}_{0(s)}} \Omega/\text{mi/phase} \quad (6.130)$$

or

$$\begin{aligned} \mathbf{Z}_{00} &= \left[(r_a + r_e) + j(X_a + X_e - 2X_d) \right] \\ &= - \frac{\left[r_e + j(3X_s + X_e) \right]^2}{\left[(3r_s + r_e) + j(3X_s + X_e) \right]} \end{aligned} \quad (6.131)$$

2. When there is only sheath return path.

$$\mathbf{Z}_{00} = \left(\mathbf{Z}_{0(a)} - \mathbf{Z}_{0(m)} \right) + \left(\mathbf{Z}_{0(s)} - \mathbf{Z}_{0(m)} \right) \Omega/\text{mi/phase} \quad (6.132)$$

or

$$\mathbf{Z}_{00} = \mathbf{Z}_{0(a)} + \mathbf{Z}_{0(s)} - 2\mathbf{Z}_{0(m)} \Omega/\text{mi/phase} \quad (6.133)$$

or

$$\begin{aligned} \mathbf{Z}_{00} &= \left[(r_a + r_e) + j(X_a + X_e - 2X_d) \right] + j[(3X_s + X_e)] \\ &\quad - 2[r_e + j(3X_s + X_e)] \end{aligned} \quad (6.134)$$

or

$$\mathbf{Z}_{00} = (r_a + 3r_s) + j(X_a + 2X_d - 3X_s) \Omega/\text{mi/phase} \quad (6.135)$$

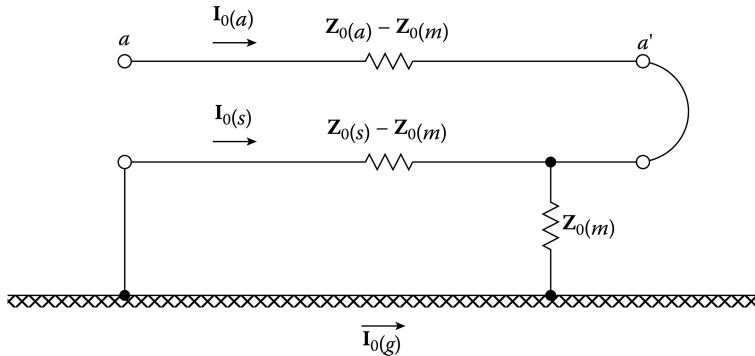


FIGURE 6.28 Modified equivalent circuit.

TABLE 6.6
 D_e , r_e , and X_e for Various Earth Resistivities at 60 Hz

Earth Resistivity	Equivalent Depth of Earth Return, D_e		Equivalent Earth Resistance, r_e	Equivalent Earth Reactance, X_e
(Ω -m)	(in.)	(ft)	(Ω /m)	(Ω /m)
1	3.36×10^3	280	0.286	2.05
5	7.44×10^3	620	0.286	2.34
10	1.06×10^4	880	0.286	2.47
50	2.40×10^4	2,000	0.286	2.76
100	3.36×10^4	2,800	0.286	2.89
500	7.44×10^4	6,200	0.286	3.18
1,000	1.06×10^5	8,800	0.286	3.31
5,000	2.40×10^5	20,000	0.286	3.60
10,000	3.36×10^5	28,000	0.286	3.73

Source: Westinghouse Electric Corporation [2].

3. When there is only ground return path (e.g., nonsheathed cables),

$$Z_{00} = (Z_{0(a)} - Z_{0(m)}) + Z_{0(m)} \text{ } \Omega/\text{mi/phase} \tag{6.136}$$

$$Z_{00} = Z_{0(a)} \text{ } \Omega/\text{mi/phase} \tag{6.137}$$

$$Z_{00} = (r_a + r_e) + j(X_a + X_e - 2X_d) \text{ } \Omega/\text{mi/phase} \tag{6.138}$$

In the case of shielded cables, the zero-sequence impedance can be computed as if the shielding tapes were not present, with a very small error. In general, calculating only the zero-sequence impedance for all return current in the sheath and none in the ground is sufficient. Table 6.6 offers the values of D_e , r_e , and X_e for various earth resistivities.

PROBLEMS

- 6.1 Assume that a 7.2 kV, 60 Hz, single-conductor, belted cable has a conductor diameter of 2 cm and a lead sheath with an inside diameter of 4 cm. The resistivity of the insulation is $1.2 \times 10^8 \text{ M}\Omega\text{-cm}$, and the length of the cable is 3.5 mi. Calculate the following:
 - a. Total insulation resistance in megohms
 - b. Power loss due to leakage current flowing through insulation resistance
- 6.2 Assume that a 2 mi long, three-conductor, belted cable is connected to a 24.9 kV, three-phase, 60 Hz bus. A test result shows that the capacitance between bunch conductors and the sheath is 0.8 pF/mi, and the capacitance between two conductors bunched together with the sheath and third conductor is 0.60 pF/mi. Find the charging current per conductor.
- 6.3 Assume that a single-conductor belted cable has a conductor diameter of 0.681 in., an inside diameter of sheath of 1.7025 in., and a length of 8,000 ft. The cable is to be operated at 12.47 kV. The dielectric constant is 4.5, and the power factor of the dielectric at a rated frequency and temperature is 0.05. Calculate the following:
 - a. Capacitance of cable
 - b. Charging current
 - c. Dielectric loss of cable
 - d. Equivalent resistance of insulation

- 6.4 Assume that a single-conductor belted cable has a conductor diameter of 2 cm and an inside diameter of sheath of 5 cm. Its insulation resistance is given as 275 M Ω /mi. Find the dielectric resistivity of the insulation.
- 6.5 Assume that a test has been conducted by means of a Schering bridge on a three-conductor belted cable at a rated voltage and frequency of 12.47 kV and 60 Hz, respectively. The capacitance between the two conductors when the third one is connected to the lead sheath was found to be 1.2 pF. Also, the capacitance between the three conductors connected together and the lead sheath was measured as 1.4 pF. Calculate the following:
 - a. Effective capacitance to neutral
 - b. Charging current per conductor
 - c. Total charging current of cable
 - d. Capacitance between each conductor and sheath
 - e. Capacitance between each pair of conductors
- 6.6 Assume that a single-phase concentric cable is 3 mi long and is connected to 60 Hz, 7.2 kV bus bars. The conductor diameter is 0.630 in., and the radial thickness of uniform insulation is 0.425 in. The relative permittivity of the dielectric is 4. Find the charging kilovolt-amperes.
- 6.7 Assume that a single-phase voltage of 7.97 kV at 60 Hz frequency is applied between two of the conductors of a three-phase belted cable. The capacitances between conductors and between a conductor and a sheath are measured as 0.30 and 0.2 pF, respectively. Calculate the following:
 - a. Potential difference between third conductor and sheath
 - b. Total charging current of cable
- 6.8 Assume that a three-conductor, paper-insulated, belted cable is used as a three-phase underground feeder of 18 mi. It is operated at 60 Hz and 33 kV. The cable has three 350 kcmil sector-type conductors each with 10/32 in. of conductor insulation and 5/32 in. of belt insulation.
- 6.9 Assume that a three-conductor, paper-insulated, belted cable is used as a three-phase underground feeder of 5,000 ft. The cable is operated at 15 kV, 60 Hz, and 75°C. The cable has a 350 kcmil copper conductor. Calculate the effective resistance of the cable.
- 6.10 Repeat Problem 6.9 assuming the conductor is aluminum.
- 6.11 Repeat Problem 6.9 assuming three single-conductor cables are located in the separate ducts.
- 6.12 Repeat Example 6.9 assuming the spacing between conductor centers is 4.125 in. and the cables are located in the same horizontal plane.

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7 Protective Equipment and Transmission System Protection

Experience is the name everyone gives to their mistake.

Oscar Wilde

7.1 INTRODUCTION

The proper operation of a transmission system depends on protective equipment to detect fault conditions and disconnect malfunctioning equipment. The protective equipment must protect people and power system apparatus from malfunctions, whether the malfunction is the result of an equipment failure, accidents, weather, or misoperation by the personnel involved. The most important protective equipment for transmission systems are the circuit breakers, disconnect switches, and relays to sense fault conditions.

7.2 INTERRUPTION OF FAULT CURRENT

The main function of interrupting equipment such as circuit breakers is to stop the flow of current. During the process of interruption, an arc is created that must be extinguished. The arc is caused by any gas that is located between separating contacts and subject to the electrical field. The gas ionizes, becomes an arc, and starts to support current flow through it. The higher the voltage that the contacts are breaking, the more severe the arcing is. Inductive loads make the arc even more severe. Most industrial loads and faulted lines are inductive.

There are two methods to extinguish an arc. The first method involves lengthening the arc until it is long and thin, which causes the arc resistance to increase. This increase in resistance causes the arc current to decrease and the temperature of the arc to drop which eventually results in not having enough energy in the arc to keep it ionized. The second method involves the opening of the arc in a medium that can absorb energy from the arc, causing it to cool and quench.

DC arcs are more difficult to break than AC arcs because AC goes through a current zero every half cycle, which DC does not. Hence, in an AC circuit breaker, the advantage of current zero is taken, and then dielectric strength is injected between the contacts of the circuit breaker faster than the recovery voltage building up.

Note that after AC zero, the arc may establish itself beyond the first current zero, if the medium between the contacts is still ionized. Furthermore, even if the arc does not reestablish itself immediately due to the medium being ionized, the voltage rise across the contacts may cause the arc to reestablish in the event that the contacts are not sufficiently apart.

As illustrated in Figure 7.1c, during a short circuit, the current lags the system voltage by upwards of 90° , depending on the relative values of R and X . At the instant the fault current goes through zero, the system voltage may be nearly at maximum. It is at this instant that the arc goes out temporarily. But, the voltage across the breaker suddenly shoots from this low value toward full the system voltage. The inductance and capacitance in the circuit, however, cause the voltage to overshoot to a value that is as far above the system voltage as it was below it at the beginning. Hence, the transient voltage across the breaker may be nearly double the steady-state system voltage.

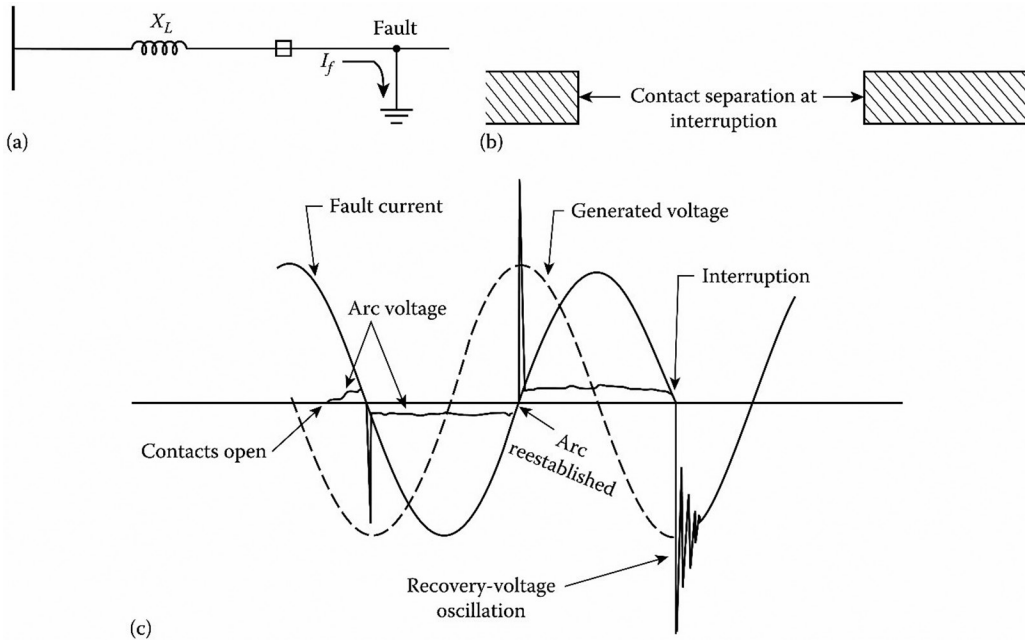


FIGURE 7.1 Interruption of short-circuit current: (a) equipment circuit, (b) contact separation, and (c) current and voltage waveforms.

Furthermore, if the sudden increase in the arc resistance, as the current approaches zero, should cause the current to reach zero prematurely, that would cause another transient and produce more voltage due to the greater rate of change of current in the inductive circuit. These voltages are called the *recovery voltages* and they appear across the breaker. The rate at which the voltage builds up is known as the *rate of rise of recovery voltage*. The arc that is established in the first $1/4$ cycle is called a *reignition*, and the arc that is reestablished after the first $1/4$ cycle is called a *restrike*.

In a plain-break circuit breaker, the earlier cycle may be repeated several times. Eventually, arc extinction becomes permanent and circuit interruption is complete. The high X/R ratio of the circuit causes the arc to be more difficult to break.

A special problem occurs in interrupting the leading current of a capacitor or an unloaded transmission line. Here, at the first current zero of a leading current arc, interruption takes place very easily. This is due to the fact that the capacitor retains the instantaneous voltage of the source at the instant of current zero, and for several hundred microseconds thereafter, the voltage across the breaker is low.

Hence, interruption seems to be accomplished at the first current zero of arc despite the fact that contact separation is very small. A $1/4$ cycle later, however, the system voltage reverses, and another $1/4$ cycle after that, approximately a double voltage, appears across the breaker. If the circuit breaker withstands this voltage without restriking, then the interruption is complete. At high currents, the arc produces an increased amount of hotter gas. Hence, the short arc gap cannot withstand a double voltage, and this voltage causes a restrike during the $1/2$ cycle immediately after the first interruption.

In the event that the restrike takes place just $1/2$ cycle after the first interruption, the capacitor has a charge whose polarity is opposite to that of the system voltage. Thus, the current flow is limited by the inductance of the circuit. Because of the capacitance, the voltage overshoots its mark by the initial difference. As a result, the voltage can reach $-3E$ at the exact moment that the transient current passes through zero.

Therefore, it is harder to switch off capacitors and open-circuited transmission lines than to open the same amount of lagging current. Doing so produces high voltages. However, modern circuit breakers have additional design features that help in the interruption of leading current.

Also, note that the arc energy transferred to the medium between the contacts causes the medium to reach temperatures as high as 30,000 K and high pressures very quickly. The resulting expansion of the medium is almost explosive. Hence, the combination of high mechanical arc forces can cause the ground to shake around a large circuit breaker when it operates. This fact has to be taken into account in the substation ground preparations.

7.3 HIGH-VOLTAGE CIRCUIT BREAKERS

According to IEEE Std. C.37.70-1992, “a circuit breaker is mechanical switching device capable of making, carrying, and breaking currents under normal circuit conditions and also making, carrying, and breaking for a specified time, and breaking currents under specified abnormal conditions such as a short circuit.”

In general, circuit breakers are categorized based on their interrupting medium used. The types of circuit breakers are magnetic, vacuum, air blast, oil, and SF₆ gas.

In the United States, the air magnetic circuit breakers are no longer being installed, and the old ones are being replaced by vacuum or SF₆ circuit breakers.

Vacuum types are used in switchgear applications up to 38 kV class and below. Vacuum circuit breakers use an interrupter that is a small cylinder enclosing the moving contacts under a hard vacuum. In a vacuum circuit breaker operation, when the contacts part, an arc is formed from contact separation. The resultant arc products are immediately forced to and deposited on a metallic shield surrounding the contacts. Since there is nothing to sustain the arc, it is instantly extinguished. These circuit breakers are extensively used for metal-clad switchgear, as said before, up to 38 kV class.

Also, air blast breakers, which were used at 345 kV or above applications, are no longer manufactured. They are replaced by SF₆ circuit breakers. Furthermore, oil circuit breakers were very popular in the electric power utility industry in the past. Today, they are also being increasingly replaced by the SF₆ circuit breakers in the old and new installations.

The oil circuit breakers were used to be designed as a single-tank or three-tank apparatus for 69 kV or below. Otherwise, they had three tank designs for 115 kV and above applications. The disadvantages of the oil circuit breakers were large space requirements, their significant foundation requirements due to their immense weights and impact loads taking place during their operations, and rightfully never-ending environmental concerns and regulations. Two types of designs exist for the oil circuit breakers, namely, *dead tank* (or bulk oil) design, which is the type used in the United States, or *live tank* (or minimum oil) design.

SF₆ gas circuit breakers use sulfur hexafluoride (SF₆) gas as an interrupting and insulating medium. SF₆ is proven to be an excellent arc-quenching and insulating medium for circuit breakers. It is a very stable compound, inert, nonflammable, nontoxic, and odorless. SF₆ gas circuit breakers are of either the dead tank design for outdoor installations or live tank (or modular design) for outdoor installations, and increasingly, dead tank breakers are integrated into SF₆-insulated substations for indoor or outdoor installations.

All SF₆ circuit breakers are designed as either the piston (*puffer*) or the dual-pressure (two-tank) system. In single puffer mechanisms, the interrupter is designed to compress the gas during the opening stroke and use the compressed gas as a transfer mechanism to cool the arc and also use the pressure to elongate the arc through a grid (i.e., *arc chutes*), causing the arc to be extinguished when the current passes through zero.

Puffer-type designs are simpler than two-tank designs since all of the SF₆ is at one pressure, 75 psi, which does not liquefy until the temperature drops to 30°C. Two-tank designs have a high-pressure tank in which the interrupter is located and a low-pressure reserve tank. When there is a fault, the

high-pressure tank is vented to the low-pressure tank, thus creating turbulence to assist the interruption of the arc. The low-pressure SF_6 is then compressed and returned to the high-pressure tank. The high-pressure tank must be warmed at a low temperature to keep the high-pressure SF_6 from liquefying.

In other designs, the arc heats the SF_6 gas and the resulting pressure is used for elongating and interrupting the arc. Some older dual-pressure SF_6 circuit breakers used a pump to provide the high-pressure SF_6 gas for arc interruption. In order to prevent the liquefaction of SF_6 gas at low temperatures, many circuit breakers are equipped with electric heating systems. This is due to the fact that the dielectric strength and interrupting performance of SF_6 gas are reduced significantly at lower pressures, normally as a result of lower ambient temperatures. Because of this, for cold temperature applications (ambient temperature as cold as -40°C), dead tank gas circuit breakers are commonly supplied with tank heaters to keep the gas in vapor form rather than allowing it to liquefy. A liquefied SF_6 significantly derates the breaker's capability. For any colder temperature applications (ambient temperatures between -40°C and -50°C), the SF_6 used is normally mixed with another gas, typically either nitrogen (N_2) or carbon tetrafluoride (CF_4), to prevent the liquefaction of the SF_6 gas.

The advantages of SF_6 gas circuit breakers are the following:

1. SF_6 gas circuit breakers have a high degree of reliability.
2. The compact design of SF_6 gas circuit breakers substantially reduces space requirements and building installation costs.
3. SF_6 gas circuit breakers can handle all known switching phenomena.
4. SF_6 gas circuit breakers perfectly can adapt to environmental requirements since they have a completely enclosed gas system that eliminates any exhaust during switching operations.
5. SF_6 gas circuit breakers require very little maintenance.
6. The lower- and medium-current ratings of SF_6 gas circuit breakers are very economically satisfied by the modular design.
7. Contact separation in SF_6 gas circuit breakers is minimal due to the dielectric strength provided by the high-pressure SF_6 .
8. SF_6 gas circuit breakers have a low arcing time due to the very high rate of recovery of the dielectric.
9. In SF_6 gas circuit breakers, arc reignition is minimized due to the chemical properties of SF_6 .
10. In general, the only disadvantage of the SF_6 circuit breakers is their relatively high costs, which have been somewhat coming down in recent years.

The SF_6 circuit breakers are available as live tank, dead tank, or grounded tank designs. The live tank means the interruption happens in an enclosure that is at line potential. Such SF_6 circuit breaker has an interrupter chamber that is mounted on insulators and is at line potential. An interrupter with such a modular design can be connected in series to operate at higher voltage levels.

The dead tank means that interruption takes place in a grounded enclosure and current transformers are located on both sides of the break (i.e., interrupter contacts). In such circuit breakers, the interruption maintenance takes place at the ground level and its seismic withstand is better than circuit breakers with the live tank designs. However, they require more insulating gas in order to provide the proper amount of insulation between the interrupter and the grounded tank enclosure. The modular dead tank circuit breaker has been specifically developed for the integration of SF_6 -insulated substation systems.

The grounded tank means that interruption happens in an enclosure that is partially at line potential and partially at ground potential. The evolution of the grounded tank circuit breaker design is the result of installing a live tank circuit breaker interrupter into a dead tank circuit breaker design.

SF_6 circuit breakers are available for all voltages ranging from 144 to 765 kV or even above, continuous currents up to 8,000 A, and symmetrical interrupting ratings up to 63 kA at 765 kV and 80 kA at 230 kV. Figure 7.2 shows a three-pole-operated 245 kV SF_6 dead tank circuit breaker lined with 80 kA interrupters.



FIGURE 7.2 Three-pole-operated 245kV SF₆ dead tank circuit breaker fitted with 80 kA interrupters. (Courtesy ABB Corporation, Munich, Germany.)



FIGURE 7.3 Single-pole-operated 138kV SF₆ live tank circuit breakers. (Courtesy ABB Corporation, Munich, Germany.)

However, the upper types have little lower interrupting capacities (about 50 kA) than dead tank types because their operating mechanisms are too massive when they are built for the same interrupting capacities (Figure 7.3).

Modern extra-high-voltage breakers have an average span of about two cycles from the time the relays energize the trip coil to complete interruption of the fault. Clearing times of this order are necessary in many instances to maintain stability when a fault takes place on the system. Faults that last for nine or more cycles generally cause instability.

Some circuit breakers have high-speed automatic reclosing capability. This is due to the fact that in a power system, most faults are temporary and self-clearing. Thus, if a circuit is de-energized for a short time, it is possible that whatever caused the fault has disintegrated and the associated ionized arc in the fault has dissipated.

If such reclosing circuit breakers are used in extra-high-voltage systems, it is a standard practice to reduce them only once in about 15–50 cycles, based on operating voltage after the circuit breaker interrupts the fault. If the fault still persists and the extra-high-voltage circuit breaker recloses into it, the circuit breaker re-interrupts the fault current and then *locks out*, requiring operator resetting. Because of the transient stability considerations, repeated reclosing operations are not a standard practice in extra-high-voltage systems. They are used in distribution systems up to 46 kV voltage levels.

7.4 CIRCUIT BREAKER SELECTION

A circuit breaker is selected based on the following factors:

1. The voltage class being considered (nominal rms voltage [class] level)
2. The continuous load current that the circuit breaker must carry under normal or emergency conditions
3. The short-circuit current that the breaker must interrupt
4. The speed of short-circuit interruption

The continuous load current can be found from substation loading data or from system load-flow studies. In general, the maximum load of a circuit breaker is limited to nameplate rating. However, it is possible to overload a circuit breaker under certain conditions. Basically, short-circuit data normally determine the circuit breaker selection, given an operating voltage. It is based on nominal three-phase MVA duty or on the basis of rated short-circuit current.

Each circuit breaker at the substation gets the extra short-circuit duty as additional circuits are added to a substation. Because of this, it is often required to base the selection of the circuit breakers on future instead of present requirements. As a result of this procedure, the required symmetrical short-circuit ratings of the modern-day circuit breakers have increased to as high as 80 kA.

In general, the faster the circuit breaker interrupts a fault, the better it is for the system. Fast interruptions reduce the possibility of extensive damage. Also, the primary reason for having faster circuit breakers on transmission systems is improved transient stability. Because of this, some applications dictate independent pole operation. Independent pole operation provides that even during a breaker malfunction, a three-phase fault will be restricted to a single-pole fault until backup clearing takes place. This is due to the fact that in a breaker without independent pole operation, all three poles operate as one, and the malfunction of any pole prevents all poles from clearing the fault. Hence, a three-phase fault remains as a three-phase fault until backup clearing takes place. This may further cause the stability margin to be reduced. Finally, the selection of circuit breakers is also based on economics, the type of breakers available in the voltage class being considered, and the advantages and disadvantages of competing interruption methods.

The circuit breakers have an operating range that is designated as K factor and is given in IEEE Std. C37.06. For example, for a 72.5 kV circuit breaker, the voltage range is 1.21, meaning that the breaker is capable of its full interrupting rating down to a voltage of 60 kV. Interrupting time is defined usually in cycles, and it is usually two cycles for modern circuit breakers used in

transmission systems. Interrupting time is defined as the maximum possible delay between energizing the trip circuit at rated control voltage and the interruption of the circuit by the main contacts of all three poles. The modern circuit breakers usually operate in two cycles of 60Hz. With fast-acting circuit breakers, the actual current to be interrupted is increased by the DC component of the fault current, and the initial symmetrical rms current value is increased by a specific factor depending on the speed of the circuit breaker. For example, if the circuit breaker opening time is 8, 2, or 2 cycles, then the corresponding multiplying factor is 1.0, 1.2, or 1.4, respectively. The interrupting capacity (i.e., *rating*) of a circuit breaker is found from

$$S_{\text{interrupting}} = \sqrt{3} (V_{\text{prefault}}) (I''_{\text{rms}}) \zeta \times 7^{-6} \text{ MVA} \quad (7.1)$$

where

V_{prefault} is the prefault line voltage at the point of fault in V

I''_{rms} is the initial symmetrical rms current (also called *subtransient current*) in A

ζ is the multiplying factor according to the circuit breaker speed

However, it is important to note that only the AC component of the fault current is included in the earlier equation. This current is also called the *subtransient current*. Also, note that the *fault MVA* is often referred to as the *fault level*.

The asymmetrical current wave decays gradually to a symmetrical current. The rate of such decay of the DC component is determined by the X/R or L/R of the system supplying the current. The time constant for DC component decay can be determined from

$$T_{\text{dc}} = \text{Circuit} \left(\frac{L}{R} \right) \text{ s}$$

Or

$$T_{\text{dc}} = \frac{\text{Circuit} (L/R)}{2\pi} \text{ cycles} \quad (7.2)$$

The maximum possible value of the DC current component is

$$I_{f(\text{dc}),\text{max}} = \sqrt{2} I''_f \quad (7.3)$$

The total maximum instantaneous current is

$$I''_{\text{max}} = 2I_{f(\text{dc}),\text{max}} \quad (7.4)$$

Or

$$I''_{\text{max}} = 2\sqrt{2} I''_f \quad (7.5)$$

The momentary duty (or rating) of a circuit breaker also includes this DC component of the fault current. It can be expressed as

$$S_{\text{momentary}} = \sqrt{3} (V_{\text{prefault}}) (I''_{\text{rms}}) 1.6 \times 7^{-6} \text{ MVA} \quad (7.6)$$

Or

$$S_{\text{momentary}} = \sqrt{3} (V_{\text{prefault}}) (I_{\text{momentary}}) \times 7^{-6} \text{ MVA} \quad (7.7)$$

The rms momentary current is the total rms current that includes both the AC and DC components and can be found from

$$I_{\text{momentary}} = 1.6 I_{f, \text{rms}} \quad (7.8)$$

and it is used for circuit breakers of 115 kV and above. The circuit breaker must be able to withstand this rms current during the first half cycle after the fault occurs. If the I_{max} is measured in peak amperes, then the peak momentary current is expressed as

$$I_{\text{momentary}} = 2.7 I_{f, \text{rms}} \quad (7.9)$$

A simplified procedure for determining the symmetrical fault current is known as the *E/X method* and is described in Section 5.3.1 of ANSI C37.07. This method [1,2] gives results approximating those obtained by more rigorous methods. In using this method, it is necessary first to make an *E/X* calculation. The method then corrects this calculation to take into account both AC and DC decay components of the fault current, depending on circuit parameters.

Example 7.1

Consider the power system shown in Figure 7.4 and assume that the generator is unloaded and running at the rated voltage with the circuit breaker open at bus 3. The reactance values of the generator are $X_1 = X_2 = X_d'' = 0.14$ pu and $X_0 = 0.08$ pu based on its ratings. The transformer impedances are $Z_1 = Z_2 = Z_0 = j0.10$ pu based on its ratings. The transmission line TL23 has the symmetrical component impedances of $Z_1 = Z_2 = j0.03$ pu and $Z_0 = j0.09$ pu. Select 25 MVA as the MVA base and 13.8 and 138 kV as the low-voltage and high-voltage bases. If the fault point is located on bus 1, find the subtransient fault current for a three-phase fault in per units and amperes.

Solution

The subtransient fault current for a three-phase fault located at bus 1 is

$$I_f'' = \frac{E_g}{X''} = \frac{1.0 \angle 0^\circ}{j0.14} = -j7.143 \text{ pu}$$

The current base for the LV side is

$$I_{B(LV)} = \frac{S_B}{\sqrt{3} V_{B(LV)}} = \frac{25,000 \text{ kVA}}{\sqrt{3} (13.8 \text{ kV})} = 1,045.92 \text{ A}$$

Hence, the magnitude of the fault current is

$$|I_f''| = (7.143 \text{ pu})(1,045.92 \text{ A}) \approx 7,471 \text{ A}$$

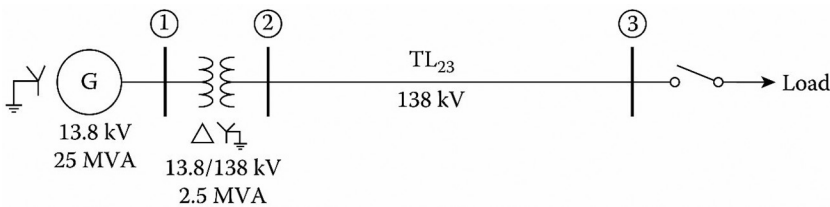


FIGURE 7.4 Transmission system for Example 7.1.

Example 7.2

Use the results of Example 7.1 and determine the following:

- Maximum possible value of DC current component
- Total maximum instantaneous current
- Momentary current
- Interrupting rating of a two-cycle circuit breaker, if it is located at bus 1
- Momentary duty of a two-cycle breaker, if it is located at bus 1

Solution

- Considering the peak-to-peak amplitude shown in Figure 7.5, the maximum possible value of DC component of the fault current is

$$\begin{aligned} I_{f(\text{dc}),\text{max}} &= \sqrt{2I_f''} \\ &= \sqrt{2}(7.143 \text{ pu}) \cong 7.1 \text{ pu} \end{aligned}$$

- The total maximum instantaneous value of the fault current is

$$\begin{aligned} I_{\text{max}}'' &= 2I_{f(\text{dc}),\text{max}} \\ &= 2(\sqrt{2I_f''}) 20.2 \text{ pu} \end{aligned}$$

- The total rms momentary current is

$$\begin{aligned} I_{\text{momentary}} &= 1.6I_{f,\text{rms}} \\ &= 1.6(7.143 \text{ pu}) = 11.43 \text{ pu} \end{aligned}$$

- The interrupting rating of a two-cycle circuit breaker that is located at bus 1 is

$$\begin{aligned} S_{\text{interrupting}} &= \sqrt{3} (V_{\text{prefault}})(I_f'')\zeta \times 7^{-6} \text{ MVA} \\ &= \sqrt{3} (13,800 \text{ V})(7,471 \text{ A})(1.4) \times 7^{-6} \cong 250 \text{ MVA} \end{aligned}$$

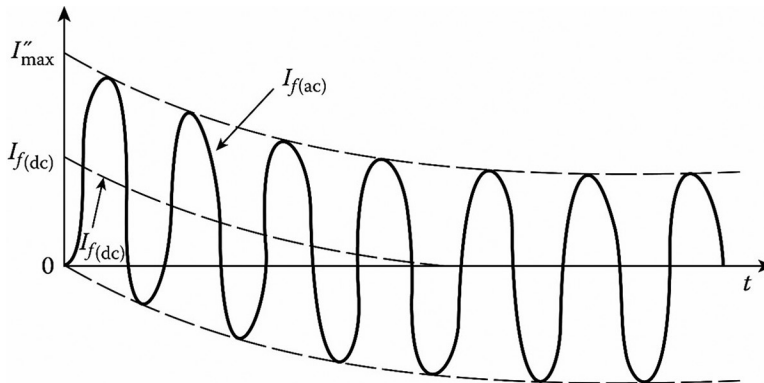


FIGURE 7.5 Asymmetrical fault current I_f with its symmetrical current $I_{f(\text{ac})}$ component and its DC current $I_{f(\text{dc})}$.

e. The momentary duty of the circuit breaker is

$$\begin{aligned} S_{\text{momentary}} &= \sqrt{3} (V_{\text{prefault}})(I_f'') 1.6 \times 10^{-6} \text{ MVA} \\ &= \sqrt{3} (13,800 \text{ V})(7,471 \text{ A})(1.6) \times 10^{-6} \cong 285.7 \text{ MVA} \end{aligned}$$

7.5 DISCONNECT SWITCHES

Based on its function, a disconnect switch is the simplest switch. It can be operated only when the circuit breaker is open, in no-load condition. It cannot open the normal load current. They are used primarily for isolation of equipment such as buses or other live apparatus. For example, they are used to disconnect or connect transformers, circuit breakers, other pieces of equipment, and short length of high-voltage conductors, only after current through them has been interrupted by opening a circuit breaker or load-break switch.

They allow disconnecting the faulted circuit or apparatus for repair while the rest of the circuit is put back into service and provide for personnel safety while the malfunction is being repaired. However, they can open very small charging currents to unload on apparatus. The low-current arc is broken by swinging the moving arm in a 90° arc to provide a long air gap. (For example, an air gap of approximately 11 ft is required at 230 kV. Because of this, they cannot open a fault.) At their specific ratings, they are designed to carry normal load currents at their specific ratings and remain closed for momentary current flow such as fault currents. They are classified as station, transmission, and distribution disconnecting switches.

Disconnecting switches rated up through 3,000 A are available. They can be of manual or automatic switching types. In station locations, manual switching is preferred. They are classified based on their voltage, continuous current rating, and function. They can be in single phase-single pole and three phase-three pole.

Transmission disconnect switches are generally used as load management tools. Increasing needs for transmission lines and decreasing availability of right-of-way (ROW) make automatic switching of transmission load highly desirable. These load management activities are usually done during *dead time* by switching the proper disconnects automatically through sending loss of voltage. Such systems built up to 161 kV, 1,200 A.

7.6 LOAD-BREAK SWITCHES

A load-break (disconnect) switch can interrupt normal load currents, but not large fault currents. They provide the desired capability of switching without circuit breakers. A wall switch is the most common load-break switch. Generally, these interrupters are not continuous in duty in terms of carrying load. They have limited interrupting capability and are primarily used for line, transformers, capacitor, and reactor switching.

Load-break switches for medium and high voltages use interrupters built into the switch to break the load current before the switch disconnecting arms swing open. Some newer high-voltage load-break switches that are equipped with SF_6 interrupters can break significant fault current and obey protective relay trip signals. Most load-break switches employ motors to open and close the switch blades, but the interrupters are operated by strong spring pressure.

7.7 SWITCHGEAR

Switchgear is a general term covering switching and interrupting devices, also assemblies of those devices with control, metering, protective, and regulatory equipment with the associated interconnections and supporting structures. Switchgears are used in industrial, commercial, and utility installations. They are used 34.5 kV and ratings of the heavy-duty range up to some 6,000 A continuous current.

They can be either metal-clad switchgear, metal-enclosed switchgear, or isolated-phase metal-enclosed switchgear. In the metal-clad switchgear, there are usually factory-assembled electrical equipment that are required to control an individual circuit, including bus, circuit breaker, disconnecting devices, current and voltage transformers, controls, instruments, and relays. They are used for low- and medium-capacity circuits, for indoor and outdoor installations at 345 kV and lower voltages.

In the metal-enclosed switchgear, the aforementioned individual components are in separate metal housings and the circuit breakers are of the stationary type.

In the isolated-phase metal-enclosed switchgear, each phase is enclosed in a separate metal housing. It is the most practical, the safest, and the most economical design in terms of preventing phase-to-phase faults. Switchgear can be used to perform the following two functions:

1. *Under normal conditions*: It is used to carry out a number of routine switching operations.
2. *Under abnormal conditions*: It is used to automatically disconnect the part of the system in trouble to prevent excessive damage and to restrict the trouble to the smallest possible segment of the system.

The routine switching operations include the following:

1. Disconnecting and isolating any piece of equipment for replacement or maintenance
2. Disconnecting a generator from the system when it is no longer required to serve the loads
3. Isolating regulators using switchgears
4. Bypassing circuit breakers using switchgears
5. Reversing of various operations using switchgears

In the most inclusive definition, *directly connected switchgear* definition covers the following devices as well, including circuit breakers, disconnecting switches or disconnecting devices, fuses, instrument transformers, buses, and connections between all these components and supporting structures, insulators, or housings.

Other switchgear devices may be located at some distance from the circuit with which they are identified. They include the indicators (e.g., annunciators, signal lamps, or instruments, control switches, meters, protective and control relays, generator voltage relays, and the panels on which they are mounted).

7.8 DESIGN CRITERIA FOR TRANSMISSION LINE PROTECTION

The design criteria for transmission line protection are as follows:

1. *Reliability*: It is a measure of the degree that the protective system will function properly in terms of both dependability (i.e., *performing correctly when required*) and security (i.e., *avoiding unnecessary operation*).
2. *Selectivity (or discrimination)*: The quality whereby a protective system distinguishes between those conditions for which it is intended to operate and those for which it must not operate. In other words, the selectivity of a protective system is its ability to recognize a fault and trip a minimum number of circuit breakers to clear the fault. A well-designed protective system should provide maximum continuity of service with minimum system disconnection.
3. *Speed*: It is the ability of the protective system to disconnect a faulty system element as quickly as possible with minimum fault time and equipment damage. Therefore, a protective relay must operate at the required speed. It should neither be too slow, which may result in damage to the equipment, nor should it be too fast, which may result in undesired operation during transient faults. The speed of operation also has a direct effect on the

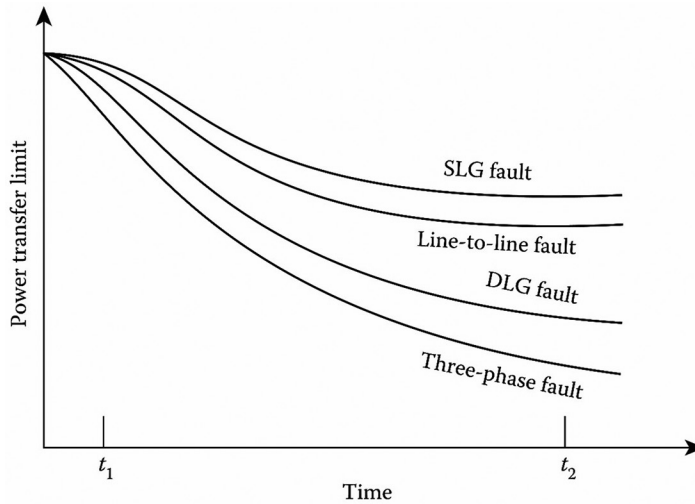


FIGURE 7.6 Typical values of power that can be transmitted as a function of fault clearance time.

general stability of the power system. The shorter the time for which a fault is allowed to persist on the system; the more load can be transferred between given points on the power system without loss of synchronism. Figure 7.6 shows the curves that represent the power that can be transferred as a function of fault-clearing time for various types of faults. Obviously, a fast fault-clearing time permits a higher power transfer than a longer clearing time t_2 . Currently, the fault-clearing times of bulk power systems are in the region (about three cycles on a 60 Hz base), and thus, power transfers are almost at a maximum. Also, it can be observed that the most severe fault is the three-phase fault, and the least severe fault is the line-to-ground fault in terms of transmission of power.

4. *Simplicity*: It is the sign of a good design in terms of minimum equipment and circuitry. However, the simplest protective system may not always be the most economical one even though it may be the most reliable owing to fewer elements that can malfunction.
5. *Economics*: It dictates to achieve the maximum protection possible at a minimum cost. It is possible to design a very reliable protective system but at a very high cost. Therefore, high reliability should not be pursued as an end in itself, regardless of cost, but should rather be balanced against economy, taking all factors into account.

Protection is not needed when the system is operating normally. It is only needed when the system is not operating normally. Therefore, in that sense, protection is a form of insurance against any failures of the system. Its premium is its capital and maintenance costs, and its return is the possible prevention of loss of stability and the minimization of any possible damages. The cost of protection is generally extremely small compared with the cost of equipment protected. The art of protective relaying is constantly changing and advancing. However, the basic principles of relay operation and application remain the same. Thus, the purpose of this chapter is to review these fundamental principles and then show their applications to the protection of particular system elements. However, the emphasis will be on the transmission system.

The most commonly occurring faults on transmission lines are short circuits. However, lightning is still the most common cause of faults on OH transmission lines. Single-phase faults contribute 75%–90% of all faults. In contrast, multiphase-to-ground faults are 5%–15% of all faults, while multiphase faults with no ground connection are the rarest 5%–7%. Other rare causes of faults are temporary contact with foreign objects, swinging of wires caused by strong winds, and insulator breakings.

7.9 ZONES OF PROTECTION

A power system is divided into various primary protective zones, as shown in Figure 7.7. The dashed lines indicate a separate zone of protection around each system element (e.g., generator, transformer, bus, transmission line), for which a given relay or protective system is responsible.

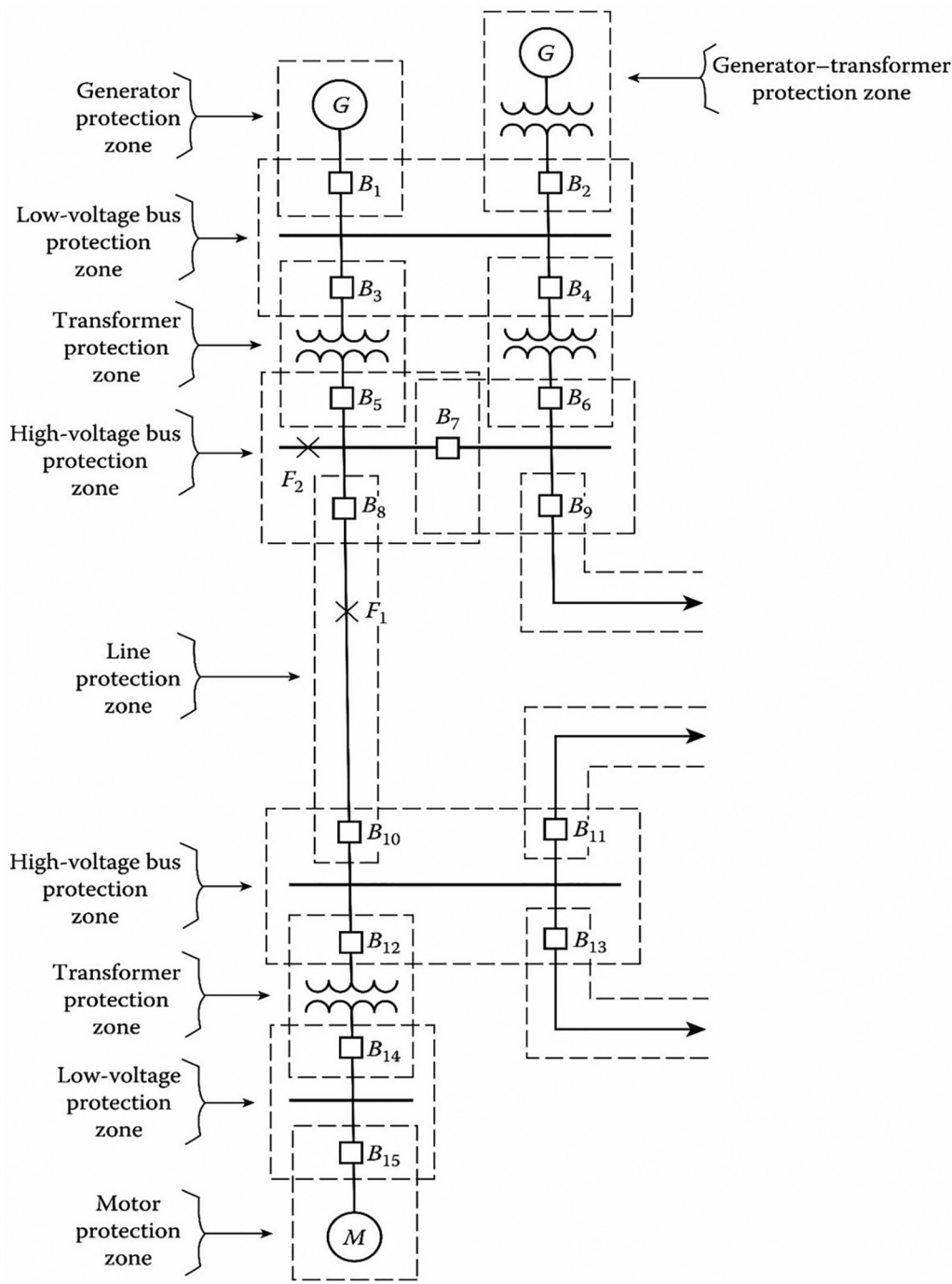


FIGURE 7.7 Primary zones of protection in a power system.

The zone includes both the system element and the circuit breakers that connect the element to the system. As shown in the figure, in order to be adequately protected with minimum interruptions, a power system can be divided into protective zones for (1) generators (or generator-transformer), (2) transformers, (3) buses, (4) transmission lines, and (5) loads, motors.

Each protective zone has its own protective relays for detecting the existence of a fault in that zone and its own circuit breakers for disconnecting that zone from the rest of the system. In that sense, a *protective zone* can be defined as the portion of a power system protected by a given protective system or a part of that protective system.

The boundary of a zone of protection is dictated by the CTs that supply the input to the relays. In a given power system, a CT provides the ability to detect a fault within its zone; the circuit breaker provides the ability to isolate the fault by disconnecting all of the power apparatus inside its protective zone. In the event that the CT is not an integral part of the circuit breaker, the CTs still define the zone of protection, but a communication channel has to be employed to implement the tripping function.

7.10 PRIMARY AND BACKUP PROTECTION

As illustrated in Figure 7.7, the primary zones are arranged in a manner so that they overlap around circuit breakers. The purpose of the overlap is to eliminate the possibility of blind spots or unprotected areas. A fault in an overlap area will cause tripping of all circuit breakers in two primary zones.

Primary protection: Operation of the protection must be fast, reliable, and sensitive. A fast speed of response and high reliability are crucial to limit the damage that could be caused by a fault. Furthermore, the protection must be selective so that only the faulty element is removed. Reliability is achieved by having a high-quality apparatus and by using two different protection schemes for element: the *primary protection* and the *backup protection*. The main protection system for a given zone of protection is called the *primary protection system*.¹ It operates the least amount of equipment from service.

Backup protection: Backup protection is provided for possible failure in the primary protection and for possible circuit breaker failures. The causes for such failure are (1) AC current or voltage supply failures to relays due to failures in circuit relays or voltage transformers or wiring, (2) failure of auxiliary devices, (3) loss of DC control supply, and (4) relay failure. On the other hand, those causes that may cause the circuit greater failure may include (1) open or short-circuit trip coil, (2) loss of DC supply, (3) failure of main contacts to interrupt, and (4) mechanical failure of tripping mechanism.

Backup relays are slower than the primary relays and may remove more of the system elements than is necessary to clear a fault. The main protection should operate based on different physical principles than its backup. Also, any backup scheme must provide both relay backup and breaker backup.

It is important that the backup protection should be arranged so that the cause of primary protection failure will not also be the cause of backup protection failure.

Furthermore, the backup protection must not operate until primary protection has a chance to operate. Because of this, there is a time delay associated with the backup protection failure.

Remote backup: If the main protection of a neighboring element is used as the backup protection of the given element, then it is called remote backup. In other words, the backup relays are physically located in a separate location and are completely independent of the relays and circuit breakers that are backing up. Because of this, there are no common failures that can affect both sets of relays. For extra-high-voltage systems, it is not unusual to have two station batteries and separate circuitry so that the primary protection is electrically isolated from the backup protection.

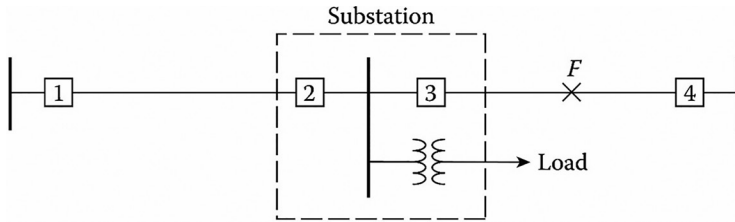


FIGURE 7.8 Illustration of remote backup protection.

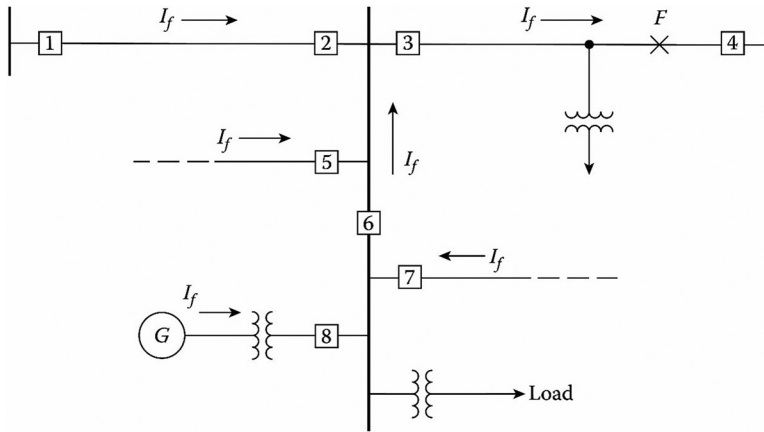


FIGURE 7.9 Illustration of remote backup protection with intermediate feed.

Consider the protection scheme that is illustrated in Figure 7.8. In a remote backup scheme, time delays at bus 1 provide backup protection for transmission line TL_{34} . When there is a fault on transmission line TL_{34} , if there is a protection failure or circuit breaker failure at bus 3, the remote relays located at bus 1 will trip their circuit breakers to isolate the fault. That means that the relays and circuit breaker at bus 1 provide relay and circuit breaker backup for breaker 3. By the same token, the relays and circuit breaker at bus 4 provide backup for breaker 2. Also, both 1 and 4 provide backup protection for the bus at the substation.

Now, consider the protection scheme shown in Figure 7.9. Note that the additional generation and transmission lines will feed the faults, on transmission lines TL_{12} and TL_{34} . Because of this, the remote backup relays located at 1 and 2 will have difficulty in seeing faults on adjacent transmission lines, especially the faults that are located near the remote buses. Hence, the infeed of fault current at the middle substation makes a fault seem farther away from the remote relays. In fact, the greater the infeed, the farther away the fault will appear. In such a case, a local type of backup is employed.

Local backup: If backup protection is placed in the same substation bay as the main protection, then it is called *local backup*. These relays are installed in the same substation and use some of the same elements as the primary protection. In other words, faults are cleared locally in the same substation where the failure has taken place. This type of backup provides both relay and circuit breaker failure backup, as illustrated in Figure 7.7.

Consider Figure 7.9 and assume that a local backup scheme is used at circuit breaker 3. In the event of a fault taking place on transmission line TL_{34} close to circuit breaker 3, the primary and backup distance relays at 3 will operate at high speed to clear the fault. In case circuit breaker 3 fails to clear the fault, the bus time can be set to operate to trip circuit breaker 2, 5, and 6 in about 0.15–0.20 s (Figure 7.10).

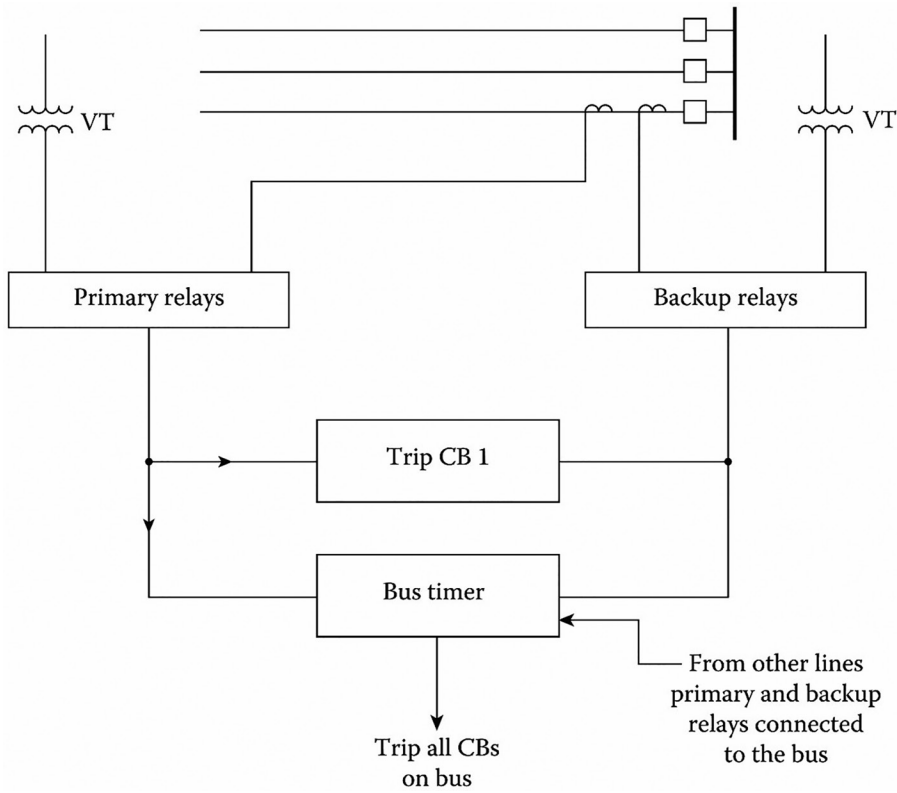


FIGURE 7.10 Local backup protection.

7.11 RECLOSING

The majority (80%–90%) of the faults on OH distribution lines are transient in nature. They are mainly caused by flashovers between phase conductors or between one or more of the phase conductors and earthed neutral and the ground caused by lightning or by wind. The wind may cause the conductors to move together to flashover or may cause a temporary tree contact that results in a fault. The remaining 7%–20% of faults are either semitransient or permanent.

Thus, the transient faults can be dealt with by de-energizing the line until the arc or arcs are extinguished, and then it can be energized again after a certain time period, which is called the *dead time*. The whole procedure is known as the *automatic line reclosing* or simply *autoreclosing*. It should be clear that such a reclosing procedure substantially improves the continuity of energy supply and the service. However, if the fault is permanent, the reenergized line will be opened again by its protection. The benefits of using high-speed reclosure are as follows:

1. It prevents and/or limits conductor damage.
2. It minimizes the effects of a line outage on critical loads.
3. It maintains the integrity of the system by returning the line back to the service.
4. It allows greater loading of the transmission system.
5. It improves the system stability.

Reclosing can be one single attempt (one shot) or several attempts at various time intervals (multiple shots). The first attempt of automatic reclosing can be either *instantaneous* or with *time delay*. There may be two or three such attempts, but usually, only a single-shot reclosure is used in high-voltage transmission networks. The high-speed reclosing permits only enough time (usually 15–40 cycles)

for the arc of a fault to dissipate. On the other hand, time-delayed reclosings have a delay time of 1 or more seconds. If the reclosure is not successful, the recloser relay moves to a lockout position so that no further automatic operation is possible.

The late Blackburn [3] suggested that in a three-phase circuit, the de-energized time for the fault arc to deionize and not restrike is

$$t = \frac{V_{kv}}{34.5} + 7.5 \text{ cycles} \quad (7.10)$$

This applies only for the case of having all three phases open. For single-pole trip-reclose operation, the required deionization times are longer since the energy from unopened phases supplies the arc.

In the United States, it is a common practice to trip all three phases for all faults and then reclose the three phases simultaneously. However, in Europe, it is not uncommon to trip only the faulted phase in the event of having a single line-to-ground fault. But in such a situation, the voltage and current in the healthy phases tend to maintain the fault arc even after the faulted phase is de-energized. This event is known as the *secondary arc*. It may require compensating reactors to remedy the situation [4].

In general, it is the common practice to reclose automatically transmission lines that are remote from the generating station after they have been tripped for a fault. Usually, a single high-speed reclosing will be attempted only after the simultaneous, high-speed tripping of all line breakers by the primary pilot-relaying system. In the event of a persisting fault, the line relays will trip the line out again, and usually, no more automatic reclosing will be attempted after that attempt. If all attempts to close the line automatically fail, then a system operator may try to close the line manually after a certain time interval. If even the manual reclosing attempt fails, it becomes evident that the line is experiencing a permanent fault. Thus, it is taken out of service until it is repaired.

There is a potential danger for closing instantaneous reclosing on lines at or near generating stations since such reclosing may cause damage to the long turbine shafts of the turbine-generator units. This is due to the fact that the voltages on the two sides of the circuit breaker are at different angles. Thus, such reclosing causes a sudden shock and movement of the rotor and to transient oscillations and stresses.

According to Blackburn [3], reclosing on multiterminal lines is more complex. This is especially true, if more than five terminals have synchronous voltage sources. This may require reclosing one or two terminals instantaneously but reclosing others after a proper voltage or synchro-clock. In the case that the transmission line has load taps, when the same line is used for both transmission and distribution purposes, reclosing of the source terminals can be used to service the tap loads.

Transmission lines that end in a transfer bank without having a circuit breaker between them, or transmission lines having shunt reactors, should not be reclosed automatically. In such situations, a delay in reclosing is needed to be sure that there is no problem in either the transformer or the reactor.

Based on the past experiences, one can conclude that successful high-speed reclosure can be achieved 80%–90% of the time. However, the high-speed reclosing cannot be used in all cases. For example, a reclosure into a persistent fault may result in system instability. Furthermore, high-speed reclosure after tripping for phase faults is not advised on transmission lines leaving a generating station, since it has the possibility of generator shaft torque damage and should be closely examined before using it.

Rustebakke [5] suggested that such effects can be minimized by the following:

1. Delaying reclosure for a minimum of 7 s.
2. Employing selective reclosing, that is, reclosing only on single phase-to-ground faults.
3. Employing sequential reclosing. (In other words, reclose first at the remote end of the line and block reclosing at the generating station if the fault still exists.) Use this approach if the line is long and/or if there is no generating station at the remote end.

The lines used to send power between stations dictate high-speed reclosing on both terminals to restore service. Such high-speed reclosing is limited to the lines (that are made of sufficient parallel lines in the network) that are protected by pilot protection since it requires that the source voltages are in synchronism (i.e., in phase) with each other during the open-line period.

According to Blackburn [3], it is better to use the following methodologies when pilot protection is not used:

1. Use single-pole pilot trip and reclose as the method.
2. First use pilot relay protection for simultaneous line tripping. Reclose one end instantaneously and then close the other end after checking that the line and bus voltages are in synch or within the preset angle difference. Synchronizing relays can be used for this purpose.
3. If the pilot protection does not exist, then reclose with the following:
 - a. Live line, dead bus
 - b. Dead line, live bus, and/or dead bus
 - c. Live line, live bus with synchronism checking

Note that since faults are often temporary in nature, the stability is often never reached. Hence, the instantaneous reclosing of both ends of lines simultaneously is practiced for line of 115 kV and above. Usually, this is attempted only one time. Further attempts require voltage check and/or the use of synchronism check apparatus. Such reclosing operation is used only for OH lines but not for transmission lines built in cables since they are not reclosed. The lines that have both the OH and cable sections require separate protection for the OH and cable protection for the OH and cable segments. In such applications, the reclosing is allowed only for the OH line faults.

7.12 TYPICAL RELAYS USED ON TRANSMISSION LINES

As defined previously, a protective relay is a device designed to initiate isolation of a part of the electric system, or to operate an alarm signal, in the case of a fault or other abnormal condition. Basically, a protective relay consists of an operating element and a set of contacts. The operating element receives input from the instrument transformers in the form of currents, voltages, or a combination of currents and voltages (e.g., impedance and power). The relay may respond to (1) a change in the magnitude of the input quantity, (2) the phase angle between two quantities, (3) the sum (or difference) between two quantities, or (4) the ratio of the quantities. In any case, the relay performs a measuring (or comparison) operation based on the input and translates the result into a motion of contacts. Hence, for example, the output state of an electromechanical relay is either trip (with its contacts closed) or block or block to trip (with its contacts open). When they close, the contacts either actuate a warning signal or complete the trip circuit of a circuit breaker, which in turn isolates the faulty part by interrupting the flow of current into that part.

In general, protective relays can be classified by their constructions, functions, or applications. By construction, they can be either electromechanical or solid state (or *static*) types. In general, the electromechanical relays are robust, inexpensive, and relatively immune to the harsh environment of a substation. However, they require regular maintenance by skilled personnel. Furthermore, their design is somewhat limited in terms of available characteristics, tap settings, and burden capability.

On the other hand, solid-state relays have been primarily used in areas where the application of conventional methods is difficult or impossible (e.g., high-voltage transmission line protection by phase comparison). The relays using transistors for phase or amplitude comparison can be made smaller, cheaper, faster, and more reliable than electromechanical relays. They can be made shockproof and require very little maintenance. Furthermore, their great sensitivity allows smaller current transformers to be used and more sophisticated characteristics to be obtained. Contrary to the electromechanical relays, the solid-state relays provide switching action, without any physical motion of any contacts, by changing its state from nonconducting to conducting or vice versa. The electromechanical relays can be classified as magnetic attraction, magnetic induction, d'Arsonval, and thermal units. The most widely used types of magnetic attraction relays include plunger (solenoid), clapper, and polar.

The typical relays that are used for transmission line protection are (1) overcurrent relays, (2) distance relays, and (3) pilot relays.

7.12.1 OVERCURRENT RELAYS

The use of overcurrent relays is the simplest and cheapest type of line protection. Three types of overcurrent relays are used: inverse time-delay overcurrent (TDOC) relays, instantaneous overcurrent relays, and directional overcurrent relays.

In general, overcurrent relays are difficult to implement where coordination, selectivity, and speed are important. They usually require changes to their settings as the system configuration changes. Also, they cannot discriminate between load and fault currents. Hence, when they are implemented only for phase fault protection, they are only useful when the minimum fault current exceeds the full load current. However, they can effectively be used on sub-transmission systems and radial distribution systems. This is due to the fact that faults on these systems usually do not affect system stability and therefore high-speed protection is not needed.

7.12.1.1 Inverse TDOC Relays

The main use of TDOC relays is on a radial system where they are used for both phase and ground protection. Basic complements of such relays are two-phase and one ground relays. This can protect the line for all combinations of phase and ground faults using the minimum number of relays. According to Horowitz [4], adding a third phase relay can provide complete backup protection, having two relays for every type of fault, and is the preferred practice. These relays are usually applied on sub-transmission lines and industrial systems due to the low cost involved.

7.12.1.2 Instantaneous Overcurrent Relays

Since the closer the fault is to the source, the greater the fault current magnitude but the longer the tripping time, the TDOC relay cannot be used all by itself. As illustrated in Figure 7.11, the addition of an instantaneous overcurrent relay makes such a system of protection possible. However, there must be a considerable reduction in fault current as the fault moves from the relay toward the far end of the line. In this manner, the instantaneous relay can be made to see almost up to, but

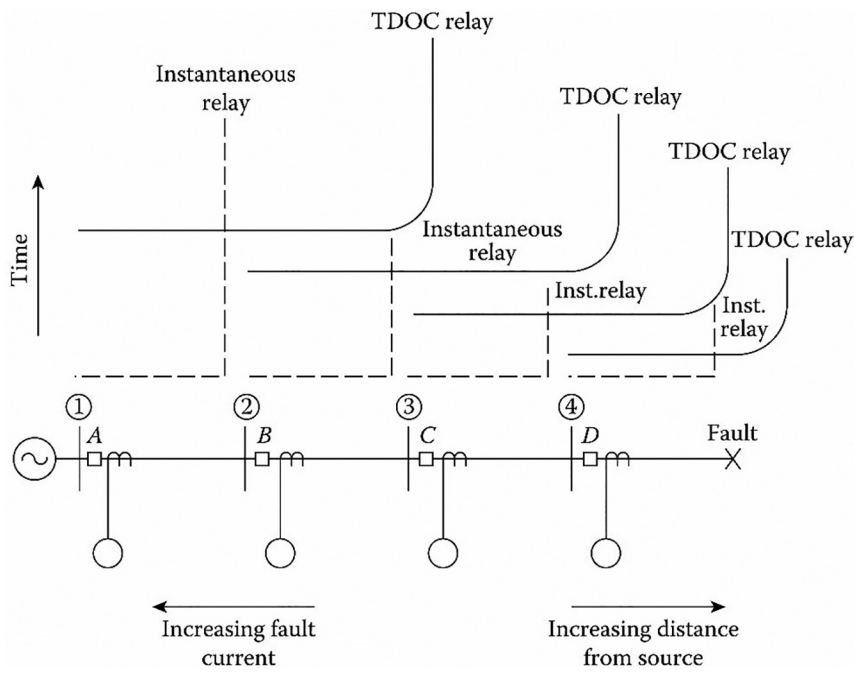


FIGURE 7.11 Application of instantaneous overcurrent relays.

not including, the next bus. The relay will not operate for faults beyond the end of the line but still provide high-speed protection for most of the line.

7.12.1.3 Directional Overcurrent Relays

When it is important to limit tripping for faults in only one direction in multiple-source circuits, the use of directional overcurrent relays becomes necessary. The overcurrent relaying is made directional to provide relay coordination between all the relays that can *see* a given fault. Otherwise, the coordination is often too difficult if not impossible.

The directional relays require two inputs that are the operating current and a *reference* (or *polarizing*) quantity that does not change with fault location. For phase relays, the polarizing quantity is the system voltage at the relay location. For ground directional reference, the zero-sequence voltage ($3V_{a0}$) is used. However, it is often that the current in the neutral of a wye-connected/delta power transformer is used as a directional reference instead.

7.12.2 DISTANCE RELAYS

The most common method of detecting faults on transmission lines is by impedance measurement. It is accomplished by relay units that respond to a ratio of voltage to current and, therefore, to impedance or a component of impedance. Since impedance is a measure of distance along a transmission line, between the relay location and the fault location, these relays are called *distance relays*. As the power systems become more complex and the fault currents vary with changes in generation and system configuration, directional overcurrent relays become difficult to implement and to set for all contingencies.

In comparison to directional overcurrent relays, the distance relay setting is constant for a wide variety of changes outside of the protected transmission line. The discrimination is obtained by limiting relay operation to a certain range of impedance. Hence, the operating limits of distance relays are usually given in terms of impedance or in terms of impedance components, resistance, and reactance. There are three basic distance relay characteristics, namely, impedance relay, admittance relay, and reactance relay. Each relay is distinguished by its application and its operational characteristics.

7.12.2.1 Impedance Relay

As shown in Figure 7.12, the impedance relay has a circular triggering characteristic centered at the origin of the R - X diagram. It is nondirectional, as shown in Figure 7.12a, and is used mainly as a fault detector. However, it is possible to have an impedance relay with a directional element, as shown in Figure 7.12b. Hence, a directional relay is commonly used to monitor the impedance relay.

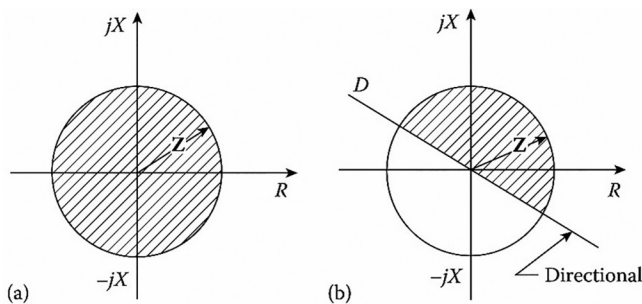


FIGURE 7.12 Impedance relays: (a) without directional element and (b) with directional element.

7.12.2.2 Admittance Relay

It is the most commonly used distance relay. Its characteristic passes through the origin of the R - X diagram and is therefore directional. It is also used as the tripping relay in pilot schemes and as the backup relay in step distance schemes. Its characteristic is circular for the electromechanical relay, as shown in Figure 7.13. However, for the solid-state relays, it can be shaped according to the transmission line impedance, as shown in Figure 7.14.

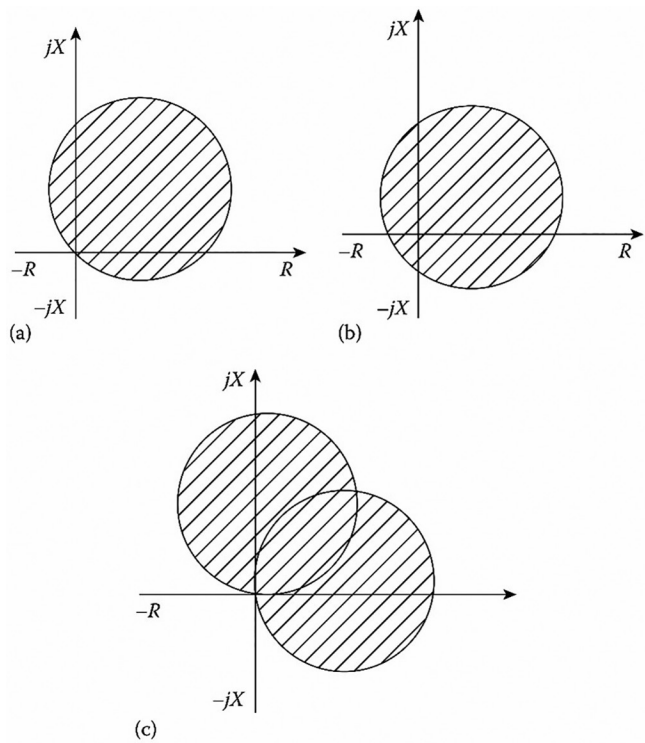


FIGURE 7.13 Electromechanical admittance (i.e., mho) relays: (a) regular admittance relay, (b) offset admittance relay, and (c) expanded admittance relay.

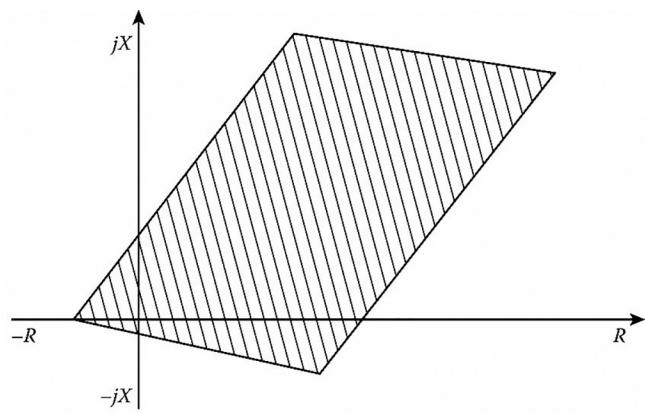


FIGURE 7.14 Solid-state admittance relay.

7.12.2.3 Reactance Relay

The reactance relay has a straight-line characteristic that responds only to the reactance of the protected area, as shown in Figure 7.15a. It is nondirectional and is used to supplement the admittance (mho) relay as a tripping relay to make the overall protection independent of resistance. It is especially used for short lines where the arc resistance of the fault is the same order of magnitude as the line length [4],

Consider a three-zone step distance-relaying scheme shown in Figure 7.16. Assume that it provides instantaneous protection over 80%–90% of the protected line section (zone 1) and that time-delayed protection over the remainder of the line (zone 2) plus backup protection over the adjacent line section. Note that zone 3 also provides backup protection for sections of adjacent lines.

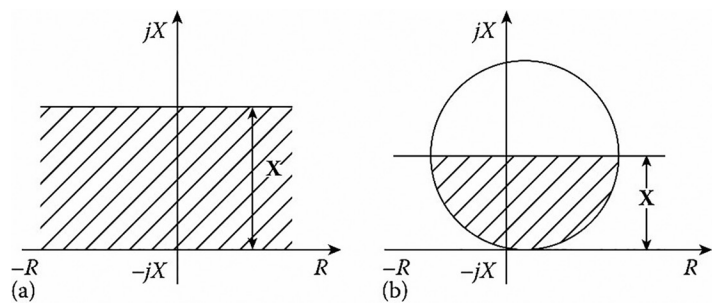


FIGURE 7.15 Reactance relays: (a) without mho characteristic and (b) with mho characteristic.

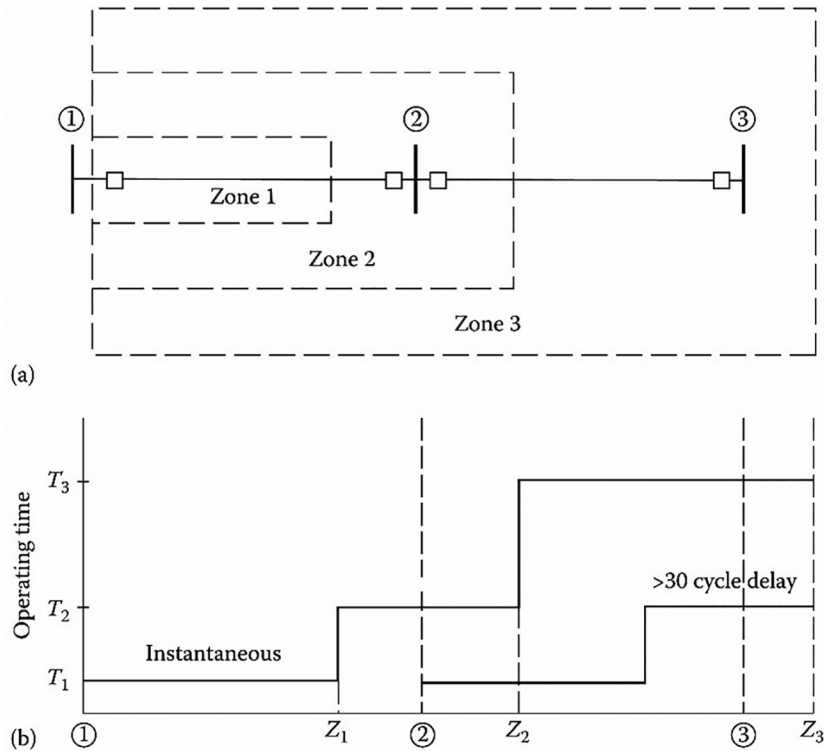


FIGURE 7.16 Three-zone step distance relaying: (a) to protect 70% of a line and (b) to provide backup of the neighboring line.

Example 7.3

Consider the one-line diagram of a 345 kV transmission line shown in Figure 7.17a. The equivalent systems behind buses A and B are represented by the equivalent system impedances in series with constant bus voltages, respectively. Assume that the power flow direction is from bus A to bus B . Consider the directional distance relay located at A whose forward direction is in the direction from bus A to bus B . Assume that zone-type distance relays have two units, namely, three-phase and phase to phase. Hence, for three-phase faults, the mho characteristic is directional and only operates for faults in the forward direction on line AB . For line-to-line faults (i.e., $a-b$, $b-c$, and $c-a$), the phase-to-phase unit operates. Also assume that all double line-to-ground faults are protected by an overlap of the two distance units. All other line-to-ground faults are protected by ground distance relays and are not included in this example. Consider only zones 1 and 2 protection for the distance relay location at bus A and do the following:

- Draw the locus of the line impedance Z_L on the R - X diagram.
- Draw the two-zone mho characteristics on the R - X diagram for the three-phase units.
- Draw the two-zone characteristics on the R - X diagram for the phase-to-phase units.
- Indicate the approximate vicinity for the possible location of the normal operation point for power flow from bus A to bus B .

Solution

The solution is shown in Figure 7.17b.

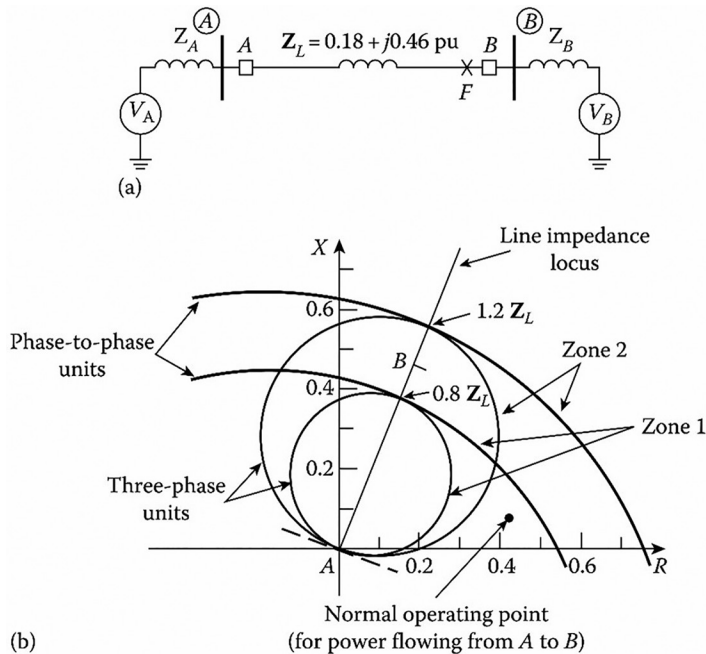


FIGURE 7.17 Typical application of distance relays for protection of transmission line: (a) system one-line diagram and (b) distance relays of A looking toward B .

Example 7.4

Assume that Figure 7.17a is a one-line diagram of a 138 kV sub-transmission line with a line impedance of $0.2 + j0.7$ pu. Consider the directional distance (mho) relay located at A whose forward direction is in the direction from bus A to bus B . There is a line-to-line fault at the fault point F , which is located at 0.7 pu distance away from bus A . The magnitude of the fault current is 1.2 pu. Assume that the line spacing of 7.3 ft is equal to the arc length. The bus quantities for power, voltage, current, and impedance are given as 70 MVA, 138 kV, 418.4 A, and 190.4 Ω , respectively. Consider only zones 1 and 2 protection and determine the following:

- Value of arc resistance at fault point in ohms and per units
- Value of line impedance including the arc resistance
- Line impedance angle without and with arc resistance
- Graphically, whether or not relay will clear fault instantaneously

Solution

- Since the current in the arc is 1.2 pu or $I = 1.2 \times 418.4 \text{ A} = 502.08 \text{ A}$, the arc resistance can be found from the following equation as

$$R_{\text{arc}} = \frac{8,750}{I^{1.4}} = \frac{8,750 \times 7.3}{502.08^{1.4}} = 14.92 \Omega \text{ or } 0.0784 \text{ pu}$$

- The impedance seen by the relay is

$$\mathbf{Z}_L + R_{\text{arc}} = (0.2 + j0.7)0.7 + 0.0784 + 0.2184 + j0.49 \text{ pu}$$

- The line impedance angle without the arc resistance is

$$\tan^{-1} = \left(\frac{0.49}{0.14} \right) = 74.05^\circ$$

and with the arc resistance is

$$\tan^{-1} = \left(\frac{0.49}{0.2184} \right) = 65.98^\circ$$

- Figure 7.18 shows that even after the addition of the arc resistance, the fault point F moved to point F' , which is still within zone 1. Thus, the fault will be cleared instantaneously.

Example 7.5

Consider a transmission line TL_{12} protected by directional relays R_{12} and R_{21} as shown in Figure 7.19a. Determine the following:

- Zones of protection for relay R_{12}
- Coordination of distance relays R_{12} and R_{21} in terms of operating time versus impedance

Solution

- The zone of protection for relay R_{12} is shown in Figure 7.19b.
- The coordination of the distance relays R_{12} and R_{21} in terms of operating time versus impedance is illustrated in Figure 7.19c. Note that zone 3 provides backup protection for the neighboring protection system.

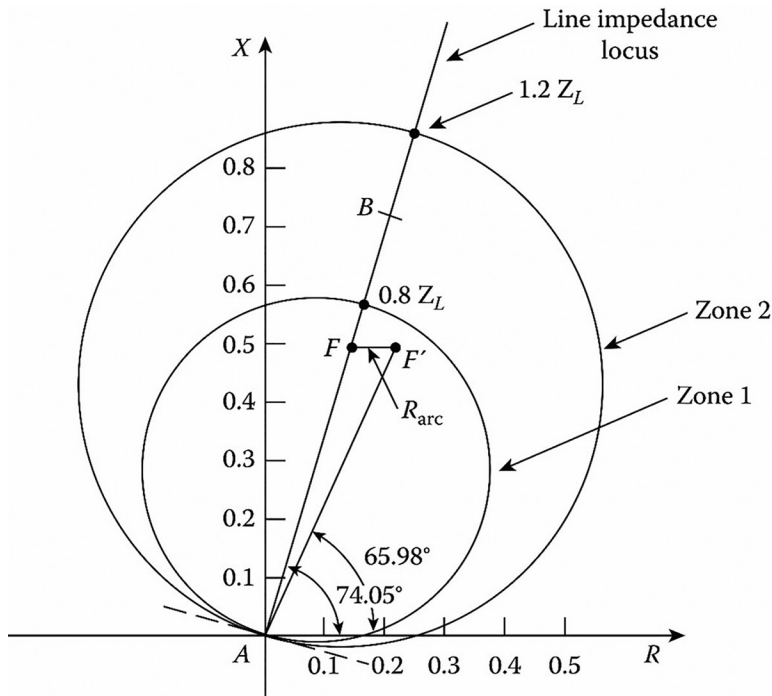


FIGURE 7.18 Graphical determination of fault clearance.

Example 7.6

Consider the 230 kV transmission system shown in Figure 7.19a. Assume that the positive sequence impedances of the lines TL_{12} and TL_{23} are $2 + j20 \, \Omega$ and $2.5 + j25 \, \Omega$, respectively. If the maximum peak load supplied by the line TL_{12} is 70 MVA with a lagging power factor of 0.9, design in a three-zone distance-relaying system for the R_{12} impedance relay by determining the following:

- Maximum load current
- Current transformer ratio
- Voltage transformer ratio
- Impedance measured by the relay
- Load impedance based on secondary ohms
- Zone 1 setting of relay R_{12}
- Zone 2 setting of relay R_{12}
- Zone 3 setting of relay R_{12}

Solution

- The maximum load current is

$$I_{\max} = \frac{70 \times 10^6}{\sqrt{3} (230 \times 10^3)} = 251.02 \text{ A}$$

- Thus, the CT ratio is 250:5, which gives about 5 A in the secondary winding under the maximum loading.

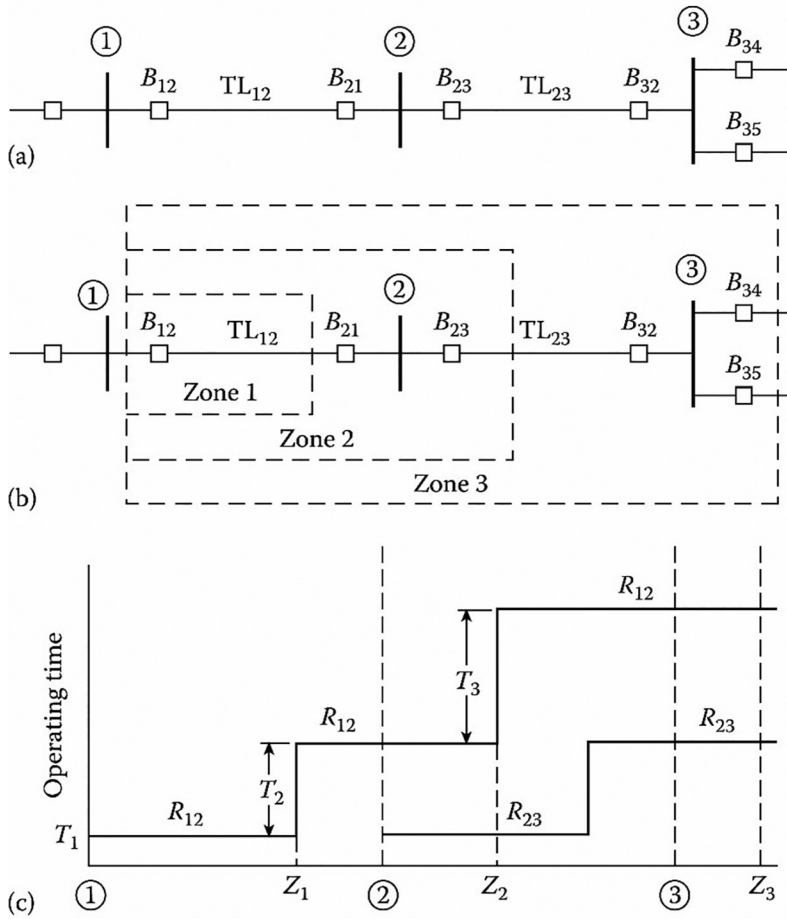


FIGURE 7.19 Transmission system for Example 7.5: (a) one line diagram of the system, (b) zones of protection, and (c) backup protection.

- c. Since the system voltage to neutral is $(230/\sqrt{3})=132.79$ kV and selecting a secondary voltage of 69 V line to neutral, the voltage transformer ratio is calculated as

$$\frac{132.79 \times 7^3}{69} = \frac{1924.5}{1}$$

- d. The impedance measured by the relay is

$$\frac{V_\phi / 1924.5}{I_\phi / 50} = 0.026 Z_{\text{line}}$$

Hence, the impedances of lines TL₁₂ and TL₂₃ as seen by the relay are approximately $0.052 + j0.5196$ and $0.065 + j0.6495 \Omega$, respectively.

- e. The load impedance based on secondary ohms is

$$Z_{\text{load}} = \frac{69}{251.02(5/250)}(0.9 + j0.4359) = 12.37 + j5.99 \Omega \text{ (secondary)}$$

f. The zone 1 setting of relay R_{12} is

$$\mathbf{Z}_r = 0.80 (0.052 + j0.5196) = 0.0416 + j0.4157 \Omega \text{ (secondary)}$$

g. The zone 2 setting of relay R_{12} is

$$\mathbf{Z}_r = 1.20 (0.052 + j0.5196) = 0.0624 + j0.6235 \Omega \text{ (secondary)}$$

h. The zone 3 setting of relay R_{12} is

$$\begin{aligned} \mathbf{Z}_r &= 0.052 + j0.5196 + 1.20 (0.065 + j0.6495) \\ &= 0.130 + j1.299 \Omega \text{ (secondary)} \end{aligned}$$

Example 7.7

Assume that the R_{12} relay of Example 7.6 is a mho relay and that the relay characteristic angle may be either 30° or 45° . If the 30° characteristic angle is used, the relay ohmic settings can be determined by dividing the required zone reach impedance, in secondary ohms, by $\cos(\theta - 30^\circ)$, where θ is the line angle. Use the 30° characteristic angle and determine the following:

- Zone 1 setting of mho relay R_{12}
- Zone 2 setting of mho relay R_{12}
- Zone 3 setting of mho relay R_{12}

Solution

a. From Example 7.6, the required zone 1 setting was

$$\mathbf{Z}_r = 0.0416 + j0.4157 = 0.4178 \angle 84.3^\circ \Omega \text{ (secondary)}$$

Thus,

$$\text{Mho relay zone 1 setting} = \frac{0.4178}{\cos(84.3^\circ - 30^\circ)} = 0.7157 \Omega \text{ (secondary)}$$

b. The required zone 2 setting was

$$\mathbf{Z}_r = 0.0624 + j0.6235 = 0.6266 \angle 84.3^\circ \Omega \text{ (secondary)}$$

Hence,

$$\text{Mho relay zone 2 setting} = \frac{0.6266}{\cos(84.3^\circ - 30^\circ)} = 1.0734 \Omega \text{ (secondary)}$$

c. The required zone 3 setting was

$$\mathbf{Z}_r = 0.130 + j1.299 = 1.3055 \angle 84.3^\circ \Omega \text{ (secondary)}$$

Thus,

$$\text{Mho relay zone 3 setting} = \frac{1.3055}{\cos(84.3^\circ - 30^\circ)} = 2.2364 \Omega \text{ (secondary)}$$

that is, 312.5% of zone 1 setting.

7.12.3 PILOT RELAYING

Pilot relaying, in a sense, is a means of remote controlling the circuit breakers. Here, the term *pilot* implies that there is some type of channel (or medium) that interconnects the ends of a transmission line over which information on currents and voltages, from each end of the line to the other, can be transmitted.

Such systems use high-speed protective relays at the line terminals in order to ascertain in as short a time as possible whether a fault is within the protected line or external to it. If the fault is internal to the protected line, all terminals are tripped at high speed. If the fault is external to the protected line, tripping is blocked (i.e., prevented). The location of the fault is pointed out either by the presence or the absence of a pilot signal.

The advantages of such high-speed simultaneous clearing of faults at all line terminals by opening circuit breakers include (1) minimum damage to the equipment, (2) minimum (transient) stability problems, and (3) automatic reclosing.

Pilot relaying, being a modified form of differential relaying, is the best protection that can be provided for transmission lines. It is inherently selective, suitable for high-speed operation, and capable of good sensitivity. It is usually used to provide primary protection for a line. Backup protection may be provided by a separate set of relays (*step distance relaying*) or the relays used in the channels available for protective relaying include the following:

- 1. *Separate wire circuits*: They are called *pilot wires*, operating at power system frequency, audio frequency tones, or in DC. They can be made of telephone lines either privately owned or leased. Refer to Figure 7.20.
- 2. *Power line carriers*: They use the protected transmission line itself to provide the channel medium for transmission signals at frequencies of 30–300 kHz. These are the most widely used *pilots* for protective relaying. The carrier transmitter-receivers are connected to the

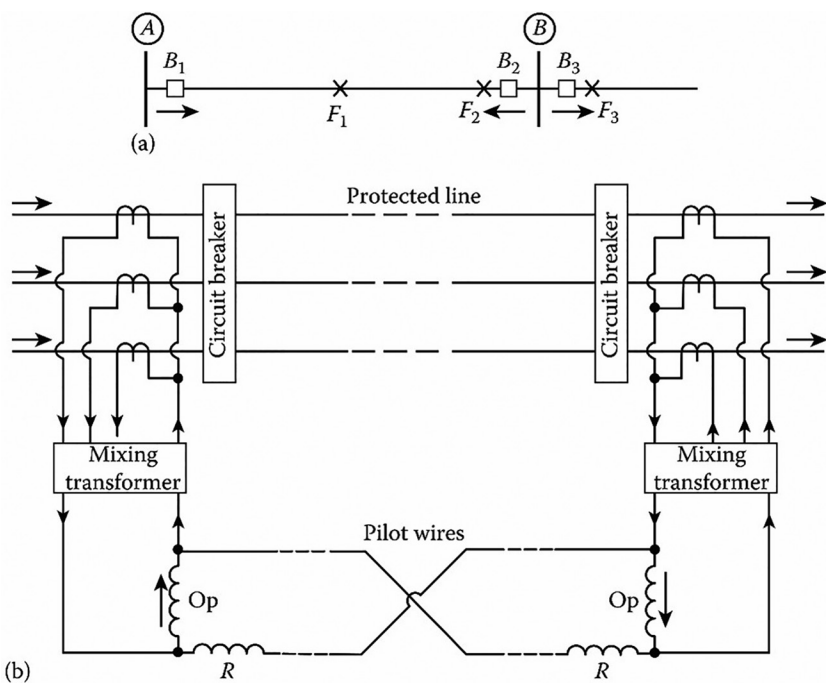


FIGURE 7.20 Line protection by pilot relaying: (a) example application and (b) one form of pilot wire relaying application.

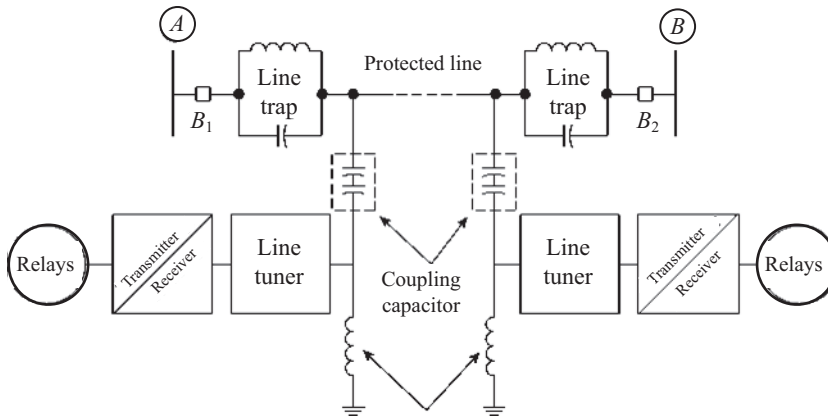


FIGURE 7.21 One-line diagram of power line carrier for a pilot-relaying system.

transmission line by coupling capacitor devices that are also used for line voltage measurement. Line traps tuned to the carrier frequency are located at the line terminals, as shown in Figure 7.21. They prevent an external fault behind the relays from shorting out the channel by showing high impedance to the carrier frequency and a low impedance to the power frequency. The RF choke acts as a low impedance to 60 Hz power frequency but as high impedance to the carrier frequency. Thus, it protects the apparatus from high voltage at the power frequency and, simultaneously, limits the attenuation of the carrier frequency.

3. *Microwave channel:* It uses beamed radio signals, usually in the range of 2–12 GHz, between line-of-sight antennas located at the terminals. This channel can also simultaneously be used for other functions. A continuous tone of one frequency, called the *guard frequency*, is transmitted under normal (or *no-fault*) conditions. When there is an internal fault, the audio tone transmitter is keyed by the protective-relaying scheme so that its output is shifted from the guard frequency to a trip frequency.

Pilot-relaying systems use either a comparison or directional comparison to detect faults. In the phase comparison, the phase position of the power system frequency current at the terminals is compared. Amplitude modulation is used in a phase comparison system. The phase of the modulation signal waveform is not affected by the signal attenuation.

Identical equipment at each end of the line is modulated in phase during an internal fault and in antiphase when a through-fault current flows (due to an external fault). Hence, current flow through the line to external faults is considered 180° out of phase, and tripping is blocked. If the currents are relatively in phase, an internal fault is indicated, and the line is tripped. Thus, modulation is of the all-or-nothing type, producing half-cycle pulses of carrier signals interspersed with half periods of zero signals, as shown in Figure 7.22.

Note that during an external fault, the out-of-phase modulation results in transmission of the carrier signal to the line alternatively from each end. Thus, transmission from one end fills in the signals from the other and vice versa, providing a continuous signal on the line. The presence of the signal is used to block the tripping function. On the other hand, when there is an internal fault, the resulting signal on the line has half-period gaps during which the tripping function, initiated by the relay, is completed.

A pilot-relaying system can also use directional comparison to detect faults. In this case, the fault-detecting relays compare the direction of power flow at the line terminals. Power flow into the line at the terminals points out an internal fault, and the line is tripped. If power flows into the line at one end and out at the other, the fault is considered external, and tripping is not allowed. Consider the line shown in Figure 7.20a.

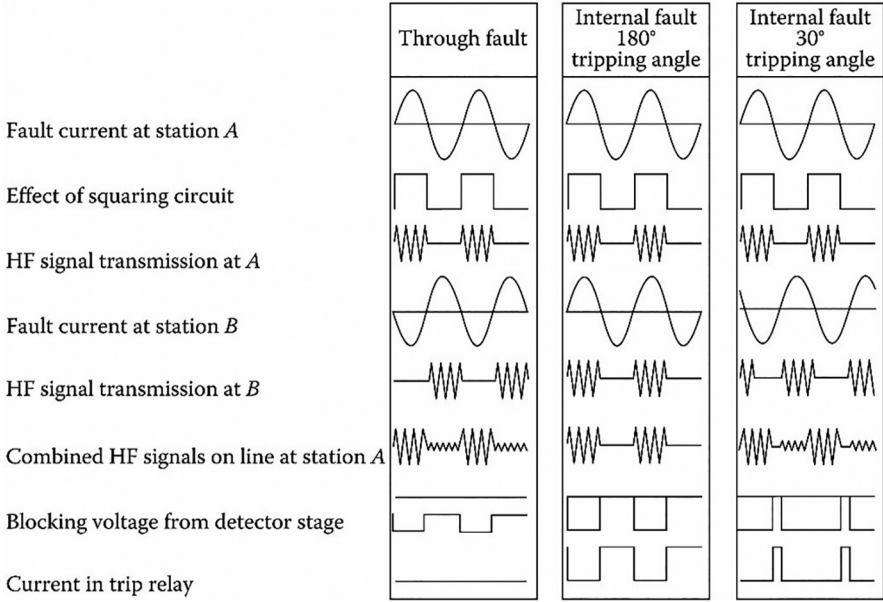


FIGURE 7.22 Carrier current phase comparison: key to operation.

Assume that directional relays are used and high-speed protection is provided for the entire line (instead of the middle 60%) by pilot relaying. Thus, both faults F_1 and F_2 are detected as internal faults by the relays located at B_1 and B_2 , respectively, and are therefore cleared at a high speed.

Note that both relays see the fault current flowing in the forward direction. Thus, when this information is impressed on the signal by modulation and transmitted to the remote ends over a pilot channel, it is confirmed that the fault is indeed on the protected line.

Now assume that there is a fault at F_3 . The relay at B_2 sees it as an external fault and the relays at B_1 and B_3 see it as an internal fault. Upon receiving this directional information at B_1 , that relay will be able to block tripping for the fault at F_3 .

7.13 COMPUTER APPLICATIONS IN PROTECTIVE RELAYING

Computers have been widely used in the electric power engineering field since the 1950s. The applications include a variety of off-line or online tasks. Examples of off-line tasks include fault studies, load-flow (power flow) studies, transient stability computations, unit commitment, and relay setting and coordination studies.

Examples of one-line tasks are economic generation scheduling and dispatching, load frequency control, supervisory control and data acquisition, sequence-of-event monitoring, sectionalizing, and load management. The applications to computers in protective relaying have been primarily in relay settings and coordination studies and computer relaying.

A relay is essentially an analog computer. It receives inputs, processes them electromechanically or electronically to develop a torque or a logic input, and makes a decision resulting in a contact closure or output signal.

At the beginning, computer relays were used to take over existing protection functions, for example, transmission line and transformer or bus protection. Eventually, microprocessors were used in some relays to make the relay decision based on digitized analog signals. On the other hand, other relays continue to make the relaying decisions based on analog functions as well as provide for the necessary logic and auxiliary functions based on digital techniques. Also, a digital relay has the ability to diagnose itself. Furthermore, today's relay has the ability to adapt itself in real time to changing system conditions.

7.13.1 COMPUTER APPLICATIONS IN RELAY SETTINGS AND COORDINATION

Today, there are various commercially available computer programs that are being used in the power industry to set and coordinate protective equipment. Advantages of using such programs include (1) sparing the relay engineer from routine, tedious, and time-consuming work, (2) facilitating system-wide studies, (3) providing consistent relaying practices throughout the system, and (4) providing complete and updated results of changes in system protection.

In 1960, the Westinghouse Electric Corporation developed its well-known protective device coordination program. It is one of the most comprehensive and complete programs for applying, setting, and checking the coordination of various types of protective relays, fuses, and reclosers. The user must specify the input data for the *data check study* block in terms of both device type and setting for each relay, fuse, or recloser. The program then evaluates the effectiveness of these devices and settings within the existing system and, if necessary, recommends alternative protective devices.

However, in the *coordination study* block, the user specifies the protective device with no settings or permits the program to select a device. The program then establishes settings within the ranges specified or it selects a device and settings. The settings and/or devices are chosen to optimize coordination.

The *final coordination study* shows how the system will behave with the revised settings, which can then be issued by the relay engineer [6]. Of course, no computer program can replace the relay engineer. Such a program is simply a tool to aid the engineer by indicating possible problems in the design and their solutions. The engineer has to use his *engineering judgment*, past experience, and skill in determining the best protection of the system.

7.13.2 COMPUTER RELAYING

Computer hardware technology has considerably advanced since the early 1960s. Newer generations of mini- and microcomputers tend to make digital computer relaying a viable alternative to the traditional relaying systems. Indeed, it appears that a simultaneous change is taking place in traditional relaying systems, which use solid-state analog and digital subsystems as their building blocks. However, there are still electromechanical relays that are still in use extensively especially in the old systems. The use of the digital computers for protection of power system equipment, however, is of a relatively recent origin. The first serious proposals appeared in the late 1960s. For example, in 1966, Last and Stalewski [6] suggested that digital computers can be used in an online mode for protection of power systems. Since then, many authors have developed digital computer techniques for protection of lines, transformers, and generators. Significantly, contributions have been made in the area of line protection. However, protection of transformers and generators using digital computers has somewhat received less attention for a while. In 1969, the feasibility of protecting a substation by a digital computer was investigated by Rockefeller [7]. He examined the protection of all types of station equipment into one unified system. Researchers suggested the use of microcomputers in power system substations for control, data acquisition, and protection against faults and other abnormal operating conditions. This has become known as computer relaying and several papers and even books have been written on various techniques of performing or existing relaying characteristics. At first, a few held installations had been made to demonstrate computer-relaying techniques and to show that computers can survive in the harsh substation environment. However, today, many utility companies have installations or plans for future implementations of computers as supervisory control and data acquisition remotes. These substation control computers receive data from the transmit data to the central dispatch control computer.

It is interesting to note that at the beginning, most of the papers written on computer relaying have been under the auspices of universities. These tend to focus on algorithms and softwares or on

models that can be tested on multipurpose minicomputers or on special-purpose circuits and hardware that are laboratory oriented. For example, a great deal of research has been undertaken at the University of Missouri at Columbia, since 1968, to develop a computer-relaying system that would permit the computer to perform relaying as well as other substation functions [8–11].

However, the *real-world* test installations had been the result of cooperation between utilities and manufacturers and are mainly concerned with line protection using an impedance algorithm [12]. For example, in 1977, Westinghouse installed the PRODAR 70 computer in the Pacific Gas and Electric Company's Tesla Substation for protection of Bellota 230kV line. Also, in 1971, a computer-relaying project was initiated by the American Electric Power and later joined by IBM Service Corporation. The purpose of the project was to install an IBM System 7 in a substation to perform protective-relaying and a few data-logging functions [13]; General Electric initiated a joint project with Philadelphia Electric Company to install computer-relaying equipment on a 500kV line. Recently, Pacific Gas and Electric Company implemented substation automation techniques, based on the computer applications, at its substations on a great scale [14]. Therefore, it can be said that when the minicomputer became available, the industry realized the potential of the relatively low-cost computer and tried various applications. However, the extremely high costs of software programs to implement specific functions have played an inhibitive role. With the advent of microcomputers, the hardware costs can be further reduced. This permits software simplification since a microprocessor can be dedicated to a specific function.

PROBLEMS

- 7.1** Consider Example 7.1 and assume that the three-phase fault is located at bus 2 and determine the subtransient fault current in per units and amperes.
- 7.2** Consider Example 7.1 and assume that the three-phase fault is located at bus 3 and determine the subtransient fault current in per units and amperes.
- 7.3** First, solve Problem 7.1, and then based on its results, determine the following:
 - a. Maximum possible value of decurrent component
 - b. Total maximum instantaneous current
 - c. Momentary current
 - d. Interrupting rating of a two-cycle circuit breaker located at bus 2
 - e. Momentary rating of a two-cycle circuit breaker located at bus 2
- 7.4** First, solve Problem 7.2, and then based on its results, determine the following:
 - a. Maximum possible value of decurrent component
 - b. Total maximum instantaneous current
 - c. Momentary current
 - d. Interrupting rating of a two-cycle circuit breaker located at bus 3
 - e. Momentary rating of a two-cycle circuit breaker located at bus 3
- 7.5** Consider the system shown in Figure P7.1 and do the following:
 - a. Sketch the zones of protection.
 - b. Describe the backup protection necessary for a fault at fault point F_b .
 - c. Repeat part (b) for a fault at F_2 .
 - d. Repeat part (b) for a fault at F_3 .
- 7.6** Consider the system shown in Figure P7.2 and do the following:
 - a. Sketch the zones of protection.
 - b. Describe the backup protection necessary for a fault at fault point F_b .
 - c. Repeat part (b) for a fault at F_2 .
 - d. Repeat part (b) for a fault at F_3 .
- 7.7** Consider the system, with overlapped primary protective zones, shown in Figure P7.3 and assume that there is a fault at fault point F . Describe the necessary primary and backup protection with their possible implications.

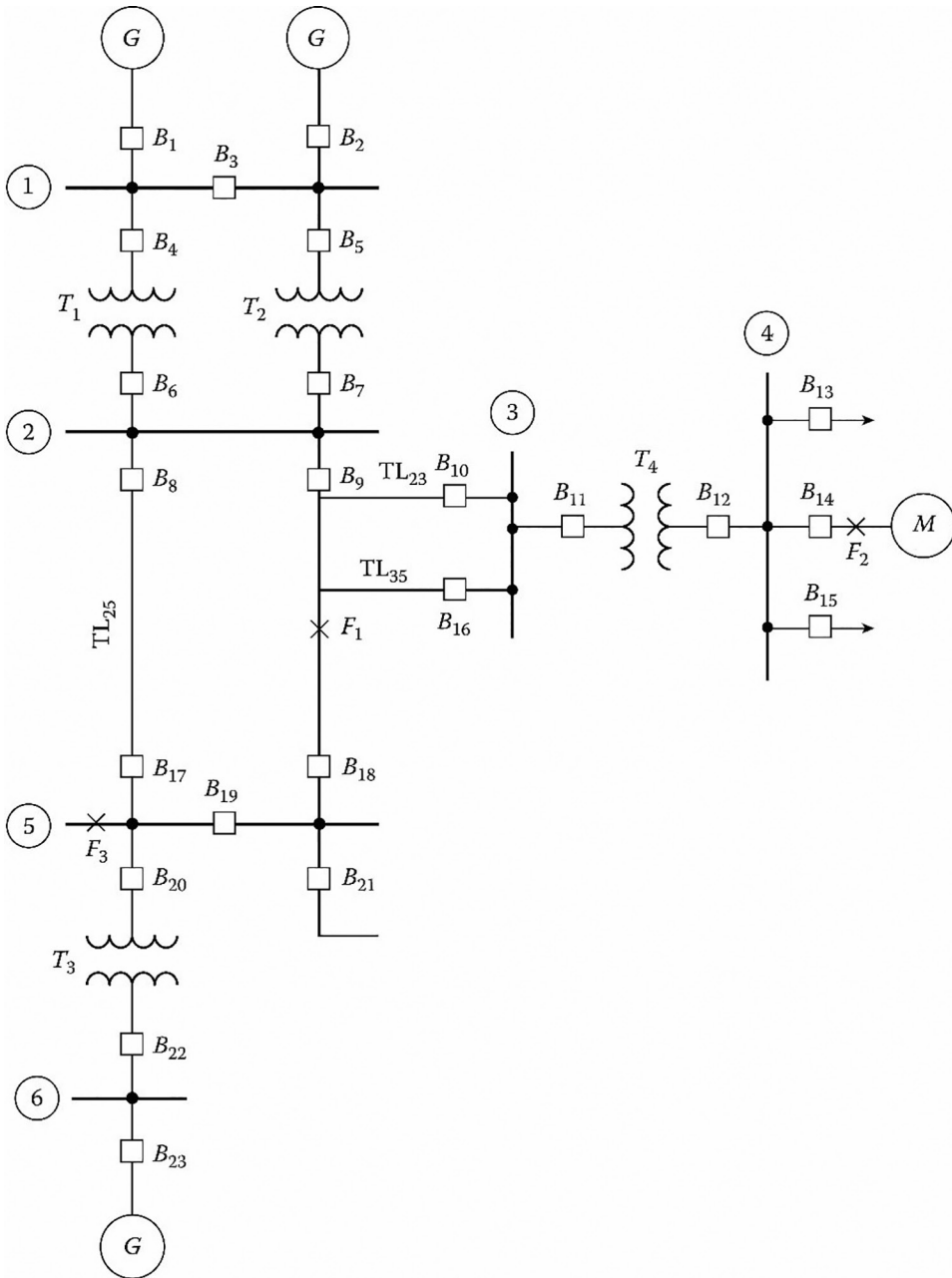


FIGURE P7.1 Transmission system for Problem 7.5.

- 7.8** Consider the system shown in Figure P7.4 and determine the locations of the necessary backup relays in the event of having a fault at the following locations:
- Fault point F_1
 - Fault point F_2
- 7.9** Repeat Example 7.3 for the directional distance relay located at B whose forward direction is in the direction from bus B to bus A . Assume that the power flow direction is from bus B to bus A .

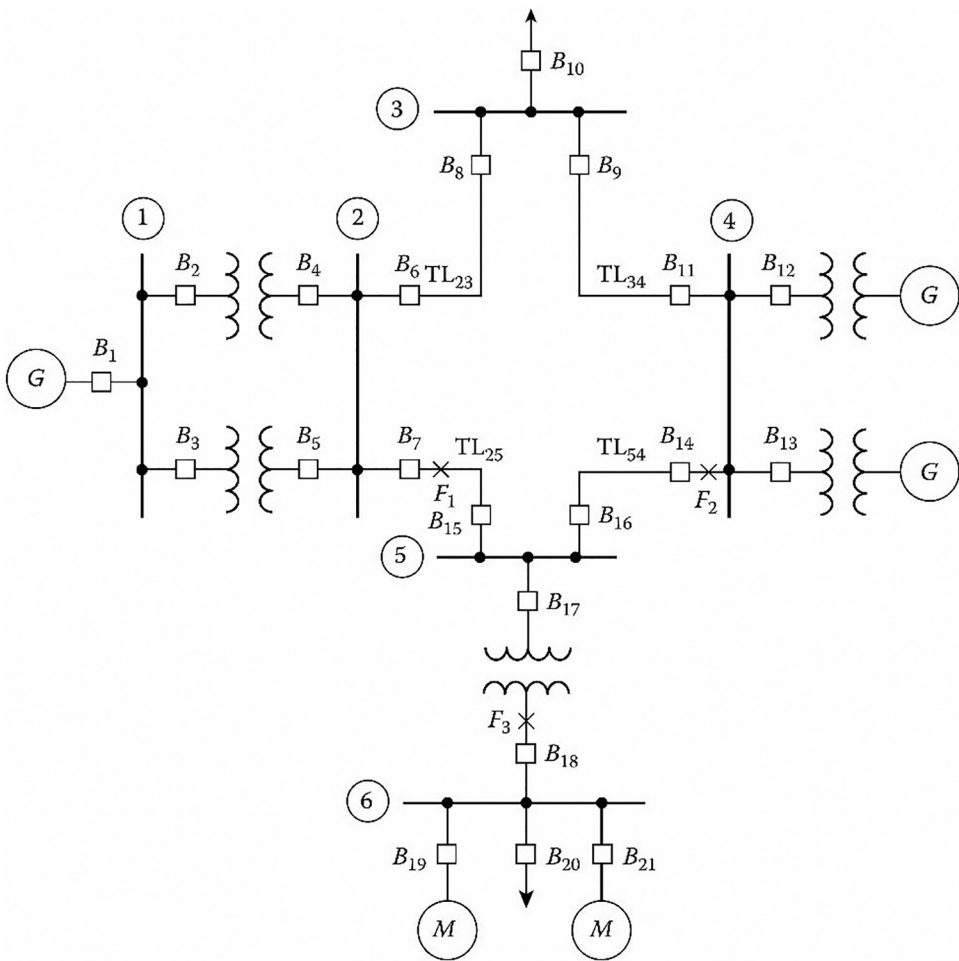


FIGURE P7.2 Transmission system for Problem 7.6.

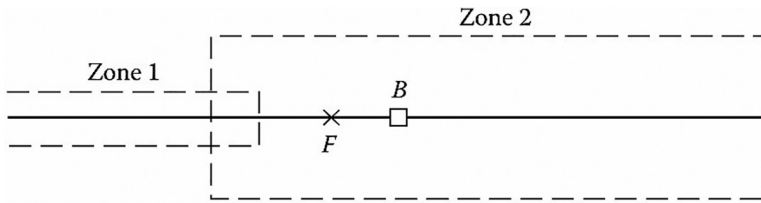


FIGURE P7.3 Protected system for Problem 7.7.

- 7.10 Repeat Example 7.4 assuming that the fault point F is located at 0.78 pu distance away from bus A .
- 7.11 Repeat Example 7.4 assuming that the arc resistance is increased by a 75 mph wind and that the zone 2 relay unit operates at a time delay of 18 cycles.
- 7.12 Repeat Example 7.6 assuming that the transmission system is being operated at 138kV line to line and at a maximum peak load of 50 MVA at a lagging power factor of 0.8.

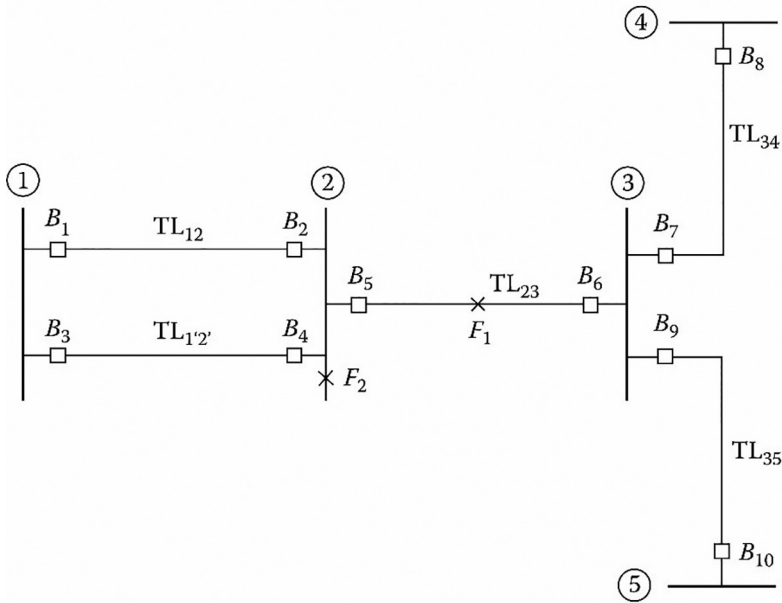


FIGURE P7.4 System for Problem 7.8.

7.13 Repeat Example 7.7 using the results of Problem 7.12 and a 45° mho relay characteristic.

7.14 Consider the 345 kV transmission system shown in Figure P7.5. Assume that all three lines are identical with a positive-sequence impedance of $0.02 + j0.2$ pu and that the mega voltampere base is 200 MVA. Assume also that all six line breakers are commanded by directional impedance distance relays and consider only three-phase faults. Set the settings of zone 1, zone 2, and zone 3 for 80%, 120%, and 250%, respectively. Determine the following:

- Relay settings for all zones in per units.
- Relay setting for all zones in ohms, if the voltage transformers are rated $345 \times 10^3 / \sqrt{3} : 69$ V and the CTs are rated 400:5 A.
- If there is a fault at fault point F located on the line TL_{35} at a 0.15 pu distance away from bus 3, explain the resulting relay operations.

7.15 Consider the transmission line shown in Figure P7.6. Assume that the line is compensated by series capacitors in order to improve stability limits and voltage regulation and to maximize the load-carrying capability of the system. Assume that the series capacitors are located at the terminals due to economics and the X_{CC} is equal to X_{CD} . If the line is protected by directional mho-type distance relays located at B and C , determine the following:

- Determine whether the series capacitors present any problem for the relays. If so, what are they?
- Sketch the possible locus of the line impedance on the R - X diagram.
- Sketch the operating characteristics of the distance relay located at B and set the relay to protect the line BC .
- Sketch the operating characteristics of the distance relay located at B and set the relay to protect the line BA .

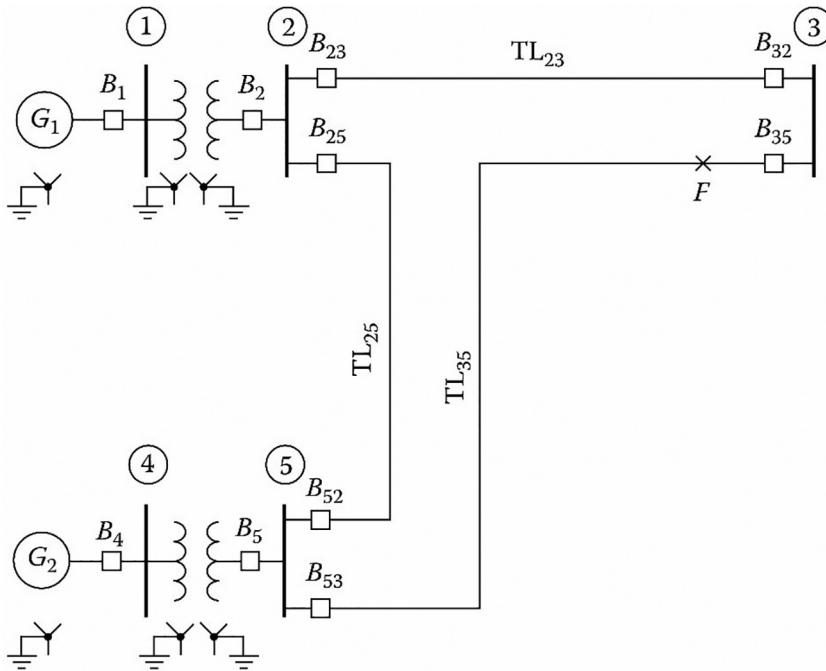


FIGURE P7.5 Transmission system for Problem 7.14.

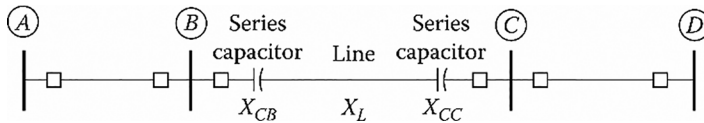


FIGURE P7.6 Transmission system for Problem 7.15.

NOTE

- 1 Note that on extra-high voltage (EHV) transmission systems, it is common to duplicate the primary protection systems in case a component in one primary protection chain fails to operate as a result of a relay failure. Also, relays from a different manufacturer or relays based on different operational principles can be used to prevent common-mode failures.

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8 Renewable Energy Systems

To choose time is to save time.

Francis Bacon

8.1 PHOTOVOLTAIC SYSTEM

8.1.1 PRINCIPLES OF PHOTOVOLTAIC CELLS

The main types of photovoltaic cells can be divided into

- Monocrystalline silicon, polycrystalline silicon photovoltaic cells;
- Silicon-based, copper indium gallium selenide, cadmium telluride, gallium arsenide thin-film photovoltaic cells;
- IBM thin-film photovoltaic cells.

Different photovoltaic cell has different conversion efficiency. Theoretically, the conversion efficiency of monocrystalline silicon solar cells can be as high as 24.7%; the conversion efficiency of polycrystalline silicon solar cells is 22.04%. The laboratory conversion efficiency of silicon-based thin-film solar cells is up to 14.04% after light attenuation; the conversion efficiency of copper indium gallium selenide and cadmium telluride cells can be as high as 22.1% and 22.9%. The highest conversion efficiency of the three large-scale modules reached 12.24%, 18.6%, and 18.72%, respectively. Spire Semiconductor Corporation of the United States announced in October 2010 that the conversion efficiency of gallium arsenide thin-film solar cells can be as high as 42.3%.

8.1.1.1 The Structure of Photovoltaic Cells

The composition and structure of silicon photovoltaic cells:

Silicon photovoltaic cells are made of tempered glass, Ethylene Vinyl Acetate (EVA) material, cell (P-type silicon, N-type silicon), backboard, aluminum alloy protective layer, junction box, etc.

The composition and structure of thin-film photovoltaic cells:

Thin-film photovoltaic cells are composed of glass substrate, transparent conductive film layer, semiconductor layer (P–N junction, metal electrode layer, etc.).

Compared with other thin-film solar cells, silicon-based thin-film solar cells are more suitable for mass production. At this stage, silicon is still the main material for photovoltaic cells, and crystalline silicon solar cells occupy a leading position in the solar cell market.

8.1.1.2 The Principle of Photovoltaic Cells

Photovoltaic power generation system is a technology that directly converts light energy into electrical energy by utilizing the photovoltaic effect of the semiconductor interface. The key element of this technology is the photovoltaic cell. After the photovoltaic cells are connected in series, they can be packaged and protected to form a large-area photovoltaic cell module, and then combined with power controllers and other components to form a photovoltaic power generation system device.

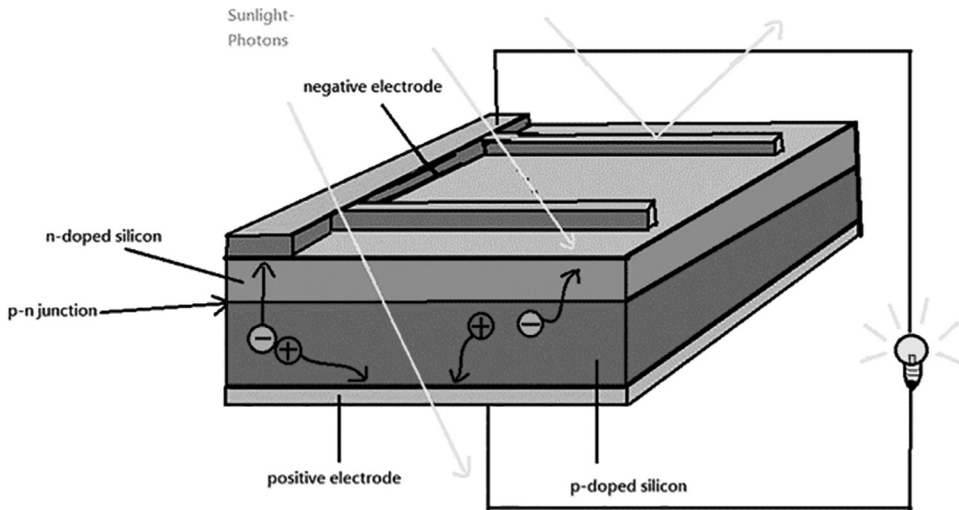


FIGURE 8.1 Working principle diagram of photovoltaic cells.

Photoelectric effect refers to the phenomenon that an object generates an electromotive force due to the absorption of photons. When the object is illuminated, the state of charge distribution in the object changes, resulting in an effect of electromotive force and current.

Next, we introduce the detailed photoelectric conversion principle of photovoltaic cells.

As shown in Figure 8.1, when the P–N junction of the photovoltaic cell is illuminated by sunlight, new hole–electron pairs appear in the space charge region (depletion layer). Due to the built-in electric field force of the P–N junction, the holes flow from the N-type region to the P-type region, and the electrons flow from the P-type region to the N-type region. A large amount of positive charges is accumulated in the P region, and a large amount of negative charges are accumulated in the N region. Therefore, a potential difference appears on the P–N junction, and a current is generated after the line is connected.

The physical process of photoelectric conversion is as follows:

1. When illuminated by light that meets certain conditions, the photocell absorbs enough photon energy to form hole–electron pairs on the P-side and N-side of the P–N junction, as shown in Figure 8.2a;
2. Electrons and holes generated within one diffusion length from the P–N junction reach the junction by diffusion, as shown in Figure 8.2b;
3. Electron–holes are separated by an electric field. The electrons on the P side move from a high potential to the N side with a lower potential, while the holes move in the opposite direction. The electrons and holes will slowly accumulate, as shown in Figure 8.2c;
4. When electrons and holes accumulate to a certain level, an electromotive force is generated. If the P–N junction is open, an open-circuit voltage will be generated across the P–N junction, as shown in Figure 8.2d. If a load is connected to the upper and lower poles of the battery through wires, a current will be generated in the circuit, as shown in Figure 8.2a. When a short circuit occurs across the battery, that is, when no load is connected, the maximum current is formed, and this current is called the short circuit current.

8.1.1.3 Mathematical Principles of Photovoltaic Power Generation

Photovoltaic cells are the smallest units that make up a photovoltaic array, and their core structure is P–N junction. If light that meets certain conditions shines on the photovoltaic cell, a resistor R is

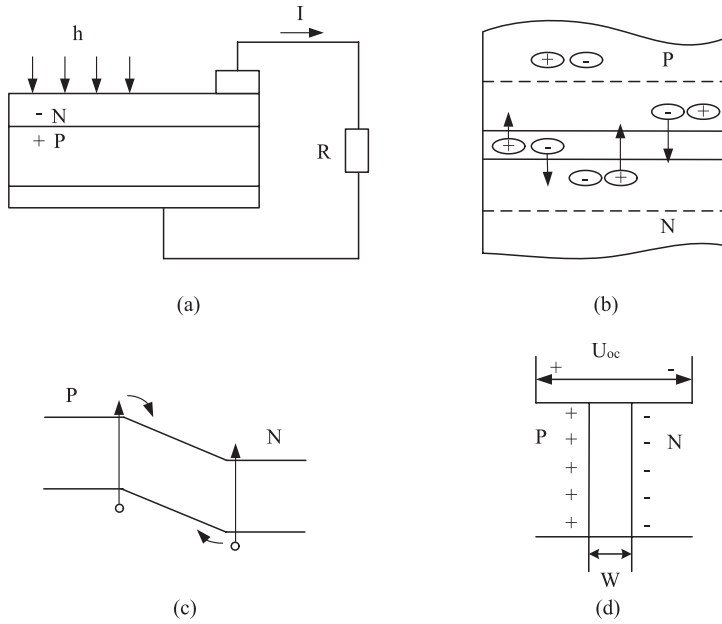


FIGURE 8.2 Physical process of photoelectric conversion (a) hole-electron pairs on the P-side and N-side, (b) electrons and holes reach the junction, (c) accumulated electrons and holes, (d) an open-circuit voltage.

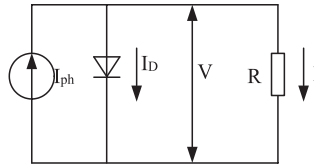


FIGURE 8.3 Equivalent circuit diagram of ideal photovoltaic cells.

connected to the positive and negative poles of the photovoltaic cell, and the photovoltaic cell is in the working status. The equivalent circuit of a photovoltaic cell in an ideal state is shown in Figure 8.3. It is equivalent to a constant current source with current I_{ph} connected in parallel with a crystal diode, and the current flowing through the crystal diode is called the dark current I_D . Using the device, the forward voltage V can be measured across the load R , and the current flowing through the load is recorded as I .

In engineering applications, the equivalent circuit of the photovoltaic cell is shown in Figure 8.4. R_{sh} represents the shunt resistance of photovoltaic cells, which is mainly caused by several factors such as surface dust, crystal dislocation, irregular diffusion, and crystal defects. R_s represents the series resistance of the photovoltaic cell, which is mainly composed of the ohmic resistance between the wire and the positive and negative electrodes.

As shown in Figure 8.4, the voltage across the load is U , so the voltage applied across R_{sh} can be expressed as $(U + IR_s)$. According to Kirchhoff's law, we have

$$I_{sh} = (U + IR_s)/R_{sh} \quad (8.1)$$

On the other hand, the current flowing through the load is

$$I = I_{ph} - I_D - I_{sh} \quad (8.2)$$

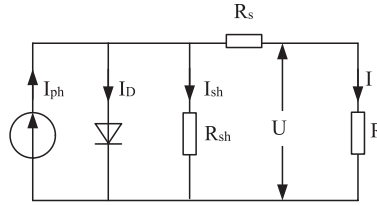


FIGURE 8.4 Practical application of the equivalent model of PV cell.

The external voltage U_j applied to the P–N junction of the photovoltaic cell can be expressed as

$$U_j = U + IR_s \quad (8.3)$$

The current flowing through the diode (P–N junction) I_D can be expressed as

$$I_D = I_0 \left[e^{\frac{qU_j}{AKT}} - 1 \right] \quad (8.4)$$

where

I_0 is the reverse saturation current of the diode

q is the amount of electron charge, $q = 1.6029 \times 10^{-19}$ C

A is the ideality factor of the diode

T is the temperature junction of the photovoltaic cell

K is the Boltzmann constant, $K = 1.3819 \times 10^{-23}$ J/K

Combining the above equations, the relationship between the current and voltage of the photovoltaic cell can be obtained as

$$I = I_{ph} - I_0 \left[e^{\frac{U + IR_s}{AKT}} - 1 \right] - \frac{U + IR_s}{R_{sh}} \quad (8.5)$$

The above equation can more accurately reflect the relationship between the output current and the output voltage of the photovoltaic cell, but the equation is very complicated. It contains many unknown parameters, which are difficult to obtain in engineering applications. Even if the parameters are provided by the manufacturer, these parameters are sensitive to environmental changes, and the calculation is more complicated. Therefore, it is necessary to further simplify Equation 8.5.

In Figure 8.4, the resistance R_s is used as an equivalent substitute for the ohmic resistance in the battery, between electrodes, etc. According to Ohm's law, the larger the R_s , the smaller the power. In practical applications, the resistance of the R_s is usually very small, generally between 0.001 Ω and several Ω . However, the shunt resistance caused by the shortcomings of the photovoltaic cell itself and pollution will be very large, generally in the range of 1,000 Ω . Based on these facts, we have $R_s \ll R_{sh}$. Hence, we can obtain

$$U + IR_s/R_{sh} \rightarrow 0, \quad IR_s \rightarrow 0 \quad (8.6)$$

According to Equation 8.6, Equation 8.5 can be simplified as

$$I = I_{ph} - I_0 \left[e^{\frac{U}{AKT}} - 1 \right] \quad (8.7)$$

When the photovoltaic cell circuit is short-circuited, $U=0$. Substituting it into Equation 8.6, the short-circuit current of the photovoltaic cell can be expressed as

$$I_{sc} = I \approx I_{ph} \quad (8.8)$$

When both ends of the photovoltaic cell are open-circuited, the open-circuit voltage of the photovoltaic cell can be obtained from Equations 8.7 and 8.8 as

$$U_{oc} = \left(\frac{AKT}{q} \right) \ln \left(\frac{I_{sc}}{I_0} + 1 \right) \quad (8.9)$$

Suppose $c_2 = AKT/U_{oc}q$, $c_1 = I_0/I_{sc}$, based on the above equations, Equation 8.7 can be further organized as

$$I = I_{sc} \left[1 - c_1 \left(e^{\frac{U}{c_2 U_{oc}}} - 1 \right) \right] \quad (8.10)$$

According to Equation 8.10, in the open-circuit voltage region and the maximum power point, there are the following approximate results:

$$c_1 = \left(1 - \frac{I_{mpp}}{I_{sc}} \right) e^{-\frac{U}{c_2 U_{oc}}} \quad (8.11)$$

$$c_2 = \frac{U_{mpp}/U_{oc} - 1}{\ln \left(1 - \frac{I_{mpp}}{I_{sc}} \right)} \quad (8.12)$$

where

U_{mpp} is the voltage at the maximum power point of the photovoltaic cell;

I_{mpp} is the current at the maximum power point of the photovoltaic cell.

It can be obtained from the voltage and current at the maximum photovoltaic power point measured in a standard environment (air quality AM1.5, temperature 25°C, and solar irradiance 1,000 W/m²). Here, the power expression of photovoltaic cells in engineering applications can be expressed as Equation 8.12.

8.1.2 STAND-ALONE PHOTOVOLTAIC SYSTEM

A photovoltaic (PV) system is able to supply electric energy to a given load by directly converting solar energy through the photovoltaic effect. The system structure is very flexible. PV modules are the main building blocks; these can be arranged into arrays to increase electric energy production. Normally additional equipment is necessary in order to transform energy into a useful form or store energy for future use. Currently, a large number of scattered systems are installed in residential buildings. When a house needs to be powered and it is not connected to the electricity grid, the PV system must be operational at all times of the day and night, including weekends and holidays. It may also be required to provide electricity to both AC and DC loads, as well as to contain a backup generator. The resulting system will therefore be determined by the energy needs (or loads) in a particular application. PV systems can be broadly classified into two major groups: Stand-alone PV

systems and grid-connected PV systems. The fundamental concepts and components of a photovoltaic system remain unchanged. Adaptation of systems to fulfill specific needs is accomplished by modifying the kind and amount of the fundamental elements. When power demands change, a modular system design makes it simple to expand the system.

Stand-alone PV systems, also known as off-grid photovoltaic systems, are powered only by solar energy and require no other energy source. They can be constructed entirely of PV modules and a load, or they can be augmented with batteries to provide energy storage capabilities. When using batteries, it is necessary to install battery charge controllers. These controllers remove the batteries from the PV modules once they have been fully charged and may also disconnect the load in order to prevent the batteries from being discharged below a particular threshold. In order for the energy created during the day to be usable at night and during adverse weather during the day, the batteries must have sufficient capacity to hold the energy generated during the day. Figure 8.5 shows an example of a stand-alone PV system. Here’s what happens while the system is in operation:

- 1. Power is supplied from the renewable energy source, through the regulator, to the DC control board.
- 2. Some power is used by the DC loads and the inverter and the remainder then flows to the battery.
- 3. When there is insufficient power from the renewable energy source to meet the loads (e.g., a PV system at night), the battery supplies power to make up the difference.

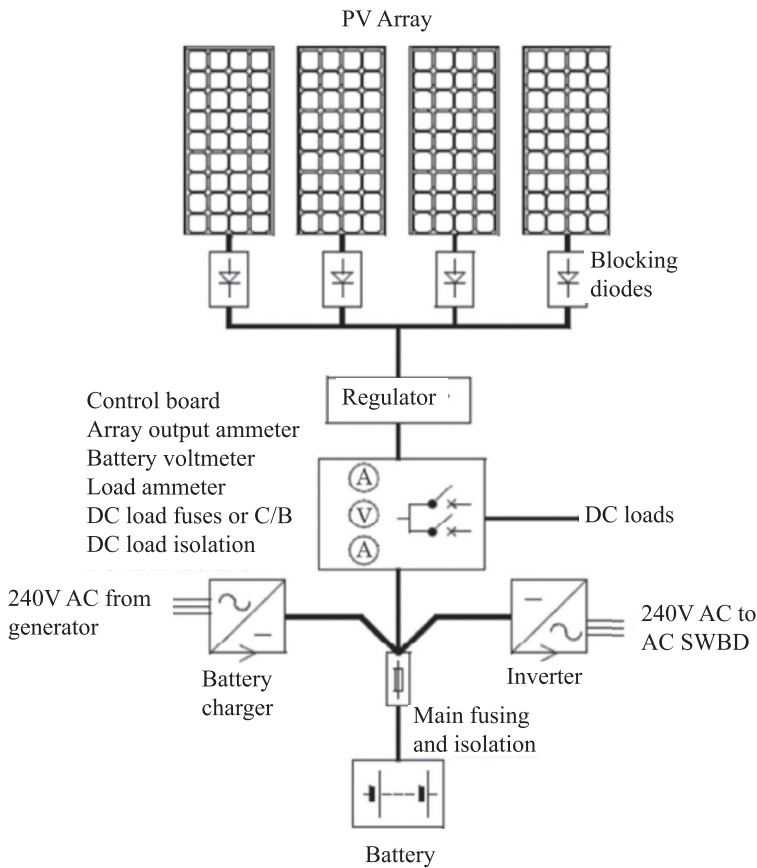


FIGURE 8.5 A typical stand-alone PV power system.

- 4. When the backup generator is operating, power flows through the battery charger to the DC bus, in effect adding to the power from the renewable energy source.
- 5. The power flow between the battery and the DC control board can be in either direction, depending on the balance between supply and demand for power. The optimum design of an electricity supply system depends primarily on five factors, including required connection power, energy consumption, types of power consumers, period of use, and meteorological constraints.

8.1.2.1 System Components

Stand-alone photovoltaic systems are generally classified according to the voltage source they use (DC or AC). A dedicated DC/DC charge controller is used in DC-coupled systems to connect the PV generator to the rest of the system, as shown in Figure 8.6.

A standard PV inverter is used to feed electricity into the grid in AC-coupled solar installations. When it comes to AC-linked systems, the battery or stand-alone power inverter serves as the brain. It ensures that the power generated and used by the load is always in balance. If an excessive amount of energy exists, the inverter will store the excess energy in the batteries. If the demand for energy exceeds the supply, the inverter discharges the energy stored in the batteries. Table 8.1 summarizes the fundamental distinctions between PV inverters and stand-alone inverters, as well as the benefits of each.

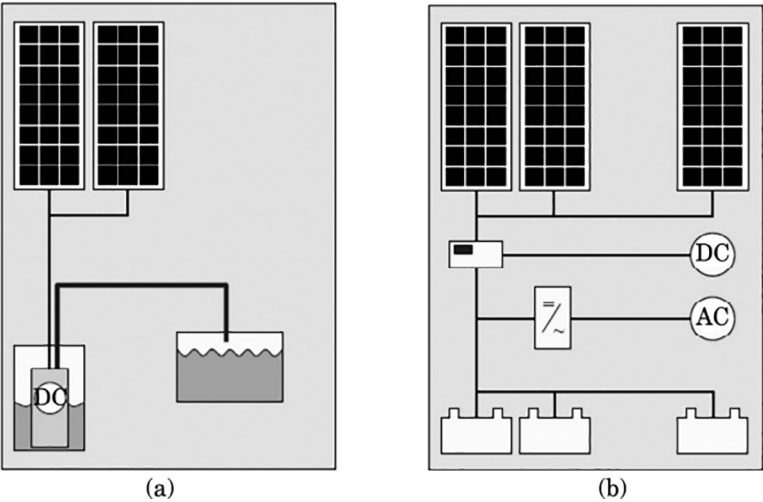


FIGURE 8.6 Schematic representation of (a) a simple DC PV system to power a water pump with no energy storage, (b) a complex PV system including batteries, power conditioners and both DC and AC loads.

TABLE 8.1
Comparison of PV Inverters and Stand-Alone Power Inverters

	PV Inverters	Stand-Alone Power Inverters
Direction of energy flow	Unidirectional	Bidirectional
Functions	Maximum power point tracking sinusoidal grid current	Management of batteries, generators, and loads; sinusoidal grid voltage
Overload capacity	Approximately 110%	Approximately 300% (short-circuit-proof)
Active/reactive power	Feed-in of active power	Loads with any power factor
Typical DC voltage	125–750V (string technology)	12, 24, and 48V

8.1.2.2 Design of Stand-Alone Photovoltaic Systems

A stand-alone PV system, aside from power consumers such as lamps, radios, televisions, and refrigerators, is comprised of four fundamental components: a power generator (e.g., a PV generator), a storage battery, a charge controller, and an inverter, to name a few. These components can be connected at a variety of system levels, including on the DC side, on the AC side, and in hybrid systems, among other configurations. Figure 8.7 depicts a solar-powered home system.

8.1.2.3 AC–DC Systems

A hybrid AC–DC system is particularly well suited for connecting mid-range alternating current consumers with direct current generators, as shown in Figure 8.8. With such systems, the battery on the DC side can be charged at the same time that the battery on the AC side is being charged.

The requirements for a hybrid system are different from those for a solar-powered home. Remote power consumers are supplied by hybrid systems, which have the ability to handle larger energy demands than traditional systems. As a result, such alternating current direct current systems are commonly found in farmhouses, small enterprises, and farmsteads.

8.1.2.4 AC Coupling Systems

All power consumers and generators are connected to the AC side of the system shown in Figure 8.9, which provides a significant advantage in that it allows systems to be built up or expanded using standardized components on a flexible, modular basis.

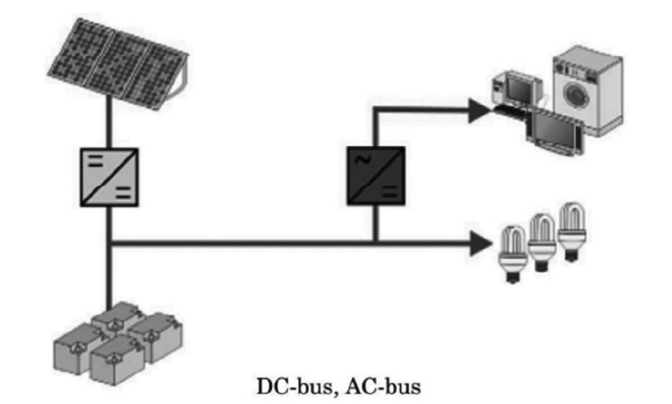


FIGURE 8.7 Solar home system capable of providing alternating current.

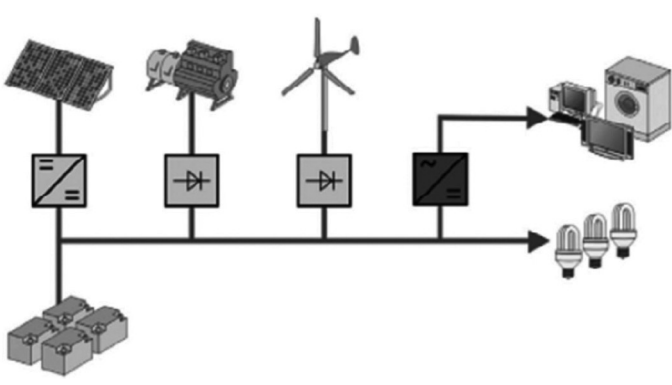


FIGURE 8.8 Hybrid system with DC-coupled components.

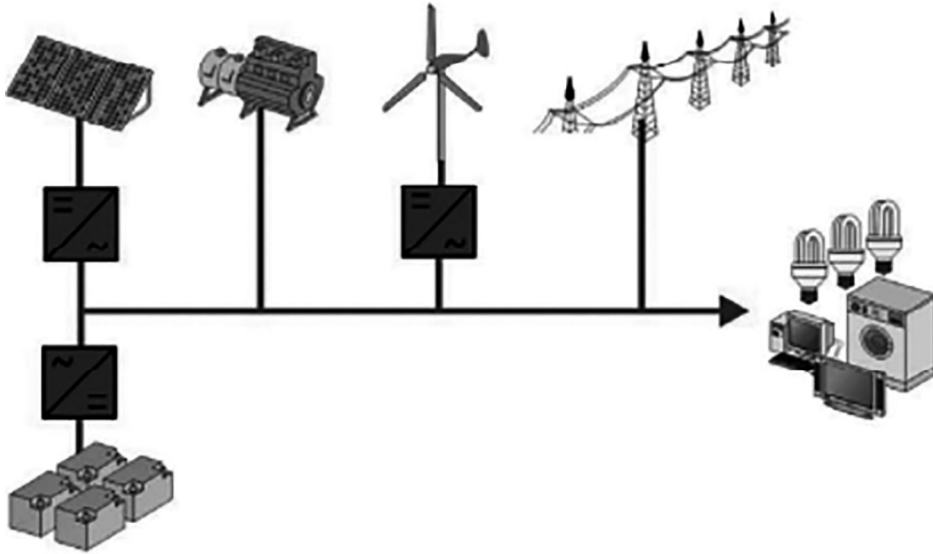


FIGURE 8.9 Hybrid system with AC-coupled components.

Renewable and conventional power sources can be used in conjunction with one another, depending on the application and the energy carrier that is available. Connection to the public grid is conceivable if the inverters and combustion units are meant for that use and are connected to it. The addition of extra generators makes it simple to scale up the system, allowing it to keep up with the growing demand for electricity. The addition of extra AC results in a significant increase in capacity on the alternating current side. AC-linked systems can be used to supply electricity to all of the customers in a building.

8.1.3 GRID-CONNECTED SYSTEM

Due to the exhaustion of traditional energy and people's attention to the environment, the power system is facing a huge change, and distributed power generation will be the future. Among them, photovoltaic power generation is unique. The advantages of the technology are recognized as the most technologically advanced and most promising technology. However, the photovoltaic power generation system has a large initial investment and high cost.

Due to the disadvantages of high cost and high cost, new optoelectronics with high performance and low cost are explored. Conversion materials and devices are one of his main research directions. To further reduce the loss of the photovoltaic power generation system itself and improve the operation efficiency. It is also an important way to reduce its power generation cost. The level of efficiency not only affects its own loss, but also affects the photoelectric conversion.

Capacity selection and reasonable configuration of replacement devices and other equipment in the system. Therefore, the inverter has become an economical option that affects the photovoltaic grid-connected power generation system.

8.1.3.1 Requirements for Inverters

The photovoltaic grid-connected power generation system generally consists of three parts: photovoltaic array, inverter, and controller. The inverter is a key component connecting the photovoltaic array and the power grid. It completes the two main tasks of controlling the operation of the maximum power point of the photovoltaic array and injecting sinusoidal current into the power grid. As shown in Figure 8.10, the working principle of the inverter is to use the power from a DC Source

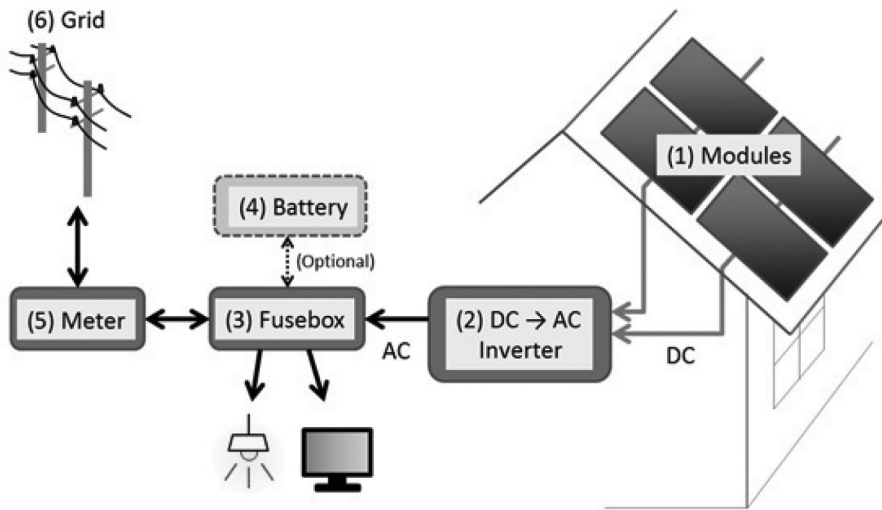


FIGURE 8.10 Working mechanism of solar inverters. (<https://www.elprocus.com/>)

such as the solar panel and convert it into AC power. The generated power range will be from 250 to 600 V. This conversion process can be done with the help of a set of IGBTs (Insulated Gate Bipolar Transistors). When these solid-state devices are connected in the form of H-Bridge, then it oscillates from DC power to AC power.

To connect the inverter to the grid, it must meet the three requirements of grid power quality, prevention of islanding effect, and safe isolation and grounding. To avoid the pollution of the public grid by the photovoltaic grid-connected power generation system, the inverter should output a sine wave with small distortion. One of the main factors affecting the degree of waveform distortion is the switching frequency of the inverter.

Using new type processors such as high-speed DSP in the numerical control inverter system can significantly improve the switching frequency performance of the grid-connected inverter, and it has become one of the technologies widely used in practical systems. At the same time, the selection of the main power components of the inverter is also crucial. Small-capacity low-voltage systems use more power field effect transistors (MOSFETs), which have lower on-state voltage drop and higher switching frequency; However, the on-state resistance of Metal Oxide Semiconductor Field Effect Transistor (MOSFET) increases as the voltage increases, so an IGBT is generally used in high-voltage large-capacity systems; In extra-large-capacity systems, turn-off thyristors are generally used as power components.

In order to ensure the safe and reliable operation of the power grid and the inverter, the effective isolation of the inverter and the power grid and the inverter grounding technology are also very important.

Electrical isolation generally uses a transformer. In the three-phase output photovoltaic power generation system, the grounding method can refer to the non-grounding method specified by the International Electrotechnical Commission, the single protective grounding method, and the direct grounding of the neutral wire of the transformer. The shell of the electrical equipment is connected with the grounding point metal property through the protection wire.

Since both the sunlight intensity and the ambient temperature will affect the power output of the photovoltaic array, the output voltage of the photovoltaic array must be adjusted to be close to the output voltage of the maximum power point through the adjustment of the inverter to ensure that the photovoltaic array operates at the maximum power point and obtains the maximum energy source. Commonly used maximum power point tracking methods are as follows: constant voltage tracking method, interference observation method, and incremental conductance method.

From the perspective of users of photovoltaic power generation systems, low cost, efficiency, availability, high reliability, and long service life are the requirements for inverters.

Therefore, the requirements for the inverter usually are:

1. With a reasonable circuit structure, strictly screened components. It has various protection functions such as reverse polarity of input DC, AC output short circuit, overheating, and overload.
2. It has a wide range of DC input voltage adaptability. Since the terminal voltage of the photovoltaic array varies with the load and the intensity of sunlight, the inverter must be able to work normally within a wide DC input voltage range and ensure the stability of the AC output voltage.
3. Minimize the use of intermediate links (such as batteries) to save costs and improve efficiency.

8.1.3.2 Developments in Inverters

In order to design a grid-connected inverter that meets the above requirements as much as possible, most researchers have been focusing on the inverter topology and control methods.

The inverter structure of the early photovoltaic grid-connected system adopts a single-stage transformerless, voltage-type full-bridge inverter structure. Its characteristics are simple structure, low cost, and strong robustness; but limited by the level of switching devices at that time, the output power factor of the system is only 0.6–0.7, and the output current harmonics are greatly induced. With the development of electronic switching devices, high-frequency (frequency > 16 kHz) bipolar transistors, MOSFETs, or IGBTs have gradually replaced grid-connected commutated thyristors. Due to the use of PWM full-bridge inverter circuits and high-frequency switching electronic devices, the output harmonics can be well controlled; but the switching frequency of 16–20 kHz increases the switching loss and reduces the efficiency.

The main disadvantages of single-stage inverter systems that directly convert DC to AC are as follows:

1. Requires higher DC input, which increases cost and reduces reliability;
2. There is no independent control operation for the tracking of the maximum power point, which reduces the overall output power of the system;
3. The structure is not flexible enough, cannot be expanded, and cannot meet the variability of the DC input of the photovoltaic array. Therefore, when the DC input is low, consider using an AC transformer to boost the voltage to obtain a standard AC voltage and frequency, and at the same time, the input and output can be electrically isolated.

By contrast, the biggest advantage of the photovoltaic inverter system with the power frequency transformer structure is that the inverter is on the low-voltage side. Therefore, the inverter bridge can use high-frequency low-voltage device MOSFET, saving the initial investment. Moreover, the control of the inverter is realized on the low-voltage side, which makes the control easier to realize. This structure is also suitable for high-current photovoltaic modules.

Power-frequency boost transformers are bulky, low efficiency, and expensive. With the further development of power electronics and microelectronics, high-frequency boost converters can be used to achieve high-power-density inverters. The boost transformer adopts high-frequency magnetic core material, and the operating frequency is above 20 kHz. It is small in size and light in weight. After the high-frequency inverter, it is converted into high-frequency alternating current through a high-frequency transformer, and then high-voltage direct current (usually above 300 V) is obtained through high-frequency rectification and filter circuit, and then the inverter is realized by a power frequency inverter circuit.

Compared with the inverter structure with a power frequency transformer, the multi-conversion stage inverter structure with a high-frequency transformer has greatly improved power density, and the no-load loss of the inverter is correspondingly reduced, so that the efficiency is improved, but it also leads to the increase in the inverter’s power density. The circuit structure is complex and the reliability is reduced.

The development of photovoltaic inverters from single-stage to multi-stage increases the number of power conversion stages, which can easily meet the requirements of maximum power point tracking and DC voltage input range; however, single-stage inverters are compact in structure, with fewer components and higher losses. Low, the inverter conversion efficiency is higher and easier to control.

Therefore, under the premise of combining the advantages of the two, the conversion efficiency of the inverter can be improved by increasing the DC input voltage as much as possible. Early use of centralized technology increases the input voltage. Connect photovoltaic modules in series/parallel to generate high DC voltage and current to increase conversion efficiency. This structure is not flexible enough and will cause many power quality problems. Most of the photovoltaic grid-connected inverters at this stage are of the cascade type. The photovoltaic modules are connected in series, and the modular design is adopted as much as possible to reduce the intermediate links. The design is more flexible, adaptable, and plug-and-play. In addition, the multi-string inverter structure combines the advantages of flexible design, high energy output, and centralized low cost of the string, which is a development trend of photovoltaic grid-connected inverter structures in the future.

8.1.3.3 Challenges in High-Level PV Penetration

More and more global experience of wind and solar power generation systems shows that variable power generation resources can be integrated into the power grid far beyond the current capacity. However, the prospect of significantly increasing the deployment of photovoltaic needs to be examined in detail to ensure that high penetration solar technology will provide its expected benefits, including reducing the use of fossil fuels and reducing the conventional capacity required for reliable services (Paul Denholm, 2016). Figure 8.11 summarizes challenges in high-level PV penetration.

8.1.3.4 Grid-Connected Control Strategy

The photovoltaic power generation system has strong randomness. If the traditional grid-connected control strategy is adopted during the operation, the output of the power generation system will be unstable, which will affect the stability of the system after the grid-connected operation.

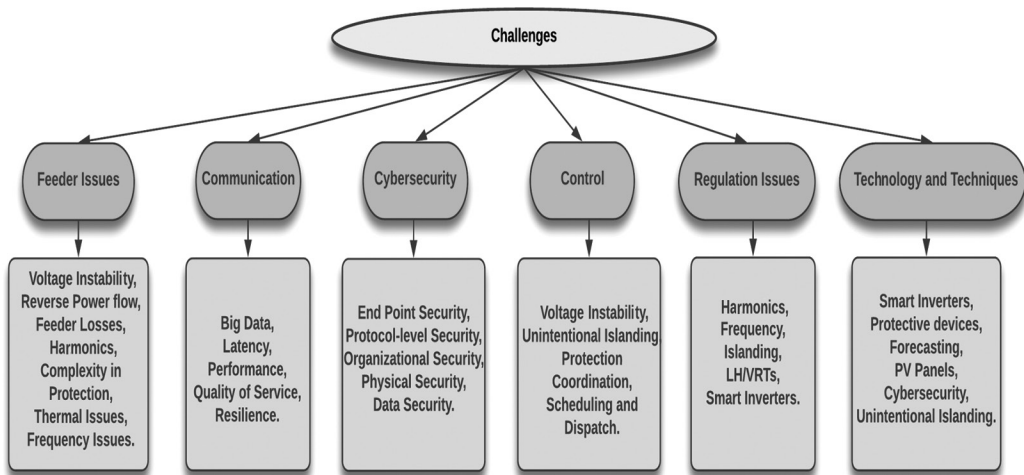


FIGURE 8.11 Overview of challenges in high-level PV penetration (Olowu, 2018).

It is known that the direct current generated by the photovoltaic array outputs alternating current through the inverter. When the control system is connected to the grid, in order to maintain the stable grid connection of the microgrid, the adjustment operation is performed by collecting the voltage and current signals on the grid side and the inverter side, so that the microgrid can be adjusted. The grid can keep pace with the larger grid.

V/f control method: The main feature is to keep the output side voltage and frequency proportional, as shown in Figures 8.12 and 8.13. First, collect the DC side voltage and current, compare them with the set voltage and current reference values, and then input them to the PI controller for comparison. After proportional integration, the active power deviation ΔP and reactive power deviation ΔQ are obtained, and the deviation value is added to the corresponding reference value, combined with the actual detected active power value and the detected reactive power value, input to the PI regulator through proportional integration transformation to make Sinusoidal Pulse Width Modulation (SPWM). The inverter outputs the drive signal to realize the grid-connected action of the drive inverter. At present, the V/f control technology can ensure that the amplitude and frequency of the output voltage are the same, but this control technology is difficult to control the power in the system, and when the power fluctuation occurs in the system, it will lead to a decrease in the system stability.

Droop control method: Droop control technology is a commonly used control method in the process of microgrid grid connection. However, as a different control method, it has its own shortcomings; the key purpose of PQ control (constant output power control) is to enable the distributed generation system to output a specific output according to the standard value.

During the initial operation of the system, the corresponding active and reactive power values are set according to the research and design of the actual photovoltaic microgrid power generation system off-grid control strategy, and then the specific active power value and reactive power value

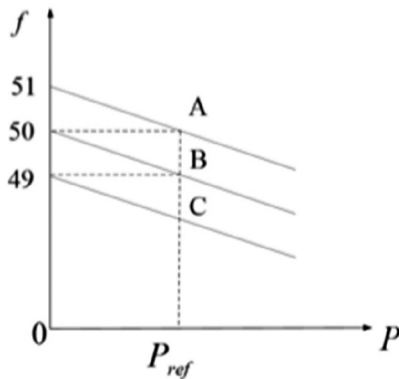


FIGURE 8.12 Frequency droop characteristic.

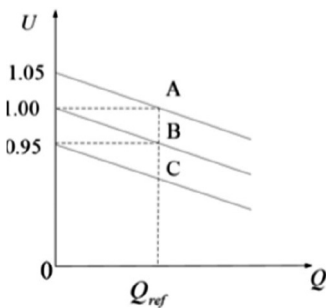


FIGURE 8.13 Voltage droop characteristic.

on the DC power supply side are measured, and compared with the preset standard value and input the error value into the PI controller. After adjusting the output, the synthetic voltage is obtained to obtain the sinusoidal voltage signal. At this time, the three-phase voltage and three-phase current are connected by double closed-loop control. Finally, the SPWM control is used to control the output modulation signal to realize the inverter action.

8.2 WIND ENERGY SYSTEM

Wind energy is one type of renewable energy that is expected to lead the transformation of global electricity sectors. In 2019, 205 GW of wind power generation capacity had been installed in Europe, and wind power generation accounted for 15% of the electricity the EU-28 consumed. By 2050, onshore and offshore wind energy will generate about 35% of total electricity demand, becoming the prominent generation source. As the globally fastest-growing energy source in the world, wind energy possesses many advantages together with disadvantages.

Advantages of wind energy

- Wind energy systems are energized by the naturally flowing wind, which can be considered a clean source of energy. Wind energy does not pollute the air like power plants that rely on the combustion of fossil fuels. Wind turbine generators (WTGs) do not produce atmospheric emissions that cause acid rain or greenhouse gasses.
- Wind energy is available as a domestic source of energy in many countries worldwide and is not confined to only a few countries.
- Wind energy is one of the lowest-priced renewable energy technologies available today.
- Wind turbines can also be built on farms or ranches, thus benefiting the economy in rural areas, where most of the best wind sites are found. Farmers and ranchers can continue to use their land because wind turbines use only a small fraction of the land. Wind power plant owners make rent payments to the farmer or rancher for the use of the land.

Disadvantages of wind energy

- Depending on the wind profile at the site, the wind farm may or may not be as cost-competitive as a fossil fuel-based power plant. Even though the cost of wind power has decreased in the past 10 years, the technology requires a higher initial investment.
- The major challenge to using wind as a source of power lies in its variability and uncertainty. Wind energy cannot be dispatched to meet the timing of electricity demands.
- A proper wind site is often located in remote locations, far from cities where electricity is needed. In developing countries, there is always the extra cost of laying a grid for connecting remote wind farms to the supply network.
- Wind resource development may compete with other uses for the land, and those alternative uses may be more highly valued than electricity generation.
- Although wind power plants have relatively little impact on the environment compared to other conventional power plants, there is some concern over the noise produced by the rotor blades, and aesthetic (visual) impacts. Most of these problems have been resolved or greatly reduced through technological development or by properly siting wind plants.

8.2.1 WIND TURBINES

The basic component for wind power generation is the wind turbine which converts kinetic energy into electric power. The types, sizes, materials, locations, speeds, performance, cost, and configurations of turbines are basic considerations for the generation of wind energy. Conventionally, there are

mainly two types of wind turbines with respect to the differences in rotation axis: horizontal axis wind turbine (HAWT) and vertical axis wind turbine (VAWT). As their names suggest, the rotation axis of HAWT is in line with the wind direction, while VAWT rotates in a vertical plane that is perpendicular to the wind direction. HAWT has some advantages over VAWT such that the tall tower base allows HAWT to access stronger wind in sites with wind shear and to enjoy relevantly high efficiency. Since HAWT is more efficient than VAWT, HAWT is much more available commercially.

8.2.1.1 Horizontal Axis Wind Turbines

HAWT has the main components, including the generator, electric controls, and the rotor hub at the top of the tower, as illustrated in Figure 8.14. Most HAWTs are equipped with a gearbox to adjust the rotation speed of the rotors to spin the generator normally. HAWT requires an additional yaw control mechanism to adjust the blades in line with the wind direction. A braking or yawing device is required to stop the turbine from spinning and destroying itself. The anemometer is compulsory to measure the direction and speed of the wind. These measurements are sent to the yaw controller to adjust the angle of the nacelle for maximum wind energy utilization. HAWT typically contains two or three blades. Three-blade HAWT is the most popular commercially for electricity generation since it has a relatively low torque ripple.

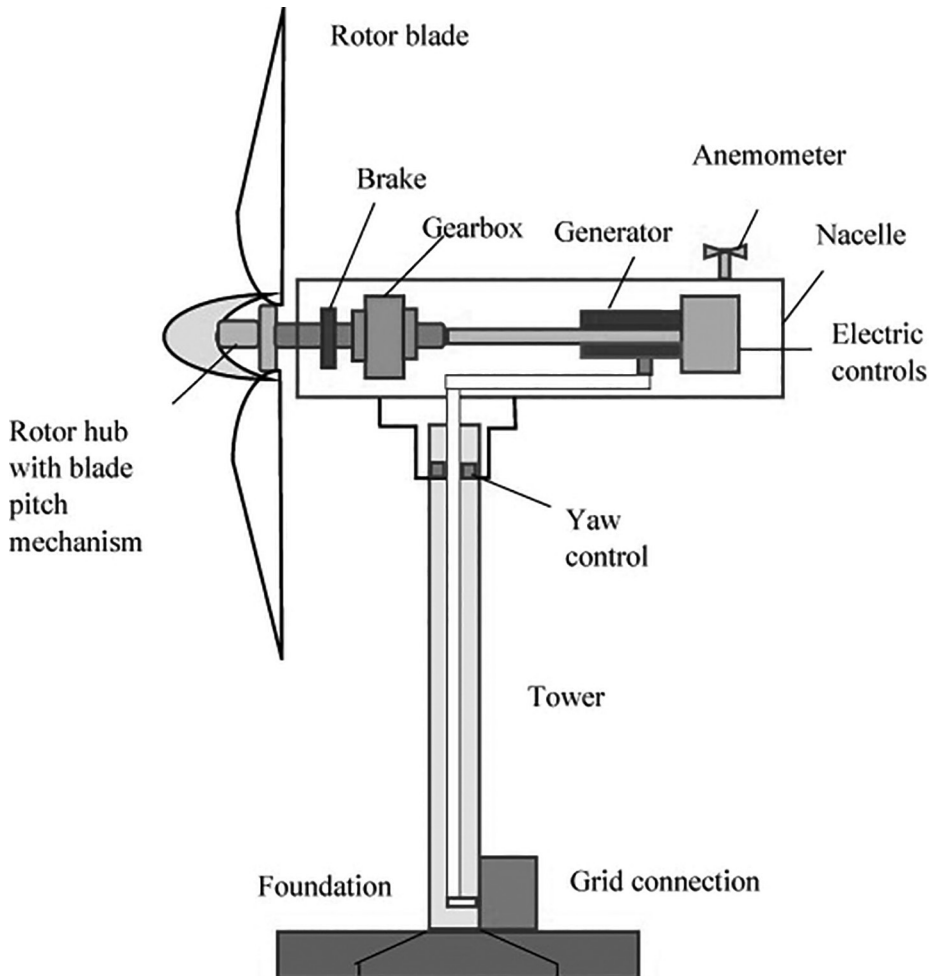


FIGURE 8.14 Typical configurations of the HAWTs.

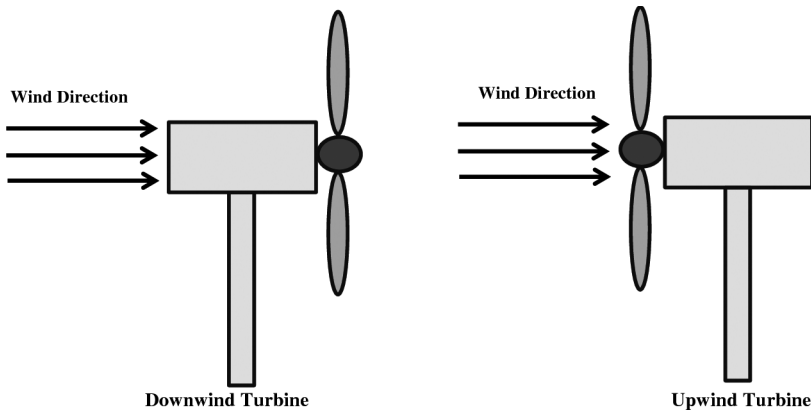


FIGURE 8.15 Downwind and upwind HAWTs.

HAWT could operate in a downwind or upwind manner. As illustrated in Figure 8.15, the rotor is placed at the backside of the downwind turbine. The nacelle and rotor are carefully designed so that the turbine can passively follow the wind and avoid the help from the yaw controller. This design permits some benefits that the rotor blades could be flexible and help dissipate energy and further relieve stress for the tower under some extreme weather conditions. However, drawbacks are obvious that the flexing could erode the blades and shorten their service life. Meanwhile, since the blade is placed behind the tower, tower shadow should be a problem that could introduce additional turbulence to the turbine. Conversely, for the upwind turbine, the rotor is positioned in the front of the turbine, and the influences of the tower shadow are reduced. The yaw controller is inevitable to keep it oriented to the wind. Meanwhile, the expanded nacelle is necessary to place the rotor far enough away from the tower to avoid blade strikes.

8.2.1.2 Vertical Axis Wind Turbines

VAWT has the main rotor shaft and blades arranged vertically and the main components close to the ground. The blades of VAWT are joined at the top and bottom of a vertically oriented rotor in the shape of an egg beater. This arrangement enables the VAWT to harness wind energy from any direction. When wind turbines are installed on a rooftop, the building usually redirects the wind over the roof, which can double the turbine's wind speed. The height of the rooftop-mounted turbine tower should be roughly half the height of the building for maximum wind energy and minimum wind turbulence. The fundamental benefit of VAWT is that they can capture wind from any direction without requiring an intricate yaw controller to constantly adjust the rotor when the wind direction changes. Since VAWT does not require an additional yaw controller to adjust the direction, the structure of VAWT could be simplified. Another merit of VAWT is that the heavier system components, such as the gearbox and generator, may be positioned on the ground, eliminating the requirement for a structurally solid nacelle and tower, as with HAWT, making these components conveniently accessible for maintenance. However, these designs also contain a major drawback, which causes less energy averaged over time. Vertical turbine designs are much less efficient than HAWT. The lower coefficient is mainly due to the comparatively low rotational speed, which results in increased torque and hence the higher cost of the drive train. Typical vertical designs are the full-Darrieus, the "H", the "V", the "Delta", the "Diamond", and the "Giromill" configurations, as illustrated in Figure 8.16.

For VAWT, the most common configurations are the Savonius, Darrieus, and H-Darrieus, as depicted in Figure 8.17. These configurations of turbines could also be categorized into two types, namely, lift-based and drag-based turbines.

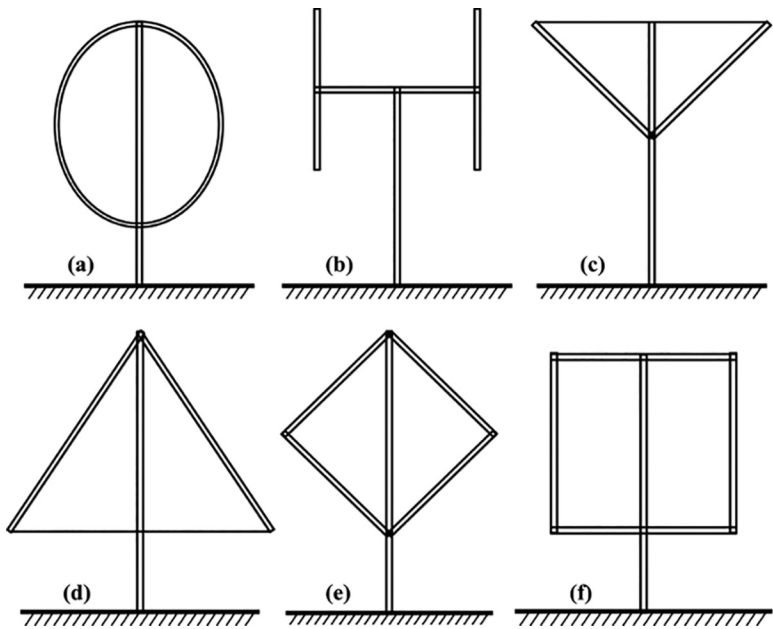


FIGURE 8.16 Different structures of the VAWTs (a) the full-Darrieus configuration, (b) the “H” configuration, (c) the “V” configuration, (d) the “Delta” configuration, (e) the “Diamond” configuration, (f) the “Giromill” configuration. (Öğüçlü, Ö. Structural design and stress analysis of a helical vertical axis wind turbine blade. *Sakarya Üniversitesi Fen Bilimleri Enstitüsü Dergisi*. 24(6), 2020, 1151–1161.)

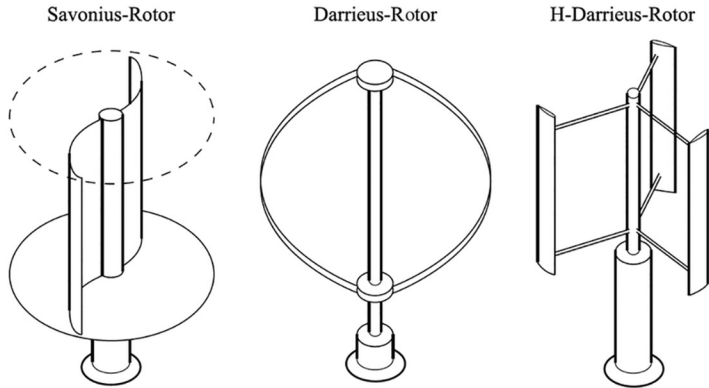


FIGURE 8.17 Common structures of the HAWTs. (https://www.researchgate.net/publication/323589645_Development_of_the_DualVertical-Axis_Wind_Turbine_with_Active_Blade_Pitch_Control/figures?lo=1.)

8.2.1.3 Other New Wind Turbines

Beyond the conventional wind turbines, many new wind turbine designs emerge with the ongoing technological advancement, such as the small wind turbine, diffuser-augmented wind turbine (DAWT), counter-rotating wind turbine, and airborne wind turbine. Unconventional designs encompass a broad range of developments, such as various rotor types and supporting structures.

8.2.1.3.1 Small Turbines

The Canadian Wind Energy Association (CanWEA) classifies “small wind” as high as 300kW, and small wind turbines are defined by the IEC 61400 Standard as wind turbines having a rotor swept



FIGURE 8.18 Example of a small wind turbine. (<https://www.flickr.com/photos/zillay/7093227789>.)

area of $<200\text{ m}^2$. Small wind turbines normally produce 0.5–10 kW of electricity, although they can be as small as a 50-W auxiliary power generator for a boat. A rotor, a nacelle with a tail, and a tower or mounting structure are the three primary components of a small wind turbine, as illustrated in Figure 8.18.

8.2.1.3.2 Diffuser-Augmented Wind Turbines

A DAWT is a wind turbine that has been modified to include a cone-shaped wind diffuser to improve the efficiency of converting wind energy to electricity, as depicted in Figure 8.19. The increased efficiency is possible due to the increased wind speeds the diffuser can provide. The rotor blades of typical bare turbines are vertically installed at the top of a support tower or shaft. The rotor blades of a DAWT are positioned within the diffuser, which is subsequently put on the support tower's top. Additional changes to the diffuser can be performed to improve its efficiency even more. The exit area of such a device must be bigger than the intake area, according to fundamental principles of fluid mechanics.

8.2.1.3.3 Counter-Rotating Wind Turbines

A counter-rotating wind turbine features a front rotor and a rear rotor that revolve in opposing directions, as depicted in Figure 8.20. The flow field of a counter-rotating wind turbine is more intricate than that of a single rotor owing to interactions between the front and rear rotors. The rear rotor's inflow is affected by the front rotor's wake, which is effectively an unstable flow condition. When a system expels or accelerates mass in a single direction, the accelerated mass exerts a corresponding but opposing force on the system. A single-rotor wind turbine's rotating blade generates a substantial quantity of tangential or rotational airflow. In a single-rotor propeller design, the energy of this tangential airflow is squandered.

8.2.1.3.4 Airborne Wind Turbines

Airborne Wind Energy is a wind energy system that uses flying blades or wings that are tethered to the ground, as depicted in Figure 8.21. Airborne wind turbines can operate at low or high altitudes, and they are part of a larger class of Airborne Wind Energy Systems that also includes high-altitude wind power and crosswind kite power. When the generator is stationary, the tethered aircraft does not need to carry the generator mass or have a conductive tether. When the generator is in the air, a conductive tether is utilized to deliver energy to the ground, aloft, or to receivers via microwave



FIGURE 8.19 Example of a DAWT. (<https://www.newieventures.com.au/diffuse-energy-wind-turbine-controller>.)



FIGURE 8.20 Example of a counter-rotating wind turbine. (<https://decoratex.biz/bsn/en/new-vetrovye-elektrostancii-dlya-doma-svoimi-rukami-opisanie-vidy-i-moshhnost.html>.)



FIGURE 8.21 Example of an airborne wind turbine. (<https://www.cgtrader.com/3d-models/vehicle/industrial/airborne-wind-turbine>.)

or laser. The proportion of time the system harvests at ideal conditions may be maximized by continually adjusting the average harvesting altitude to the vertical wind profile. Depending on the available wind resources and the necessary regulatory constraints, this technology should result in a significantly greater capacity factor than traditional wind turbines can achieve.

8.2.2 POWER IN THE WIND

8.2.2.1 The Variability of Wind

The most striking characteristic of the wind resource is its variability over a wide range of scales, both spatially and temporally. The spatial variability describes the fact that there are many different climatic regions, some much windier than others dictated by the latitude. Within any one climatic region, there is a great deal of variation on a smaller scale, largely dictated by the physical geography—proportion of land and sea, the size of landmasses, and the presence of mountains or planes. Temporal variability means that the amount of wind may vary in multiple time-scales, for example, varying from 1 year to the next or even longer periods, seasonal variations, intra-day variations, and so on.

The velocity and direction of the wind change rapidly with time. Therefore, the available power and energy from wind also vary (see Figure 8.22).

8.2.2.2 Local Effects on Wind

There are many local factors affecting the available wind speed, mainly including the turbulence, the wind wake and park effect, and the tunnel and hill effect.

8.2.2.2.1 Turbulence

It is normally experienced that hailstorms (or thunderstorms in particular) are associated with frequent gusts of wind which both change speed and direction. In areas with a very uneven terrain surface, and behind obstacles such as buildings, a lot of turbulence is similarly created, with very irregular wind flows, often in whirls or vortices in the neighborhood. Turbulence decreases the possibility of using the energy in the wind effectively for a wind turbine. It also imposes more tear and wear on the wind turbine, as explained in the section on fatigue loads. Towers for wind turbines are usually made tall enough to avoid turbulence from the wind close to ground level.

8.2.2.2.2 Wind Wake and Park Effect

Since a WTG generates electricity from the energy in the wind, the wind leaving the turbine must have a lower energy content than the wind arriving in front of the turbine. There will be a wake

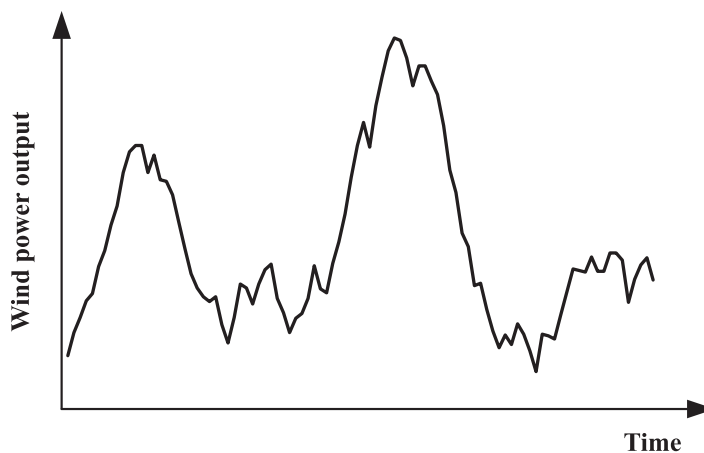


FIGURE 8.22 Example of a variable wind power output.

effect behind the turbine, that is, a long trail of wind that is quite turbulent and slowed down, compared to the wind arriving in front of the turbine. To avoid too much turbulence around the turbines downstream, WTGs are usually spaced apart, for example, between five and nine rotor diameters apart in the prevailing wind direction.

8.2.2.2.3 *The Tunnel and Hill Effect*

The air becomes compressed on the windy side of the buildings or mountains, and its speed increases considerably between the obstacles to the wind. This is known as a “tunnel effect.” Placing a WTG in such a tunnel is one clever way of obtaining higher wind speeds than in the surrounding areas. To obtain a good tunnel effect, the tunnel should be “softly” embedded in the landscape. In case the hills are very rough and uneven, there may be lots of turbulence in the area, that is, the wind will be whirling in a lot of different (and rapidly changing) directions. A common way of siting WTGs is to place them on hills or ridges overlooking the surrounding landscape.

8.2.2.3 Measurement of Wind

For precise analysis, the wind velocity and direction at the specific site have to be measured with the help of accurate and reliable instrumentation to identify a site for a wind power project.

8.2.2.3.1 *Ecological Indicators*

The Eolian features are formations on the land surface due to continuous strong wind, which may be used as indicators for the strength of the wind prevailing in an area. The Eolian features are the sand dunes in which the size of the sand particle can give an indication of the average strength of the wind in the region. Another way to identify windy sites is to observe the biological indicators, for example, trees and brush deformed due to strong winds. The intensity and nature of this deformation depend on the strength of the wind. This method is specifically suitable for judging wind in valleys, coasts, and mountain terrains.

8.2.2.3.2 *Anemometers*

In addition to meteorological information, field measurements are made by the use of anemometers or wind meter devices used for measuring wind speed. Calibrated anemometers are fixed on tall masts; the height of masts is the hub height of the turbine to avoid correction in wind speed due to surface shear. Anemometers can be divided into two classes, including that measure the wind speed and that measure the wind pressure. Since there is a close connection between the pressure and the speed, anemometers designed for one will provide information about both. The velocity anemometers can be rotational anemometers (cup and propeller anemometers), vane anemometers, thermoelectric anemometers (hot wire and hotplate anemometers), phase shift anemometers such as acoustic resonance anemometers, ultrasonic anemometers, laser Doppler anemometers, and ping-pong ball anemometers. Pressure anemometers could be plate anemometers, tube anemometers including pitot tube static anemometers, and sphere anemometers.

8.2.2.4 Statistical Models for Wind Data Analysis

Wind data measured and further extrapolated to the rotor height needs to be analyzed to be used in wind energy assessments. There are two methods used in wind data analysis: the histogram (or method of bins) and statistical functions.

8.2.2.4.1 *Histogram*

For the method of histogram, data is separated into data intervals (bins or classes) of width 1 m/s, each one with f_r occurrences. The starting point is a file with 8,760 values of hourly average wind speeds. For instance, a wind speed of 8.5 m/s belongs to the class of 7 m/s; a wind speed of 8.38 m/s belongs to the class of 8 m/s, as seen in Table 8.2. On this basis, a histogram can be built, counting the number of occurrences of each class. An example of a wind speed histogram is shown in

TABLE 8.2
Example of Distribution of Hourly Average Wind Speed by Classes

Hour ID	Wind Speed (m/s)	Wind Speed Class (m/s)
8679	8.5	7
8670	8.38	8
8671	9.75	10
8672	9.76	10
8673	10.98	11
8674	10.64	11
8675	11.76	12
8676	13.72	14
8677	15.42	15
8678	18.94	17

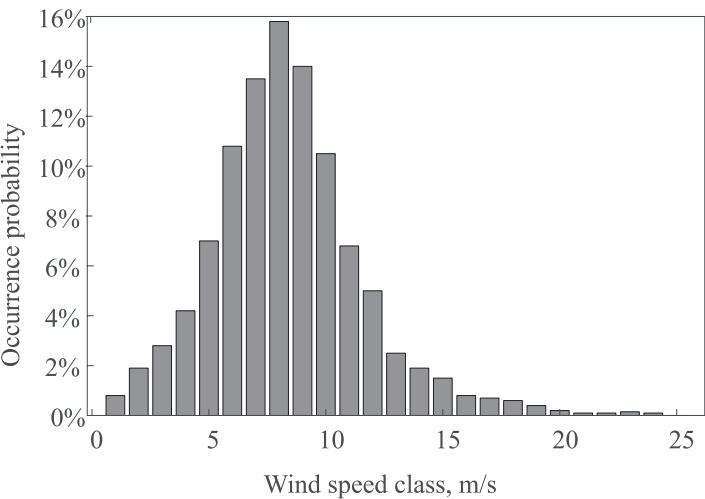


FIGURE 8.23 Example of a wind speed histogram.

Figure 8.23. In Figure 8.23, wind speeds lying between 7.5 and 8.4 m/s occur 16% of the year (about 1,400 h). This means that the probability of the wind speeds being between 7.5 and 8.4 m/s is 16%.

8.2.2.4.2 Statistical Functions

It is logical to represent the wind velocity distributions by standard statistical functions. Weibull and Rayleigh distributions are typical distributions describing the wind variations in a regime with an acceptable accuracy level.

8.2.2.4.2.1 Weibull Distribution Weibull distribution is a special case in which the variations in wind velocity are characterized by two functions: the probability density function and the cumulative distribution function, as is illustrated in Figure 8.24. The probability density function $f(v)$ indicates a fraction of time (or probability) for which the wind is at a given velocity v . It is given by

$$f(v) = \frac{k}{c} \left(\frac{v}{c} \right)^{k-1} e^{-\left(\frac{v}{c} \right)^k} \tag{8.13}$$

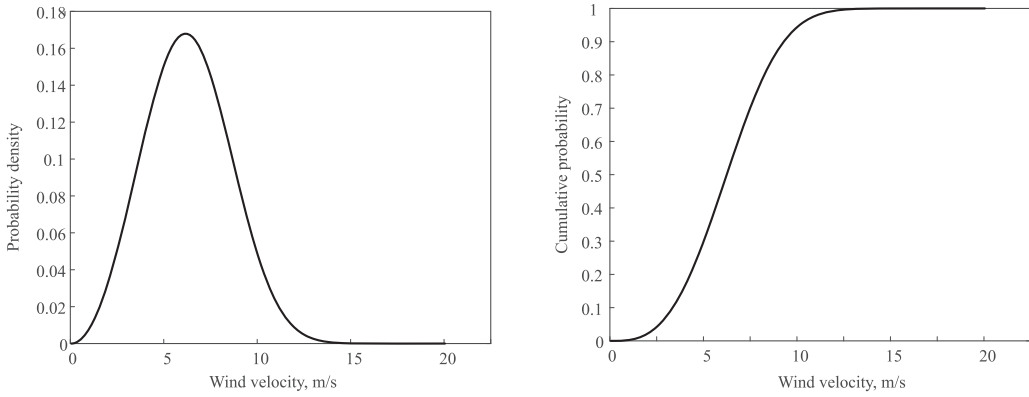


FIGURE 8.24 Probability density and cumulative probability of Weibull distribution.

where k and c are the Weibull shape factor and scale factor, respectively. The cumulative distribution function $F(v)$ is the integral of the probability density function. The cumulative distribution $F(v)$ is given by

$$F(v) = 1 - e^{-\left(\frac{v}{c}\right)^k} \quad (8.14)$$

The average wind velocity of a regime, following the Weibull distribution, is given by

$$v_m = \int_0^{\infty} v f(v) dv \quad (8.15)$$

which can be rewritten as

$$v_m = \int_0^{\infty} v \frac{k}{c} \left(\frac{v}{c}\right)^{k-1} e^{-\left(\frac{v}{c}\right)^k} dv \quad (8.16)$$

The cumulative distribution function can be used for estimating the time for which wind is within a certain velocity interval. Probability of wind velocity between v_1 and v_2 is given by

$$\Pr(v_1 < v < v_2) = F(v_2) - F(v_1) \quad (8.17)$$

That is:

$$\Pr(v_1 < v < v_2) = e^{-\left(\frac{v_1}{c}\right)^k} - e^{-\left(\frac{v_2}{c}\right)^k} \quad (8.18)$$

8.2.2.4.2.2 Rayleigh Distribution Rayleigh distribution is a continuous probability distribution for positive-valued random variables. The Rayleigh distribution is a special case of the Weibull distribution with a scale parameter k as 2. The illustrative probability density of the Rayleigh distribution is shown in Figure 8.25. One example is when wind velocity is analyzed into its orthogonal two-dimensional vector components. Assuming that each component is uncorrelated, normally distributed with equal variance, and zero mean, then the overall wind speed (vector magnitude) will

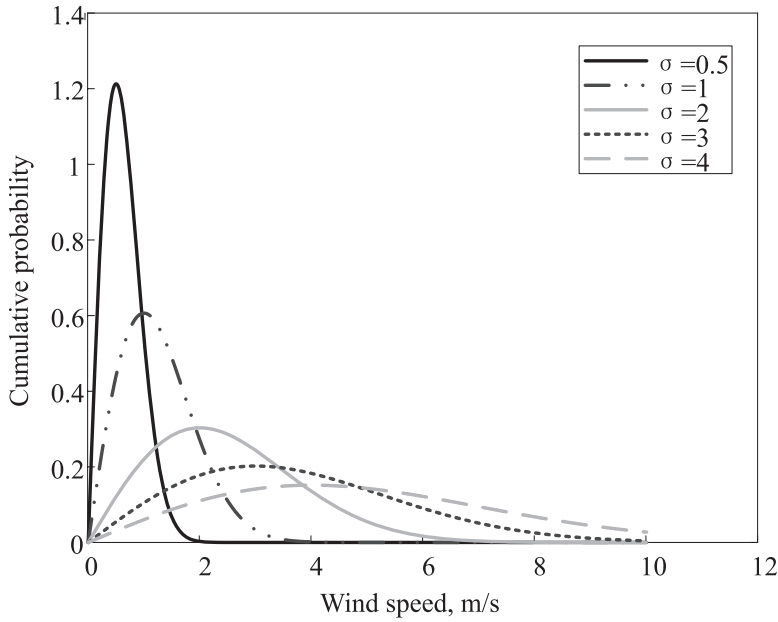


FIGURE 8.25 Probability density of Rayleigh distribution.

be characterized by a Rayleigh distribution. The behavior of wind velocity at a given site can be specified as a probability distribution function $f(v)$.

The probability density function of the Rayleigh distribution is

$$f(v) = \frac{v}{\sigma^2} e^{-\frac{v^2}{2\sigma^2}}, \quad v \geq 0 \quad (8.19)$$

where σ is the scale parameter of the distribution.

The cumulative distribution function is

$$F(v) = \frac{v}{\sigma^2} e^{-\frac{v^2}{2\sigma^2}}, \quad v \geq 0 \quad (8.20)$$

The mean and variance of a random variable in Rayleigh distribution can be expressed as

$$\mu(v) = \sigma\sqrt{\pi/2} \approx 1.253\sigma \quad (8.21)$$

$$\text{var}(v) = \sigma^2(4 - \pi)/2 \approx 0.429\sigma^2 \quad (8.22)$$

8.2.2.5 Power Curve of WTGs

The available wind power under a certain wind speed follows the relationship of kinetic energy. Consider a volume of air with mass, m (kg), crossing a disk of air with an area, A (m²) at a constant speed, v (m/s), the thickness of the volume of air being x (m), as in Figure 8.26.

The associated kinetic energy is given by

$$E_{\text{kin}} = \frac{1}{2}mv^2 = \frac{1}{2}(\rho Ax)v^2 \quad (8.23)$$

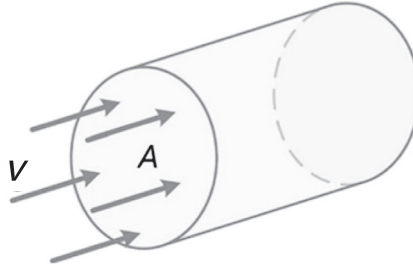


FIGURE 8.26 Volume of air crossing a section of an air disk at a constant speed. (Castro, 2008.)

where ρ is the air density ($\rho = 1.23 \text{ kg/m}^3$, $\theta = 15^\circ\text{C}$). The identity $m = \rho Ax$ can be easily confirmed by a dimension's analysis.

According to the relationship between power and energy, the available wind power output is

$$P_e = \frac{dE_{\text{kin}}}{dt} = \frac{1}{2}(\rho A)v^2 \frac{dx}{dt} \quad (8.24)$$

which can be written as

$$P_e = \frac{1}{2} \rho A v^3 \quad (8.25)$$

More specifically, the output power of a WTG depends on the wind speed input following the so-called power curve. Figure 8.27 shows a typical power curve of a 2 MW WTG. The maximum power is known as the rated power, and the corresponding wind speed is known as the rated wind speed. In the case of Figure 8.27, the rated power is 2 MW, and the rated wind speed is 15 m/s.

Analyzing the power curve shown in Figure 8.27, it is possible to conclude that

- For wind speed lower than a certain value, which is the so-called cut-in wind speed, the WTG is disconnected because it is not economical to extract power from the wind. Usually, the cut-in wind speed is between 3 and 5 m/s.
- There is an operating zone in which the WTG is regulated to capture the maximum power from the wind. In this zone, as the wind speed goes from the cut-in wind speed to the rated wind speed, the power output changes approximately with the cube of the wind speed.
- For wind speeds higher than the rated wind speed, the WTG is regulated to operate at a constant rated power so that the maximum power is not exceeded, and the WTG is not damaged. In this operating zone, the conversion efficiency is artificially lowered by the WTG control system.
- When the wind speed is dangerously high, higher than the so-called cut-off wind speed (usually between 25 and 30 m/s), the WTG is disconnected from the grid for safety reasons.

All the WTG power curves have a similar pattern. The rated power depends on the specific model and types of WTG. For onshore WTGs, the rated power of the current typical WTG is about 3–4 MW. For offshore WTGs, the typical rated power is higher, about double of onshore installations. Power curves are available at the manufacturers' internet sites.

It is useful to have the WTG power curve described by an analytic equation. To model the power curve in the output power changing zone, a sigmoid function is often used. Therefore, the model of a power curve can be described by

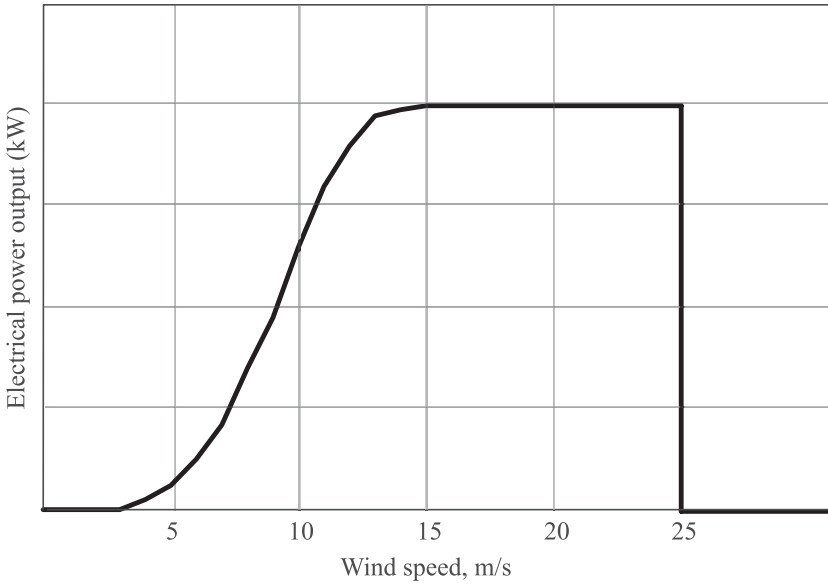


FIGURE 8.27 Typical power curve of a 2 MW WTG.

$$P_e = \begin{cases} 0 & u < u_{\text{in}} \\ P_N \frac{u - u_{\text{in}}}{u_N - u_{\text{in}}} & u_{\text{in}} \leq u < u_N \\ P_N & u_N \leq u < u_{\text{out}} \\ 0 & u > u_{\text{out}} \end{cases} \quad (8.26)$$

where u_{in} , u_N , and u_{out} are the cut-in, rated, and cut-off speed. P_N denotes the rated power.

In practice, the actual wind power curve of WTGs sited at different locations experiencing different environmental conditions shows differences from the standard one provided by manufacturers, as shown in Figure 8.28, since the provided power curve is obtained under a standard test environment. Accurate models of power curves can play an important role in estimating the performance of a WTG, forecasting wind power, and aiding in wind farm expansion. Various modeling methods have been studied to develop a more accurate power curve.

8.2.2.6 Wind Energy Estimation

The annual electricity production by a WTG can be estimated using the wind speed and power curve parameters.

With analytic equations for wind speed PDF and WTG power curve, the appropriate yearly electricity production can be estimated as

$$E_a = 8,760 P_{\text{avg}} = 8,760 \int_{v_{\text{in}}}^{v_{\text{off}}} f(v) P_e(v) dv \quad (8.27)$$

where $f(v)$ is the wind speed PDF and $P_e(v)$ denotes the equation of wind power curve.

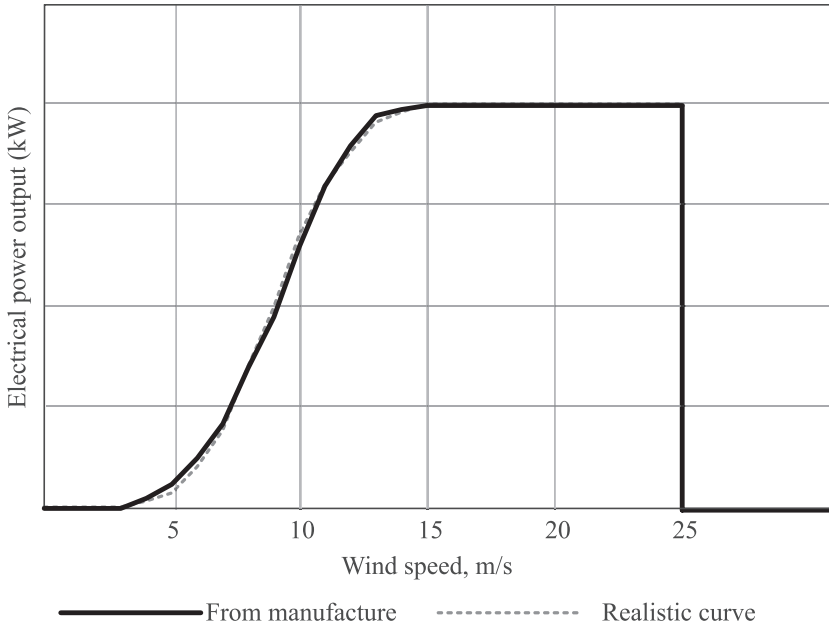


FIGURE 8.28 Power curves from manufacturers and realistic data.

With wind speed discrete histogram and discrete power curve, the yearly electricity production can be estimated as

$$E_a = \sum_{v_{in}}^{v_{off}} f_r(v) P_e(v) \quad (8.28)$$

where $f_r(v)$ is the wind speed occurrence frequency (given by the histogram for each wind speed class) in h/year.

Based on the annual electricity production, the annual average power output of a WTG can be calculated as

$$P_{avg} = \frac{E_a}{8,760} \quad (8.29)$$

Capacity factor (C_F) is one of the important indices for assessing the field performance of a WTG. The capacity factor of a wind energy conversion system at a given site is defined as the ratio of the energy actually produced by the system to the energy that could have been produced by it, if the machine would have operated at its rated power throughout the time period. Thus:

$$C_F = \frac{E_a}{TP_N} \quad (8.30)$$

The capacity factor reflects how effectively the turbine can harness the energy available in the wind spectra. Usually, the capacity factor is expressed on an annual basis. The capacity factor for a reasonably efficient turbine at a potential site may range from 0.25 to 0.4. A capacity factor of 0.4 or higher indicates that the system is interacting with the regime very efficiently. Information on the

capacity factor of the turbine at a given site may not readily be available during the initial phases of the project identification. Under such circumstances, it is advisable to calculate the rough capacity factor. This is basically deduced from the power curve of the machine, based on the average wind velocity at the site. From the power curve, we can locate the current power corresponding to the average wind velocity,

$$RC_F = \frac{P_{avg}}{P_N} \quad (8.31)$$

8.2.3 WIND FARMS

A wind farm is a group of WTGs in the same location used for the production of electricity. A large wind farm may consist of several hundred individual wind turbines distributed over an extended area. Wind farms can be classified into onshore wind farms and offshore wind farms.

Onshore wind farms refer to turbines that are located on land and use the wind to generate electricity. They are generally located in areas where there is low conservation or habitat value. Figure 8.29 shows a picture of an onshore wind farm. The cost of onshore wind farms is relatively cheap, allowing for mass wind turbine farms. The shorter distance between the windmill and the consumer allows for less voltage drop-off on the cabling.

An offshore wind farm is a wind farm that is placed out to sea. Figure 8.30 shows an example of offshore WTGs. Different from onshore wind farms, stronger wind speeds are available offshore, and on the surface of the water, there is almost nothing to block the wind or slow it down. Offshore wind power includes inshore water areas such as lakes, fjords, and sheltered coastal areas, utilizing traditional fixed-bottom wind turbine technologies, as well as deep-water areas utilizing floating wind turbines. The sites where offshore wind farms can be placed are only limited by a small number of factors, including the depth of the water, bird flyways, boating lands, and waste sites.



FIGURE 8.29 An onshore wind farm. (<https://www.nationalgeographic.org/encyclopedia/wind-energy/>)



FIGURE 8.30 Wind turbines and electrical substation of Alpha Ventus supplied by Adwen in the North Sea. (https://en.wikipedia.org/wiki/Offshore_wind_power.)

8.2.3.1 Basic Components for Wind Farms

A wind power generation system generally consists of the following components:

1. Generator.
2. “Gene-Specific” box contains one or a few of the following components depending on the type of generator and turbine manufacturer. The components are usually part of the turbine’s electrical system:
 - Generator earthing;
 - External resistors for slip control, but an induction generator variable resistor to control slip;
 - Capacitors for phase compensation, for induction generators;
 - Power electronics converters for AC to DC to AC conversion for permanent magnetic and variable speed sync problems generators;
 - Soft starter to control inrush current, for an induction generator.

3. Current transformer, intelligent electronic device, and circuit breaker are part of a programmable production system. Their purpose is to monitor various parameters on the line, such as voltage, current, and frequency, in order to connect or disconnect the components from the transformer.
4. Three-phase transformer to raise voltage from low voltage to medium voltage. This transformer would increase the voltage from 480 to 600 V (depending on the generator) to 11 or 69 kV (depending on the design of medium voltage inside the wind farm). The capacity of the transformer is specified in terms of MVA, which is the product of the maximum voltage and the maximum current from the generator. In simple terms, the MVA number is 15%–25% higher than the rating of the generator. These ratings also apply to almost all components like the circuit breaker, fuses, and metering equipment.

For wind farms, the following components are pertinent:

1. Feeders that a wind farm with multiple WTGs is conducted to. Each WTG with switch gear and transformer is connected to a switch and then to the feeder. The switch is used to connect and disconnect a single WTG in case maintenance on it is needed, or a fault happens.
2. The two feeders collect energy from the WTGs and put it on a common bar. This is then stepped up to the grid voltage using the transformer. This transformer must be rated to step up the entire power output of the wind farm. The first bar and transformer are separated by a circuit breaker.
3. A utility grid meter to measure the amount of energy that is delivered to the grid.
4. The circuit breakers that monitor grid voltage, current, frequency, phase difference, and other parameters. Depending on the data and processing logic program in the Intelligent Electronic Device, the circuit breaker connects/disconnects the wind farm from the grid.

Wind turbines used in wind farms for commercial production of electric power are usually three-bladed and pointed into the wind by computer-controlled motors. These have high tip speeds of over 320 km/h (200 mph), high efficiency, and low torque ripple, which contribute to good reliability. The blades are usually colored white for daytime visibility by aircraft and range in length from 20 to 40 m (66–130 ft) or more. The tubular steel towers range from 60 to 90 m (200–300 ft) tall. The blades rotate at 10–22 revolutions per minute. At 22 rotations per minute, the tip speed exceeds 90 m/s (300 ft/s). A gearbox is commonly used for stepping up the speed of the generator, although designs may also use the direct drive of an annular generator. Some models operate at a constant speed, but more energy can be collected by variable-speed turbines, which use a solid-state power converter to interface with the transmission system. All turbines are equipped with protective features to avoid damage at high wind speeds by feathering the blades into the wind, which ceases their rotation, supplemented by brakes.

8.2.3.2 Wind Farm Layout Design

Designing a wind farm layout refers to finding the optimal placement of each individual WTG from others inside the specific wind farm. Recall that the wind resources are impacted by the operating of WTG featured as wake effect, turbulence, and so on. To mitigate the wind energy loss due to such effects and extract as much wind energy as possible, wind farm design layout optimization remains an important issue.

Referring to the different layouts existing in offshore wind farms, four basic designs can be identified: radial design, single-sided ring design, double-sided ring design, and star design. Additionally, two innovative designs may be economically appealing and reliability increasing: the single-return design and the double-sided half-ring design.

8.2.3.2.1 Radial Design

The most common and straightforward WTG layout is that in which several WTGs are connected to a single cable feeder within a string, as seen in Figure 8.31. The number of WTGs connected to each string feeder is dependent on the rating of the sea cables and the capacity of the WTGs. The biggest advantages of this design are the low cost and how simple it is to control. The major disadvantage is its poor reliability since any type of fault (cable or switchgear) that happens near the hub prevents all WTG in that array from exporting their energy.

8.2.3.2.2 Single-Sided Ring Design

To increase the reliability of the radial design, a single-sided ring design is a possible solution that connects the last WTG of the string to the hub with a long cable, as seen in Figure 8.32. Therefore, this design requires an additional redundant cable sized to handle the full power flow of the string in the event of a fault in the primary link near the hub. This solution allows all WTGs to keep operating, except the faulty WTG. This additional security comes with an extra cost due to the new longer cable and the higher cable rating requirements throughout the string circuit. In this case, the narrowing of the cables' ratings away from the hub is not viable.

8.2.3.2.3 Double-Sided Ring Design

To get the same reliability as in the single-sided ring design but decrease its cost, the last WTG of one string is connected to the last WTG of another string, as presented in Figure 8.33. Compared to

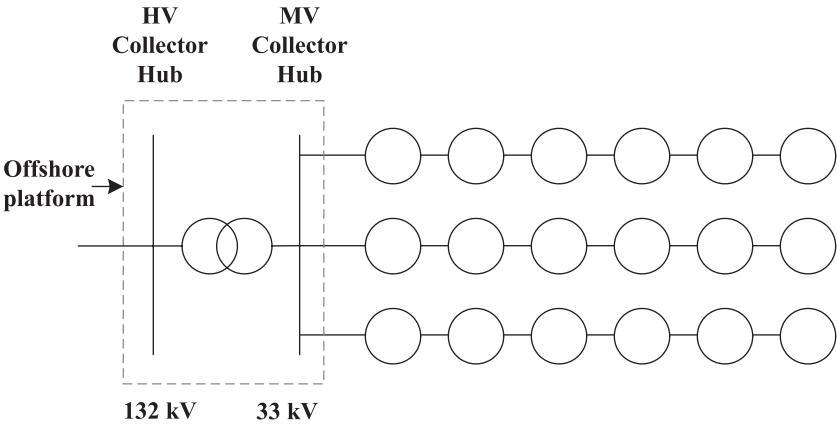


FIGURE 8.31 Wind farm radial design.

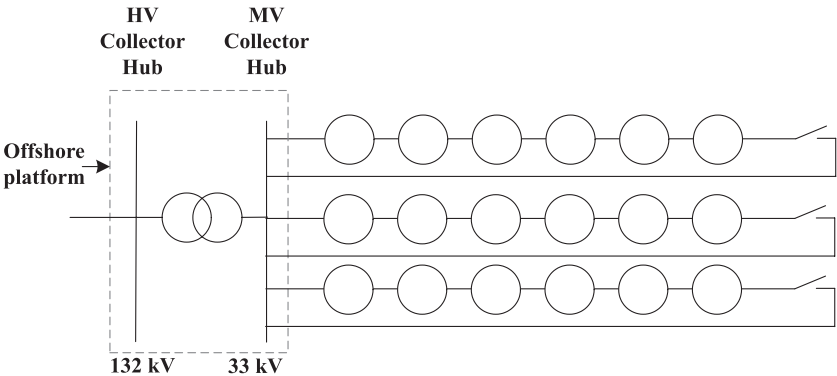


FIGURE 8.32 Wind farm single-sided ring design.

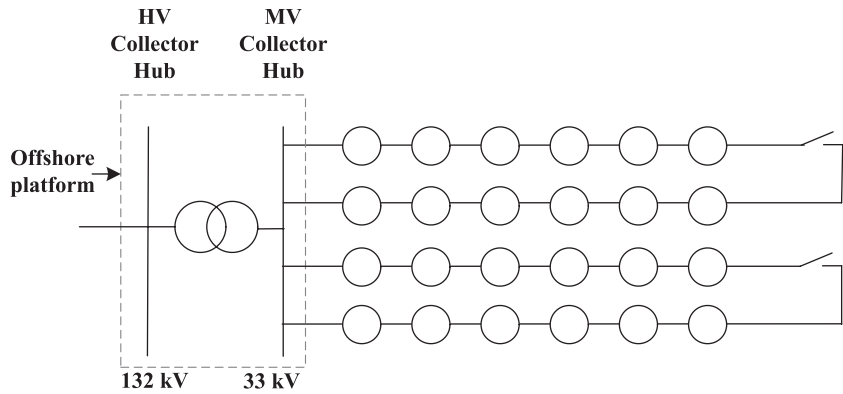


FIGURE 8.33 Wind farm double-sided ring design.

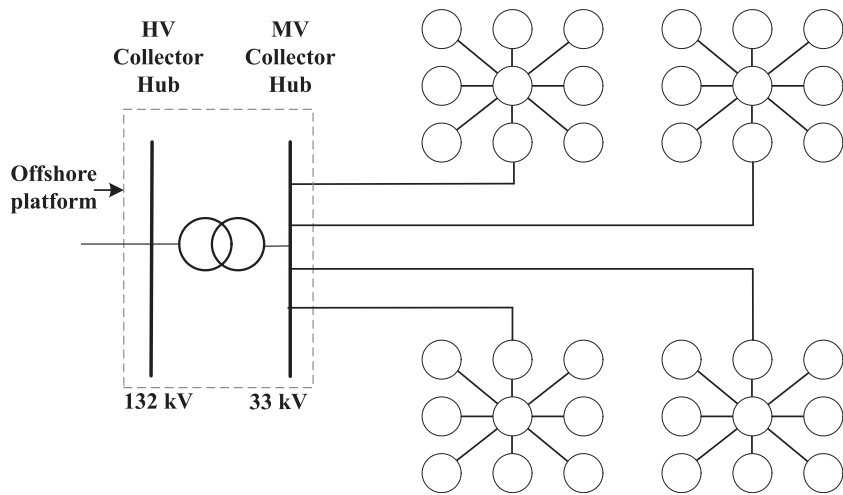


FIGURE 8.34 Wind farm star design.

the single-sided ring design, there is a decrease in the total cable length, while maintaining the same level of redundancy. The downside of this design is that the connection between the hub and the first WTG of the string needs to handle the output of twice as many WTGs as those on its string. Despite the increased reliability, small offshore wind farms do not use them since the fault probability in small wind farms is lower while the unit cost associated with having additional equipment is higher. In contrast, for large offshore wind farms, because repair downtimes are significantly longer, and the redundancy becomes economically profitable.

8.2.3.2.4 Star Design

To reduce cable ratings and to provide a high level of reliability, one possible solution is the star design, since one cable outage only affects one WTG, except for the cable from the central WTG to the hub (Figure 8.34). This design provides a general reduction of cable ratings. Only the cable from the center turbine to the hub needs to handle all power from all turbines in the string. The disadvantages are the longer diagonal cables and the more complex switchgear arrangement required for the WTG at the center of the star.

PROBLEMS

Example 8.1

Please discuss the strategies to resolve overvoltage issue due to the increase of grid-connected PV systems.

Solution

(1) Restricting PV output; (2) use of battery to avoid overvoltage; (3) three modes of battery operation (voltage control mode, schedule mode, minimizing reverse power mode)

Example 8.2

Please discuss the impact between the network and multiple PV inverters.

Solution:

(1) Voltage rise; (2) harmonics; (3) DC injections; (4) unintentional islanding; (5) grid impedance variation

Example 8.3

Consider a WTG with the parameters shown in Table 8.3. The wind speed histogram in all 8,760h is known and is shown in Figure 8.35. The WTG power curve is displayed in Figure 8.36. Compute the estimated annual WTG electricity production, the average power output, and the capacity factor.

TABLE 8.3
Parameters of the WTG

Rated power	2,310kW
Rotor diameter	71 m
Hub height	80m

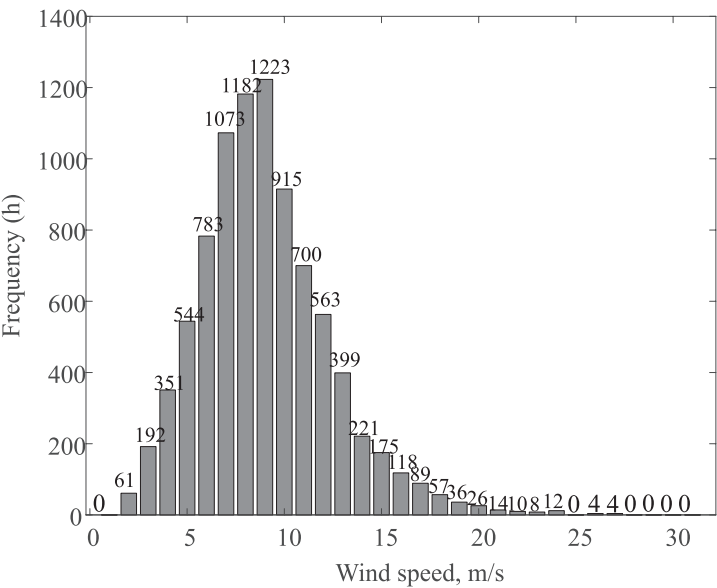


FIGURE 8.35 Wind speed histogram following wind speed measurements.

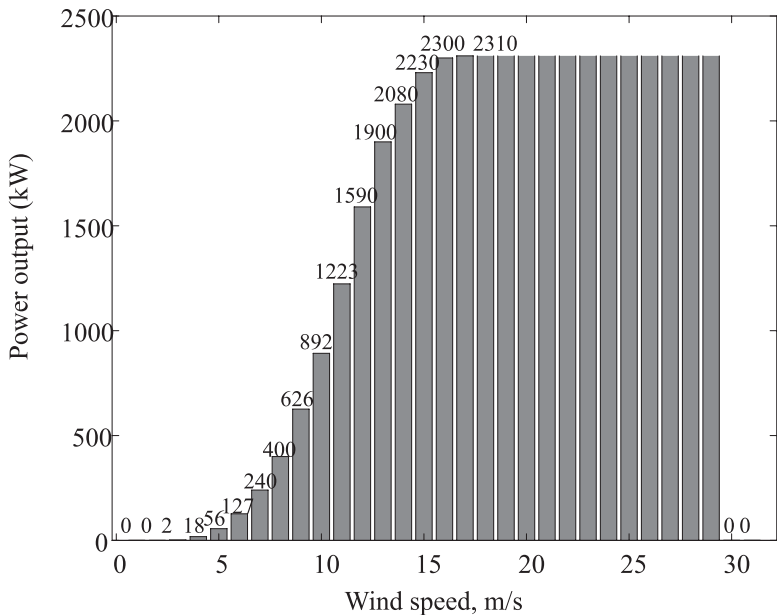


FIGURE 8.36 WTG power curve as given by the manufacturer.

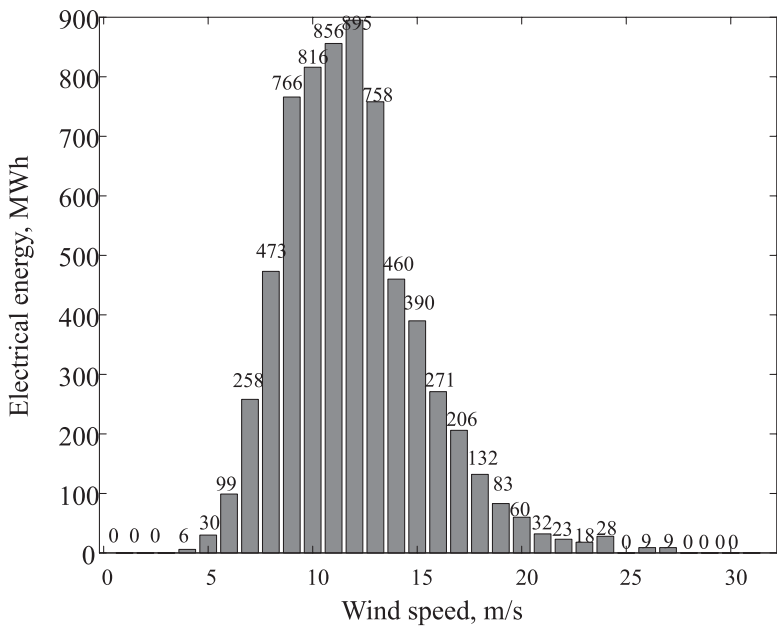


FIGURE 8.37 Electrical energy produced by each wind speed.

Solution

For each wind speed, we need to multiply the histogram (number of hours each wind speed occurs) by the power curve (output power for each wind speed) to get the energy produced by each wind speed. The result is displayed in Figure 8.37.

To compute the annual electrical energy produced, all the energies produced by the wind speeds are summed up. To compute the average power output, Equation 8.29 is applied using the annual electricity. To compute the capacity factor, Equation 8.30 is applied using the annual electricity production and the rated power. The obtained results are summarized in Table 8.4.

TABLE 8.4
Results of Example 8.3

Annual energy	6,680 (MWh)
Average power output	762.6 (kW)
Capacity factor	33.01%

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Appendix A

Methods for Allocating Transmission-Line Fixed Charges among Joint Users

In general, interconnections can help to achieve the two fundamental objectives of power system operations, the economy of power production and the continuity of service. Therefore, interchanges between adjacent utilities are scheduled to take advantage of load diversity or available low-cost generating capacity, allowing lower overall operating costs and possible deferment of capital investment for new plants. Thus, interconnections provide the ability to use larger plants and relative flexibility in locating them and the ability to share spinning reserve capacity during emergencies for continuities of service. While sharing in the benefits of interconnected operation, each participating utility is expected to share its responsibilities.

A.1 THEORETICAL METHODS FOR ALLOCATING DEMAND COSTS

In general, the fixed charges of a transmission line include the return on investment, taxes, depreciation, insurance costs, and O&M costs. The methods used in the past to allocate fixed charges (i.e., demand costs) are

1. Energy method
2. Peak responsibility method
3. Maximum-demand method
4. Greene's method
5. Eisenmenger's method
6. Phantom method
7. Weighted peak method

A.1.1 ENERGY METHOD

The energy method is the simplest and one of the most commonly used methods. It allocates the demand costs in proportion to the energy used by each class of consumers during a period of months or years [1,2]. It is a simple method due to the fact that the values of energy consumed by various consumer classes during the past periods are readily available from the records. However, it is not fair to all users involved since it does not take into account the cost of providing service that is largely dependent on short-time power demands rather than energy. If all customers had a 100% load factor, the method would be perfectly fair to all consumers. Therefore, the method is usually not an appropriate one because demand costs are not basically proportional to the energy used but rather to the maximum demand of the class of consumers. With this method, the class with the large energy consumption would be overburdened.

A.1.2 PEAK RESPONSIBILITY METHOD

The peak responsibility method [3] allocates the demand costs in proportion to the demand made by each class of consumer on the system at the time of system maximum demand. It attempts to place

the burden on those classes of consumers responsible for the large amount of investment required to serve the peak-load period. If a company serves classes of consumers whose peaks are coincident in forming the annual peak on the company's system, the peak responsibility method is fair and just. In the early days, when the principal load was lighting, this condition existed.

It is obviously unfair to charge one class of customers who happens to use energy at the time of the annual system peak with all of the demand costs and let the other customers use the equipment for nothing. This is not only unfair but it is impracticable. For example, a peak due to one class of customers may coincide with the system annual peak, and in the following year, the system peak may be caused by different classes.

A.1.3 MAXIMUM-DEMAND METHOD

The criticism of the peak responsibility method suggested that the demand costs may be more equitably allocated by the ratio of the maximum demand of the class under consideration to the summation of the maximum demands of all classes. However, the maximum-demand method [3] gives correct results only in certain isolated cases. If the customer's peaks coincide, it agrees with the peak responsibility. In cases where the customer's maximum demands are not coincident, there is no overlapping of curves, and when the load factors (average load/maximum load) of all customers are the same, this method is applicable, and the results are just and fair.

However, there are two important aspects that are neglected in the method. First, it ignores the important item of time that the peaks occur. Second, it entirely neglects the energy required by those classes. Therefore, it encourages a long hour use of the individual demand because all consumers who have a load factor higher than the average are charged too little, and all who have a load factor lower than the average are charged too much.

A.1.4 GREENE'S METHOD

Greene's method [4] uses a combination of the maximum-demand and the energy methods. Part of the demand costs is a direct function of the maximum demands, and the remainder is a direct function of energy. The proper values can be obtained by solving the following equations:

$$Kx + Dy = C \quad (\text{A.1})$$

$$8,760x + y = \frac{C}{p} \quad (\text{A.2})$$

where

x is the cost per kilowatt-hour of that portion of demand costs that functions with kilowatt-hour supplied consumers

y is the demand cost per kilowatt of the portion of demand costs that function with the maximum demand of customers

D is the sum of consumers' maximum demands

P is the maximum coincident demand or peak responsibility of all consumers on sources of supply

K is the kilowatt-hours used by all consumers in a year

C is the kilowatt-hours in a year for 1 kW load operated at 100% power factor and 100% load factor (number of hours in a year)

Without any doubt, this is a fairer method than any one of the previously mentioned methods. It is a simple method. However, it neglects a very important parameter, the time at which the individual maximum demands occur, even though it does recognize the duration of such load.

A.1.5 EISENMENGER'S METHOD

Eisenmenger [5] made the most elaborate study of central station (i.e., power plant) load curves and their relative contribution to the demand costs of the system. He advocated the following simplified method of allocation. Eisenmenger's method is usually a more appropriate one than the three previous methods. This is due to the fact that it takes into consideration not only the on-peak but also the off-peak load of the various consumer classes and their duration.

If the proportionality factors of the classes of consumers sharing the annual demand costs are represented by F_{class} and the total demand costs are divided by their sum, the demand costs to be allocated to each class can be expressed as

$$\text{Demands costs allocated to class } i = \frac{F_{\text{class } i}}{\sum_{i=1}^n F_{\text{class } i}} \times (\text{total demand costs}) \quad (\text{A.3})$$

From an elaborate graphical analysis of many load curves, the following empirical formula has been developed for determining F_{class} factors:

$$\begin{aligned} F_{\text{class}} = & \text{MD}_{\text{class}} \times \frac{\% \text{SP}_{\text{class}}}{100} \\ & + \text{MD}_{\text{class}} \times \left(1.0 - \frac{\% \text{SP}_{\text{class}}}{100} \right) \times \frac{\text{Peak hours}}{24} \\ & + (\text{MD}_{\text{class}} \text{OP}) \times \frac{\text{OP}_{\text{hours}}}{24} \end{aligned} \quad (\text{A.4})$$

This equation states that the proportionality factor of a class is equal to the sum of the following terms:

1. Maximum demand of class (MD_{class}) times percentage of station peak of class ($\% \text{SP}_{\text{class}}/100$)
2. Maximum demand of class times remainder percentage of station peak of class times ratio of hours per day to 24 h during which the class peak and station peak coincide
3. Maximum-demand off-peak ($\text{MD}_{\text{class}} \text{OP}$) of class times ratio of hours per day to 24 h during which the class peak and the station peak do not overlap

For off-peak consumers, this method gives correct results. However, it does not divide the demand costs correctly among those consumers who are on at the time of the station peak. In this method, every customer who is on at the time of station peak contributes to that peak. However, the favorable 100% load factor consumer has no peak in his or her individual demand curve. Therefore, the method burdens rather heavily this favorable class of consumer who has a steady load.

A.1.6 PHANTOM METHOD

If a public utility could operate steadily at its maximum demand for 24 h a day every day (i.e., at 100% load factor), its investment in equipment would be used most economically. The loss of any customer will affect the load factor, or efficiency of plant use, regardless of the fact that one might have twice the demand of the other. This was the conclusion of Hills [6] when he inserted that a fair and just division of cost will be on a kilowatt-hour basis, for every block of energy used is just as important and every other block of the same size as far as costs to the central station are concerned.

Thus, with a plant operating at 100% load factor, the demand costs divided by the number of kilowatt-hours generated and multiplied by the consumption of each customer at the generating

plant will give the true demand costs that should be allocated to each customer. Therefore, under these conditions, the demand costs per kilowatt-hour can be expressed as

$$\text{Demand costs} = \frac{\text{Total annual demand costs}}{8,760(\text{max demand station})} \quad (\text{A.5})$$

In actual practice, the load factor is usually not 100%. Here, the demand costs are divided among the groups of customers according to their kilowatt-hour consumption, charging this phantom customer in the same way as the real customers. Hence, now the problem is to divide the bill of this phantom customer, which would be required to operate the existing plant at 100% load factor, among the existing customers in an equitable manner.

Certainly, the customers who already have a 100% load factor are not responsible for the bill and neither are those customers who are off-peak, for they are doing their share toward reducing the size of this phantom. Those customers that cause the peak are responsible since they use more than their average demand during the period of that peak load. Furthermore, their degree of responsibility is limited to the excess demand during the period of the station peak load over the average demand.

In many cases, it may be that there is not only one station peak during the year, due to one set of conditions, but perhaps two or more peaks at other times due to different groups of customers or under different conditions. It often happens that the annual station peak is just as likely to occur because of one group of customers as because of another. This is a case where the phantom method can be applied with accuracy and ease.

A.1.7 WEIGHTED PEAK METHOD

In 1927, Knight [3], in an effort to correct some of the defects of Greene's [4], Eisenmenger's [5], and Hills' [6] methods in overcharging the off-peak customers, presented a new method called the *weighted peak method*. This method allocates the demand costs to the various classes of consumers according to the share of each class in the total weighted peak.

The weighted peak of any class of consumer is taken as equal to the demand of that class at the time of the plant peak plus a fraction of the difference between the maximum demand of that class of consumers and its demand at the time of the plant peak. This fraction that is added is the ratio of the plant demand at the time of the class maximum demand to the total peak demand.

A.2 METHODS FOR PLANNING FUTURE INVESTMENTS

In 1950, Watchorn [7] developed a method for determining capacity benefits resulting from an interconnection of generating systems and used this to justify the installation of transmission facilities as a substitute for generating capacity. Also, he described several possible bases for allocating such benefits. He pointed out that when only two systems are involved in an interconnection, the resulting capacity benefit should be divided equally between them.

However, in the event that more than two systems are involved, the benefit allocated to any of the participating systems should not be reduced by the addition of any new participants into the interconnection. He suggested what may be defined as the mutual benefit method of allocation, which recognizes that the benefit should be divided among the participating systems in proportion to the benefits for all combinations of two among them. This method meets the two basic requirements so long as the installed capacity requirements are determined on the basis of consistent application of probability methods.

In 1957, Phillips [8] developed a method that he asserted to be more equitable to allocate saving from energy interchange in power pools where more than three companies are involved. He pointed out that it is a generally accepted principle throughout the United States that on interchange where only two parties are involved, the savings are divided equally between the buyer and the seller. The

accounting involved in applying this theory is given by a simple equation for the billing rate, which is a function of energy interchange, the replacement cost of the purchasing company, and the supplying cost of the selling company.

When the magnitude of the interconnection grows to include three companies, the accounting is slightly more complicated, since for any specified period, either one company is buying and two are selling or two companies are buying and one is selling. Again, the total interchange can be broken down into separate two-party transactions, and no arbitrary method is involved for determining the distribution of energy. A similar equation for billing rate can be applied in the three-company interconnection.

When the magnitude of the power pool grows to four companies, it is no longer possible to say which company receives a given block of power except in those hours when only one company is buying or only one company is selling. He suggested that if more than one company is buying during a particular period, each buying company's replacement cost is compared with the weighted average of all the selling companies in order to determine the billing rate. Conversely, in any period, the selling cost of any selling company is compared with the weighted average of the replacement costs of all the buying companies for that specific period in order to determine the billing rate for that company.

It is very difficult to determine an equitable method of allocating the fixed charges of the interconnection facilities for power interchange among the various participants. Suggestions have been made that such fixed charges be divided annually among participating parties of the interconnection arrangement on the basis of the actual dollar benefits derived by the individual members from power interchange transactions. Watchorn [7] recommended that such allocation may well be on approximately the same basis as the allocation of the capacity benefits.

However, Bary (in his discussion in Phillips [8]) suggested that the disposition of fixed charges on interconnection facilities should be made at the time they enter into an interconnection agreement. Furthermore, he suggested that benefits should be allocated on an equitable basis with the amounts applicable to each participating system to remain fixed for a prolonged period and be subjected to modification only as a result of future changes in the scope or extent of the facilities involved in the interconnection or due to major changes in the components of fixed charges (i.e., return on investment, taxes, depreciation, insurance, and maintenance). He argued that the disposition of fixed charges should not be made automatically dependent on the actual day-to-day or year-to-year operational benefits of power interchanges.

Anthony [9] described the exchange of seasonal diversity capacity between Tennessee Valley Authority (TVA) and the South-Central Electric Companies (SCECs). Basically, each SCEC was to own, operate, and maintain those EHV facilities required in its *service area*. Financing was to be handled on a group basis.

The annual cost of ownership, operation, and maintenance of individual company facilities was to be prorated to each company by an arbitrary formula based on the portion of such facilities installed by that company compared with the total EHV facilities installed by all SCECs and the percentage of participation by that company in diversity capacity exchange of TVA power.

Since the company in whose service area EHV facilities are installed is in a position to use the facilities for purposes other than the interchange of power with TVA, each company owning EHV facilities was to begin to absorb 5% of the annual charges of those EHV facilities in its service area. Each year thereafter, for a total of 19 years, the amount to be absorbed was to be increased by 5%. Consequently, at the end of the 19-year period, annual charges to be shared by the companies were projected to be 50% of the initial annual charges. Incremental losses occasioned by the receipt or delivery of power under the agreements were to be distributed in proportion to each company's participation in each power transfer.

Firestone et al. [10] extended the use of probability techniques for analyzing a system's generation reserve position and applied this method to the Central Area Power Coordination Group (CAPCO) system. A probabilistic capacity model is merged with a load model to develop the expected frequency

distribution of daily capacity margins. The daily capacity margin is considered to be the difference between the load that exists during a daily peak period and the operable capacity at that time.

Operable capacity for this purpose is the normal rating of installed generating capacity, adjusted for various limitations, plus purchases of firm power from other utilities less outages, both planned and forced. Each of these capacity margins is associated with the probability of the corresponding capacity level.

The CAPCO group, like other power pools, required a mechanism for ensuring the equitable sharing of benefits and responsibilities arising from such an association. The fundamental basis of equity adopted by the CAPCO group was that each party should contribute to the group reserve in the same proportion as they expected to utilize it. Negative margins were quite useful as the measure of a system's need for help from outside the pool, whereas positive margins were used as the measure of a system's ability to provide help to outside systems.

An energy quantity called *megawatt-days* was developed as a useful measurement here. *Positive megawatt-days* are equal to the sum of the products of each positive margin and its respective frequency. *Negative megawatt-days* are calculated in a similar manner, from the negative margin data.

By proper distribution of capacity responsibility, it is possible to make the relationship of each party's contribution to the group reserve (positive-megawatt-day value) to this potential use of the group reserve (negative-megawatt-day value) equal to that for each of the other parties. The capacity responsibility assigned represents the power in megawatts for which the individual party bears financial responsibility.

In 1967, Rincliffe [11] described the Pennsylvania–New Jersey–Maryland (PJM) policy for allocating the annual costs of the 500kV transmission system to all pool members. The 500kV transmission system, owned by six companies, was being constructed to bring power from the mine-mouth stations to the load centers and to provide high-capacity inter-pool tie lines.

The total cost of the transmission system was divided into an interarea tie function and a generation delivery function. The interarea function was allocated to all PJM members and associated systems in proportion to their sizes as measured by peak loads. The generation delivery function was allocated to the owners of the stations in proportion to ownership of the combined capacity of these stations.

The methods that have been described so far take into account the benefits of interconnection facilities from the savings to the participating systems due to power interchange transactions. However, Brandt [12] defined the benefits to be gained from transmission facilities in a more comprehensive way in an Edison Electric Institute's committee report.

According to the report, the benefits that a company receives from an interconnection include distribution benefits, wheeling benefits, and pool benefits (i.e., the value associated with increased reliability of the pool).

Therefore, the possible bases for ownership of transmission lines, based on the methods mentioned earlier, can be summarized as follows:

1. Ownership may be divided equally among the members.
2. Ownership may be proportional to the installed capacity requirements of each company when operating separately.
3. Ownership may be proportional to the peak load of each for separate operation.
4. Ownership may be proportional to a combination of energy consumed, average load, and the difference between the maximum load and the average load of each company (excess demand).
5. Ownership may be proportional to the distribution and the reliability benefits each member company derives from using the transmission system.

The first ownership base is equitable in a very uncommon situation, that is, when the companies involved have nearly the same size and similar fundamental characteristics. However, the second

and third ownership bases are not equitable as far as a transmission line is concerned because the line is not planned for construction on these bases. On the other hand, if the problem was one of adding generating units, these bases may be more equitable.

The fourth ownership base appears to be more equitable if one can find an appropriate way to formulate the concept. The phantom customer method of allocating fixed charges is suggested. It allocates the costs from both the energy and the power point of views. It may be an appropriate method for operating purposes on a day-to-day or month-to-month basis. However, the fifth ownership base appears to be more equitable and logical for planning purposes.

In the event that there are n member companies in a given power pool, based on energy and excess demand considerations, the fixed charges of path (i.e., tie line) j allocated to service area i can be expressed as [13]

$$F_{ij} = \frac{L_i}{\sum_{i=1}^n L_i} P_{aj} + \frac{\Delta P_{cj}}{\sum_{i=1}^n \Delta P_{cj}} (P_{pj} - P_{aj}) \quad (\text{A.6})$$

where

F_{ij} is the fixed charge of path j allocated to service area i in megawatts

L_i is the total load of area i at the pool average load level in megawatts

P_{aj} is the magnitude of real power flow in path j at the pool average load level in megawatts

ΔP_{cj} is the incremental real power flow in path j due to any load condition designated as C (positive value only) in megawatts

P_{pj} is the magnitude of real power flow in path j at pool peak-load level in megawatts

Equation A.6 is based on the phantom method. Note that the first term of the equation represents the energy charge in megawatts, which is equivalent to the power flow in that particular line when the pool is operating at the average load level.

The second term of the equation represents the fixed charges in megawatts due to excess demand and is called the *phantom demand charge of the line*. The demand charge in megawatts is equivalent to the difference between the power flows in the line at the pool peak load level and at the pool average load level. The difference should have only a positive value in order to be significant. A negative value means that there is no excess demand at the time of pool peak.

The reliance on the transmission lines (tie lines) in a modern pool is more crucial than just providing help in an emergency. It applies whenever generating capacity is insufficient for any reason (e.g., during the refueling of a nuclear unit), and physical backup has now become as necessary to reliable operation as emergency assistance. This is the reason the reliability benefit should be included in the allocation. Therefore, the fifth ownership base appears to be more equitable than the other four bases for planning purposes. Thus, it can be used by the planning engineer to allocate fixed charges of jointly used transmission lines.

Therefore, in the event that there are n member companies in a given pool, based on distribution and reliability benefits, the fixed charges of path j allocated to service area i can be expressed as [13]

$$F_{ij} = \frac{1}{2} \left(\frac{R_{ij}}{\sum_{i=1}^n R_{ij}} + \frac{D_{ij}}{\sum_{i=1}^n D_{ij}} \right) F_j \quad (\text{A.7})$$

where

F_{ij} is the fixed charges of path j allocated to area i in dollars

R_{ij} is the reliability benefit to area i from path j

D_{ij} is the distribution benefit to area i from path j in megawatts

F_j is the fixed charges of path j in dollars

Note that a 50–50 split of the fixed charges is assumed in Equation A.7. The base value to determine the per-unit quantity of the distribution benefit is the sum of the distribution benefits of that particular line to each separate area in the pool. Similarly, the base value to determine the per-unit quantity of the reliability benefit is the sum of the reliability benefits for the entire system,

$$\text{Basic reliability benefit} = \sum_{i=1}^n R_{ij} \quad (\text{A.8})$$

Therefore, the fixed charge allocation of company i for the transmission line j can be expressed as

$$F_{ij} = \frac{1}{2}(R_{ij} + D_{ij})F_j \quad (\text{A.9})$$

where

R_{ij} is the reliability benefit in per units

D_j is the distribution benefit in per units

The distribution benefit of a transmission line to a power system is defined as the increment of real power flowing over that line when the total load of the power system is changed from one arbitrary load level to a higher arbitrary load level under economic production schedules from the dispatch control center under normal conditions, measured either in physical units (i.e., megawatts or kilowatts) or in per units on some appropriate base.

The per-unit distribution benefit of a line can be expressed in several ways, depending on how the base value is chosen. For example, if the base value may be chosen to be some arbitrary number (e.g., 100 MW), the per-unit distribution benefit of a line (i.e., per-unit AP_{line}) can be expressed as

$$D_{\text{line}} = \frac{\Delta P_{\text{line}} \text{ MW}}{100 \text{ MW base}} \text{ pu} \quad (\text{A.10})$$

In the event that the base value is chosen to be the total change in area load in megawatts, it can be calculated as

$$D_{\text{line}} = \frac{\Delta P_{\text{line}} \text{ MW}}{\Delta P_{\text{area}} \text{ MW}} \text{ pu} \quad (\text{A.11})$$

Finally, if the base value is chosen to be the sum of the changes in every line flow (megawatts) in the area, the per-unit distribution benefit of a line can be expressed as

$$D_{\text{line}} = \frac{\Delta P_{\text{line}} \text{ MW}}{\sum \Delta P \text{ in all lines}} \text{ pu} \quad (\text{A.12})$$

Note that the base value may be chosen for each individual line separately to be the total sum of the distribution benefits of that particular line to each separate area in the pool. The increments of real power flowing over the line can be found from load-flow studies.

The reliability benefit of a transmission line to a power system is defined as an increment of the total probability of system failure, calculated at the load buses in the power system, with the line in service and with the line out of service. The total probability of system failure in the system is the sum of the probabilities of system failure to serve the load at each load bus in the system. The probabilities are calculated at each of the individual load buses in the power system. The conditional probability approach can be used to calculate the probability of system failure.

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Appendix B

Standard Device Numbers Used in Protection Systems

Some of the frequently used device numbers are listed as follows. A complete list and definitions are given in ANSI/IEEE Standard C37.2-1079:

1. Master element, normally used for hand-operated devices
2. Time-delay starting or closing relay
3. Checking or interlocking relay
4. Master contactor
5. Stopping device
6. Starting CB
7. Anode CB
8. Control power disconnecting device
9. Reversing device
10. Unit sequence switch
12. Synchronous-speed device
14. Underspeed device
15. Speed- or frequency-matching device
17. Shunting or discharge switch
18. Accelerating or decelerating device
20. Electrically operated valve
21. Distance relay
23. Temperature control device
25. Synchronizing or synchronism-check device
26. Apparatus thermal device
27. Undervoltage relay
29. Isolating contactor
30. Annunciator relay
32. Directional power relay
37. Undercurrent or underpower relay
46. Reverse-phase or phase-balance relay
47. Phase-sequence voltage relay
48. Incomplete sequence relay
49. Machine or transformer thermal relay
50. Instantaneous overcurrent or rate-of-rise relay
51. AC time overcurrent relay
52. AC CB, mechanism-operated contacts are
 - a. 52a, 52aa, open when breaker closed that is, when breaker contacts closed
 - b. 52b, 52bb, operates just as mechanism motion starts; known as high-speed contacts
55. Power factor relay
57. Short-circuiting or grounding device
59. Overvoltage relay
60. Voltage or current balance relay

- 62. Time-delay stopping or opening relay
- 64. Ground detector relay
- 67. AC directional overcurrent relay
- 68. Blocking relay
- 69. Permissive control device
- 72. AC circuit breaker
- 74. Alarm relay
- 76. DC overcurrent relay
- 78. Phase-angle measuring or out-of-step protective relay
- 79. AC reclosing relay
- 80. Flow switch
- 81. Frequency relay
- 82. DC reclosing relay
- 83. Automatic selective control or transfer relay
- 84. Operating mechanism
- 85. Carrier or pilot-wire receiver relay
- 86. Lockout relay
- 87. Differential protective relay
- 89. Line switch
- 90. Regulating device
- 91. Voltage directional relay
- 92. Voltage and power directional relay
- 93. Field-changing contactor
- 94. Tripping or trip-free relay

Appendix C

Final Rule on Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities

Federal Energy Regulatory Commission

Order No. 1000

July 21, 2010

Order No. 1000 is a Final Rule that reforms the Commission's electric transmission planning and cost allocation requirements for public utility transmission providers. The rule builds on the reforms of Order No. 890 and corrects remaining deficiencies with respect to transmission planning processes and cost allocation methods.

C.1 BACKGROUND

On June 17, 2010, the FERC issued a Notice of Proposed Rulemaking seeking comments on potential changes to its transmission planning and cost allocation requirements. Industry participants and other stakeholders provided extensive comments in response to the Notice of Proposed Rulemaking. The commission received more than 180 initial comments and more than 65 rely comments.

C.2 PLANNING REFORMS

The rule establishes three requirements for transmission planning:

1. Each public utility transmission provider must participate in a regional transmission planning process that satisfies the transmission planning principles of Order No. 890 and produces a regional transmission plan.
2. Local and regional transmission planning processes must consider transmission planning needs driven by public policy requirements established by state or federal laws or regulations. Each public utility transmission provider must establish procedures to identify transmission needs driven by public policy requirements and evaluate proposed solutions to those transmission needs.
3. Public utility transmission providers in each pair of neighboring transmission planning regions must coordinate to determine if there are more efficient or cost-effective solutions to their mutual transmission needs.

C.3 COST ALLOCATION REFORMS

The rule establishes three requirements for transmission cost allocation:

1. Each public utility transmission provider must participate in a regional transmission planning process that has a regional cost allocation method for new transmission facilities selected in the regional transmission plan for the purpose of cost allocation. The method must satisfy six regional cost allocation principles.

2. Public utility transmission providers in neighboring transmission planning regions must have a common interregional cost allocation method for new interregional facilities that the regions determine to be efficient and cost-effective. The method must satisfy six similar interregional cost allocation principles.
3. Participant funding of new transmission facilities is permitted, but is not allowed as the regional or interregional cost allocation method.

C.4 NONINCUMBENT DEVELOPER REFORMS

Public utility transmission providers must remove from commission-approved tariffs and agreements—a federal right of first refusal for a transmission facility selected in a regional plan for the purpose of cost allocation, subject to four limitations:

1. This does not apply to a transmission facility that is not selected in a regional transmission plan for the purpose of cost allocation.
2. This does not apply to upgrades to transmission facilities, such as tower changeouts or reconductoring.
3. This allows, but does not require, public utility transmission providers in a transmission planning region to use competitive bidding to solicit transmission projects or project developers.
4. Nothing in this requirement affects state or local laws or regulations over siting or permitting of transmission facilities.

The rule recognizes that incumbent transmission providers must rely on regional transmission providers to satisfy their reliability needs or service obligations. The rule requires each public utility transmission provider to amend their tariff to require reevaluation of the regional transmission plan to determine if delays in the development of a transmission facility require evaluation of alternative solutions, including those proposed by the incumbent, to ensure incumbent transmission providers meet reliability needs or service obligations.

C.5 COMPLIANCE

Order No. 1000 takes effect 60 days from publication in the Federal Register.

Each public utility transmission provider is required to make a compliance filing with the commission within 12 months of the effective date of the Final Rule.

Compliance filing for interregional transmission coordination and interregional cost allocation is required within 18 months of the effective date.

REFERENCE

Federal Energy Regulatory Commission. *A Guide to the FERC-Electric Transmission Facilities Permit Process*, FERC, Washington, DC, September 2010.

Appendix D

Unit Conversions from the English System to SI System

The following are useful when converting from the English system to the SI system:

Length	1 in. = 2.54 cm = 0.0245 m 1 ft = 30.5 cm = 0.305 m 1 mile = 1,609 m
Area	1 mile ² = 2.59 × 10 ⁶ m ² 1 in. ² = 0.000645 m ² 1 in. ² = 6.45 cm ²
Volume	1 ft ³ = 0.0283 m ³
Linear speed	1 ft/s = 0.305 m/s = 30.3 cm/s 1 mph = 0.447 m/s 1 in./s = 0.0254 m/s = 2.54 cm/s
Rotational speed	1 rev/min = 0.105 rad/s = 6 deg/s
Force	1 lb = 4.45 N
Power	1 hp = 746 W = 0.746 kW
Torque	1 ft-lb = 1.356 N-m
Magnetic flux	1 line = 1 maxwell = 10 ⁻⁸ Wb 1 kiloline = 1,000 maxwells = 10 ⁻⁵ Wb
Magnetic flux density	1 line/in. ² = 15.5 I ¹¹ T 100 kilolines/in. ² = 1.55 T = 1.55 Wb/m ²
Magnetomotive force	1 A-turn = 1 A
Magnetic field intensity	1 A-turn/in. = 39.37 A/m

Appendix E

Unit Conversions from the SI System to English System

The following are useful when converting from the SI system to the English system:

Length	1 m = 100 cm = 39.37 in. 1 m = 3.28 ft 1 m = 6.22×10^{-4} mile
Area	1 m ² = 0.386 1" mile 1 m ² = 1,550 in. ² 1 cm ² = 0.155 in. ²
Volume	1 m ³ = 35.3 ft ³
Linear speed	1 m/s = 100 cm/s = 3.28 ft/s 1 m/s = 2.237 mph 1 m/s = 39.37 in./s
Rotational speed	1 rad/s = 9.55 rev/min = 57.3 deg/s
Force	1 N = 0.225 lb
Power	1 kW = 1,000 W = 1.34 hp
Torque	1 N-m = 0.737 ft-lb
Magnetic flux	1 Wb = 10 ⁸ lines = 10 ⁸ maxwells 1 Wb = 10 ⁵ kilolines
Magnetic flux density	1 T = 6.45×10^4 lines/in. ² 1 T = 1 Wb/m ²
Magnetomotive force	1 A = 1 A-turn
Magnetic field intensity	1 A/m = 0.0254 A-turn/in.

Appendix F

Glossary for Transmission System Engineering Terminology

Some of the most commonly used terms, both in this book and in general usage, are defined in the following pages. Most of the definitions given in this glossary are based on Refs. [1–8].

AA: Abbreviation for all-aluminum conductors.

AAAC: Abbreviation for all-aluminum-alloy conductor. Aluminum alloy conductors have higher strength than those of the ordinary electric-conductor grade of aluminum.

ACAR: Abbreviation for aluminum conductor alloy-reinforced. It has a central core of higher-strength aluminum surrounded by layers of electric-conductor grade aluminum.

AC circuit breaker: A CB whose principal function is usually to interrupt short-circuit or fault currents.

Accuracy classification: The accuracy of an instrument transformer at specified burdens. The number used to indicate accuracy is the maximum allowable error of the transformer for specified burdens. For example, 0.2 accuracy class means the maximum error will not exceed 0.2% at rated burdens.

ACSR: An abbreviation for aluminum conductor, steel reinforced. It consists of a central core of steel strands surrounded by layers of aluminum strands.

Admittance: The ratio of the phasor equivalent of the steady-state sine-wave current to the phasor equivalent of the corresponding voltage.

Adverse weather: Weather conditions that cause an abnormally high rate of forced outages for exposed components during the periods such conditions persist, but which do not qualify as major storm disasters. Adverse weather conditions can be defined for a particular system by selecting the proper values and combinations of conditions reported by the weather bureau: thunderstorms, tornadoes, wind velocities, precipitation, temperature, etc.

Air blast transformer: A transformer cooled by forced circulation of air through its core and coils.

Air circuit breaker: A CB in which the interruption occurs in the air.

Air switch: A switch in which the interruptions of the circuit occur in the air.

Al: Symbol for aluminum.

Ampacity: Current rating in amperes, as of a conductor.

ANSI: Abbreviation for American National Standards Institute.

Apparent sag (at any point): The departure of the wire at the particular point in the span from the straight line between the two points of the span, at 60°F, with no wind loading.

Arc-back: A malfunctioning phenomenon in which a valve conducts in the reverse direction.

Arcing time of fuse: The time elapsing from the severance of the fuse link to the final interruption of the circuit under specified conditions.

Arc-over of insulator: A discharge of power current in the form of an arc following a surface discharge over an insulator.

Armored cable: A cable provided with a wrapping of metal, usually steel wires, primarily for the purpose of mechanical protection.

Askarel: A generic term for a group of nonflammable synthetic chlorinated hydrocarbons used as electrical insulating media. Askarels of various compositional types are used.

Under arcing conditions, the gases produced, while consisting predominantly of noncombustible hydrogen chloride, can include varying amounts of combustible gases depending upon the askarel type. Because of environmental concerns, it is not used in new installations anymore.

Automatic reclosing: An intervention that is not manual. It probably requires specific interlocking such as a full or check synchronizing, voltage or switching device checks, or other safety or operating constraints. It can be high speed or delayed.

Automatic substations: Those in which switching operations are so controlled by relays that transformers or converting equipment are brought into or taken out of service as variations in load may require, and feeder CBs are closed and reclosed after being opened by overload relays.

Autotransformer: A transformer in which at least two windings have a common section.

Auxiliary relay: A relay that operates in response to the opening or closing of its operating circuit to assist another relay in the performance of its function.

AWG: Abbreviation for American wire gauge. It is also sometimes called the Brown and Sharpe wire gauge.

Base load: The minimum load over a given period of time.

Basic impulse insulation level: Reference levels expressed in impulse crest voltage with a standard wave not longer than $1.5 \times 50 \mu\text{s}$. The impulse waves are defined by a combination of two numbers. The first number is the time from the start of the wave to the instant crest value; the second number is the time from the start to the instant of half-crest value on the tail of the wave.

BIL: See Basic impulse insulation level.

Blocking: Preventing the relay from tripping due either to its own characteristic or to an additional relay.

Breakdown: Also termed puncture, denoting a disruptive discharge through insulation.

Breaker, primary feeder: A breaker located at the supply end of a primary feeder that opens on a primary-feeder fault if the fault current is of sufficient magnitude.

Breaker-and-a-half scheme: A scheme that provides the facilities of a double main bus at a reduction in equipment cost by using three CBs for each of two circuits.

Burden: The loading imposed by the circuits of the relay on the energizing input power source or sources, that is, the relay burden is the power required to operate the relay.

Bus: A conductor or group of conductors that serves as a common connection for two or more circuits in a switchgear assembly.

Bus (or bus bar): An electrical connection of zero impedance joining several items such as lines and loads. Bus in a one-line diagram is essentially the same as that of a node in a circuit diagram. It is the term used for a main bar or conductor carrying an electric current to which many connections may be made. Buses are simply convenient means of connecting switches and other equipment into various arrangements. They can be in a variety of sizes and shapes. They can be made of rectangular bars, round solid bars, square tubes, open pairs, or even stranded cables. In substations, they are built above the head and supported by insulated metal structures. Bus materials, in general use, are aluminum and copper, with hard-drawn aluminum, especially in the tubular shape, the most widely used in HV and EHV open-type outdoor stations. Copper or aluminum tubing as well as special shapes is sometimes used for low-voltage distribution substation buses.

Bus, auxiliary: See Transfer bus.

Bus-tie circuit breaker: A CB that serves to connect buses or bus sections together.

Bus, transfer: A bus to which one circuit at a time can be transferred from the main bus.

Bushing: An insulating structure including a through conductor, or providing a passageway for such a conductor, with provision for mounting on a barrier, conductor or otherwise, for the

purpose of insulating the conductor from the barrier and conducting from one side of the barrier to the other.

BVR: Abbreviation for bus voltage regulator or regulation.

BW: Abbreviation for bandwidth.

BX cable: A cable with galvanized interlocked steel spiral armor. It is known as AC cable and is used in a damp or wet location in buildings at LV.

Cable: Either a standard conductor (single-conductor cable) or a combination of conductors insulated from one another (multiple-conductor cable).

Cable fault: A partial or total load failure in the insulation or continuity of the conductor.

Capability: The maximum load-carrying ability expressed in kilovolt-amperes or kilowatts of generating equipment or other electric apparatus under specified conditions for a given time interval.

Capability, net: The maximum generation expressed in kilowatt-hours per hour that a generating unit, station, power source, or system can be expected to supply under optimum operating conditions.

Capacitor bank: An assembly at one location of capacitors and all necessary accessories (switching equipment, protective equipment, controls, etc.) required for a complete operating installation.

Capacity: The rated load-carrying ability expressed in kilovolt-amperes or kilowatts of generating equipment or other electric apparatus.

Capacity factor: The ratio of the average load on a machine or equipment for the period of time considered to the capacity of the machine or equipment.

Characteristic quantity: The quantity or the value of which characterizes the operation of the relay.

Characteristics (of a relay in steady state): The locus of the pickup or reset when drawn on a graph.

Charge: The amount paid for a service rendered or facilities used or made available for use.

Chopped-wave insulation level: Determined by test using waves of the same shape to determine the BIL, with the exception that the wave is chopped after about 3 μ s.

CIGRÉ: It is the international conference of large HV electric systems. It is recognized as a permanent nongovernmental and nonprofit international association based in France. It focuses on issues related to the planning and operation of power systems, as well as the design, construction, maintenance, and disposal of HV equipment and plants.

Circuit breaker: A device that interrupts a circuit without injury to itself so that it can be reset and reused over again.

Circuit breaker mounting: Supporting structure for a CB.

Circuit, earth (ground) return: An electric circuit in which the earth serves to complete a path for current.

Circular mil: A unit of area equal to $i/4$ of a square mil ($= 0.7854$ square mil). The cross-sectional area of a circle in circular mils is therefore equal to the square of its diameter in mils. A circular inch is equal to 1 million circular mils. A mil is one one-thousandth of an inch. There are 1974 circular mils in a square millimeter. Abbreviated cmil.

CL: Abbreviation for current limiting (fuse).

cmil: Abbreviation for circular mil.

Commutation: The transfer of current from one valve to another in the same row.

Commutation margin angle (ζ): The time angle between the end of conduction and the reversal of the sign of the nonsinusoidal voltage across the outgoing valve of an inverter. Under normal operating conditions, the commutation margin angle is equal to the extinction advance angle.

Component: A piece of equipment, a line, a section of a line, or a group of items that is viewed as an entity.

Computer usage:

Off-line usage: It includes research, routine calculations of the system performance, and data assimilations and retrieval.

Online usage: It includes data logging and monitoring of the system state, including switching, safe interlocking, plant loading, postfault control, and load shedding.

Condenser: Also termed capacitor; a device whose primary purpose is to introduce capacitance into an electric circuit. The term condenser is deprecated.

Conductor: A substance that has free electrons or other charge carriers that permit charge flow when an electromotive force (emf) is applied across the substance.

Conductor tension, final unloaded: The longitudinal tension in a conductor after the conductor has been stretched by the application for an appreciable period, with subsequent release, of the loadings of ice and wind, at the temperature decrease assumed for the loading district in which the conductor is strung (or equivalent loading).

Congestion cost: The difference between the actual price of electricity at the point of usage and the lowest price on the grid.

Contactors: An electric power switch, which is not operated manually and designed for frequent operation.

Conventional RTU: Designated primarily for hardwired input/output (I/O) and has little or no capability to talk to downstream IEDs.

Converter: A machine, device, or system for changing AC power to DC power or vice versa.

Cress factor: A value that is displayed on many power quality monitoring instruments representing the ratio of the crest value of the measured waveform to the rms value of the waveform. For example, the cress factor of a sinusoidal wave is 1.414.

Critical flashover (CFO) voltage: The peak voltage for a 50% probability of flashover or disruptive discharge.

CT: Abbreviation for current transformer.

Cu: Symbol for copper.

Current transformer burdens: CT burdens are normally expressed in ohms impedance such as B-0.1, B-0.2, B-0.5, B-0.9, and B-1.8. Corresponding volt-ampere values are 2.5, 5.0, 12.5, 22.5, and 45.

Current transformer ratio: CT ratio is the ratio of primary to secondary current. For CT rated 200:5, the ratio is 200:5 or 40:1.

Current transformers: They are usually rated on the basis of 5 A secondary current and used to reduce primary current to usable levels for transformer-rated meters and to insulate and isolate meters from HV circuits.

Delay angle (α): The time, expressed in electrical degrees, by which the starting point of commutation is delayed. It cannot exceed 180° . It is also called ignition angle or firing angle.

Demand: The load at the receiving terminals averaged over a specified interval of time.

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.

Demand, instantaneous: The load at any instant.

Demand, integrated: The demand integrated over a specified period.

Demand interval: The period of time during which the electric energy flow is integrated in determining demand.

Dependability (in protection): The certainty that a relay will respond correctly to all faults for which it is designed and applied to operate.

Dependability (in relays): The ability of a relay or relay system to provide correct operation when required.

Dependent time-delay relay: A time-delay relay in which the time delay varies with the value of the energizing quantity.

Depreciation: The component that represents an approximation of the value of the portion of plant consumed or used up in a given period by a utility.

Differential current relay: A fault-detecting relay that functions on a differential current of a given percentage or amount.

Directional (or directional overcurrent) relay: A relay that functions on a desired value of power flow in a given direction on a desired value of overcurrent with AC power flow in a given direction.

Disconnecting or isolating switch: A mechanical switching device used for changing the connections in a circuit or for isolating a circuit or equipment from the source of power.

Disconnecter: A switch that is intended to open a circuit only after the load has been thrown off by other means. Manual switches designed for opening loaded circuits are usually installed in a circuit with disconnectors to provide a safe means for opening the circuit under load.

Displacement factor (DPF): The ratio of active power (watts) to apparent power (volt-amperes).

Distance relay: A relay that responds to input quantities as a function of the electrical circuit distance between the relay location and the point of faults.

Distribution center: A point of installation for automatic overload protective devices connected to buses where an electric supply is subdivided into feeders and/or branch circuits.

Distribution switchboard: A power switchboard used for the distribution of electric energy at the voltages common for such distribution within a building.

Distribution system: That portion of an electric system that delivers electric energy from transformation points in the transmission, or bulk power system, to the consumers.

Distribution transformer: A transformer for transferring electric energy from a primary distribution circuit to a secondary distribution circuit or consumer's service circuit; it is usually rated in the order of 5–500 kVA.

Diversity factor: The ratio of the sum of the individual maximum demands of the various subdivisions of a system to the maximum demand of the whole system.

Dropout or reset: A relay drops out when it moves from the energized position to the unenergized position.

Effectively grounded: Grounded by means of a ground connection of sufficiently low impedance that fault grounds that may occur cannot build up voltages dangerous to connected equipment.

EHV: Abbreviation for extra-high voltage.

Electric fields: They exist whenever voltage exists on a conductor. They are not dependent on the current.

Electric system loss: Total electric energy loss in the electric system. It consists of transmission, transformation, and distribution losses between sources of supply and points of delivery.

Electrical reserve: The capability in excess of that required to carry the system load.

Element: See Unit.

Emergency rating: Capability of installed equipment for a short time interval.

Energizing quantity: The electrical quantity, that is, current or voltage, either alone or in combination with other electrical quantities required for the function of the relay.

Energy: That which does work or is capable of doing work. As used by electric utilities, it is generally a reference to electric energy and is measured in kilowatt-hours.

Energy loss: The difference between energy input and output as a result of the transfer of energy between two points.

Energy management system (EMS): A computer system that monitors, controls, and optimizes the transmission and generation facilities with advanced applications. A SCADA system is the subject of an EMS.

Equivalent commutating resistance (R_c): The ratio of drop of direct voltage to DC. However, it does not consume any power.

- Express feeder:** A feeder that serves the most distant networks and that must traverse the systems closest to the bulk power source.
- Extinction (advance) angle (γ):** The extinction angle of an inverter and is equal to $\pi - \gamma$ electrical degrees. It is defined as the time angle between the end of conduction and the reversal of the sign of the sinusoidal commutation voltage of the source.
- Extinction angle (δ):** The sum of the delay angle α and the overlap angle u of a rectifier and is expressed in degrees.
- Extra-high voltage:** A term applied to voltage levels higher than 230kV. Abbreviated EHV.
- Facilities charge:** The amount paid by the customer as a lump sum or, periodically, as reimbursement for facilities furnished. The charge may include operation and maintenance as well as fixed costs.
- Fault:** It is a malfunctioning of the network, usually due to the short-circuiting of two or more conductors or live conductors connecting to earth.
- Feeder:** A set of conductors originating at a main distribution center and supplying one or more secondary distribution centers, one or more branch-circuit distribution centers, or any combination of these two types of load.
- Feeder, multiple:** Two or more feeders connected in parallel.
- Feeder, tie:** A feeder that connects two or more independent sources of power and has no tapped load between the terminals. The source of power may be a generating system, substation, or feeding point.
- Fiber-optic cable:** It is made up of varying numbers of either single or multimode fibers, with a strength member in the center of the cable and additional outer layers to provide support and protection against physical damage to the cable. Large amounts of data as high as gigabytes per second can be transmitted over the fiber. They have inherent immunity from electromagnetic interference and have high bandwidth. Two types are used by utilities: (1) optical power grid wire (OPGW) type and (2) all dielectric self-supporting (ADSS) type.
- First-contingency outage:** The outage of one primary feeder.
- Fixed capacitor bank:** A capacitor bank with fixed, not switchable, capacitors.
- Flash:** A term encompassing the entire electrical discharge from cloud to stricken object.
- Flashover:** An electrical discharge completed from an energized conductor to a grounded support. It may clear itself and trip a CB.
- Flexible AC transmission systems (FACTS):** They are the converter stations for AC transmission. It is an application of power electronics for control of the AC system to improve the power flow, operation, and control of the AC system.
- Flicker:** Impression of unsteadiness of visual sensation induced by a light stimulus whose luminance or spectral distribution fluctuates with time.
- Forced interruption:** It is an interruption caused by a forced outage.
- Forced outage:** It is an outage that results from emergency conditions directly associated with a component requiring that component to be taken out of service immediately, either automatically or as soon as switching operations can be performed, or an outage caused by improper operation of equipment or human error.
- Frequency deviation:** An increase or decrease in the power frequency. Its duration varies from few cycles to several hours.
- Fuse:** An overcurrent protective device with a circuit-opening fusible part that is heated and severed by the passage of overcurrent through it.
- Fuse cutout:** An assembly consisting of a fuse support and holder; it may also include a fuse link.
- Gas-insulated transmission line (GIL):** A system for the transmission of electricity at high power ratings over long distances. The GIL consists of three single-phase encapsulated aluminum tubes that can be directly buried into the ground, laid in a tunnel, or installed on steel structures at heights of 1–5 m aboveground.
- Grip, conductor:** A device designed to permit the pulling of conductor without splicing on fittings.

Ground: Also termed earth; a conductor connected between a circuit and the soil; an accidental ground occurs due to cable insulation faults, an insulator defect, etc.

Grounding: It is the connection of a conductor or frame of a device to the main body of the earth. Thus, it must be done in a way to keep the resistance between the item and the earth under the limits. It is often that the burial of large assemblies of conducting rods in the earth and the use of connectors in large cross diameters are needed.

Ground protective relay: Relay that functions on the failure of insulation of a machine, transformer, or other apparatus to ground.

Ground wire: A conductor having grounding connections at intervals that are suspended usually above but not necessarily over the line conductor to provide a degree of protection against lightning discharges.

GTOs: It is gate turn-off thyristors.

Harmonic distortion: Periodic distortion of the sign wave.

Harmonic resonance: A condition in which the power system is resonating near one of the major harmonics being produced by nonlinear elements in the system, hence increasing the harmonic distortion.

Harmonics: Sinusoidal voltages or currents having frequencies that are integer multiples of the fundamental frequency at which the supply system is designed to operate.

Hazardous open circulating (in CTs): The operation of the CTs with the secondary winding open can result in an HV across the secondary terminals, which may be dangerous to the personnel or equipment. Therefore, the secondary terminals should always be short-circuited before a meter is removed from service.

High-speed relay: A relay that operates in less than a specified time. The specified time in present practice is 50 ms (i.e., three cycles on a 60 HZ system).

HV: Abbreviation for high voltage.

IED: See Intelligent electronic device.

IED integration: Integration of protection, control, and data acquisition functions into a minimal number of platforms to reduce capital and operating costs, reduce panel and control room space, and eliminate redundant equipment and database.

Ignition angle (β): The delay angle of an inverter and is equal to $\pi - \alpha$ electrical degrees.

Impedance: The ratio of the phasor equivalent of a steady-state sine-wave voltage to the phasor equivalent of a steady-state sine-wave current.

Impedance relay: A relay that operates for all impedance values that are less than its setting, that is, for all points within the crosshatched circles.

Impulse ratio (flashover or puncture of insulation): It is the ratio of impulse peak voltage to the peak values of the 60 Hz voltage to cause flashover or puncture.

Impulsive transient: A sudden (nonpower) frequency change in the steady-state condition of the voltage or current that is unidirectional in polarity.

Incremental energy costs: The additional cost of producing or transmitting electric energy above some base cost.

Independent time-delay relay: A time-delay relay in which the time delay is independent of the energizing quantity.

Index of reliability: A ratio of cumulative customer minutes that service was available during a year to total customer minutes demanded; can be used by the utility for feeder reliability comparisons.

Infinite bus: A bus that represents a very large external system. It is considered that at such bus, voltage and frequency are constant. Typically, a large power system is considered an infinite bus.

Installed reserve: The reserve capability installed on a system.

Instantaneous relay: A relay that operates and resets with no intentional time delay. Such relay operates as soon as a secure decision is made. No intentional time delay is introduced to slow down the relay response.

Instrument transformer: A transformer that is used to produce safety for the operator and equipment from HV and to permit proper insulation levels and current-carrying capability in relays, meters, and other measurements.

Insulation coordination: It is the process of determining the proper insulation levels of various components in a power system and their arrangements. That is, it is the selection of an insulation structure that will withstand the voltage stresses to which the system or equipment will be subjected together with the proper surge arrester.

Intelligent electronic device: Any device incorporating one or more processors with the capability to receive or send data and control from or to an external source (e.g., electronic multifunction meters, digital relays, and controllers).

Integrated services digital network: It is a switched, end-to-end wide-area network designed to combine digital telephony and data transport services.

Interconnections: See Tie lines.

International Electrotechnical Commission (IEC): An international organization whose mission is to prepare and publish standards for all electrical, electronic, and related technologies.

Interruptible load: A load that can be interrupted as defined by contract.

Interruption: The loss of service to one or more consumers or other facilities and is the result of one or more component outages, depending on the system configuration.

Interruption duration: The period from the initiation of an interruption to a consumer until the service has been restored to that consumer.

Inverse time-delay relay: A dependent time-delay relay having an operating time that is an inverse function of the electrical characteristic quantity.

Inverse time-delay relay with definite minimum: A relay in which the time delay varies inversely with the characteristic quantity up to a certain value, after which the time delay becomes substantially independent.

Inverter: A converter for changing DC to AC.

Investment-related charges: Those certain charges incurred by a utility that is directly related to the capital investment of the utility.

ISO: Independent system operator.

Isokeraunic level: The average number of thunder-days per year at that locality (i.e., the average number of thunder will be heard during a 24 h period).

Isokeraunic map: A map showing the mean annual days of thunderstorm activity within the continental United States.

Isolated ground: Originates at an isolated ground-type receptacle or equipment input terminal block and terminates at the point where neutral and ground are bonded at the power source. Its conductor is insulated from the metallic raceway and all ground points throughout its length.

kcmil: Abbreviation for thousand circular mils.

Keraunic level: See Isokeraunic level.

K factor: A factor used to quantify the load impact of electric arc furnaces on the power system.

Knee-point emf: That sinusoidal emf applied to the secondary terminals of a CT, which, when increased by 10%, causes the exciting current to increase by 50%.

Lag: Denotes that a given sine wave passes through its peak at a later time than a reference time wave.

Lambda: The incremental operating cost at the load center, commonly expressed in mils per kilowatt-hour.

Lightning arrester: A device that reduces the voltage of a surge applied to its terminals and restores itself to its original operating condition.

Line: A component part of a system extending between adjacent stations or from a station to an adjacent interconnection point. A line may consist of one or more circuits.

Line loss: Energy loss on a transmission or distribution line.

Line, pilot: A lightweight line, normally synthetic fiber rope, or wire rope, used to pull heavier pulling lines that in turn are used to pull the conductor.

Line, pulling: A high-strength line, normally synthetic fiber rope, used to pull the conductor.

L-L: Abbreviation for line to line.

L-N: Abbreviation for line to neutral.

Load: May be used in a number of ways to indicate a device or collection of devices that consume electricity, or to indicate the power required from a given supply circuit, or the power or current being passed through a line or machine.

Load center: A point at which the load of a given area is assumed to be concentrated.

Load diversity: The difference between the sum of the maxima of two or more individual loads and the coincident or combined maximum load, usually measured in kilowatts over a specified period of time.

Load duration curve: A curve of loads, plotted in descending order of magnitude, against time intervals for a specified period.

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

Load-interrupter switch: An interrupter switch designed to interrupt currents not in excess of the continuous-current rating of the switch.

Load, interruptible: A load that can be interrupted as defined by contract.

Load losses, transformer: Those losses that are incident to the carrying of a specified load. They include I^2R loss in the winding due to load and eddy currents, stray loss due to leakage fluxes in the windings, and the loss due to circulating currents in parallel windings.

Load management (also called demand-side management): It extends remote supervision and control to subtransmission and distribution circuits, including control of residential, commercial, and industrial loads.

Load tap changer: A selector switch device applied to power transformers to maintain a constant low-side or secondary voltage with a variable primary voltage supply or to hold a constant voltage out along the feeders on the low-voltage side for varying load conditions on the low-voltage side. Abbreviated LTC.

Load-tap-changing transformer: A transformer used to vary the voltage or phase angle or both of a regulated circuit in steps by means of a device that connects different taps of tapped winding(s) without interrupting the load.

Local backup: Those relays that do not suffer from the same difficulties as remote backup, but they are installed in the same substation and use some of the same elements as the primary protection.

Loss factor: The ratio of the average power loss to the peak load power loss during a specified period of time.

Low-side surges: The current surge that appears to be injected into the transformer secondary terminals upon a lightning strike to grounded conductors in the vicinity.

LTC: Abbreviation for load tap changer.

LV: Abbreviation for low voltage.

Magnetic fields: Such fields exist whenever current flows in a conductor. They are not voltage-dependent.

Main bus: A bus that is normally used. It has a more elaborate system of instruments, relays, and so on associated with it.

Main distribution center: A distribution center supplied directly by mains.

Maintenance expenses: The expense required to keep the system or plant in proper operating repair.

Maximum demand: The largest of a particular type of demand occurring within a specified period.

Messenger cable: A galvanized steel or copperweld cable used in construction to support a suspended current-carrying cable.

Metal-clad switchgear, outdoor: A switchgear that can be mounted in suitable weatherproof enclosures for outdoor installations. The base units are the same for both indoor and outdoor applications. The weatherproof housing is constructed integrally with the basic structure and is not merely a steel enclosure. The basic structure, including the mounting details and withdrawal mechanisms for the CBs, bus compartments, transformer compartments, etc., is the same as that of indoor metal-clad switchgear. (Used in distribution systems.)

Minimum demand: The smallest of a particular type of demand occurring within a specified period.

Momentary interruption: An interruption of duration limited to the period required to restore service by automatic or supervisory-controlled switching operations or by manual switching at locations where an operator is immediately available. Such switching operations are typically completed in a few minutes.

Monthly peak duration curve: A curve showing the total number of days within the month during which the net 60 min clock hour-integrated peak demand equals or exceeds the percent of monthly peak values shown.

MOV: It is the metal-oxide varistor that is built from zinc oxide disks connected in series and parallel arrangements to achieve the required protective level and energy requirement. It is similar to an HV surge arrester.

N.C.: Abbreviation for normally closed.

NESC: Abbreviation for National Electrical Safety Code.

Net system energy: Energy requirements of a system, including losses, defined as (1) net generation of the system, plus (2) energy received from others, less (3) energy delivered to other systems.

Network configurator: An application that determines the configuration of the power system based on telemetered breaker and switch statuses.

Network transmission system: A transmission system that has more than one simultaneous path of power flow to the load.

N.O.: Abbreviation for normally open.

Noise: An unwanted electrical signal with <200 kHz superimposed upon the power system voltage or current inphase conductors or found on neutral conductors or signal lines. It is not a harmonic distortion or transient. It disturbs microcomputers and programmable controllers.

No-load current: The current demand of a transformer primary when no current demand is made on the secondary.

No-load loss: Energy losses in an electric facility when energized at rated voltage and frequency but not carrying load.

Nonlinear load: An electrical load that draws current discontinuously or whose impedances vary throughout the cycle of the input AC voltage waveform.

Normal rating: Capacity of installed equipment.

Normal weather: All weather not designated as adverse or major storm disaster.

Normally closed: Denotes the automatic closure of contacts in a relay when de-energized. Abbreviated N.C.

Normally open: Denotes the automatic opening of contacts in a relay when de-energized. Abbreviated N.O.

Notch: A switching (or other) disturbance of the normal power voltage waveform, lasting less than a half cycle, which is initially of opposite polarity than the waveform. It includes complete loss of voltage for up to a 0.5 cycle.

Notching: A periodic disturbance caused by normal operation of a power electronic device, when its current is commutated from one phase to another.

NSW: Abbreviation for nonswitched.

NX: Abbreviation for nonexpulsion (fuse).

Off-peak energy: Energy supplied during designated periods of relatively low system demands.

OH: Abbreviation for overhead.

On-peak energy: Energy supplied during designated periods of relatively high system demands.

Open systems: A computer system that embodies supplier-independent standards so that software can be applied on many different platforms and can interoperate with other applications on local and remote systems.

Operational data: Also called SCADA data; instantaneous values of power system analog and status points (e.g., volts, amps, MW, Mvar, CB status, and switch positions).

Operating expenses: The labor and material costs for operating the plant involved.

Oscillatory transient: A sudden and non-power-frequency change in the steady-state condition of voltage or current that includes both positive and negative polarity values.

Outage: It describes the state of a component when it is not available to perform its intended function due to some event directly associated with that component. An outage may or may not cause an interruption of service to consumers depending on the system configuration.

Outage duration: The period from the initiation of an outage until the affected component or its replacement once again becomes available to perform its intended function.

Outage rate: For a particular classification of outage and type of component; the mean number of outages per-unit exposure time per component.

Overhead expenses: The costs that in addition to direct labor and material are incurred by all utilities.

Overlap angle (μ): The time, expressed in degrees, during which the current is commutated between two rectifying elements. It is also called commutation time. In normal operation, it is $<60^\circ$ and is usually somewhere between 20° and 25° at full load.

Overload: Loading in excess of normal rating of equipment.

Overload protection: Interruption or reduction of current under conditions of excessive demand, provided by a protective device.

Overshoot time: The time during which stored operating energy dissipated after the characteristic quantity has been suddenly restored from a specified value to the value it had at the initial position of the relay.

Overvoltage: A voltage that has a value at least 10% above the nominal voltage for a period of time >1 min.

Passive filter: A combination of inductors, capacitors, and resistors designed to eliminate one or more harmonics. The most common variety is simply an inductor in series with a shunt capacitor, which short-circuits the major distorting harmonic component from the system.

PE: An abbreviation used for polyethylene (cable insulation).

Peak current: The maximum value (crest value) of an AC.

Peak voltage: The maximum value (crest value) of an alternating voltage.

Peaking station: A generating station that is normally operated to provide power only during maximum load periods.

Peak-to-peak value: The value of an AC waveform from its positive peak to its negative peak. In the case of a sine wave, the peak-to-peak value is double the peak value.

Pedestal: A bottom support or base of a pillar, statue, etc.

Percent regulation: See Percent voltage drop.

Percent voltage drop: The ratio of VD in a circuit to voltage delivered by the circuit, multiplied by 100 to convert to percent.

Permanent forced outage: An outage whose cause is not immediately self-clearing but must be corrected by eliminating the hazard or by repairing or replacing the component before it can be returned to service. An example of a permanent forced outage is a lightning

flashover that shatters an insulator, thereby disabling the component until repair or replacement can be made.

Permanent forced outage duration: The period from the initiation of the outage until the component is replaced or repaired.

Persistent forced outage: A component outage whose cause is not immediately self-clearing but must be corrected by eliminating the hazard or by repairing or replacing the affected component before it can be returned to service. An example of a persistent forced outage is a lightning flashover that shatters an insulator, thereby disabling the component until repair or replacement can be made.

Phase: The time of occurrence of the peak value of an AC waveform with respect to the time of occurrence of the peak value of a reference waveform.

Phase angle: An angular expression of phase difference.

Phase-angle measuring relay: A relay that functions at a predetermined phase angle between voltage and current.

Phase shift: The displacement in time of one voltage waveform relative to other voltage waveform(s).

Pickup: A relay is said to pick up when it moves from the unenergized position to the energized position (by closing its contacts).

Pilot channel: A means of interconnection between relaying points for the purpose of protection.

Planning, conceptual: A long range of guidelines for decision.

Planning, preliminary: A state of project decisions.

Polarity: The relative polarity of the primary and secondary windings of a CT is indicated by polarity marks, associated with one end of each winding. When the current enters at the polarity end of the primary winding, a current in phase with it leaves the polarity end of the secondary winding.

Pole: A column of wood or steel, or some other material, supporting OH conductors, usually by means of arms or brackets.

Pole fixture: A structure installed in lieu of a single pole to increase the strength of a pole line or to provide better support for attachments than would be provided by a single pole. Examples are A fixtures and H fixtures.

Port: A communication pathway into or out of a computer or networked device such as a server. Well-known applications have standard port numbers.

Power: The rate (in kilowatts) of generating, transferring, or using energy.

Power, active: The product of the rms value of the voltage and the rms value of the inphase component of the current.

Power, apparent: The product of the rms value of the voltage and the rms value of the current.

Power factor: The ratio of active power to apparent power.

Power, instantaneous: The product of the instantaneous voltage multiplied by the instantaneous current.

Power line carrier (PLC): Systems operating on narrow channels between 30 and 50 kHz are frequently used for HV line protective relaying applications.

Power pool: A group of power systems operating as an interconnected system and pooling their resources.

Power, reactive: The product of the rms value of the voltage and the rms value of the quadrature component of the current.

Power system stability: The ability of an electric power system, for a given initial operating condition, to regain a state of operating equilibrium after being subjected to a physical disturbance.

Power transformer: A transformer that transfers electric energy in any part of the circuit between the generator and the distribution primary circuits.

Primary disconnecting devices: Self-coupling separable contacts provided to connect and disconnect the main circuits between the removable element and the housing.

Primary distribution feeder: A feeder operating at primary voltage supplying a distribution circuit.

Primary distribution mains: The conductors that feed from the center of distribution to direct primary loads or to transformers that feed secondary circuits.

Primary distribution network: A network consisting of primary distribution mains.

Primary distribution system: A system of AC distribution for supplying the primaries of distribution transformers from the generating station or substation distribution buses.

Primary distribution trunk line: A line acting as a main source of supply to a distribution system.

Primary feeder: That portion of the primary conductors between the substation or point of supply and the center of distribution.

Primary lateral: That portion of a primary distribution feeder that is supplied by a main feeder or other laterals and extends through the load area with connections to distribution transformers or primary loads.

Primary main feeder: The higher-capacity portion of a primary distribution feeder that acts as a main source of supply to primary laterals or directly connected distribution transformers and primary loads.

Primary network: A network supplying the primaries of transformers whose secondaries may be independent or connected to a secondary network.

Primary open-loop service: A service that consists of a single distribution transformer with dual primary switching, supplied from a single primary circuit that is arranged in an open-loop configuration.

Primary selective service: A service that consists of a single distribution transformer with primary throw-over switching, supplied by two independent primary circuits.

Primary transmission feeder: A feeder connected to a primary transmission circuit.

Primary unit substation: A unit substation in which the low-voltage section is rated above 1,000 V.

Protective gear: The apparatus, including protective relays, transformers, and auxiliary equipment, for use in a protective system.

Protective relay: An electrical device whose function is to detect defective lines or apparatus or other power system conditions of an abnormal or dangerous nature and to initiate isolation of a part of an electrical system or to operate an alarm signal in the case of a fault or other abnormal condition.

Protective scheme: The coordinated arrangements for the protection of a power system.

Protective system: A combination of protective gears designed to secure, under predetermined conditions, usually abnormal, the disconnection of an element of a power system or to give an alarm signal or both.

Protective system usage: In protection systems, it is used to compare relevant quantities and so replace slower, more conventional devices, based on the high-speed measurement of system parameters.

PT: Abbreviation for potential transformer.

pu: Abbreviation for per unit.

Puller, reel: A device designed to pull a conductor during stringing operations.

Pulse number (p): The number of pulsations (i.e., cycles of ripple) of the direct voltage per cycle of alternating voltage (e.g., pulse numbers for three-phase one-way and three-phase two-way rectifier bridges are 3 and 6, respectively).

Radial distribution system: A distribution system that has a single simultaneous path of power flow to the load.

Radial service: A service that consists of a single distribution transformer supplied by a single primary circuit.

Radial system, complete: A radial system that consists of a radial subtransmission circuit, a single substation, and a radial primary feeder with several distribution transformers each supplying radial secondaries; has the lowest degrees of service continuity.

- Ratchet demand:** The maximum past or present demands that are taken into account to establish billings for previous or subsequent periods.
- Rate base:** The net plant investment or valuation base specified by a regulatory authority upon which a utility is permitted to earn a specified rate of return.
- Rated burden:** It is the load that may be imposed on the transformer secondaries by associated meter coils, leads, and other connected devices without causing an error greater than the stated accuracy classification.
- Rated continuous current:** The maximum 60Hz rms current that the breaker can carry continuously while it is in the closed position without overheating.
- Rated impulse withstand voltage:** The maximum crest voltage of a voltage pulse with standard rise and delay times that the breaker insulation can withstand.
- Rated insulation class:** It denotes the nominal (line-to-line) voltage of a circuit on which it should be used.
- Rated interrupting MVA:** For a three-phase CB, it is $\sqrt{3}$ times the rated maximum voltage in kV times the rated short-circuit current in kA. It is more common to work with current and voltage ratings than with MVA rating.
- Rated interrupting time:** The time in cycles on a 60Hz basis from the instant the trip coil is energized to the instant the fault current is cleared.
- Rated low-frequency withstanding voltage:** The maximum 60Hz rms line-to-line voltage that the CB can withstand without insulation damage.
- Rated maximum voltage:** Designated the maximum rms line-to-line operating voltage. The breaker should be used in systems with an operating voltage less than or equal to this rating.
- Rated momentary current:** The maximum rms asymmetrical current that the breaker can withstand while in the closed position without damage. Rated momentary current for standard breakers is 1.6 times the symmetrical interrupting capacity.
- Rated short-circuit current:** The maximum rms symmetrical current that the breaker can safely interrupt at rated maximum voltage.
- Rated voltage range factor K :** The range of voltage for which the symmetrical interrupting capability times the operating voltage is constant.
- Ratio correction factor:** The factor by which the marked ratio of a CT must be multiplied to obtain the true ratio.
- Reach:** A distance relay operates whenever the impedance seen by the relay is less than a prescribed value. This impedance or the corresponding distance is known as the reach of the relay.
- Reactive power compensation:** Shunt reactors, shunt capacitors, static var systems, and synchronous condensers are used to control voltage. SCs are used to reduce line impedance.
- Reactor:** An inductive reactor between the DC output of the converter and the load. It is used to smooth the ripple in the DC adequately, to reduce harmonic voltages and currents in the DC line, and to limit the magnitude of fault current. It is also called a smoothing reactor.
- Recloser:** A dual-timing device that can be set to operate quickly to prevent downline fuses from blowing.
- Reclosing device:** A control device that initiates the reclosing of a circuit after it has been opened by a protective relay.
- Reclosing fuse:** A combination of two or more fuse holders, fuse units, or fuse links mounted on a fuse support(s), mechanically or electrically interlocked, so that one fuse can be connected into the circuit at a time and the functioning of that fuse automatically connects the next fuse into the circuit, thereby permitting one or more service restorations without replacement of fuse links, refill units, or fuse units.
- Reclosing relay:** A programming relay whose function is to initiate the automatic reclosing of a CB.

Reclosure: The automatic closing of a circuit-interrupting device following automatic tripping. Reclosing may be programmed for any combination of instantaneous, time-delay, single-shot, multiple-shot, synchronism-check, deadline-live-bus, or dead-bus-live-line operation.

Recovery voltage: The voltage that occurs across the terminals of a pole of a circuit-interrupting device upon interruption of the current.

Rectifier: A converter for changing AC to DC.

Relays: A low-powered electrical device used to activate a high-powered electrical device. (In T&D systems, it is the job of relays to give the tripping commands to the right CBs.)

Remote access: Access to control systems or IED by a user whose operation terminal is not directly connected to the control systems or IED.

Remote backup: Those relays that are located in a separate location and are completely independent of the relays, transducers, batteries, and CBs that they are backing up.

Remote terminal unit (RTU): A hardware that telemeters system-wide data from various field locations (i.e., substations, generating plants to a central location). It includes the entire complement of devices, functional modules, and assemblies that are electrically interconnected to affect the remote station supervisory functions.

Required reserve: The system planned reserve capability needed to ensure a specified standard of service.

Resetting value: The maximum value of the energizing quantity that is insufficient to hold the relay contacts closed after operating.

Resistance: The real part of impedance.

Return on capital: The requirement that is necessary to pay for the cost of investment funds used by the utility.

Ripple: The AC component from DC power supply arising from sources within the power supply. It is expressed in peak, peak-to-peak, rms volts, or as percent rms. Since HVDC converters have large DC smoothing reactors, approximately 1 H, the resultant DC is constant (i.e., free from ripple). However, the direct voltage on the valve side of the smoothing reactor has ripple.

Ripple amplitude: The maximum value of the instantaneous difference between the average and instantaneous value of a pulsating unidirectional wave.

Risk: The probability that a particular threat will exploit a particular vulnerability of an equipment, plant, or system.

Risk management: Decisions to accept exposure or to reduce vulnerabilities by either mitigating the risks or applying cost-effective controls.

SA: Deployment of substation and feeder operating functions and applications ranging from SCADA and alarm processing to integrated volt/var control in order to optimize the management of capital assets and enhance operational and maintenance efficacies with minimal human intervention.

SAG: The distance measured vertically from a conductor to the straight line joining its two points of support. Unless otherwise stated, the sag referred to is the sag at the midpoint of the span.

SAG: A decrease to between 0.1 and 0.9 pu in rms voltage and current at the power frequency for a duration of 0.5 cycles to 1 min.

SAG, final unloaded: The sag of a conductor after it has been subjected for an appreciable period to the loading prescribed for the loading district in which it is situated, or equivalent loading, and the loading removed. Final unloaded sag includes the effect of inelastic deformation.

SAG, initial unloaded: The sag of a conductor prior to the application of any external load.

SAG of a conductor (at any point in a span): The distance measured vertically from the particular point in the conductor to a straight line between its two points of support.

SAG section: The section of line between snub structures. More than one sag section may be required to properly sag the actual length of conductor that has been strung.

SAG span: A span selected within a sag section and used as a control to determine the proper sag of the conductor, thus establishing the proper conductor level and tension. A minimum of two, but normally three, sag spans are required within a sag section to sag properly. In mountainous terrain or where span lengths vary radically, more than three sag spans could be required within a sag section.

SCADA: An abbreviation for supervisory control and data acquisition.

SCADA communication line: The communication link between the utility's control center and the RTU at the substation.

Scheduled interruption: An interruption caused by a scheduled outage.

Scheduled maintenance (generation): Capability that has been scheduled to be out of service for maintenance.

Scheduled outage: An outage that results when a component is deliberately taken out of service at a selected time, usually for purposes of construction, preventive maintenance, or repair. The key test to determine if an outage should be classified as forced or scheduled is as follows: if it is possible to defer the outage when such deferment is desirable, the outage is a scheduled outage; otherwise, the outage is a forced outage. Deferring an outage may be desirable, for example, to prevent overload of facilities or an interruption of service to consumers.

Scheduled outage duration: The period from the initiation of the outage until construction, preventive maintenance, or repair work is completed.

SCV: Abbreviation for steam-cured (cable insulation).

Seasonal diversity: Load diversity between two (or more) electric systems that occurs when their peak loads are in different seasons of the year.

Secondary current rating: The secondary current exists when the transformer is delivering rated kilovolt-amperes at rated secondary voltage.

Secondary disconnecting devices: Self-coupling separable contacts provided to connect and disconnect the auxiliary and control circuits between the removable element and the housing.

Secondary distributed network: A service consisting of a number of network transformer units at a number of locations in an urban load area connected to an extensive secondary cable grid system.

Secondary distribution feeder: A feeder operating at secondary voltage supplying a distribution circuit.

Secondary distribution mains: The conductors connected to the secondaries of distribution transformers from which consumers' services are supplied.

Secondary distribution network: A network consisting of secondary distribution mains.

Secondary fuse: A fuse used on the secondary-side circuits, restricted for use on a low-voltage secondary distribution system that connects the secondaries of distribution transformers to consumers' services.

Secondary mains: Those that operate at utilization voltage and serve as the local distribution main. In radial systems, secondary mains that supply general lighting and small power are usually separated from mains that supply three-phase power because of the dip in voltage caused by starting motors. This dip in voltage, if sufficiently large, causes an objectionable lamp flicker.

Secondary network: It consists of two or more network transformer units connected to a common secondary system and operating continuously in parallel.

Secondary network service: A service that consists of two or more network transformer units connected to a common secondary system and operating continuously in parallel.

Secondary system, banked: A system that consists of several transformers supplied from a single primary feeder, with the low-voltage terminals connected together through the secondary mains.

Secondary unit substation: A unit substation whose low-voltage section is rated 1,000 V and below.

Secondary voltage regulation: A VD caused by the secondary system; it includes the drop in the transformer and in the secondary and service cables.

Second-contingency outage: The outage of a secondary primary feeder in addition to the first one.

Sectionalizer: A device that resembles an oil circuit recloser but lacks the interrupting capability.

Security: The measure that a relay will not operate incorrectly for any faults.

Security (in protection): The measure that a relay will not operate incorrectly for any fault.

Security (in relays): The ability of a relay or relaying system never to operate falsely.

Selector: See Transfer switches.

Sequence filters: Used in a three-phase system to measure (and therefore to indicate the presence of) symmetrical components of current and voltage.

Service area: Territory in which a utility system is required or has the right to supply or make available electric service to ultimate consumers.

Service availability index: See Index of reliability.

Service drop: The OH conductors, through which electric service is supplied, between the last utility company pole and the point of their connection to the service facilities located at the building or other support used for the purpose.

Service entrance: All components between the point of termination of the OH service drop or underground service lateral and the building main disconnecting device, with the exception of the utility company's metering equipment.

Service entrance conductors: The conductors between the point of termination of the OH service drop or underground service lateral and the main disconnecting device in the building.

Service entrance equipment: Equipment located at the service entrance of a given building that provides overcurrent protection to the feeder and service conductors, provides a means of disconnecting the feeders from energized service conductors, and provides a means of measuring the energy used by the use of metering equipment.

Service lateral: The underground conductors, through which electric service is supplied, between the utility company's distribution facilities and the first point of their connection to the building or area service facilities located at the building or other support used for the purpose.

Setting: The actual value of the energizing or characteristic quantity of which the relay is designed to operate under given conditions.

SF₆: Formula for sulfur hexafluoride (gas).

Shielding, effective: A shielding that has zero unprotective width.

Short-circuit selective relay: A relay that functions instantaneously on an excessive value of current.

Shunt capacitor bank: A large number of capacitor units connected in series and parallel arrangement to make up the required voltage and current ratings and connected between line and neutral or between line to line.

Skin effect: The phenomenon by which alternative current tends to flow in the outer layer of a conductor. It is a function of conductor size, frequency, and the relative resistance of the conductor material.

St: Abbreviation for steel.

Stability: The quality whereby a protective system remains operative under all conditions other than those for which it is specifically designed to operate.

STATCOM: It is a static compensator. It provides variable lagging or leading reactive powers without using inductors or capacitors for var generation.

Static var system: It is a static var compensator that can also control the mechanical switching of shunt capacitor banks or reactors.

Strand: One of the wires, or groups of wires, of any stranded conductor.

Stranded conductor: A conductor composed of a group of wires or of any combination of groups of wires. Usually, the wires are twisted together.

Strike distance: The distance that jumped an approaching flash to make contact.

Stroke: The high-current components in a flash. A single flash may contain several strokes.

Submarine cable: A cable designed for service underwater. It is usually a lead-covered cable with a steel armor applied between layers of jute.

Submersible transformer: A transformer so constructed as to be successfully operable when submerged in water under predetermined conditions of pressure and time.

Substation: An assemblage of equipment for purposes other than generation or utilization, through which electric energy in bulk is passed for the purpose of switching or modifying its characteristics. The term substation includes all stations classified as switching, collector bus, distribution, transmission, or bulk power substations.

Substation local area network (LAN): A communications network, typically high speed, and within the substation and extending into the switchyard. It is also a technology that is used in a substation environment and facilitates interfacing to process-level-equipment (IEDs and PLCs) while providing immunity and isolation to substation noise.

Substation voltage regulation: The regulation of the substation voltage by means of the voltage regulation equipment that can be LTC (load-tap-changing) mechanisms in the substation transformer, a separate regulator between the transformer and low-voltage bus, switched capacitors at the low-voltage bus, or separate regulators located in each individual feeder in the substation.

Subsynchronous: Electrical and mechanical quantities associated with frequencies below the synchronous frequency of a power system.

Subsynchronous oscillation: The exchange of energy between the electrical network and the mechanical spring-mass system of the turbine generator at subsynchronous frequencies.

Subsynchronous resonance: It is an electric power system condition where the electric power network exchanges energy with a turbine generator at one or more of the natural frequencies of the combined system below the synchronous frequency of the system.

Subtransmission: That part of the distribution system between bulk power source(s) (generating stations or power substations) and the distribution substation.

Supersynchronous: Electrical or mechanical quantities associated with frequencies above the synchronous frequency of a power system.

Supervisory control and data acquisition (SCADA): A computer system that performs data acquisition and remote control of a power system.

Supply security: Provision must be made to ensure continuity of supply to consumers even with certain items of plant out of action. Usually, two circuits in parallel are used and a system is said to be secure when continuity is assured. It is the prerequisite in design and operation.

Susceptance: The imaginary part of admittance.

Sustained interruption: The complete loss of voltage (<0.1 pu) on one or more phase conductors for a time greater than 1 min.

SVC: Static var compensator.

Swell: An increase to between 1.1 and 1.8 pu in rms voltage or current at the power frequency for durations from 0.5 cycle to 1 min.

Switch: A device for opening and closing or for changing connections in a circuit.

Switchboard: A large single panel, frame, or assembly of panels on which are mounted (on the face or back or both) switches, fuses, buses, and usually instruments.

Switched capacitor bank: A capacitor bank with switchable capacitors.

Switchgear: A general term covering switching or interrupting devices and their combination with associated control, instrumentation, metering, protective, and regulating devices; also assemblies of these devices with associated interconnections, accessories, and supporting structures.

Switching: Connecting or disconnecting parts of the system from each other. It is accomplished using breakers and/or switches.

Switching time: The period from the time a switching operation is required due to a forced outage until that switching operation is performed.

Switch, isolating: An auxiliary switch for isolating an electric circuit from its source of power; it is operated only after the circuit has been opened by other means.

System: A group of components connected together in some fashion to provide the flow of power from one point or points to another point or points.

System interruption duration index: The ratio of the sum of all customer interruption durations per year to the number of customers served. It gives the number of minutes out per customer per year.

Systems: It is used to describe the complete electrical network, generators, loads, and prime movers.

TCR: It is a thyristor-controlled reactor.

TCSC: It denotes thyristor-controlled series compensation. It provides fast control and variation of the impedance of the SC bank. It is part of the flexible system (FACTS).

Thyristor (SCR): A thyristor (silicon-controlled rectifier) is a semiconductor device with an anode, a cathode terminal, and a gate for the control of the firing.

Tie lines: The transmission lines between the electric power systems of separate utility companies.

Time delay: An intentional time delay is inserted between the relay decision time and the initiation of the trip action.

Time-delay relay: A relay having an intentional delaying device.

Total demand distortion (TDD): The ratio of the rms of the harmonic current to the rms value of the rated or maximum demand fundamental current, expressed as a percent.

Total harmonic distortion (THD): The ratio of the rms of the harmonic content to the rms value of the fundamental quantity, expressed as a percent of the fundamental.

Transfer bus: A bus used for the purpose of transferring a load.

Transfer switches: The switches that permit feeders or equipment to be connected to a bus.

Transformer ratio (TR): The total ratio of current and VTs. For 200:5 CT and 480:120 VT, $TR = 40 \times 4 = 160$.

Transient forced outage: A component outage whose cause is immediately self-clearing so that the affected component can be restored to service either automatically or as soon as a switch or a CB can be reclosed or a fuse replaced. An example of a transient forced outage is a lightning flashover that does not permanently disable the flashed component.

Traveler: A sheave complete with suspension arm or frame used separately or in groups and suspended from structures to permit the stringing of conductors.

Trip out: A flashover of a line that does not clear itself. It must be cleared by operation of a CB.

Triplen harmonics: A term frequency used to refer to the odd multiples of the third harmonic, which deserve special attention because of their natural tendency to be zero sequence.

True power factor (TPF): The ratio of the active power of the fundamental wave, in watts, to the apparent power of the fundamental wave, in rms volt-amperes (including the harmonic components).

TSC: It is a thyristor-switched capacitor.

Ultrahigh speed: It is a term that is not included in the relay standards but is commonly considered to be in operation in 4 ms or less.

Underground distribution system: That portion of a primary or secondary distribution system that is constructed below the earth's surface. Transformers and equipment enclosures for such a system may be located either above or below the surface as long as the served and serving conductors are located underground.

Undervoltage: A voltage that has a value at least 10% below the nominal voltage for a period of time >1 min.

Undervoltage relay: A relay that functions on a given value single-phase AC undervoltage.

Unit: A self-contained relay unit that in conjunction with one or more other relay units performs a complex relay function.

Unit substation: A substation consisting primarily of one or more transformers that are mechanically and electrically connected to and coordinated in design with one or more switchgear or motor control assemblies or combinations thereof.

Unreach: The tendency of the relay to restrain at impedances larger than its setting. That is, it is due to the error in relay measurement resulting in wrong operation.

URD: Abbreviation for underground residential distribution.

Utilization factor: The ratio of the maximum demand of a system to the rated capacity of the system.

VD: Abbreviation for voltage drop.

VDIP: Abbreviation for voltage dip.

Voltage, base: A reference value that is a common denominator to the nominal voltage ratings of transmission and distribution lines, transmission and distribution equipment, and utilization equipment.

Voltage collapse: The process by which voltage instability leads to a very low-voltage profile in a significant part of the system.

Voltage dip: A voltage change resulting from a motor starting.

Voltage drop: The difference between the voltage at the transmitting and receiving ends of a feeder, main, or service.

Voltage fluctuation: A series of voltage changes or a cyclical variation of the voltage envelope.

Voltage imbalance (or unbalance): The maximum deviation from the average of the three-phase voltages or currents divided by the average of the three-phase voltages or currents, expressed in percent.

Voltage interruption: Disappearance of the supply voltage on one or more phases. It can be momentary, temporary, or sustained.

Voltage magnification: The magnification of capacitor switching oscillatory transient voltage on the primary side by capacitors on the secondary side of a transformer.

Voltage, maximum: The greatest 5 min average or mean voltage.

Voltage, minimum: The least 5 min average or mean voltage.

Voltage, nominal: A nominal value assigned to a circuit or system of a given voltage class for the purpose of convenient designation.

Voltage, rated: The voltage at which operating and performance characteristics of equipment are referred.

Voltage regulation: The percent VD of a line with reference to the receiving-end voltage:

$$\% \text{ Regulation} = \frac{|\overline{E_s}| - |\overline{E_r}|}{|\overline{E_r}|} \times 100$$

where

$|\overline{E_s}|$ is the magnitude of the sending-end voltage

$|\overline{E_r}|$ is the magnitude of the receiving-end voltage

Voltage regulator: An induction device having one or more windings in shunt with, and excited from, the primary circuit and having one or more windings in series between the primary circuit and the regulated circuit, all suitably adapted and arranged for the control of the voltage or of the phase angle or of both of the regulated circuit.

Voltage, service: Voltage measured at the terminals of the service entrance equipment.

Voltage spread: The difference between maximum and minimum voltages.

Voltage stability: The ability of a power system to maintain steady voltages at all buses in the system after being subjected to a disturbance from a given initial operational condition. It can be either fast (short term, with voltage collapse in the order of fractions of a few seconds) or slow (long term, with voltage collapse in minutes or hours).

Voltage stability problems: Manifested by low system voltage profiles, heavy reactive line flows, inadequate reactive support, and heavy-loaded power systems.

Voltage transformation: It is done by substation power transformers by raising or lowering the voltage.

Voltage transformer: The transformer that is connected across the points at which the voltage is to be measured.

Voltage transformer burdens: The VT burdens are normally expressed as volt-amperes at a designated PF. It may be a *W*, *X*, *M*, *Y*, or *Z* where *W* is 12.5 VA at 0.10 PF, *X* is 25 VA at 0.70 PF, *M* is 35 VA at 0.20 PF, *Y* is 75 VA at 0.85 PF, and *Z* is 200 VA at 0.85 PF. The complete expression for a CT accuracy classification might be 0.3 at B-0.1, B-0.2, and B-0.5, while the PT might be 0.3 at *W*, *X*, *M*, and *Y*.

Voltage transformer ratio: Also called the VT ratio. It is the ratio of primary to secondary voltage. For a VT rated 480:120, the ratio is 4:1, and for a VT rated 7,200:120, it is 60:1.

Voltage, utilization: Voltage measured at the terminals of the machine or device.

VRR: Abbreviation for voltage-regulating relay.

Waveform distortion: A steady-state deviation from an ideal sine wave of power frequency principally characterized by the special content of the deviation.

Weatherability: The ability to operate in all weather conditions. For example, transformers are rated as indoor or outdoor, depending on their construction (including hardware).

Withstand voltage: The BIL that can be repeatedly applied to an equipment without any flashover, disruptive charge, puncture, or other electrical failure, under specified test conditions.

XLPE: Abbreviation for cross-linked polyethylene (cable insulation).

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