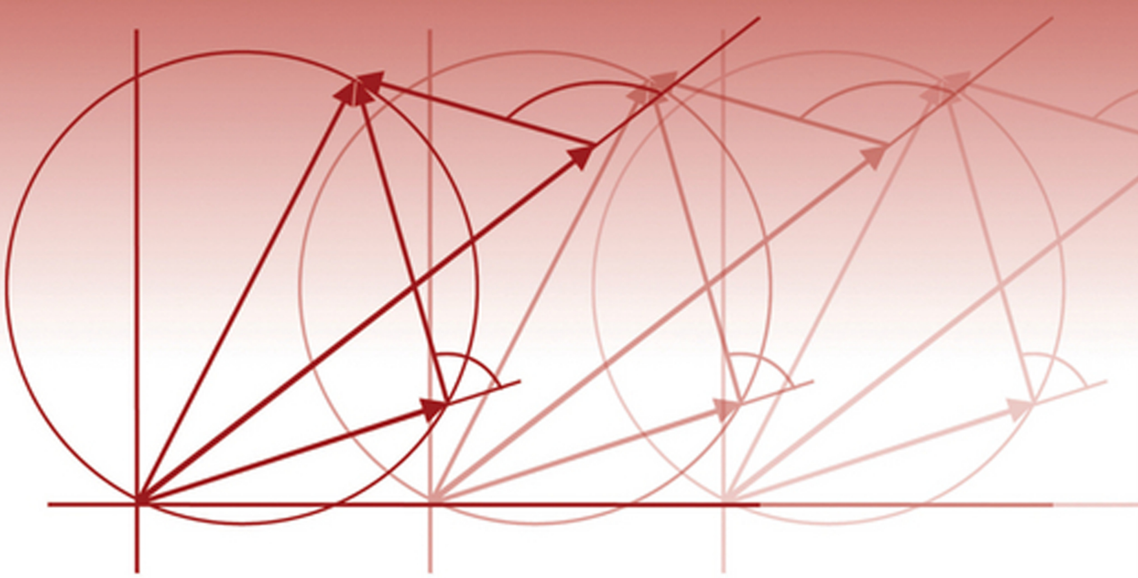
Power System Relaying

Fourth Edition

Stanley H. Horowitz
Arun G. Phadke



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Preface to the Fourth Edition

The third edition of our book, issued with corrections in 2009, continued to be used as a text book in several universities around the world. The success of our book and the positive feedback we continue to receive from our colleagues is gratifying. Since that time, we have had a few other typos and errors pointed out to us, which we are correcting in this fourth edition.

However, the major change in this edition is the inclusion of two new chapters. Chapter 14 gives an account of the application of Wide Area Measurements (WAMS) in the field of protection. WAMS technology using Global Positioning Satellite (GPS) satellites for synchronized measurements of power system voltages and currents is finding many applications in monitoring, protection, and control of power systems. Field installations of such systems are taking place in most countries around the world, and we believe that an account of what is possible with this technology, as discussed in Chapter 14, is timely and will give the student using this edition an appreciation of these exciting changes taking place in the field of power system protection. Chapter 14 also provides a list of relevant references for the reader who is interested in pursuing this technology in depth.

Another major development in the field of power system protection on the advent of renewable resources for generation of electricity is reported in the new Chapter 15. This also is a technology that is being deployed in most modern power systems around the world. As the penetration of renewable resources in the mix of generation increases, many challenges are faced by power system engineers. In particular, how to handle the interconnection of these resources with proper protection systems is a very important subject. We are very fortunate to have a distinguished expert, James Niemira of S&C Electric Company, Chicago, contributor of this chapter to our book. The chapter also includes a list of references for the interested reader. We believe this chapter will answer many of the questions asked by our students.

Finally, we would welcome continued correspondence from our readers who give us valuable comments about what they like in the book, and what other material should be included in future editions. We wish to thank all the readers who let us have their views, and assure them that we greatly value their inputs.

April 24, 2013

S.H. Horowitz
Columbus

A.G. Phadke
Blacksburg

Preface to the Third Edition

The second edition of our book, issued in 1995, continued to receive favorable response from our colleagues and is being used as a textbook by universities and in industry courses worldwide. The first edition presented the fundamental theory of protective relaying as applied to individual system components. This concept was continued throughout the second edition. In addition, the second edition added material on generating plant auxiliary systems, distribution protection concepts, and the application of electronic inductive and capacitive devices to regulate system voltage. The second edition also presented additional material covering monitoring power system performance and fault analysis. The application of synchronized sampling and advanced timing technologies using the Global Positioning Satellite (GPS) system was explained.

This third edition takes the problem of power system protection an additional step forward by introducing power system phenomena which influence protective relays and for which protective schemes, applications, and settings must be considered and implemented. The consideration of power system stability and the associated application of relays to mitigate its harmful effects are presented in detail. New concepts such as undervoltage load shedding, adaptive relaying, hidden failures, and the Internet standard COMTRADE and its uses are presented. The history of notable blackouts, particularly as affected by relays, is presented to enable students to appreciate the impact that protection systems have on the overall system reliability.

As mentioned previously, we are gratified with the response that the first and second editions have received as both a textbook and a reference book. Recent changes in the electric power industry have resulted in power system protection assuming a vital role in maintaining power system reliability and security. It is the authors' hope that the additions embodied in this third edition will enable all electric power system engineers, designers, and operators to better integrate these concepts and to understand the complex interaction of relaying and system performance.

S. H. Horowitz
Columbus

A. G. Phadke
Blacksburg

Preface to the Second Edition

The first edition, issued in 1992, has been used as a textbook by universities and in industry courses throughout the world. Although not intended as a reference book for practicing protection engineers, it has been widely used as one. As a result of this experience and of the dialog between the authors and teachers, students and engineers using the first edition, it was decided to issue a second edition, incorporating material which would be of significant value. The theory and fundamentals of relaying constituted the major part of the first edition and it remains so in the second edition. In addition, the second edition includes concepts and practices that add another dimension to the study of power system protection.

A chapter has been added covering monitoring power system performance and fault analysis. Examples of oscillographic records introduce the student to the means by which disturbances can be analyzed and corrective action and maintenance initiated. The application of synchronized sampling for technologies such as the GPS satellite is explained. This chapter extends the basic performance of protective relays to include typical power system operating problems and analysis. A section covering power plant auxiliary systems has been added to the chapter on the protection of rotating machinery. Distribution protection concepts have been expanded to bridge the gap between the protection of distribution and transmission systems. The emerging technology of static var compensators to provide inductive and capacitive elements to regulate system voltage has been added to the chapter on bus protection. The subject index has been significantly revised to facilitate reference from both the equipment and the operating perspective.

We are gratified with the response that the first edition has received as a text and reference book. The authors thank the instructors and students whose comments generated many of the ideas included in this second edition. We hope that the book will continue to be beneficial and of interest to students, teachers, and power system engineers.

S. H. Horowitz
Columbus

A. G. Phadke
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Preface to the First Edition

This book is primarily intended to be a textbook on protection, suitable for final year undergraduate students wishing to specialize in the field of electric power engineering. It is assumed that the student is familiar with techniques of power system analysis, such as three-phase systems, symmetrical components, short-circuit calculations, load flow, and transients in power systems. The reader is also assumed to be familiar with calculus, matrix algebra, and Laplace and Fourier transforms, and Fourier series. Typically, this is the background of a student who is taking power option courses at a US university. The book is also suitable for a first year graduate course in power system engineering.

An important part of the book is the large number of examples and problems included in each chapter. Some of the problems are decidedly difficult. However, no problems are unrealistic, and, difficult or not, our aim is always to educate the reader, help the student realize that many of the problems that will be faced in practice will require careful analysis, consideration, and some approximations.

The book is not a reference book, although we hope it may be of interest to practicing relay engineers as well. We offer derivations of several important results, which are normally taken for granted in many relaying textbooks. It is our belief that by studying the theory behind these results, students may gain an insight into the phenomena involved, and point themselves in the direction of newer solutions which may not have been considered. The emphasis throughout the book is on giving the reader an understanding of power system protection principles. The numerous practical details of relay system design are covered to a limited extent only, as required to support the underlying theory. Subjects which are the province of the specialist are left out. The engineer interested in such detail should consult the many excellent reference works on the subject, and the technical literature of various relay manufacturers.

The authors owe a great deal to published books and papers on the subject of power system protection. These works are referred to at appropriate places in the text. We would like to single out the book by the late C. R. Mason, *The Art and Science of Protective Relaying*, for special praise. We, and many generations of power engineers, have learned relaying from this book. It is a model of clarity, and its treatment of the protection practices of that day is outstanding.

Our training as relay engineers has been enhanced by our association with the Power System Relaying Committee of the Institute of Electrical and Electronics Engineers (IEEE), and the Study Committee SC34 of the Conférence Internationale des Grands Réseaux Electriques des Hautes Tensions (CIGRE). Much of our technical work has been under the auspices of these organizations. The activities of the two organizations, and our interaction with the international relaying community, have resulted in an appreciation of the differing practices throughout the world. We have tried to introduce an awareness of these differences in this book. Our long association with the American Electric Power (AEP) Service Corporation has helped sustain our interest in electric power engineering, and particularly in the field of protective relaying. We have learned much from our friends in AEP. AEP has a well-deserved reputation for pioneering in many phases of electric power engineering, and particularly in power system protection. We are fortunate to be a part of many important relaying research and development efforts conducted at AEP. We have tried to inject this experience of fundamental theory and practical implementation throughout this text. Our colleagues in the educational community have also been instrumental in getting us started on this project, and we hope they find this book useful. No doubt some errors remain, and we will be grateful if readers bring these errors to our attention.

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1

Introduction to Protective Relaying

1.1 What is Relaying?

In order to understand the function of protective relaying systems, one must be familiar with the nature and the modes of operation of an electric power system. Electric energy is one of the fundamental resources of modern industrial society. Electric power is available to the user instantly, at the correct voltage and frequency, and exactly in the amount that is needed. This remarkable performance is achieved through careful planning, design, installation, and operation of a very complex network of generators, transformers, and transmission and distribution lines. To the user of electricity, the power system appears to be in a steady state: imperturbable, constant, and infinite in capacity. Yet, the power system is subject to constant disturbances created by random load changes, by faults created by natural causes, and sometimes as a result of equipment or operator failure. In spite of these constant perturbations, the power system maintains its quasi-steady state because of two basic factors: the large size of the power system in relation to the size of individual loads or generators and correct and quick remedial action taken by the protective relaying equipment.

Relaying is the branch of electric power engineering concerned with the principles of design and operation of equipment (called "relays" or "protective relays") that detects abnormal power system conditions and initiates corrective action as quickly as possible in order to return the power system to its normal state. The quickness of response is an essential element of protective relaying systems – response times of the order of a few milliseconds are often required. Consequently, human intervention in the protection system operation is not possible. The response must be automatic, quick, and should cause a minimum amount of disruption to the power system. As the principles of protective relaying are developed in this book, the reader will perceive that the entire subject is governed by these general requirements: correct diagnosis of trouble, quickness of response, and minimum disturbance to the power system. To accomplish these goals, we must examine all possible types of fault or abnormal conditions that may occur in the power system. We must analyze the required response to each of these events and design protective equipment that will provide such a

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response. We must further examine the possibility that protective relaying equipment itself may fail to operate correctly, and provide for a backup protective function. It should be clear that extensive and sophisticated equipment is needed to accomplish these tasks.

1.2 Power System Structural Considerations

1.2.1 Multilayered Structure of Power Systems

A power system is made up of interconnected equipment that can be said to belong to one of the three layers from the point of view of the functions performed. This is illustrated in Figure 1.1.

At the basic level is the power apparatus that generates, transforms, and distributes the electric power to the loads. Next, there is the layer of control equipment. This equipment helps to maintain the power system at its normal voltage and frequency, generates sufficient power to meet the load, and maintains optimum economy and security in the interconnected network. The control equipment is organized in a hierarchy of its own, consisting of local and central control functions. Finally, there is the protection equipment layer. The response time of protection functions is generally faster than that of the control functions. Protection acts to open- and closed-circuit breakers (CBs), thus changing the structure of the power system, whereas the control functions act continuously to adjust system variables, such as the voltages, currents, and power flow on the network. Oftentimes, the distinction between a control function and a protection function becomes blurred. This is becoming even more of a problem with the recent advent of computer-based protection systems in substations. For our purposes, we may arbitrarily define all functions that lead to operation of power switches or CBs to be the tasks of protective relays, while all actions that change the operating state (voltages, currents, and power flows) of the power system without changing its structure to be the domain of control functions.

1.2.2 Neutral Grounding of Power Systems

Neutrals of power transformers and generators can be grounded in a variety of ways, depending upon the needs of the affected portion of the power system. As grounding practices affect fault current levels, they have a direct bearing upon relay system designs. In this section, we examine the types of grounding system in use in modern power systems and the reasons for each of the grounding choices. Influence of grounding practices on relay system design will be considered at appropriate places throughout the remainder of this book.

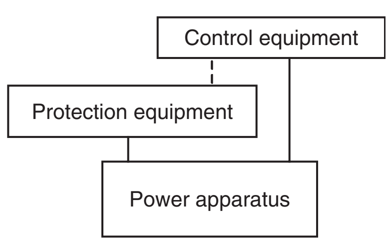

Figure 1.1 Three-layered structure of power systems

It is obvious that there is no ground fault current in a truly ungrounded system. This is the main reason for operating the power system ungrounded. As the vast majority of faults on a power system are ground faults, service interruptions due to faults on an ungrounded system are greatly reduced. However, as the number of transmission lines connected to the power system grows, the capacitive coupling of the feeder conductors with ground provides a path to ground, and a ground fault on such a system produces a capacitive fault current. This is illustrated in Figure 1.2a. The coupling capacitors to ground C_0 provide the return path for the fault current. The interphase capacitors $1/3C_1$ play no role in this fault. When the size of the capacitance becomes sufficiently large, the capacitive ground fault current becomes self-sustaining, and does not clear by itself. It then becomes necessary to open the CBs to clear the fault, and the relaying problem becomes one of detecting such low magnitudes of fault currents. In order to produce a sufficient fault current, a resistance is introduced between the neutral and the ground – inside the box shown by a dotted line in Figure 1.2a. One of the design considerations in selecting the grounding resistance is the thermal capacity of the resistance to handle a sustained ground fault.

Ungrounded systems produce good service continuity, but are subjected to high overvoltages on the unfaulted phases when a ground fault occurs. It is clear from the phasor diagram of Figure 1.2b that when a ground fault occurs on phase a, the steady-state voltages of phases b and c become $\sqrt{3}$ times their normal value. Transient overvoltages become correspondingly higher. This places additional stress on the insulation of all connected equipments. As the insulation level of lower voltage systems is primarily influenced by lightning-induced phenomena, it is possible to accept the fault-induced overvoltages as they are lower than the lightning-induced overvoltages. However, as the system voltages increase to higher than about 100 kV, the fault-induced overvoltages begin to assume a critical role in insulation design, especially of power transformers. At high voltages, it is therefore common to use solidly grounded neutrals (more precisely "effectively grounded"). Such systems have high ground fault currents, and each ground fault must be cleared by CBs. As high-voltage systems are generally heavily interconnected, with several alternative paths to load centers, operation of CBs for ground faults does not lead to a reduced service continuity.

In certain heavily meshed systems, particularly at 69 and 138 kV, the ground fault current could become excessive because of very low zero-sequence impedance at some buses. If ground fault current is beyond the capability of the CBs, it becomes necessary to insert

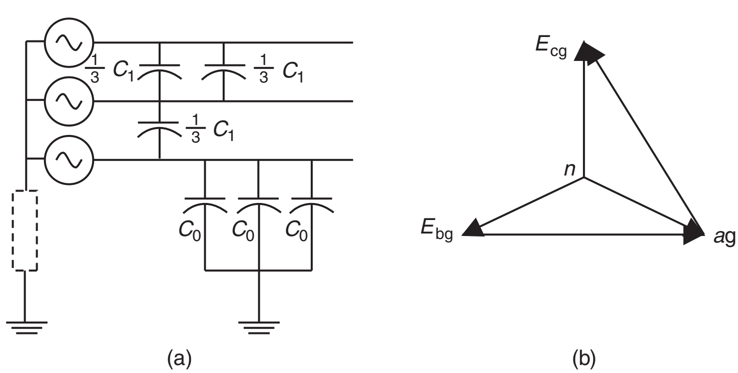

Figure 1.2 Neutral grounding impedance. (a) System diagram and (b) phasor diagram showing neutral shift on ground fault

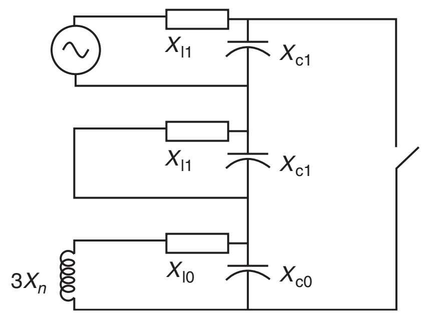

Figure 1.3 Symmetrical component representation for ground fault with grounding reactor

an inductance in the neutral in order to limit the ground fault current to a safe value. As the network Thévenin impedance is primarily inductive, a neutral inductance is much more effective (than resistance) in reducing the fault current. Also, there is no significant power loss in the neutral reactor during ground faults.

In several lower voltage networks, a very effective alternative to ungrounded operation can be found if the capacitive fault current causes ground faults to be self-sustaining. This is the use of a Petersen coil, also known as the ground fault neutralizer (GFN). Consider the symmetrical component representation of a ground fault on a power system that is grounded through a grounding reactance of X_n (Figure 1.3). If $3X_n$ is made equal to X_{c0} (the zero-sequence capacitive reactance of the connected network), the parallel resonant circuit formed by these two elements creates an open circuit in the fault path, and the ground fault current is once again zero. No CB operation is necessary upon the occurrence of such a fault, and service reliability is essentially the same as that of a truly ungrounded system. The overvoltages produced on the unfaulted conductors are comparable to those of ungrounded systems, and consequently GFN use is limited to system voltages below 100 kV. In practice, GFNs must be tuned to the entire connected zero-sequence capacitance on the network, and thus if some lines are out of service, the GFN reactance must be adjusted accordingly. Petersen coils have found much greater use in several European countries than in the United States.

1.3 Power System Bus Configurations

The manner in which the power apparatus is connected together in substations and switching stations, and the general layout of the power network, has a profound influence on protective relaying. It is therefore necessary to review the alternatives and the underlying reasons for selecting a particular configuration. A radial system is a single-source arrangement with multiple loads, and is generally associated with a distribution system (defined as a system operating at voltages below 100 kV) or an industrial complex (Figure 1.4).

Such a system is most economical to build; but from the reliability point of view, the loss of the single source will result in the loss of service to all of the users. Opening main line reclosers or other sectionalizing devices for faults on the line sections will disconnect the loads downstream of the switching device. From the protection point of view, a radial system presents a less complex problem. The fault current can only flow in one direction, that is, away from the source and toward the fault. Since radial systems are generally

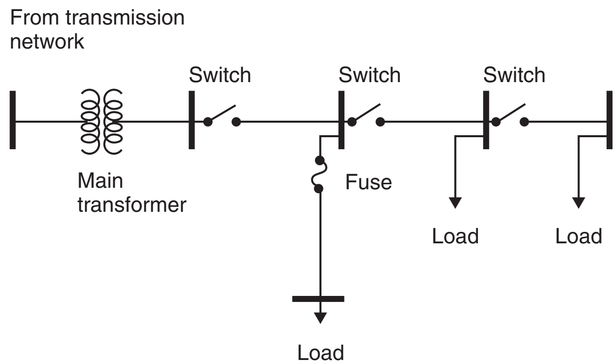

Figure 1.4 Radial power system

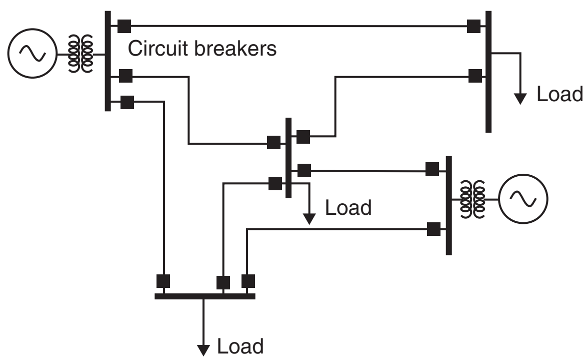

Figure 1.5 Network power system

electrically remote from generators, the fault current does not vary much with changes in generation capacity.

A network has multiple sources and multiple loops between the sources and the loads. Subtransmission and transmission systems (generally defined as systems operating at voltages of 100–200 kV and above) are network systems (Figure 1.5).

In a network, the number of lines and their interconnections provide more flexibility in maintaining service to customers, and the impact of the loss of a single generator or transmission line on service reliability is minimal. Since sources of power exist on all sides of a fault, fault current contributions from each direction must be considered in designing the protection system. In addition, the magnitude of the fault current varies greatly with changes in system configuration and installed generation capacity. The situation is dramatically increased with the introduction of the smart grid discussed in Section 6.13.

Example 1.1

Consider the simple network shown in Figure 1.6. The load at bus 2 has secure service for the loss of a single power system element. Further, the fault current for a fault at bus 2 is

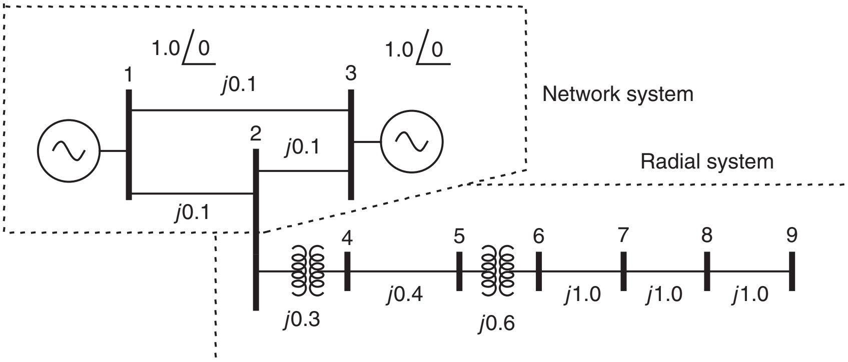

Figure 1.6 Power system for Example 1.1

$-j20.0$ pu when all lines are in service. If lines 2–3 go out of service, the fault current changes to $-j10.0$ pu. This is a significant change.

Now consider the distribution feeder with two intervening transformers connected to bus 2. All the loads on the feeder will lose their source of power if transformers 2–4 are lost. The fault current at bus 9 on the distribution feeder with system normal is $-j0.23$ pu, whereas the same fault when one of the two generators on the transmission system is lost is $-j0.229$ pu. This is an insignificant change. The reason for this of course is that, with the impedances of the intervening transformers and transmission network, the distribution system sees the source as almost a constant impedance source, regardless of the changes taking place on the transmission network.

Substations are designed for reliability of service and flexibility in operation and to allow for equipment maintenance with a minimum interruption of service. The most common bus arrangements in a substation are (a) single bus, single breaker, (b) two buses, single breaker, (c) two buses, two breakers, (d) ring bus, and (e) breaker-and-a-half. These bus arrangements are illustrated in Figure 1.7.

A single-bus, single-breaker arrangement, shown in Figure 1.7a, is the simplest, and probably the least expensive to build. However, it is also the least flexible. To do maintenance work on the bus, a breaker, or a disconnect switch, de-energizing the associated transmission lines is necessary. A two-bus, single-breaker arrangement, shown in Figure 1.7b, allows the breakers to be maintained without de-energizing the associated line. For system flexibility, and particularly to prevent a bus fault from splitting the system too drastically, some of the lines are connected to bus 1 and some to bus 2 (the transfer bus). When maintaining a breaker, all of the lines that are normally connected to bus 2 are transferred to bus 1, the breaker to be maintained is bypassed by transferring its line to bus 2 and the bus tie breaker becomes the line breaker. Only one breaker can be maintained at a time. Note that the protective relaying associated with the buses and the line whose breaker is being maintained must also be reconnected to accommodate this new configuration. This will be covered in greater detail as we discuss the specific protection schemes.

A two-bus, two-breaker arrangement is shown in Figure 1.7c. This allows any bus or breaker to be removed from service, and the lines can be kept in service through the

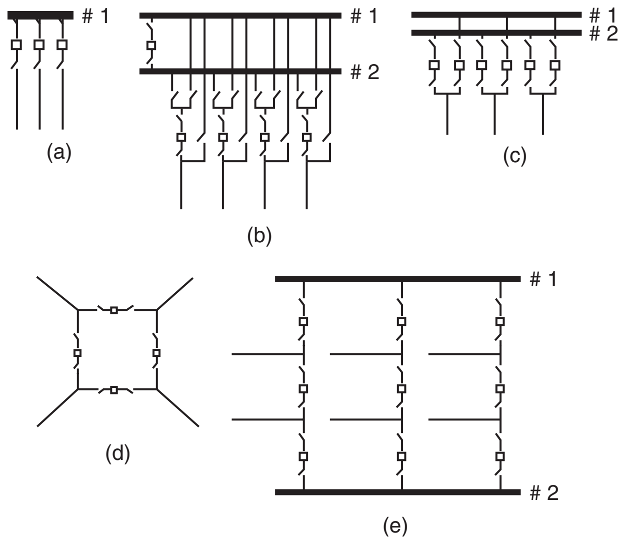

Figure 1.7 Substation bus arrangements: (a) single bus, single breaker; (b) two buses, one breaker; (c) two buses, two breakers; (d) ring bus; and (e) breaker-and-a-half

companion bus or breaker. A line fault requires two breakers to trip to clear a fault. A bus fault must trip all of the breakers on the faulted bus, but does not affect the other bus or any of the lines. This station arrangement provides the greatest flexibility for system maintenance and operation; however, this is at a considerable expense: the total number of breakers in a station equals twice the number of the lines. A ring bus arrangement shown in Figure 1.7d achieves similar flexibility while the ring is intact. When one breaker is being maintained, the ring is broken, and the remaining bus arrangement is no longer as flexible. Finally, the breaker-and-a-half scheme, shown in Figure 1.7e, is most commonly used in most extra high-voltage (EHV) transmission substations. It provides for the same flexibility as the two-bus, two-breaker arrangement at the cost of just one-and-a-half breakers per line on an average. This scheme also allows for future expansions in an orderly fashion.[1] In recent years, however, a new concept, popularly and commonly described as the "smart grid," has entered the lexicon of bus configuration, introducing ideas and practices that are changing the fundamental design, operation, and performance of the "distribution" system. The fundamental basis of the "smart grid" transforms the previously held definition of a

[1] The breaker-and-a-half bus configuration is the natural outgrowth of operating practices that developed as systems matured. Even in developing systems, the need to keep generating units in service was recognized as essential and it was common practice to connect the unit to the system through two CBs. Depending on the particular bus arrangement, the use of two breakers increased the availability of the unit despite line or bus faults or CB maintenance. Lines and transformers, however, were connected to the system through one CB per element. With one unit and several lines or transformers per station, there was a clear economic advantage to this arrangement. When the number of units in a station increased, the number of breakers increased twice as fast: one unit and two lines required four breakers, two units and two lines required six breakers, and so on. It is attractive to rearrange the bus design so that the lines and transformers shared the unit breakers. This gave the same maintenance advantage to the lines, and when the number of units exceeded the number of other elements, reduced the number of breakers required.

"distribution system," that is, a single-source, radial system to a transmission-like configuration with multiple generating sites, communication, operating, and protective equipment similar to high-voltage and extra-high-voltage transmission.

The impact of system and bus configurations on relaying practices will become clear in the chapters that follow.

1.4 The Nature of Relaying

We will now discuss certain attributes of relays that are inherent to the process of relaying, and can be discussed without reference to a particular relay. The function of protective relaying is to promptly remove from service any element of the power system that starts to operate in an abnormal manner. In general, relays do not prevent damage to equipment: they operate after some detectable damage has already occurred. Their purpose is to limit, to the extent possible, further damage to equipment, to minimize danger to people, to reduce stress on other equipments and, above all, to remove the faulted equipment from the power system as quickly as possible so that the integrity and stability of the remaining system are maintained. The control aspect of relaying systems also helps to return the power system to an acceptable configuration as soon as possible so that service to customers can be restored.

1.4.1 Reliability, Dependability, and Security

Reliability is generally understood to measure the degree of certainty that a piece of equipment will perform as intended. Relays, in contrast with most other equipments, have two alternative ways in which they can be unreliable: they may fail to operate when they are expected to, or they may operate when they are not expected to. This leads to a two-pronged definition of reliability of relaying systems: a reliable relaying system must be dependable and secure [1]. Dependability is defined as the measure of the certainty that the relays will operate correctly for all the faults for which they are designed to operate. Security is defined as the measure of the certainty that the relays will not operate incorrectly for any fault.

Most protection systems are designed for high dependability. In other words, a fault is always cleared by some relay. As a relaying system becomes dependable, its tendency to become less secure increases. Thus, in present-day relaying system designs, there is a bias toward making them more dependable at the expense of some degree of security. Consequently, a majority of relay system misoperations are found to be the result of unwanted trips caused by insecure relay operations. This design philosophy correctly reflects the fact that a power system provides many alternative paths for power to flow from generators to loads. Loss of a power system element due to an unnecessary trip is therefore less objectionable than the presence of a sustained fault. This philosophy is no longer appropriate when the number of alternatives for power transfer is limited, as in a radial power system, or in a power system in an emergency operating state.

Example 1.2

Consider the fault F on the transmission line shown in Figure 1.8. In normal operation, this fault should be cleared by the two relays R_1 and R_2 through the CBs B_1 and B_2. If R_2

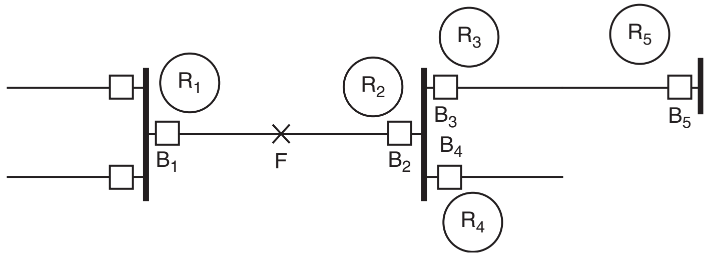

Figure 1.8 Reliability of protection system

does not operate for this fault, it has become unreliable through a loss of dependability. If relay R_5 operates through breaker B_5 for the same fault, and before breaker B_2 clears the fault, it has become unreliable through a loss of security. Although we have designated the relays as single entities, in reality they are likely to be collections of several relays making up the total protection system at each location. Thus, although a single relay belonging to a protection system may lose security, its effect is to render the complete relaying system insecure, and hence unreliable.

1.4.2 Selectivity of Relays and Zones of Protection

The property of security of relays, that is, the requirement that they not operate for faults for which they are not designed to operate, is defined in terms of regions of a power system – called zones of protection – for which a given relay or protective system is responsible. The relay will be considered to be secure if it responds only to faults within its zone of protection. Relays usually have inputs from several current transformers (CTs), and the zone of protection is bounded by these CTs. The CTs provide a window through which the associated relays “see” the power system inside the zone of protection. While the CTs provide the ability to detect a fault inside the zone of protection, the CBs provide the ability to isolate the fault by disconnecting all of the power equipment inside the zone. Thus, a zone boundary is usually defined by a CT and a CB. When the CT is part of the CB, it becomes a natural zone boundary. When the CT is not an integral part of the CB, special attention must be paid to the fault detection and fault interruption logic. The CT still defines the zone of protection, but communication channels must be used to implement the tripping function from appropriate remote locations where the CBs may be located. We return to this point later in Section 1.5 where CBs are discussed.

In order to cover all power equipments by protection systems, the zones of protection must meet the following requirements.

- All power system elements must be encompassed by at least one zone. Good relaying practice is to be sure that the more important elements are included in at least two zones.
- Zones of protection must overlap to prevent any system element from being unprotected. Without such an overlap, the boundary between two nonoverlapping zones may go unprotected. The region of overlap must be finite but small, so that the likelihood of a fault occurring inside the region of overlap is minimized. Such faults will cause the protection

belonging to both zones to operate, thus removing a larger segment of the power system from service.

A zone of protection may be closed or open. When the zone is closed, all power apparatus entering the zone is monitored at the entry points of the zone. Such a zone of protection is also known as "differential," "unit," or "absolutely selective." Conversely, if the zone of protection is not unambiguously defined by the CTs, that is, the limit of the zone varies with the fault current, the zone is said to be "nonunit," "unrestricted," or "relatively selective." There is a certain degree of uncertainty about the location of the boundary of an open zone of protection. Generally, the nonpilot protection of transmission lines employs open zones of protection.

Example 1.3

Consider the fault at F_1 in Figure 1.9. This fault lies in a closed zone, and will cause CBs B_1 and B_2 to trip. The fault at F_2, being inside the overlap between the zones of protection of the transmission line and the bus, will cause CBs B_1, B_2, B_3, and B_4 to trip, although opening B_3 and B_4 are unnecessary. Both of these zones of protection are closed zones.

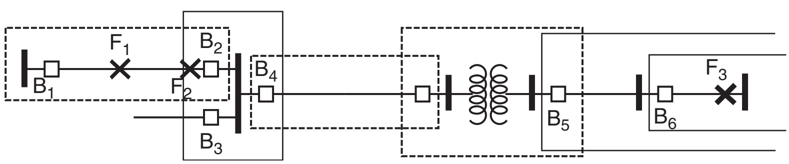

Figure 1.9 Closed and open zones of protection

Now consider the fault at F_3. This fault lies in two open zones. The fault should cause CB B_6 to trip. B_5 is the backup breaker for this fault, and will trip if for some reason B_6 fails to clear the fault.

1.4.3 Relay Speed

It is, of course, desirable to remove a fault from the power system as quickly as possible. However, the relay must make its decision based upon voltage and current waveforms that are severely distorted due to transient phenomena which must follow the occurrence of a fault. The relay must separate the meaningful and significant information contained in these waveforms upon which a secure relaying decision must be based. These considerations demand that the relay takes a certain amount of time to arrive at a decision with the necessary degree of certainty. The relationship between the relay response time and its degree of certainty is an inverse one [2], and this inverse-time operating characteristic of relays is one of the most basic properties of all protection systems.

Although the operating time of relays often varies between wide limits, relays are generally classified by their speed of operation as follows [3].

1. Instantaneous. These relays operate as soon as a secure decision is made. No intentional time delay is introduced to slow down the relay response.[2]
2. Time Delay. An intentional time delay is inserted between the relay decision time and the initiation of the trip action.[3]
3. High Speed. A relay that operates in less than a specified time. The specified time in present practice is 50 ms (three cycles on a 60 Hz system).
4. Ultrahigh Speed. This term is not included in the Relay Standards but is commonly considered to be in operation in 4 ms or less.

1.4.4 Primary and Backup Protection

A protection system may fail to operate and, as a result, fail to clear a fault. It is thus essential that provision be made to clear the fault by some alternative protection system or systems [4, 5]. These alternative protection system(s) are referred to as duplicate, backup, or breaker failure protection systems. The main protection system for a given zone of protection is called the primary protection system. It operates in the fastest time possible and removes the least amount of equipment from service. On EHV systems, it is common to use duplicate primary protection systems in case an element in one primary protection chain may fail to operate. This duplication is therefore intended to cover the failure of the relays themselves. One may use relays from a different manufacturer, or relays based upon a different principle of operation, so that some inadequacy in the design of one of the primary relays is not repeated in the duplicate system. The operating times of the primary and the duplicate systems are the same.

It is not always practical to duplicate every element of the protection chain – on high-voltage and EHV systems, the transducers or the CBs are very expensive, and the cost of duplicate equipment may not be justified. On lower voltage systems, even the relays themselves may not be duplicated. In such situations, only backup relaying is used. Backup relays are generally slower than the primary relays and remove more system elements than may be necessary to clear a fault. Backup relaying may be installed locally, that is, in the same substation as the primary protection, or remotely. Remote backup relays are completely independent of the relays, transducers, batteries, and CBs of the protection system they are backing up. There are no common failures that can affect both sets of relays. However, complex system configurations may significantly affect the ability of remote backup relays to “see” all the faults for which backup is desired. In addition, remote backup relays may remove more loads in the system than can be allowed. Local backup relaying does not suffer from these deficiencies, but it does use common elements such as the transducers, batteries, and CBs, and can thus fail to operate for the same reasons as the primary protection.

Breaker failure relays are a subset of local backup relaying that is provided specifically to cover a failure of the CB. This can be accomplished in a variety of ways. The most

[2] There is no implication relative to the speed of operation of an instantaneous relay. It is a characteristic of its design. A plunger-type overcurrent relay will operate in one to three cycles depending on the operating current relative to its pickup setting. A 125-V DC hinged auxiliary relay, operating on a 125 V DC circuit, will operate in three to six cycles, whereas a 48 V DC tripping relay operating on the same circuit will operate in one cycle. All are classified as instantaneous.

[3] The inserted time delay can be achieved by an R–C circuit, an induction disc, a dashpot, or other electrical or mechanical means. A short-time induction disc relay used for bus protection will operate in three to five cycles, a long-time induction disc relay used for motor protection will operate in several seconds and bellows or geared timing relays used in control circuits can operate in minutes.

common, and simplest, breaker failure relay system consists of a separate timer that is energized whenever the breaker trip coil is energized and is de-energized when the fault current through the breaker disappears. If the fault current persists for longer than the timer setting, a trip signal is given to all local and remote breakers that are required to clear the fault. Occasionally, a separate set of relays is installed to provide this breaker failure protection, in which case it uses independent transducers and batteries. (Also see Chapter 12 (Section 12.4).)

These ideas are illustrated by the following example, and will be further examined when specific relaying systems are considered in detail later.

Example 1.4

Consider the fault at location F in Figure 1.10. It is inside the zone of protection of transmission line AB. Primary relays R_1 and R_5 will clear this fault by acting through breakers B_1 and B_5. At station B, a duplicate primary relay R_2 may be installed to trip the breaker B_1 to cover the possibility that the relay R_1 may fail to trip. R_2 will operate in the same time as R_1 and may use the same or different elements of the protection chain. For instance, on EHV lines, it is usual to provide separate CTs, but use the same potential device with separate windings. The CBs are not duplicated but the battery may be. On lower voltage circuits, it is not uncommon to share all of the transducers and DC circuits. The local backup relay R_3 is designed to operate at a slower speed than R_1 and R_2; it is probably set to see more of the system. It will first attempt to trip breaker B_1 and then its breaker failure relay will trip breakers B_5, B_6, B_7, and B_8. This is local backup relaying, often known as breaker failure protection, for CB B_1. Relays R_9, R_{10}, and R_4 constitute the remote backup protection for the primary protection R_1. No elements of the protection system associated with R_1 are shared by these protection systems, and hence no common modes of failure between R_1 and R_4, R_9 and R_{10} are possible. These remote backup protections will be slower than R_1, R_2, or R_3; and also remove additional elements of the power system – namely lines BC, BD, and BE – from service, which would also de-energize any loads connected to these lines.

A similar set of backup relays is used for the system behind station A.

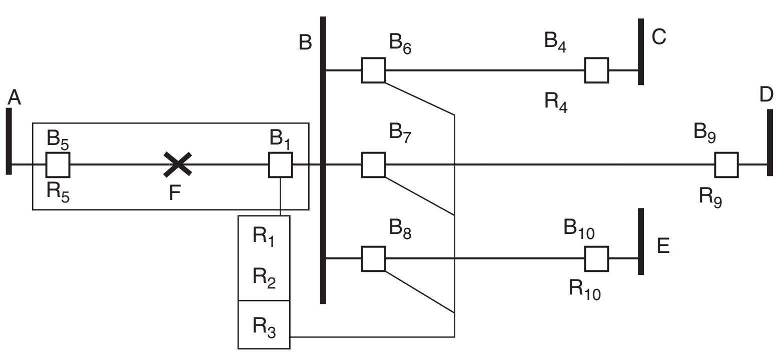

Figure 1.10 Duplicate primary, local backup, and remote backup protection