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Visit the Taylor & Francis Web site at and the CRC Press Web site at ß 2006 by Taylor & Francis Group, LLC. Preface to the Third Edition The third edition of Protective Relaying incorporates information on new developments and topics in protective relaying that has emerged since the second edition was published. This time span represents a dynamic period that involved significant technological advances and revolutionary structural changes within the electric power industry. The format of this book remains similar to the previous editions and retains the full scope of fundamentals of protection that have been presented by Lewis Blackburn in a most elegant and understandable manner. I have taken on the task of updating and expanding Blackburn's work with humility and honor. From a technical standpoint, significant advances in the development and application of digital processing devices in power system protection and control continue. A considerable amount of new material is presented on this subject along with the benefits and problems associated with applying such microprocessor-based devices in protection schemes. Over recent years, structural changes within the electric utility industry have changed the manner in which segments of power systems are owned and networks are developed. The impacts of these changes with respect to the system protection function are discussed in this edition. In addition, structural and regulatory changes have promoted the installation of generators with a wide range of sizes at locations that are distributed throughout power transmission and distribution systems. A discussion of protection requirements at the interconnection location for such distributed generation has been added to the text. New material is also presented on the application of protective systems and limiters in generator excitation systems. Other areas that have been added or significantly expanded include capacitor bank protection, underfrequency load-shedding scheme designs and performance, voltage collapse and mitigation, special protection schemes, fault and event recording, fault location techniques, and the latest advances in transformer protection. All existing material in the text has been reviewed and updated as appropriate. An addition that I hope will be rewarding to the reader is the inclusion of my personal insights on the practical application and performance aspects of power system protection and operations. These perspectives have been gained during my career, spanning over 40 years, as a protection engineer at a midsized electric utility and as a consultant to various electric power entities throughout the world. Through this experience, I believe that I have gained a peek into, and an appreciation of, many of the significant issues that confront and challenge engineers attempting to develop a background and intuition in ß 2006 by Taylor & Francis Group, LLC. power system protection. The insights presented are personal and practical, more than theoretical, and are intended to add a real-life perspective to the text. It is hoped that this material will help put various protection practices into a clearer perspective and provide useful information to improve the effectiveness of engineers working in the highly challenging and rewarding field of protective relaying. Thomas J. Domin ß 2006 by Taylor & Francis Group, LLC. Preface to the Second Edition This new edition of Protective Relaying has been written to update and expand the treatment of many important topics in the first edition, which was published in 1987. The structure is similar to that of the first edition, but each chapter has been carefully reviewed and changes have been made throughout to clarify material, present advances in relaying for the protection of power systems, and add additional examples. The chapter on generator protection has been completely rewritten to reflect current governmental rules and regulations. Many figures are now displayed in a more compact form, which makes them easier to refer to. As in the first edition, additional problems are provided at the back of the book for further study. I have tried again to present the material in a straightforward style, focusing on what will be most useful to the reader. I hope that this volume will be as well received as the first edition was. J. Lewis Blackburn ß 2006 by Taylor & Francis Group, LLC. ß 2006 by Taylor & Francis Group, LLC. Preface to the First Edition Protective relaying is a vital part of any electric power system: unnecessary during normal operation but very important during trouble, faults, and abnormal disturbances. Properly applied protective relaying initiates the disconnection of the trouble area while operation and service in the rest of the system continue. This book presents the fundamentals and basic technology of application of protective relays in electric power systems and documents the protection practices in common use. The objective is to provide a useful reference for practicing engineers and technicians as well as a practical book for collegelevel courses in the power field. Applications with examples are included for both utility and industrial–commercial systems generally operating above 480 V. Protective relay designs vary with different manufacturers and are constantly changing, especially as solid-state technology impacts this area. However, protective relaying applications remain the same: relatively independent of designs and their trends. As a result, design aspects are not emphasized in this book. This area is best covered by individual manufacturer's information. Protective relaying can be considered a vertical specialty with a horizontal vantage point; thus, although specialized, it is involved with and requires knowledge of all of the equipment required in the generation, transmission, distribution, and utilization of electrical power. In addition, it requires an understanding of how the system performs normally as well as during faults and abnormal conditions. As a result, this subject provides an excellent background for specialized study in any of the individual areas and is especially important for system planning, operation, and management. Friends and associates of 50 years and students within Westinghouse, the IEEE, CIGRE, many utilities, and industrial companies around the world have directly or indirectly contributed to this book. Their contributions and support are gratefully acknowledged. Special acknowledgment and thanks are extended to Rich Duncan for his enthusiastic encouragement and support during the preparation of this manuscript and to W.A. Elmore, T.D. Estes, C.H. Griffin, R.E. Hart, C.J. Heffernan, and H.J. Li for photographic and additional technical help. In addition, I express my gratitude to Dr. Eileen Gardiner of Marcel Dekker, Inc., who most patiently encouraged and supported this effort. J. Lewis Blackburn ß 2006 by Taylor & Francis Group, LLC. ß 2006 by Taylor & Francis Group, LLC. Author Thomas J. Domin is a registered professional engineer in the state of Pennsylvania with extensive experience working with electrical power systems. His work background includes over 40 years of experience in working for PPL, Inc., a midsized electric utility headquartered in Allentown, Pennsylvania. A major portion of this experience has been in the area of protective relaying with a major focus on the application and coordination of protective facilities on electrical power systems. The scope of his work covers electrical facilities extending from high-voltage transmission systems down through low-voltage distribution systems and includes the development of protection requirements and analysis of protection performance for power system lines, transformers, generators, capacitors, power plant auxiliary equipment, and interties with nonutility facilities. His experience includes the development of protection philosophies, standards, and practices; the specification of relaying and control logic requirements for protective systems; the development of specifications for protective relay settings; and the analysis of disturbances in electric power systems. He has also studied and analyzed generator excitation control systems, voltage control, load flow, system stability, and system operations and has worked on the development of expansion planning studies for electric utility systems. In addition to working on electrical systems within the United States, Mr. Domin has also worked on a variety of international projects involving electrical protection and power system operations. ß 2006 by Taylor & Francis Group, LLC. ß 2006 by Taylor & Francis Group, LLC. Table of Contents ß 2006 by Taylor & Francis Group, LLC. ß 2006 by Taylor & Francis Group, LLC. 1 Introduction and General Philosophies 1.1 INTRODUCTION AND DEFINITIONS What is a relay; more specifically, what is a protective relay? The Institute of Electrical and Electronic Engineers (IEEE) defines a relay as ''an electric device that is designed to respond to input conditions in a prescribed manner and, after specified conditions are met, to cause contact operation or similar abrupt change in associated electric control circuits.'' A note adds: ''Inputs are usually electric, but may be mechanical, thermal, or other quantities or a combination of quantities. Limit switches and similar simple devices are not relays'' (IEEE C37.90). Relays are used in all aspects of activity: home, communication, transportation, commerce, and industry, to name a few. Wherever electricity is used, there is a high probability that relays are involved. They are used in heating, air conditioning, stoves, dishwashers, clothes washers and dryers, elevators, telephone networks, traffic controls, transportation vehicles, automatic process systems, robotics, space activities, and many other applications. In this book we focus on one of the more interesting and sophisticated applications of relays, the protection of electric power systems. The IEEE defines a protective relay as ''a relay whose function is to detect defective lines or apparatus or other power system conditions of an abnormal or dangerous nature and to initiate appropriate control circuit action'' (IEEE 100). Fuses are also used in protection. IEEE defines a fuse as ''an over-current protective device with a circuit-opening fusible pat that is heated and severed by the passage of the overcurrent through it'' (IEEE 100). Thus, protective relays and their associated equipment are compact units of analog, discrete solid-state components, operational amplifiers, and digital microprocessor networks connected to the power system to sense problems. These are frequently abbreviated simply as relays and relay systems. They are used in all parts of the power system, together with fuses, for the detection of intolerable conditions, most often faults. Protective relaying, commonly abbreviated as relaying, is a nonprofit, nonrevenue-producing item that is not necessary in the normal operation of an electrical power system until a fault—an abnormal, intolerable situation—occurs. ß 2006 by Taylor & Francis Group, LLC. A primary objective of all power systems is to maintain a very high level of continuity of service, and when intolerable conditions occur, to minimize the extent and time of the outage. Loss of power, voltage dips, and overvoltages

OF SYSTEM PROTECTION The fundamental objective of system protection is to provide isolation of a problem area in the power system quickly, so that the shock to the rest of the system is minimized and as much as possible is left intact. Within this context, there are five basic facets of protective relay application. Before discussing these, it should be noted that the use of the term protection does not indicate or imply that the protection equipment can prevent trouble, such as faults and equipment failures, or electric shocks due to inadvertent human contacts. It cannot anticipate trouble. The protective relays act only after an abnormal or intolerable condition has occurred, with sufficient indication to permit their operation. Thus protection does not mean prevention, but rather, minimizing the duration of the trouble and limiting the damage, outage time, and related problems that may result otherwise.

The five basic facets are:

1. Reliability: assurance that the protection will perform correctly.
2. Selectivity: maximum continuity of service with minimum system disconnection.
3. Speed of operation: minimum fault duration and consequent equipment damage and system instability.
4. Simplicity: minimum protective equipment and associated circuitry to achieve the protection objectives.
5. Economics: maximum protection at minimal total cost.

Because these are the underlying foundations of all protection, further discussion is in order.

1.6.1 RELIABILITY

Reliability has two aspects, dependability and security. Dependability is defined as "the degree of certainty that a relay or relay system will operate correctly" (IEEE C 37.2). Security "relates to the degree of certainty that a relay or relay system will not operate incorrectly" (IEEE C 37.2). In other words, dependability indicates the ability of the protection system to perform correctly when required, whereas security is its ability to avoid unnecessary operation during normal day-after-day operation, and faults and problems outside the designated zone of operation. There is often a very fine line between the tolerable transients that the power system can operate through successfully, and those, such as light faults that may develop and result in a major problem if not quickly isolated. Thus, the protection must be secure (not operate on tolerable transients), yet dependable (operate on intolerable transients and permanent faults). It is these somewhat conflicting requirements, together with the speculation of what trouble may occur, when, and where, that help make power system protection the most-interesting technical science and art.

Dependability is easy to ascertain by testing the protection system to assure that it will operate as intended when the operating thresholds are exceeded. Security is more difficult to ascertain. There can be almost an infinite variety of transients that might upset the protective system, and predetermination of all these possibilities is difficult or impossible. Manufacturers often use elaborate power system simulations, computers, and sometimes staged fault tests on energized power systems to check both dependability and security. The practical and best answer to both security and dependability is the background experience of the designers, confirmed by field experience. Thus, actual in-service installations provide the best and final laboratory. This should only confirm the protection and not be used basically for the development.

As a generality, enhancing security tends to decrease the dependability, and vice versa. As an illustration, the single relay trip contact shown in Figure 1.9 represents high dependability, but it has the potential of being accidentally closed by unanticipated transients or human error resulting in an undesired operation. To minimize this potential problem, a second relay, such as a fault detector, can be used with its operating contact in series in the DC trip circuit. Now both contacts must close to trip the circuit breaker, which should occur for intolerable conditions or faults. This has increased security, for it is less likely that extraneous transients or problems would cause both relays to operate simultaneously. However, the dependability has been decreased, for it now requires two relays to operate correctly. This arrangement is used, because the dependability is still quite high, together with improved security.

Security is thus very important (as is dependability), as relays are connected for their lifetime to the power system as "silent sentinels," "waiting" for intolerable conditions and experiencing all the transients and external faults not in their operating zone. The hope always is that there will be no faults or intolerable conditions; hence, no occasion for the relays to operate. Fortunately, there are relatively few faults, on average, in a power system. It is estimated that, in general, the cumulative operating time (the times the relay is sensing and operating for an internal fault) during a relay's lifetime averages in the order of seconds to a few minutes, depending on the speed of the particular relay type. This contrasts dramatically with a life of over 30 years for many electromechanical relays. Therefore, relays basically do not wear out from operations—indeed, more wear will occur from maintenance testing and similar use.

Similar experience occurs with electronic relays, except that because of the still rapidly changing technology, the lifetime of many of these relays will probably be much shorter.

In general, experience in power systems, both large and small, utilities and industrial, indicates that their protective relay systems have greater than 99% reliability—a commendable tribute to the industry.

1.6.2 SELECTIVITY

Relays have an assigned area known as the primary protection zone, but they may properly operate in response to conditions outside this zone. In these instances, they provide backup protection for the area outside their primary zone. This is designated as the backup or overreached zone.

Selectivity (also known as relay coordination) is the process of applying and setting the protective relays that overreach other relays such that they operate as fast as possible within their primary zone, but have delayed operation in their backup zone. This is necessary to permit the primary relays assigned to this backup or overreached area time to operate. Otherwise, both sets of relays may operate for faults in this overreached area; the assigned primary relays for the area and the backup relays. Operation of the backup protection is incorrect and undesirable unless the primary protection of that area fails to clear the fault. Consequently, selectivity or relay coordination is important to assure maximum service continuity with minimum system disconnection. This process is discussed in more detail in later chapters.

1.6.3 SPEED

Obviously, it is desirable that the protection isolate a trouble zone as rapidly as possible. In some applications this is not difficult, but in others, particularly where selectivity is involved, faster operation can be accomplished by more complex and a higher-cost protection. Zero-time or very high speed protection, although inherently desirable, may result in an increased number of undesired operations. As a broad generality, the faster the operation, the higher the probability of incorrect operation. Time, generally of a very small amount, remains as one of the best means of distinguishing between tolerable and intolerable transients.

A high-speed relay is one that operates in less than 50 msec (three cycles on a 60 Hz basis) (IEEE 100). The term instantaneous is defined to indicate that no (time) delay is purposely introduced in the action of the device (IEEE 100). In practice, the terms instantaneous and high-speed are used interchangeably to describe protective relays that operate in 50 msec or less.

Modern high-speed circuit breakers operate in the range of 17–50 msec (one to three cycles at 60 Hz); others operate at less than 83 msec (five cycles at 60 Hz). Thus, the total clearing time (relays plus breaker) typically ranges from approximately 35–130 msec (two to eight cycles at 60 Hz).

In low-voltage systems, in which time-coordination is required between protective relays, relay-operating times generally will be slower; typically on the order of 0.2–1.5 sec for the primary zone. Primary-zone relay time longer than 1.5–2.0 sec are unusual for faults in this zone, but they are possible and do exist. Thus, speed is important, but it is not always absolutely required, nor is it always practical to obtain high speed without additional cost and complexity, which may not be justified.

Relay speed is especially important when the protected facility exists in a stability sensitive area of the power system network. Faster fault clearing reduces the amount that generators can accelerate during the fault and, therefore, improves stability margins. Early designs of microprocessor-type relays were more or less slower than electromechanical or solid-state equivalent designs. Modern microprocessor relay designs, however, incorporate processors and algorithms that provide operating speeds that are in the same range as that of other types of relays.

1.6.4 SIMPLICITY

A protective relay system should be kept as simple and straightforward as possible while still accomplishing its intended goals. Each added unit or component, which may offer enhancement of the protection, but is not necessarily basic to the protection requirements, should be considered very carefully. Each addition provides a potential source of trouble and added maintenance. As has been emphasized, incorrect operation or unavailability of the protection can result in catastrophic problems in a power system. Problems in the protective system can greatly impinge on the system—in general, probably more than any other power system component.

The increasing use of solid-state and digital technologies in protective relaying provides many convenient possibilities for increased sophistication. Some will enhance the protection; others add components that are desirable to have. All aspects should be evaluated carefully to assure that they really, and significantly, contribute to improve the system protection.

1.6.5 ECONOMICS

It is fundamental to obtain the maximum protection for the minimum cost, and cost is always a major factor. The lowest-priced, initial-cost protective system may not be the most reliable one; furthermore, it may involve greater difficulties in installation and operation, as well as higher maintenance costs. Protection costs are considered high when considered alone, but they should be evaluated in the light of the higher cost of the equipment they are protecting, and the cost of an outage or loss of the protected equipment through improper protection. Saving to reduce the first costs can result in spending many more times of this saving to repair or replace equipment damaged or lost because of inadequate or improper protection.

1.6.6 GENERAL SUMMARY

It would indeed be utopian if all five basic objectives could be achieved to their maximum level. Real-life practical considerations require common sense and compromise. Thus, the protection engineer must maximize these as a group for the protection problem at hand and for the requirements of the system. This is an exciting challenge that will produce many different approaches and answers.

1.7 FACTORS AFFECTING THE PROTECTION SYSTEM

There are four major factors that influence protective relaying:

1. Economic considerations
2. "Personality" of the relay engineer and the characteristics of the power system
3. Location and availability of disconnecting and isolating devices (circuit breakers, switches, and input devices (CTs and VTs))
4. Available fault indicators (fault studies and such).

These are discussed in more detail in the following sections.

1.7.1 ECONOMICS

Economics has been discussed in Section 1.6.5 and is always important. Fortunately, faults and troubles are relatively infrequent, so it is easy to decide not to spend money on protection because there have not been any problems. Certainly, the protection engineer hopes that the protection will never be called on to operate, but when trouble does occur, protection is vital for the life of the system. A single fault during which the protection promptly and correctly isolates the trouble zone, thereby minimizing the outage time and reducing equipment damage, can more than pay for the protection required.

1.7.2 PERSONALITY FACTOR

What, when, and where an intolerable condition will occur in the power system is unpredictable. The number of possibilities that exist is infinite. Consequently, the engineer must design the protective system for the most probable events, based on past experiences, anticipated possibilities that seem most likely to occur, and the equipment manufacturer's recommendations, well-seasoned by good practical judgment. This tends to make protection an art as well as a technical science. Because the personalities of protection engineers, as well as that of the power system as reflected by management, operating considerations, and historical development, are different, so is the protection that results. Although there is much common technology, protection systems and practices are far from standardized. Accordingly, protection reflects the personality of the engineers and the system, again making the art and practice of system protection most interesting.

1.7.3 LOCATION OF DISCONNECTING AND INPUT DEVICES

Protection can be applied only where there are circuit breakers or similar devices to enable isolation of the trouble area and where CT and VT, when required, are available to provide information about faults and trouble in the power system. Close cooperation between system planners and protection engineers is important to facilitate optimal performance and operation of the power system.

1.7.4 AVAILABLE FAULT INDICATORS

The troubles, faults, and intolerable conditions must provide a distinguishable difference from the normal operating or tolerable conditions. Some signal or change in the quantities—"handle"—is necessary to cause relay operation or detection of the problem. Reiterating, common handles available are current, voltage, impedance, reactance, power, power factor, power or current direction, frequency, temperature, and pressure. Any significant change in these may provide a means to detect abnormal conditions and so be employed for relay operation.

The key to the selection and application of protection is first to determine what measures (handles) exist to distinguish between tolerable and intolerable conditions. From this information, a relay or relay system can be found or designed if necessary to operate on detectable difference(s).

If a significant difference does not exist between the normal and abnormal conditions, protection is limited at best, or it is not possible at all. An example of this exists in distribution systems, where accidents or storms may result in an energized line being near or on the ground. This is totally intolerable, but the fault current can be very small or zero, and all other system parameters such as voltage, power, and frequency, may remain within normal limits. Consequently, in these situations, no handle exists for any type of relay to detect and isolate the intolerable condition.

1.8 CLASSIFICATION OF RELAYS

Relays may be classified in several different ways, such as by function, input, performance characteristics, or operating principles. Classification by function is most common. There are five basic functional types: (1) protective, (2) regulating, (3) reclosing, synchronism check, and synchronizing, (4) monitoring, and (5) auxiliary.

1.8.1 PROTECTIVE RELAYS

Protective relays and associated systems (and fuses) operate on the intolerable power system conditions and are the main thrust of this book. They are applied to all parts of the power system: generators, buses, transformers, transmission lines, distribution lines and feeders, motors and utilization loads, capacitor banks, and reactors. For the most part, the relays discussed are separate devices that are connected to the power system through CT and VTs from the highest system voltage (765 kV, at present) down to service levels of 480 V. In general, distribution equipment below 480 V is protected by fuses or protection devices that are integral with the equipment. Such devices are not discussed in depth here.

1.8.2 REGULATING RELAYS

Regulating relays are associated with tap changers on transformers and on voltage regulators of generating equipment to control the voltage levels with varying loads. Regulating relays are used during normal system operation and do not respond to system faults unless the faults are left on the system far too long. This is not normal. This book does not discuss this type of relay.

1.8.3 RECLOSING, SYNCHRONISM CHECK, AND SYNCHRONIZING RELAYS

Reclosing, synchronism check, and synchronizing relays were formerly classed as programming, but because this term is now widely used in a different context as related to computers, a name change has been made. Relays of this type are used in energizing or restoring lines to services after an outage, and in interconnecting preenergized parts of systems.

1.8.4 MONITORING RELAYS

Monitoring relays are used to verify conditions in the power system or in the protection system. Examples in power systems are fault detectors, voltage check, or directional-sensing units that confirm power system conditions but do not directly sense the fault or trouble. In a protection system, they are used to monitor the continuity of circuits, such as pilot wires and trip circuits. In general, alarm units serve as monitoring functions.

1.8.5 AUXILIARY RELAYS

Auxiliary units are used throughout a protective system for a variety of purposes. Generally, there are two categories: contact multiplication and circuit isolation. In relaying and control systems there are frequent requirements for (1) more outputs for multiple tripping, alarms, and operating other equipment, such as recording and data acquisition, lockout, and so on, (2) contacts that will handle higher currents or voltages in the secondary systems, and (3) electrical and magnetic isolation of several secondary circuits.

The seal-in (CS) relay of Figure 1.9 is an auxiliary relay application. The trip and closing relays used with circuit breakers are auxiliary relays.

1.8.6 OTHER RELAY CLASSIFICATIONS

Protective relays classified by input are known as current, voltage, power, frequency, and temperature relays. Those classified by operating principle include electromechanical, solid-state, digital, percentage differential, multirestraint, and product units. Those classified by performance characteristics are known as distance, reactance, directional overcurrent, inverse time, phase, ground, definite, high-speed, slow-speed, phase comparison, overcurrent, undervoltage, overvoltage, etc.

1.9 PROTECTIVE RELAY PERFORMANCE

It is difficult to completely evaluate an individual protective relay's performance, because many relays near the trouble area may begin to operate for any given fault. Good performance occurs only when the primary relays operate to isolate the trouble area. All other alerted relays will return to their normal quiescent mode.

Performance (relay operation) can be categorized as follows:

1. Correct, generally 95%–99%
   a. As planned
   b. Not as planned or expected
2. Incorrect, either failure to trip or false tripping
   a. Not as planned or wanted
   b. Acceptable for the particular situation
3. No conclusion

1.9.1 CORRECT OPERATION

Correct operation indicates that (1) at least one of the primary relays operated correctly, (2) none of the backup relays operated to trip for the fault, and (3) the trouble area was properly isolated in the time expected. Over many years and today close to 99% of all relay operations are corrected and wanted (i.e., operation is as planned and programmed). This is a tribute to the relay protection departments, their engineers, technicians, and all associated personnel.

The 1965 Northeast blackout was an excellent example of the "correct, not as planned or expected" category. Of the many, many relays that operated during the event, all (as far as I remember) operated correctly. That is, the system quantities got into the operating zones or levels such that the relays operated correctly, but were generally unwanted. At that time no one had anticipated this most unusual system disturbance.

Recently, a utility engineer reported that a fault was cleared in his system by two incorrect operations. This was certainly not planned or anticipated.

1.9.2 INCORRECT OPERATION

Incorrect operations result from a failure, a malfunction, or an unanticipated or unplanned operation of the protective system. This can cause either incorrect isolation of a no-trouble area, or a failure to isolate a trouble area. The reasons for incorrect operation can be one or a combination of (1) misapplication of relays, (2) incorrect setting, (3) personnel errors, and (4) equipment problems or failures (relays, breakers, CTs, VTs, station battery, wiring, pilot channel, auxiliaries, and so on).

It is practically impossible to anticipate and provide protection for the numerous possible power system problems. With the best of planning and design there will always be a potential situation that may not be "protected," or an error not detected. Occasionally, these are "covered" by an incorrect operation that can be classified as "acceptable for the particular situation." Although these are very few, they have saved power systems and minimized embarrassments.

1.9.3 NO CONCLUSION

No conclusion refers to circumstances during which one or more relays have or appear to have operated, such as the circuit breaker tripping, but no cause can be found. No evidence of a power system fault or trouble, nor apparent failure of the equipment, can cause a frustrating situation. This can result in many hours of postmortem investigations. Fortunately, the present © 2006 by Taylor & Francis Group, LLC. microprocessor relays with data recording and oscillographs can provide direct evidence or clues to the problem, as well as indicating possibilities that could not have occurred. It is suspected that many of these events are the result of personnel involvement that is not reported, or of intermittent troubles that do not become apparent during testing and investigation.

1.10 PRINCIPLES OF RELAY APPLICATION

The power system is divided into protection zones defined by the equipment and the available circuit breakers. Six categories of protection zones are possible in each power system: (1) generators and generator-transformer units, (2) transformers, (3) buses, (4) lines (transmission, subtransmission, and distribution), (5) utilization equipment (motors, static loads, or other), and (6) capacitor or reactor banks (when separately protected).

Most of these zones are illustrated in Figure 1.11. Although the fundamentals of protection are quite similar, each of these six categories has protective relays, specifically designed for primary protection, that are based on the characteristics of the equipment being protected. The protection of each zone normally includes relays that can provide backup for the relays protecting the adjacent equipment.

The protection in each zone should overlap that in the adjacent zone; otherwise, a primary protection void would occur between the protection zones. This overlap is accomplished by the location of the CTs—the key sources of power system information for the relays. This is shown in Figure 1.11 and, more specifically, in Figure 1.12. Faults between the two CTs (see Figure 1.12) result in both zone X and zone Y relays operating and both tripping the associated circuit breaker.

For case (a): this fault probably involves the circuit breaker itself and so may not be cleared until the remote breakers at either end are opened. For case (b): zone Y relays alone opening the circuit breaker would clear faults between the two CTs from the left fault source. The relays at the remote right source must also be opened for these faults. The operation of the zone X relays is not required, but it cannot be prevented.

Fortunately, the area of exposure is quite small, and the possibility of faults is low. Without this overlap, primary protection for the area between the CTs would not exist, so this overlap is standard practice in all applications.

Protection zone X Circuit breaker Protection zone Y Zone X relays (a) Zone Y relays For dead-tank breakers Protection zone X Circuit breaker Protection zone Y Zone Y relays Zone X relays (b) For live-tank breakers

FIGURE 1.12 Overlapping protection zones with their associated current transformers.

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1.11 INFORMATION FOR APPLICATION

One of the most difficult aspects of applying is often an accurate statement of the protection requirements or problem. This is valuable as an aid to a practical efficient solution, and is particularly important when assistance is desired from others who might be involved or might assist in the solution, such as consultants, manufacturers, and other engineers. The following checklist of required information has been developed from many years of assisting relay engineers with their problems. It outlines the information needed, some of which is invariably overlooked in the first definition of the problem.

The required information should include the following:

1. Single-line diagram of the system or area involved
2. Impedance and connections of the power equipment, system frequency, voltage, and phase sequence
3. Unless new, existing protection and problems
4. Operating procedures and practices affecting the protection
5. Importance of the protection; pilot, nonpilot, and so on
6. System fault study
7. Maximum load and system swing limits
8. CT and VT locations, connections, and ratios
9. Future expansion expected or anticipated.

More detail on these follows.

1.11.1 SYSTEM CONFIGURATION

A single-line diagram for application consideration or a three-line diagram for complete connections and panel-wiring drawings documenting the area to be studied and of the surrounding system should be available. The location of the circuit breakers, CT and VT, generators, buses, and taps on lines should be shown. The transformer bank connections and system grounding are necessary when considering ground-fault protection. The grounding information is often missing on station drawings.

1.11.2 IMPEDANCE AND CONNECTION OF THE POWER EQUIPMENT, SYSTEM FREQUENCY, SYSTEM VOLTAGE, AND SYSTEM PHASE SEQUENCE

Most of this information is usually included on the single-form diagram, but often omitted are the connections and grounding of the power transformer banks, and the circuit impedance. Phase sequence is necessary when a threeline connection diagram is required. © 2006 by Taylor & Francis Group, LLC.

1.11.3 EXISTING PROTECTION AND PROBLEMS

If it is a new installation this does not apply, but should be indicated. If not new, such information about the existing protection and any problems may assist updating or integration with the changes desired.

1.11.4 OPERATING PROCEDURES AND PRACTICES

Additions or changes should conform to the existing practices, procedures, and desires. When these affect the protection, they should be indicated. Often this can be accomplished by indicating that certain types of equipment or practices are unacceptable.

1.11.5 IMPORTANCE OF THE SYSTEM EQUIPMENT BEING PROTECTED

This is often apparent by the system voltage level and size. For example, high-voltage transmission lines are usually protected by high-speed pilot protection, and low-voltage systems by time-overcurrent protection. However, this should be clarified according to the desires of the protection engineers or the system requirements. In general, the more important the equipment that needs protection is to the power system and its ability to maintain service, the more important it becomes to provide full and adequate high-speed protection.

1.11.6 SYSTEM FAULT STUDY

A fault study is important for most protection applications. For phase-fault protection, a three-phase fault study is required, whereas for ground-fault protection a single-line-to-ground fault study is required. The latter should include the zero-sequence voltages and the negative-sequence currents and voltages, which can be useful if directional sensing of ground faults is involved. On lines, information concerning a fault on the line side at an open breaker (known as a "line-end" fault) is frequently important. The currents recorded should be those that will flow through the relays or fuses, rather than the total fault current. The fault study should indicate the units (in volts or amperes) at a specified voltage base, or in per unit with the base clearly specified. Experience has shown that quite often the base of the quantities is not shown, or is not clearly indicated.

1.11.7 MAXIMUM LOADS AND SYSTEM SWING LIMITS

The maximum load that will be permitted to pass through the equipment during short-time or emergency operation for which the protection must not operate should be specified. If known, the maximum system swing from which the power system can recover after a transient disturbance is important in some applications and should be specified. © 2006 by Taylor & Francis Group, LLC.

1.11.8 CURRENT AND VOLTAGE TRANSFORMER LOCATIONS, CONNECTIONS, AND RATIOS

This information is often shown on the one-line drawing, but often the data are incomplete or unclear. Where multiratio devices exist, the specific tap or ratio in use should be specified. The grounding of the VT or voltage devices should be clear.

1.11.9 FUTURE EXPANSION

The system growth or changes that are likely to occur within a reasonable time and are known or planned should be indicated.

Not all of the foregoing items are necessarily apply to a specific problem or system requirement, but this checklist should assist in providing a better understanding of the protection problems and requirements. Usually, the fault study, together with related information, will provide information on the measurable quantities (handles) to which the protective relays can respond. When this is not apparent, the first priority for any application is to search for the handles that can be used to distinguish between tolerable and intolerable conditions.

1.12 STRUCTURAL CHANGES WITHIN THE ELECTRIC POWER INDUSTRY

The electric power industry has historically been structured with entities that are vertically integrated monopolies that are regulated by governmental agencies. These industry entities are mainly made up of investor owned utilities and also consist of utilities that are owned by municipalities or electric cooperatives. Under such structure, each utility owned all generation, transmission, and distribution facilities within its designated service territory. Each utility likewise owned the protection systems that existed within its territory which included those at generating plants, on the transmission and distribution system, down to the point of interface with customer facilities. The utility was solely responsible for the application, design, construction, settings, testing, and maintenance of all related protection facilities.

In the 1990s, a movement developed to restructure the US electric power industry to one that is more competitive in nature. Various legislatives have been passed at both the federal and state levels to force such changes to be implemented. It was felt that competition would lead to greater efficiencies within the industry and would ultimately benefit consumers by providing lower-priced electric energy. This movement is still in an evolutionary state but has initiated significant changes to the industry. Many of the laws that have been passed are state laws, so differences do exist among various areas of the country. The basic result, however, is a power system in which © 2006 by Taylor & Francis Group, LLC. generation and supply are unregulated. Anyone can own generating facilities with the transmission system opened up to all qualified users. Likewise, anyone can offer to supply energy to customers. Transmission and distribution facilities typically remain regulated and are owned by the incumbent utility. Proposals have been made, however, in which transmission facilities would be combined and owned by a "regional transmission owner" in a given area.

Traditional utilities can still own generation facilities and can also offer to be a supplier. However, these functions must be operated as separate subsidiaries with adequate safeguards to prevent competitive advantage. The responsibility of maintaining a competitive wholesale energy market and assuring power system reliability, in many cases, has been delegated to independent system operators.

The final structure of the electric power industry has yet to evolve. Nevertheless, the direction has been set and participants need to adjust to function effectively with the new environment. Concern has been expressed that power system reliability may decline due to a deteriorating effect that competition may have on the cooperative atmosphere that had prevailed in the past. Credibility to this concern is supported by several severe blackouts, power shortages, and slow response to outages that have occurred in areas where competition has been implemented. Politicians need to be alert to this threat and consider any legislation necessary to assure that a level of reliability and customer service comparable to that which has prevailed and expected in this country is maintained.

Structural changes in the power industry does not change the technical and practical aspect that relate to the application of power system protection. Such change, however, does have an impact on the manner in which the protection process is carried out. It presents new challenges, and requires the need for new processes to emerge. The impact of economic constraints, which can develop in a competitive atmosphere, may result in pressures to decrease resources available to support the protection function. Economic benefit from application of protection is sometimes difficult to quantify. Protection engineers need to develop skills required to economically justify proposed protection installations. Familiarity with concepts used in the power system planning process should be a priority.

The separation of the various entities within the structure of the power industry will require good documentation and a system for exchanging information in order to conduct protection studies and verify protection information. With generators and transmission facilities being owned by different entities, additional hazards to the supply system can be created. Such hazards must be identified and appropriate protection systems applied. This subject is discussed further in Chapter 8. © 2006 by Taylor & Francis Group, LLC.

Protection must also be designed to accommodate a desired generator installation at a specific location. Such schemes are not protective schemes applied typically for fault protection but are applied to guard against undesired system operation conditions that may result from operation of the generator. Application of "Special Protection Schemes" may be required in order to accommodate a desired generator installation at a specific location. Such schemes are not protective schemes applied typically for fault protection but are applied to guard against undesired system operation conditions that may result from operation of the generator. Special protection schemes are discussed in greater detail in Chapter 14.

Uniform protection design standards, application practices, and maintenance and testing requirements need to be documented and provided to all entities. An auditing and enforcement system to assure compliance to such standard is required.

1.13 RELIABILITY AND PROTECTION STANDARDS

With the significant structural changes that have been evolving within the electric power industry, it has been recognized that standards and procedures need to be developed in order to facilitate effective protection and to ensure reliable system operations. Reliability standards have existed for planning and operating power systems for many years. Compliance with these standards has been open to interpretation and is voluntary in nature. With separation of ownership within the industry, reliance on such voluntary compliance is not considered practical to assure that good reliability practices are followed.

The impact of technical requirements relating to the types of equipment being installed along with the manner in which it is connected, operated, and protected be documented so that all participants in the market are treated in a fair and similar manner. Considerable work has transpired in recent times to expand the scope and detail contained in such standards with a greater emphasis on mandatory compliance through the passing of new legislation, expanded oversight, and penalties for violations.

Much of this work is being done by groups with oversight or regulatory authority over the industry. This includes reliability councils, state agencies, federal agencies, and regional transmission organizations. In the protection area, a variety of ANSI=IEEE standards has been developed over the years and continues to be developed as conditions change. These standards cover various aspects of design requirements for protective equipment and the manner in which such equipment needs to be applied to protect specific electrical facilities.

Protection requirements related to issues pertaining to power system reliability and safety applicable to power systems within specified jurisdictional areas are being developed as part of the above process being carried out within oversight and regulatory agencies. The main focus of these protection standards relate to facilities associated with bulk power systems since it is the health of the bulk power system that is critical to maintaining continual and safe operation of the nation's power grid and in preventing large scale disturbances and outages. Since portions of the power grid are built and owned by many separate entities, standards and related © 2006 by Taylor & Francis Group, LLC. enforcement procedures are critical to the prevention of weak spots within this vast network.

Standards for designs at lower voltage levels are often developed by the utilities themselves in order to meet performance requirements mandated by regulatory agencies. Oversight of standards for lower voltage level facilities does exist in areas where multiple ownerships exist. Consequently, the major emphasis of protection standards that are currently being developed to promote reliability and a fair market pertain to protection requirements for bulk power facilities and for the intertie locations at which generation connects to the utility power system. Generator intertie protection requirements are discussed further in Chapter 8.

For bulk power facilities, the reliability standards are typically built around the important objectives of protective systems as described earlier, such as:

1. Preventing or minimizing equipment damage. Equipment damage can be costly to the owner, such equipment also poses important challenges to the operating reliability of the power system.
2. Minimizing the scope of an outage and the time it takes to restore service following a disturbance to a minimum. Achieving these goals requires that faults be detected and cleared in time frames such that the power system remains stable.
3. Assuring that faults are detected and cleared in time frames such that the power system remains stable.
4. Allowing power system facilities to be loaded to their full normal and emergency ratings.

Operation design of bulk power systems are such that, as a minimum, the system must remain operational upon the sudden, unexpected loss of any single facility on the system. System operators will alter the generation dispatch or the configuration of the system in order to remain within those operational criteria. To align with this "single contingency" concept, protection standards for bulk power systems typically require that "redundancy" exists within the protection design. Redundancy is required to assure that the failure of any single protection component, such as an instrument transformer, relay, breaker, control circuit, or communication channel will not result in the failure to detect and isolate faults. The major objectives of the protection systems must remain intact after such failure.

The type of protective equipment that is applicable, as well as its configuration, that is typically required to meet such requirements, is discussed in subsequent chapters as protection schemes for various types of equipment are covered.

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2 Fundamental Units: Per Unit and Percent Values

2.1 INTRODUCTION

Power systems operate at voltages where kilovolt (kV) is the most convenient unit for expressing voltage. Also, these systems transmit large amounts of power, so that kilovolt-ampere (kVA) and megavolt-ampere (MVA) are used to express the total (general or apparent) threephase power. These quantities, together with kilowatts, kilovars, amperes, ohms, flux, and so on, are usually expressed as a per unit or percent of a reference or base value. The per unit and percent nomenclatures are widely used because they simplify specification and computations, especially when different voltage levels and equipment sizes are involved.

This discussion is for three-phase electric systems that are assumed to be balanced or symmetrical up to a point or area of unbalance. This means that the source voltages are equal in magnitude and are 120 degrees displaced in phase relations, and that the impedances of the three-phase circuits are of equal magnitude and phase angle. With this as a beginning, various shunt and series unbalances can be analyzed, principally by the method of symmetrical components. This method is reviewed in Chapter 4.

2.2 PER UNIT AND PERCENT DEFINITIONS

Percent is 100 times per unit. Both percent and per unit have been used for many years, but per unit is more convenient and is used as a matter of convenience or of personal choice, and it is important to designate either percent (%) or per unit (pu).

The per unit value of any quantity is the ratio of that quantity to its base value; the ratio is expressed as a nondimensional decimal number. Thus, actual quantities, such as voltage (V), current (I), power (P), reactive power (Q), volt-amperes (VA), resistance (R), reactance (X), and impedance (Z), in per unit or percent of a specified base are:

$$\text{Per unit quantity} = \frac{\text{actual quantity}}{\text{base quantity}} \quad (2.1)$$

$$\text{Percent quantity} = \frac{\text{actual quantity}}{\text{base quantity}} \times 100 \quad (2.2)$$

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where actual quantity is the scalar or complex value of a quantity expressed in its proper units, such as volts, amperes, ohms, or watts. Base value of a quantity refers to an arbitrary or convenient reference of the same quantity chosen and designated as the base. Thus, per unit and percent are dimensionless ratios that may be either scalar or complex numbers.

As an example, for a chosen base of 115 kV, voltages of 92, 115, and 161 kV become 0.80, 1.00, and 1.40 pu or 80%, 100%, and 140%, respectively.

2.3 ADVANTAGES OF PER UNIT AND PERCENT

Some of the advantages of using per unit or percent are as follows:

1. Its representation results in more meaningful data when the relative magnitudes of all the similar circuit quantities can be compared directly.
2. The per unit equivalent impedance of any transformer is the same when referred to either the primary or the secondary side.
3. The per unit impedance of a transformer in a three-phase system is the same, regardless of the type of winding connections (wye-delta, delta-wye, wye-wye, or delta-delta).
4. The per unit method is independent of voltage changes and phase shifts through transformers, and the base voltages in the windings are proportional to the number of turns in the windings.
5. Manufacturers usually specify the impedance of equipment in per unit or percent on the base of its nameplate rating (kVA or MVA) and voltage (V or kV). Thus, the rated impedance can be used directly if the bases chosen are the same as the nameplate ratings.
6. The per unit impedance values of various ratings of equipment lie in a narrow range, whereas the actual ohmic values may vary widely. Therefore, when actual values are unknown, a good approximate value can be used. Typical values for various types of equipment are available from many sources and reference books. Also, the correctness of a specified unit can be checked, when the typical values are known.
7. There is less chance of confusion between single-phase power and three-phase power, or between line-to-line voltage and line-to-neutral voltage.
8. The per unit method is very useful for simulating the steady-state and transient behavior of power systems on computers.
9. The driving or source voltage usually can be assumed to be 1.0 pu for fault and voltage calculations.
10. With per unit, the product of two quantities expressed in per unit is expressed in per unit itself. However, the product of two quantities expressed as percent must be divided by 100 to obtain the result in percent. Consequently, it is desirable to use per unit, rather than percent, in computations.

2.4 GENERAL RELATIONS BETWEEN CIRCUIT QUANTITIES

Before continuing the discussion of the per unit method, a review of some general relations between circuit quantities applicable to all three-phase power systems is in order. This will focus on the two basic types of connections, wye and delta, shown in Figure 2.1. For either of these, the following basic equations apply:

$$S_{3\phi} = \sqrt{3}\, V_{LL}\, I \text{ VA} \quad (2.3)$$

$$V_{LN} = \frac{V_{LL}}{\sqrt{3}} \angle +30° \text{ V (for abc sequence)} \quad (2.4)$$

$$S_{1\phi} = V_{LN}\, I \text{ VA} \quad (2.5)$$

$$S_{3\phi} = 3\, S_{1\phi} \quad (2.6)$$

where V_{LL} is the line-to-line voltage, V_{LN} the line-to-neutral voltage and I the line current (A). These quantities are often expressed in volts, amperes, and volt-amperes, but with kV, the equations apply for kVA or MVA. In these equations, S is the apparent power in volt-amperes (kVA or MVA) and I is the line current in amperes. The apparent power can be written as:

$$S = P + jQ \quad (2.7)$$

where P is the real power in watts (W, kW, MW), and Q is the reactive power in vars (var, kvar, Mvar). Thus $S = \sqrt{P^2 + Q^2}$ (2.8), $P = S \cos\theta$ (2.9), $Q = S \sin\theta$ (2.10).

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FIGURE 2.1 Three-phase wye- and delta-connected circuits: (a) wye-connected and (b) delta-connected.

Wye-connected impedances (Figure 2.1a): $Z_Y = \frac{V_{LN}}{I}$; delta-connected impedances (Figure 2.1b): $Z_\Delta = \frac{V_{LL}}{I_\Delta} = \frac{\sqrt{3} V_{LL}}{I}$, so $Z_\Delta = 3 Z_Y$ (2.11)–(2.14).

These equations show that circuit quantities S, V, I, and Z are related such that the selection of any two of them determines the values of the remaining two quantities. Usually, the wye connection is assumed, so that (2.3) through (2.5), (2.10), and (2.12) are the equations. In this case the line currents are equal, and no phase shift exists. If a circuit is delta-connected, it can be converted into an equivalent wye connection for calculation purposes.

Equation 2.6 and Equation 2.8 assume equal impedances in the wye and delta circuits. From these equations $Z_\Delta = 3 Z_Y$ or $Z_Y = Z_\Delta / 3$. This equation is useful to convert delta impedances to equivalent wye values. Alternatively, Equation 2.8 and Equation 2.9 can be used directly if the need arises to express the impedance and current in terms of delta circuit quantities.

2.5 BASE QUANTITIES

In the following, the subscript B is used to indicate the base value, so that S_B, V_B, I_B, Z_B, and so on, are the base quantities of S, V, I, Z. Thus, it is more convenient to use the abbreviations: MVA instead of S_{MVA} and kV instead of V for base quantities. The base quantities are defined so that the relationships among them are the same as those that exist among the actual quantities. For any given circuit, one needs to select only two base quantities, and then the others can be derived from equations relating all the quantities, as follows.

Base current: $I_B = \frac{1000\, \text{MVA}_B}{\sqrt{3}\, \text{kV}_B}$ A (2.15)

Base impedance: $Z_B = \frac{(\text{kV}_B)^2}{\text{MVA}_B}$ Ω (2.16)

The following equations relate per unit quantities: $S_{pu} = S / S_B$, $V_{pu} = V / V_B$, $I_{pu} = I / I_B$, $Z_{pu} = Z / Z_B$ (2.17)–(2.20).

The base impedance may also be written in the form $Z_B = \frac{1000 (\text{kV}_B)^2}{\text{kVA}_B}$ Ω (2.21) and then per unit impedance is:

$$Z_{pu} = \frac{\text{MVA}_B\, Z_\Omega}{(\text{kV}_B)^2} \quad (2.22)$$

$$\%Z = \frac{100\, \text{MVA}_B\, Z_\Omega}{(\text{kV}_B)^2} \quad (2.23)$$

If the ohm values are desired from per unit or percent values, the equations are:

$$Z_\Omega = \frac{(\text{kV}_B)^2\, Z_{pu}}{\text{MVA}_B} \quad (2.24)$$

$$Z_\Omega = \frac{10\, (\text{kV}_B)^2\, \%Z}{\text{kVA}_B} \quad (2.25)$$

In the equations above, the ohm values and per unit values are for the individual circuit quantities (i.e., per phase, wye values).

Generally, base values are chosen so that the base voltages are the rated voltages of the equipment and the base MVA is some convenient value, such as 100 MVA. It is recommended that these and the actual quantities always be shown in units, rather than in per unit, for purposes of quick checking. If the values are in per unit, decimal-point errors are likely. One should always ask, when a number is encountered, "What is it? amperes? volts? per unit what?" Initially, the proper units are obvious, but it is easy to forget them later. Units are always helpful to check calculations, and it is essential to designate per unit with "pu" and percent with "%" consistently.

Careful and consistent labeling of all quantities and the correct designation of all ratios will help avoid many errors. It is not necessary to write out all the units in every step of the calculations, but they should be clearly established and shown in the final answers. A little extra effort in this respect will often save a great deal of time and effort later.

Currents in amperes and impedances in ohms should be referred to a specific voltage base or a primary or secondary side of transformer banks. Per unit values are independent of voltage and phase shifts through transformers. Thus, it is not necessary to specify the voltage level for per unit quantities; however, the voltage base should be clear as to whether they are primary or secondary, high or low, and so on.

When per unit or percent values are specified for impedances, resistances, or reactances, two bases must be indicated. These are the MVA (or kVA) and the kV bases (using Equation 2.16 through Equation 2.18). Without the two bases, the per unit or percent values are meaningless. For electrical equipment, these two bases are the rated values that are shown on the equipment nameplate, or on the manufacturer's drawings, or other data supplied. When several ratings are given, generally, it is correct to assume that the normal or base value is the one at which the equipment is normally used in service. Fundamentally, the manufacturer should specifically indicate the MVA (or kVA) base, and the voltage (or kV) base of the per unit or percent values supplied.

For three-phase systems, the three-phase MVA base and the line-to-line kV are almost always used. The base current and impedance calculated with these quantities are the per phase values. Voltages generally are expressed in line-to-neutral values when ratings are specified for the equipment, and as line-to-line values for system studies. Within the system, all voltages should be specified by line-to-line values, or the base should be clearly indicated where necessary. The impedance and per unit values are not the same as when the system values are computed with line-to-neutral voltages and single-phase MVA.

2.6 PER UNIT AND PERCENT IMPEDANCE RELATIONS

In many cases the impedance values are known in the per unit of specific MVA and kV bases, and it is necessary to convert them to another base. This is accomplished as follows. From Equation 2.22, the ratio of the new per unit value to the old per unit value is:

$$Z_{pu2} = Z_{pu1} \left(\frac{\text{MVA}_2}{\text{MVA}_1}\right) \left(\frac{\text{kV}_1}{\text{kV}_2}\right)^2 \quad (2.26)$$

For percent values the same relationship exists:

$$\%Z_2 = \%Z_1 \left(\frac{\text{MVA}_2}{\text{MVA}_1}\right) \left(\frac{\text{kV}_1}{\text{kV}_2}\right)^2 \quad (2.27)$$

Generally, the kV bases are the same, so that (2.26) and (2.27) reduce to:

$$Z_{pu2} = \frac{\text{MVA}_2}{\text{MVA}_1} Z_{pu1} \quad (2.28)$$

$$\%Z_2 = \frac{\text{MVA}_2}{\text{MVA}_1} \%Z_1 \quad (2.29)$$

Thus, a common practice is to convert the impedances of all the equipment in a system to a common base, such as 100 MVA.

2.7 TRANSFORMER BANK EXAMPLE

Consider a transformer bank rated 50 MVA with a 34.5 kV and 161 kV windings connected to a 34.5 kV and a 161 kV system, respectively. The transformer impedance is 10%, as shown in Figure 2.2.

From Equation 2.15: $I_B = \frac{1000 \times 50}{\sqrt{3} \times 34.5} = 836.74$ A at 34.5 kV; $I_B = \frac{1000 \times 50}{\sqrt{3} \times 161} = 179.30$ A at 161 kV (2.30).

From Equation 2.16: $Z_B = \frac{34.5^2}{50} = 23.81$ Ω at 34.5 kV; $Z_B = \frac{161^2}{50} = 518.42$ Ω at 161 kV (2.31).

The transformer impedance on the low-voltage side is $X_T = 0.1 \times 23.81 = 2.38$ Ω at 34.5 kV, and on the high-voltage side is $X_T = 0.1 \times 518.42 = 51.84$ Ω at 161 kV (2.32). Alternatively, from Equation 2.24, the same values result.

FIGURE 2.2 Typical transformer bank.

The transformer impedance in per unit or percent is the same on either side of the transformer, but in ohms it differs by the square of the turns ratio. Thus $51.84 \times (34.5/161)^2 = 2.38$ Ω.

2.8 PER UNIT AND PERCENT IMPEDANCES OF GENERATORS

Impedance characteristics of generators are provided by the generator manufacturer and are usually given in "per unit" terms on a MVA base that is equal to the nominal MVA rating of the generator. If the manufacturer's data sheet is not available, typical data for specific types of generators can be obtained from many reference sources.

Generator reactances are a function of design and will differ depending on the type of generator. Generators are designed to operate at rated load and voltages, and characteristically, the reactances are described as follows: X_d'' — subtransient reactance; X_d' — transient reactance; X_d — synchronous reactance. (Note: The "d" subscript refers to the direct axis. Quadrature axis reactances are designated by a "q" subscript, and are the reactances when the rotor is positioned with its magnetic axis perpendicular to the flux of the stator. The generator's direct and quadrature axes reactances are approximately equal for round-rotor units.)

It is important to understand the meaning of the various types of reactances that are provided for generators. When a short circuit occurs on the terminals of a generator, the current in the armature windings will be high and, in the first few cycles, will gradually decay. The subtransient reactance is the reactance in the armature windings during the first few cycles, the transient reactance applies to the following several cycles, and the synchronous reactance applies in steady state.

The subtransient reactance X_d'' is the lowest reactance and is normally used in the protection area for determining short-circuit currents. Transient reactance, X_d', is somewhat higher and is generally used for stability studies. Synchronous reactance, X_d, is the highest reactance and corresponds to the steady state; it is used for steady-state studies and for setting some generator protective relays.

Subtransient reactance values are given for saturated and unsaturated conditions with the machine. Saturated values are the values at rated voltage. Unsaturated values are used in studies when the voltage is low, such as during faults at the terminals. Generally, the saturated reactance is used in short-circuit studies at rated voltage, and unsaturated values are used for the other conditions. Reactance values are required for machines in per unit on the machine rating and voltage base.

Typical subtransient reactance values for generators are in the range of 0.09–0.25 pu.

Since generator reactances are given on the machine rating, they must be converted to the system base for use in fault studies, using Equation 2.26.

2.9 PER UNIT AND PERCENT IMPEDANCES OF OVERHEAD LINES

Impedance of overhead lines consists of resistance, inductive reactance, and capacitive reactance. All values are usually significant. However, the capacitive reactance of lines is usually in parallel with the load and is neglected in fault calculations except for long lines. Resistance values for overhead lines are a function of the conductor type and size and the temperature. Inductive reactance is a function of conductor type, size, and spacing of the conductors. Capacitive reactance is usually specified in megohm-miles. Data on impedance for specific lines can be computed using equations from various references, or obtained from tables provided by conductor manufacturers.

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Positive-sequence impedance values are typically in the range of 0.8 Ω per mile for lines at the higher voltages. Zero-sequence impedance values are typically in the range of three times positive-sequence values.

2.10 CHANGING PER UNIT (PERCENT) QUANTITIES TO DIFFERENT BASES

The per unit (or percent) values for generator, transformers, and other equipment are generally given on the equipment ratings. For system studies, these must be converted to a common MVA base (usually 100 MVA) and to the voltage base of the system in which the equipment is connected.

2.10.1 EXAMPLE: BASE CONVERSION WITH EQUATION 2.34

The 50-MVA 34.5:161 kV transformer with 10% reactance is connected to a power system where all the other impedance values are on a 100 MVA, 34.5 kV or 161 kV base. To change the base of the transformer, Equation 2.34 is used because the transformer and system base voltages are the same. Thus $jX_T = 10\% \times 100/50 = 20\%$ or 0.20 pu on 100 MVA, 34.5 kV or 161 kV base.

2.10.2 EXAMPLE: BASE CONVERSION REQUIRING EQUATION 2.33

A generator and transformer, shown in Figure 2.3, are to be combined into a new base of 100 MVA, 110 kV. The generator has a reactance of $X_d'' = 25\%$ on 40 MVA, 11 kV; the transformer is rated 40 MVA, 115:11 kV with 10% reactance.

The equivalent generator is a 110 kV voltage base: $X_d'' = 25\% \times \frac{100}{40} \times \left(\frac{11}{110 \times 11/115}\right)^2 = ...$

FIGURE 2.3 Typical generator and transformer for Example 2.10.2.

When working with per unit the base voltage must be determined on each side of the transformer by the turns ratio. Here the 110 kV base on the 115 kV side corresponds to $110 \times 11/115 = 10.52$ kV on the generator side. Thus the generator reactance on 100 MVA, 10.52 kV base becomes $X_d'' = 0.25 \times \frac{100}{40} \times \left(\frac{11}{10.52}\right)^2 = 0.683$ pu, and the transformer reactance becomes $X_T = 0.10 \times \frac{100}{40} \times \left(\frac{115}{110}\right)^2 = 0.273$ pu.

These values on the common base can then be combined directly.

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See the Bibliography at the end of Chapter 1 for additional information.

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3 Phasors and Polarity

3.1 INTRODUCTION

Phasors and polarity are two important and very useful tools in power system protection. They aid in understanding and analyzing how the power system is connected and how it operates both during normal and abnormal operation. Thus, a sound theoretical and practical knowledge of phasors and polarity is a fundamental and valuable resource.

3.2 PHASORS

The IEEE Dictionary (IEEE 100) defines a phasor as "a complex number." Unless otherwise specified, it is used only within the context of steady-state alternating linear systems. It continues: "the absolute value (modulus) of the complex number corresponds to either the peak amplitude or root-mean-square (rms) value of the quantity, and the phase (argument) to the phase angle at zero time. By extension, the term phasor can also be applied to impedance and related complex quantities that are not time dependent."

In this book, phasors will be used to document various AC voltages, currents, fluxes, impedances, and power. For many years phasors were referred to as "vectors," but this use is discouraged to avoid confusion with space vectors. However, the former use lingers on, so occasionally a lapse to vectors may occur.

3.2.1 PHASOR REPRESENTATION

The common pictorial form for representing electrical and magnetic phasor quantities uses the Cartesian coordinates with x (the abscissa) as the axis of real quantities and y (the ordinate) as the axis of imaginary quantities. This is illustrated in Figure 3.1. Thus, a point c on the complex plane x–y can be represented as shown in this figure, and mathematically documented by the several alternative forms given in the following equation:

Phasor: Rectangular, Complex, Exponential, Polar, Polar conjugate forms.

FIGURE 3.1 Reference axes for phasor quantities: (a) Cartesian xy coordinates. (b) Impedance phasor axes. (c) Power phasor axes.

Sometimes the conjugate form is useful.

(3:2) where c is the phasor; c* is its conjugate; x is the real value (alternate: Re c or c0); y is the imaginary value (alternate: Im c or c00); jcj is the modulus (magnitude or absolute value); and f is the phase angle (argument or amplitude) (alternate: arg c). The modulus (magnitude or absolute value) of the phasor is þffiffiffiffiffiffiffiffiffiffiffiffiffiffiffiffiffiffiffi jcj ¼ x2 þ y2 : (3:3) From Equation 3.1 and Equation 3.3, x ¼ 1=2(c þ c*) ß 2006 by Taylor & Francis Group, LLC. (3:4) y¼ 3.2.2 PHASOR DIAGRAMS FOR SINUSOIDAL QUANTITIES In applying the preceding to sinusoidal (ac) voltages, currents, and fluxes, the axes are assumed as fixed, with the phasor quantities rotating at a constant angular velocity. The international standard is that phasors always rotate in the counterclockwise direction. However, as a convenience, on the diagrams the phasor is always shown at the maximum peak value or the rms value of the corresponding sinusoidal quantity. In normal practice, it represents the rms maximum value of the positive half-cycle of the sinusoid unless otherwise specifically stated. Thus, a phasor diagram shows the respective voltages, currents, fluxes, and so on, existing in the electric circuit. It should document only the magnitude and relative phase-angle relations between these various quantities. Therefore, all phasor diagrams require a scale or complete indications of the physical magnitudes of the quantities shown. The phase-angle reference is usually shown as the (zero or reference angle) may vary with convenience. As an example, in fault calculations using reactance X only, it is convenient to use the voltage V reference at þ908. Then I ¼ jV=jX and the j value cancels, so the fault current does not involve the j factor. On the other hand, in load calculations it is preferable to use the voltage V at 08 or along the x-axis so that the angle of the current I represents its actual lag or lead value. Other reference axes that are in common use are shown in Figure 3.1b and Figure 3.1c. For plotting a graph of impedance, resistance, and reactance, the R–X axis of Figure 3.1b is used. Inductive reactance is þX and capacitive reactance is X. For plotting power phasors, Figure 3.1c is used. P is the real power (W, kW, MW) and Q is the reactive power (var, kvar, Mvar). These impedance and power diagrams are discussed in latter chapters. Although represented as phasors, the impedance and power phasors do not rotate at system frequency. 3.2.3 COMBINING PHASORS The various laws for combining phasors are presented for general reference: Multiplication. The magnitudes are multiplied and the angles are added: VI ¼ jVjjIffV þ fI ß 2006 by Taylor & Francis Group, LLC. (3:6) VI * ¼ jV jjI jfffV fI (3:7) II * ¼ jI j2 : (3:8) Division. The magnitudes are divided and the angles are subtracted: V jV j f f V I f I ¼ \ I jI j (3:9) (3:10) ... 3.2.4 PHASOR DIAGRAMS REQUIRE A CIRCUIT DIAGRAM The phasor diagram, defined earlier, has an indeterminate or vague meaning unless it is accompanied by a circuit diagram. The circuit diagram identifies the specific circuit involved, with the location and assumed direction for the currents and the location and the assumed polarity for the voltages to be documented in the phasor diagram. The assumed directions and polarities are not critical, because the phasor diagram will confirm if the assumptions are correct, and provide the correct magnitudes and phase relations. These two complementary diagrams (circuit and phasor) are preferably kept separate to avoid confusion and errors in interpretation. This is discussed further in Section 3.3. 3.2.5 NOMENCLATURE FOR CURRENT AND VOLTAGE Unfortunately, there is no standard nomenclature for current and voltage, so confusion can exist among various authors and publications. The nomenclature used throughout this book has proved to be flexible and practical over many years of use, and it is compatible with the polarities of power system equipment. 3.2.5.1 Current and Flux In the circuit diagrams, current or flux is shown by either (1) a letter designation, such as I or u, with an arrow indicator for the assumed direction of flow; or (2) a letter designation with double subscripts, the order of the subscripts indicating the assumed direction. The direction is thus assumed to be the flow during the positive half-cycle of the sine wave. This convention is illustrated in Figure 3.2a. Thus, in the positive half-cycle, the current in the circuit is assumed to be flowing from left to right, as indicated by the direction of the arrow used with Is, or denoted by subscripts, as with Iab, Ibc, and Icd. The single subscript, such as Is, is a convenience to designate currents in various parts of a circuit and has no directional indication, so an arrow for the direction must be associated with these. Arrows are not required with Iab, Ibc, or Icd, but are often used for added clarity and convenience. It is very important to appreciate that, in these circuit designations, the arrows do not indicate phasors. They are only assumed as directional and locational indicators. a Iab b Vab + Is Ibc Icd c VcI Vbc VX VR + d + vc (a) Vab Vbc Open (type 0 Iab = Ibc = Icd = Is 0 Vcd Vbc Vab Vac Closed type Vcd Vad (b) Iab = Ibc = Icd = Is 0 FIGURE 3.2 Phasor diagram for the basic circuit elements: (a) Circuit diagram showing location and assumed directions of current and voltage drops. I and V are locational and directional indicators, not phasors. (b) Phasor diagrams showing current and voltage magnitudes, and phase relations. ß 2006 by Taylor & Francis Group, LLC. 3.2.5.2 Voltage Voltages can be either drops or rises. Much confusion can result by not clearly indicating which is intended or by mixing the two practices in circuit diagrams. This can be avoided by standardizing on one practice. As voltage drops are far more common throughout the power system, all voltages are shown and are always considered to be drops from a higher voltage to a lower voltage during the positive half-cycle. This convention is independent of whether V, E, or U is used for voltage in many countries. In this book, V is used and as indicated it is always a voltage drop. The consistent adoption of only drops throughout does not result in any complications, because a source voltage becomes a minus drop because current flows from a lower voltage to a higher voltage. This practice does not conflict with the polarity of equipment, such as transformers, and it is consistent with fault calculations using symmetrical components. Voltages (always drops) are indicated either (1) a letter designation with double subscripts; or (2) a small plus (þ) indicator shown at the point assumed to be at a relatively high potential. Thus, during the positive halfcycle of the sine wave, the voltage drop is indicated by the order of the two subscripts used, or from the "þ" indicator to the opposite end of the potential difference. This is illustrated in Figure 3.2a, where both methods are shown. It is preferable to show arrows at both ends of the voltage-drop designations, to avoid possible confusion. Again, it is most important to recognize that both these designations in the circuit diagrams, especially if arrows are used, are only location and direction indicators, not phasors. It may be helpful to consider current as a "through" quantity and voltage as an "across" quantity. In this sense, in the representative Figure 3.2a, the same current flows through all the elements in series, so that Iab ¼ Ibc ¼ Icd ¼ IS. By contrast, voltage Vab applies only across the terminals ab, not to a and b, and voltage Vbc across nodes b and c, and Vcd across nodes c and d. 3.2.6 PHASOR DIAGRAM With the proper identification and assumed directions established in the circuit diagram, the corresponding phasor diagram can be drawn from the calculated or test data. For the circuit diagram in Figure 3.2a, two types of phasor diagrams are shown in Figure 3.2b. The top diagram is referred to as an open type, where all the phasors originate from a common origin. The bottom diagram is referred to as a closed type, where the voltage phasors are summed together from left to right for the same series circuit. Both types are useful, but the open type is preferred to avoid the confusion that may occur with the closed type. This is amplified in the following section. ß 2006 by Taylor & Francis Group, LLC. 3.3 CIRCUIT AND PHASOR DIAGRAMS FOR A BALANCED THREE-PHASE POWER SYSTEM A typical section of a three-phase power system is shown in Figure 3.3a. Optional grounding impedances (ZGs) and (ZHs) are omitted with solid grounding. This topic is covered in Chapter 7. (Rsg) and (Rsg) represent the ground-mat resistance in the station or substation. Ground g or G represents the potential of the earth, remote ground plane, and so on. The system neutrals n0 , n or N, and n00 are not necessarily the same unless a fourth wire is used, as in a four-wire three-phase system. Upper- or lowercase N and n are used interchangeably as convenient for the neutral designation. The various line currents are assumed to flow through this series section as shown, and the voltages are indicated for a specific point on the line section. These follow the nomenclature that was discussed previously. To simplify the discussion at this point, symmetrical or balanced three-phase power system is assumed. Therefore, no current can flow in the neutrals of the two transformer banks, so that with this simplification there is no difference of voltage between n0 , n or N, n00 , and ground or G. As a result, Van ¼ Vag; Vbn ¼ Vbg; and Vcn ¼ Vcg. Again, this is true only for a balanced or symmetrical system. With this, the respective currents and voltages are equal in magnitude and 1208 apart in phase, as shown in the phasor diagram (see Figure 3.3b), in both open and closed types. The phasors for various unbalanced and fault conditions are discussed in Chapter 4. The open-type phasor diagram. The delta voltage Vab, representing the voltage (drop) from phase a to phase b, is the same as Van Vbn. Similarly, Vbc ¼ Vbn Vcn and Vca ¼ Vcn Van. As indicated, the closed-type phasor diagram can lead to difficulties. As seen in Figure 3.3b, its shape lends itself mentally to an assumption that the three vertices of the triangle represent a, b, and c phases of the power system, and that the origin 0 represents n ¼ g. Questions arise with this closed-type phasor diagram (and also in others, because the voltage drop is from phase a to neutral; similarly for the other two phases. Also why Vab, Vbc, and Vca are pointing as shown, for they are drops from phase a to phase b, phase b to phase c, and phase c to phase a, respectively. It would appear that they should be pointing in the opposite direction. The phasors shown on this closed phasor diagram (see Figure 3.3b) are absolutely correct and must not be changed. The difficulty is in combining the circuit diagram with the phasor diagram by the mental association of a, b, and c with the closed triangle. The open type avoids this difficulty. This also emphasizes the desirability of having two separate diagrams: a circuit diagram and a phasor diagram. Each serves particular, but quite different, functions. ß 2006 by Taylor & Francis Group, LLC. Line System G system H + + + + + Ia a Ib b Ic c Van Vbn Vcn Optional ZH Optional ZG n0 n or N Rsg Vag Vbg Vcg g or G Rsg Ground (a) Vcn Vca Vcn = Vcg Ic = Ib Ia = Ib Ic = Ia Ia Ib = Ic Vbn = Vbg Ib Ic Vbc Open type Vca = Vcg Van = Vag Ia Ib Vab Vbn = Vbg Closed type (b) FIGURE 3.3 Phasor diagram for a typical three-phase circuit operating with balanced or symmetrical quantities: (a) Circuit diagram showing location and assumed directions of currents and voltage drops. I and V are locational and directional indicators, not phasors. (b) Phasor diagrams showing current and voltage magnitudes and phase relations. ß 2006 by Taylor & Francis Group, LLC. 3.4 PHASOR AND PHASE ROTATION Phasor and phase rotations are two entirely different terms, although they almost look alike. The AC phasors always rotate counterclockwise at the system frequency. The fixed diagrams, plotted as in Figure 3.3b, represent what would be seen if a stroboscopic light of system frequency were imposed on the system phasors. The phasors would appear fixed in the positions plotted. In contrast, phase rotation or phase sequence refers to the order in which the phasors occur as they rotate counterclockwise. The standard sequence today is a, b, c; A, B, C; 1, 2, 3; or in some areas r, s, t. In Figure 3.3b, the sequence is a, b, c, as indicated. The IEEE dictionary (IEEE 100) defines only phase sequence; hence, this is preferred. However, phase rotation has been used over many years and is still in practice. Not all power systems operate with phase sequence a, b, c, or its equivalent. There are several large electric utilities in the United States that operate with a, c, b phase sequence. Occasionally, this sequence is used throughout the system; for others, one voltage level may be a, b, c, and another voltage level, a, c, b. The specific phase sequence is only a name designation that was established arbitrarily early in the history of a company, and it is difficult to change after many years of operation. Knowledge of the existing phase sequence is very important in three-phase connections of relays and other equipment; therefore, it should be clearly indicated on the drawings and information documents. This is especially true if it is not a, b, c. The connections from a, b, c to a, c, b or vice versa can generally be made by completely interchanging phases b and c for both the equipment and the connections. 3.5 POLARITY Polarity is important in transformers and in protection equipment. A clear understanding of polarity is useful and essential for the chapters that follow. 3.5.1 TRANSFORMER POLARITY The polarity indications for transformers are well established by standards that apply to all types of transformers. There are two varieties of polarity: subtractive and additive. Both follow the same rules. Power and instrument transformers are subtractive, whereas some distribution transformers are additive. The polarity marking can be a dot, a square, or an X, or it can be indicated by the standardized transformer terminal markings, the practices varying over the years. Polarity designated by an X in this book. ß 2006 by Taylor & Francis Group, LLC. IP Prt. + + IS VP VS Sec. VS Sec. (a) IP + Prt. VP (b) + + IS FIGURE 3.4 Polarity definitions for transformers: (a) Subtractive polarity. (b) Additive polarity. The two fundamental rules of transformer polarity, illustrated in Figure 3.4 apply to both varieties are the following: 1. Current flowing in at the polarity mark of one winding flows out of the polarity mark of the other winding. Both currents are substantially in-phase. 2. The voltage drop from polarity to nonpolarity across one winding is essentially in phase with the voltage drop from polarity to nonpolarity across the other winding(s). The currents through and the voltages across the transformers are substantially in-phase because the magnetizing current and the impedance drop through the transformers are very small and can be considered negligible. This is normal and practical for these definitions. The current transformer (CT) polarity markings are shown in Figure 3.5. Note that the direction of the secondary current is the same, independent of whether the polarity marks are together on one side or the other. IP IS IS Sec. Sec. FIGURE 3.5 Polarity markings for CTs. ß 2006 by Taylor & Francis Group, LLC. For CTs associated with circuit breakers and transformer banks, it is a common practice for the polarity marks to be located on the side away from the associated equipment. Voltage transformer polarity, but it is an extremely useful tool to check the phase relations through wye–delta transformer banks, or in connecting up a transformer bank for a specific phase shift required by the power system. The ANSI=IEEE standard for transformers states that the high voltage should lead the low voltage by 308 with wye–delt or delta–wye banks. Thus, different connections are required if the high side is wye than if the high side is delta. The connections for these two cases are shown in Figure 3.6. The diagrams below the threephase transformer connection illustrate the use of the voltage-drop rule to provide or check the connections. Arrows on these voltage phasors have been omitted (preferably not used), for they are not necessary and can cause confusion. In Figure 3.6a, the check is made by noting that a to n from polarity to nonpolarity on the left-side winding is in phase with A to N from polarity to nonpolarity on the right-side winding. Similarly, b to n (polarity to nonpolarity) is in phase with B to C (polarity to nonpolarity) across the middle transformer, and c to n (polarity to nonpolarity) is in phase with C to A (polarity to nonpolarity) across the lower transformer. From this, by comparing the line-to-neutral voltages on the two sides, it is observed that phase-a-to-n voltage leads phase-A-to-neutral voltage. Accordingly, the wye side would be the high-voltage side if this is an ANSI=IEEE standard transformer. This same technique of applying voltage drops to Figure 3.6b shows that for this three-phase bank connection the voltage-drop polarity to nonpolarity a A a A b B b B n n c C c C c C (b) a B A a A c (b) n B b C FIGURE 3.6 Voltage-drop polarity rule useful in checking or connecting wye–delta transformer banks: (a) Wye-connected side leads, delta-connected side 308. (b) Deltaconnected side leads, wye-connected side 308. ß 2006 by Taylor & Francis Group, LLC. or phase a to n is in phase with the voltage-drop polarity to nonpolarity or phase A to phase C. Similarly, voltage-drop across phase b to n is in phase with voltage-drop phase B to phase A, and voltage-drop phase c to n is in phase with voltage-drop across phase C to phase B. By comparing similar voltages on the two sides of the transformer, phase-A-to-neutral voltage drop leads the phase-a-to-n voltage drop by 308, so the delta winding would be the high-voltage side if this is an ANSI=IEEE standard transformer bank. This technique is very useful to make the proper three-phase transformer connections from a desired or known voltage diagram or phase-shift requirement. As these ANSI=IEEE standards have been in existence for several years, most transformer banks in service today follow this standard, except where it is not possible because of preexisting system conditions. Many years ago, in the absence of a standard, many different connections were used. Some of the older references and textbooks reflect this. 3.5.2 RELAY POLARITY Relays involving interaction between two input quantities from the power system may have the polarity marking that is necessary for their correct operation. There are no standards in this area, so if the polarity of the relay connections is important, the relay manufacturer must both specify the polarity markings and clearly document their meaning. Relays that sense the direction of current or power flow at a specific location and, thereby, indicate the direction of the fault, provide a good practical example of relay polarity. Directional units are usually not applied alone, but rather, in combinations with other units, such as fault sensors or detectors. A common practice is to use the output of the directional-sensing unit to control the operation of the fault sensors, which often is an instantaneous or an inverse-time-overcurrent unit, or both units together. Thus, if the current flow is in the desired operating direction (trip direction) and its magnitude is greater than the fault sensor's minimumoperating current (pickup), the relay can operate. If the current is in the opposite direction (nontrip or nonoperate direction or zone), no operation can occur even though the magnitude of the current is higher than the pickup threshold current. A directional-sensing unit requires a reference quantity that is reasonably constant, against which the current in the protected circuit can be compared. For relays intended to provide operation for phase-type faults, one of the system voltages in Figure 3.3b can be used as a reference. For all practical purposes, most system voltages do not change their phase positions significantly during a fault. In contrast, line currents can shift around 1808 (essentially reverse their direction or flow) for faults on one side of the circuit CTs relative to a fault on the other side of the CTs. Typical polarity indications for three commonly used electromechanical directional-sensing units are shown in Figure 3.7. This uses the custom of showing several loops ß 2006 by Taylor & Francis Group, LLC. Maximum torque line I V Vs 308 Ip 308 Type unit zone + s r i f + p Nonoperate zone o Voltage polarized directional relay (a) Ip Ipo Vs 608 Type unit (b) 08 Type unit Operate zone Zero torque line Nonoperate zone Maximum torque line Zero torque line Maximum torque line Vps Ipo 908 Ip or Imn Operate zone Nonoperate zone (c) + p p + m I0p q Current polarized directional relay FIGURE 3.7 Typical directional relay characteristics. for voltage coils and a single loop for current coils, of placing the reference circuit or voltage-coil circuit above the current circuit, and of placing the polarity markings diagonally, all as shown on the relay schematics in Figure 3.7. However, the actual relay schematic may show their polarity markings and in the convention used. It is customary to commonly called the "polarizing" quantity, especially for ground-fault relaying, where either current polarizing or voltage polarizing is used, or both. The polarity marks (Figure 3.7) are small plus symbols (þ) placed, as illustrated, above one end of each coil, diagonally as shown, or on the opposite diagonal. As shown in Figure 3.5, relay operation is not affected whether the polarity marks are on one diagonal or the other. The meaning of the polarity for a specific relay must be stated clearly in words or by a diagram, such as the ones shown in Figure 3.7. These show the basic design characteristics of an individual relay, independent of any connection or association with the power system. The term maximum-torque line and zero-torque line derive from the electromechanical designs long used and still common in the industry. With solid-state designs, these would be the operating lines or thresholds, but the well-established terminology no doubt will continue for many years for all types of designs. ß 2006 by Taylor & Francis Group, LLC. The characteristic of relay polarity is illustrated in Figure 3.7 for three typical electromechanical units. Solid-state units can have adjustments for: (1) the maximum-torque angle and (2) the angle limits of the operate zone, but the application and operation is the same for both types. In Figure 3.7a, the maximum-operating torque or energy occurs when the current flows from polarity to nonpolarity (Ipq) and leads by 308 the voltage drop from polarity to nonpolarity (Vrs). The minimum pickup of the directional unit is specified as the maximum-torque or operating condition. As seen, the unit will operate for currents from almost 608 lagging the reference voltage Vrs to almost 1208 leading. The operating (trip, contact close) zone or area is represented by the half plane, bordered on one side by the zero-torque (nonoperating) line and extending in the direction that contains both the reference (polarizing) and operating quantities. Higher-current values will be required when Ipq deviates from the maximum-torque line. The solid-state relays can adjust this torque line for increased sensitivity by adjusting it to the fault line. The operating torque at any angle is a function of the cosine of the angle between the current (Ipq) and the maximum-torque line, as well as the magnitudes of the operating quantities. For ground-fault protection, the 608 unit in Figure 3.7b is used with a 3 V0 reference (see Figure 3.9) and the zero (watt) unit of Figure 3.7c with a 3 I0 current reference (see Figure 3.10). The unit in Figure 3.7c is also used for power or var applications. A typical application is reverse power protection for a generator. A similar type of electromechanical directional unit, as in Figure 3.7a, has its maximum-torque angle at 458 leading, instead of 308 leading. Both units are in wide use for phase-fault protection. Solid-state units with an adjustable angle feature can provide a range of angles. 3.6 APPLICATION OF POLARITY FOR PHASE-FAULT DIRECTIONAL SENSING Several phase voltages (see Figure 3.3b) exist within the power system and are available as the reference quantity for directional sensing. Five different connections for phase-fault directional sensing have been used over the years. These are outlined in Table 3.1. For a number of years, connections 4 and 5 have been used almost exclusively, so these will be discussed. The other three, used in very limited applications, are outlined in Table 3.1 for reference only. Connections 4 and 5 are fundamentally the same, and they are known as the "908 connection." The only difference between them is the angle that the system current lags the system voltage for maximum-operating torque or energy. Either 608 or 458 is the typical angle of the fault current for maximum energy or torque. The difference is of no significance because (so-called) 458 and 608 lag is the typical range of the fault angles, and the difference in the cosine of these angles is small. Either type of relay (308 or 458 maximum-torque angle) could be used. In the normal 1208 available to the relay, this represents a current sensitivity of about ß 2006 by Taylor & Francis Group, LLC. TABLE 3.1 Connection Chart for Phase-Fault Directional Sensing Phase A Connections Angles Figure I 1 2 3 4 308 608 908 (908) 908 (908) Phase A Phase B Phase C Ia Vac Ia Ib Ic Ia (Vac) Ib Vba Ic Vcb Vab Vbc Vca (Vab)... Maximum Torque Occurs When I I I lags Ib 908 lags 608 lags 458 lags 608 45 03 -0.04 A. As a result, the 908 connection is essentially the standard for phase-fault protection. The normal power load in the operating zone will operate the phase directional units, but the relay will not operate unless a fault has occurred to increase the current above the fault-sensing unit's pickup. Again, the solid-state units can adjust these angles. 3.6.1 908–608 CONNECTION FOR PHASE-FAULT PROTECTION The 908 connection (see connections 4 and 5 of Table 3.1) applies a power system voltage that lags the power system unity power factor current by 908. These voltages and currents are obtained from the power system through voltage and CTs. Typical three-phase connections are shown in Figure 3.8. Three separate units are used, one for each of the power Phase sequence a, b, c BUS system kV a b c VTs 120 v Ia a b c Ib Ic Ia Ic Ib Bus CT VTs. CTs 3V0 B C (67) b 52 Trip direction (67) + a Ic A (67) + c + Ib + Ib GND (67N) + + a b For ground-fault relays See Fig. 3.9 Safety ground c van vab 308 van Phase C relay Ia Ic vcn (b) + Ia Ia Ib Ic (a) Safety ground Phase A relay vbc Ib Phase B relay vbn Zero torque line Nonoperate zone Ia (100% P.F.) 608 308 Maximum torque line vbc Operate zone 608 vca FIGURE 3.8 (a) Typical three-line connections for phase-fault directional sensing using the 308 unit of Figure 3.7a. (b) Connections also show the ground-fault directional sensing using the 608 unit of Figure 3.7b. More details and phasor diagrams are shown in Figure 3.9; the same phases, and is typical for numerous other sensing applications. ß 2006 by Taylor & Francis Group, LLC. Only the directional-sensing units are illustrated, with the fault sensors or detectors omitted for this discussion. They are shown packaged by phase, but other packaging combinations are possible. The phase-A unit receives Ia, and the phase-A directional unit receives the 908 lagging voltage Vbc, the phase-B unit receives Ib where the 908 lagging voltage is Vca, and the phase-C directional unit receives Ic, where the 908 lagging voltage is Vab. These are also shown in Table 3.1 for connections 4 and 5 and in Figure 3.8. In Figure 3.8a the currents are connected so that when Ia, Ib, and Ic are flowing in the direction indicated by the "trip direction" arrow, the secondary currents flow through the directional units from polarity to nonpolarity. The polarity of the CTs does not have to go to the polarity of the relay, although often that is convenient, as in this example. With the trip direction of the currents established in the directional unit current coils, the voltages Vbc on unit A, Vca on unit B, and Vab on unit C must be connected from polarity to nonpolarity on the directional units, as shown. The right-hand phasor diagram of Figure 3.8b applies the directional unit characteristic of Figure 3.7a to the power system phasors. The maximum-torque line leads the voltage by 308, so the 100% unity power factor load or any relay voltage winding, the maximum-torque line is drawn 308 leading, as illustrated in the lower right-hand phasor diagram. This is 608 lagging the unit power factor position of the current phasor Ia. Therefore, whenever the phase a current in the power system lags by 608, the directional unit will operate at maximum torque with the lowest pickup value and the highest sensitivity. Because most system faults provide relatively large currents, the range of possible operation is for power system currents from almost 308 leading to 1508 lagging in the trip direction. This is the operating zone shown in Figure 3.8. Similar relations exist for the other two-phase units with phases b and c phase currents. Thus, the directional units will operate for currents from 908 to lagging the system by 608. The 908–458 connection is similar, except that the relay design provides maximum torque, leading the reference voltage by 458, rather than by 308, used for illustration. Solid-state relays can provide for setting this threshold. For most power system faults, the current will lag the fault voltage from close to say 58–158 (large arc resistance at low voltages) to 808–858 at the high voltages; thus, restricting the operating zone by adjusting the zero-torque lines is practicable. Wye–wye connected voltage transformers (VTs) are shown in the typical connections of Figure 3.8a. Open-delta connections using only two VTs to provide three-phase voltage can be used as an alternative. This is applicable only for phase-fault protection, not for ground protection. ß 2006 by Taylor & Francis Group, LLC. 3.7 DIRECTIONAL SENSING FOR GROUND FAULTS: VOLTAGE POLARIZATION The connections of a directional-sensing unit for ground-fault protection using a voltage reference (voltage polarization) are shown in Figure 3.9. The fault current is obtained from the neutral of the wye-connected CTs through the ground-fault directional unit from polarity to nonpolarity. The operating quantity is 3I0 and is greatest for a fault in the trip direction, as shown in Figure 3.9. The reference quantity for polarizing is the zero-sequence voltage 3V0. Its derivation is discussed in Section 4.9. As shown in Section 4 BUS system kV Ia Phase relays as per Figure 3.8 a b c VTs 120 v 0 CTs a b c AUX. VTs 3v0 Ground relay 52 Trip direction (67N) + 3I0 Ia o 0 0 n a b Ground fault + Safety ground (a) Ia = 3I0 vag 0 vbg vcg ~3v0 vag 3V0 308 608 (b) 3V0 relay Maximum torque line Operate zone Nonoperate zone (b) Zero torque line FIGURE 3.9 Typical three-line connections for ground-fault directional sensing with voltage polarization using the 608 unit of Figure 3.7b. ß 2006 by Taylor & Francis Group, LLC. connected and analyzed using balanced three-phase voltages and currents, it is necessary to assume a fault involving the ground for a ground relay. Thus, a phase-a-to-ground fault is assumed in the trip direction, as shown in Figure 3.9. The characteristics of this type of fault generally are a collapse of the faulted-phase voltage (Vag) with an increase in and lag of the faulted-phase current (Ia), such as typically illustrated in the left phasor diagram. Thus, the unfaulted (b and c) phase currents are small and negligible practically, so that their phase-to-ground voltages are essentially unchanged. The assumption here is that Ib ¼ Ic ¼ 0, so that Ia ¼ 3I0. This, together with V0 or 3V0, is a zero-sequence voltage derived from a broken-delta connection of the VTs (in this example, the auxiliary VTs). This voltage is the sum of the threephase-to-ground voltages, as shown in the connections and in middle phasor diagram. For balanced conditions, 3V0 voltage is zero. For ground-fault protection, a directional 608 unit (see Figure 3.7b) is used. The connections show that Ia fault current flowing in the tripping direction and to the fault, the secondary current flows into the ground-unit current coil from polarity to nonpolarity. Therefore, to provide proper operation, it is necessary to apply 3V0 to the ground relay voltage coil from polarity to nonpolarity. With 3V0 connected to the ground relay from polarity to nonpolarity, the relay characteristics in Figure 3.7b indicate that the maximum torque will occur when the current (polarity-to-nonpolarity lags in the operate zone) lags by 608. Thus, the maximum-torque line is drawn as shown in the lower-right phasor diagram of Figure 3.9. For solid-state units, as long as the magnitudes of 3V0 and 3I0 are above the pickup of the directional unit, it will operate for currents from nearly 308 leading to 1508 lagging. Ground faults on power systems, as do phase-faults, lag in the system voltage by up to about 808–858; therefore, solid-state relays can be changed are useful to limit the operating zone from the power system in Figure 3.9. An alternative check of these connections may be made by assuming that the VTs are a ground source with current flowing from the ground through the primary of the VT to the fault. If one traces this through the three VT windings, this assumed current together with the fault current from the system, will flow from polarity to nonpolarity on the ground relay windings. 3.8 DIRECTIONAL SENSING FOR GROUND FAULTS: CURRENT POLARIZATION The current that flows in the grounded neutral of a wye–delta power transformer bank can be used as a reference or polarizing quantity for ground-fault protection. Typical connections are shown in Figure 3.10, using the 08 unit. ß 2006 by Taylor & Francis Group, LLC. For ground-fault protection, the zero (watt) unit of Figure 3.7c, or its equivalent, which is used, is connected so that the fault current flows in the neutral from the ground to the transformer bank neutral for a three-phase ground fault in the trip direction. Thus, a phase-to-ground fault is shown as phase a in the trip direction. For simplification, Ib and Ic phase currents are assumed to be zero. For all practical purposes the phase angle of the current flowing up the transformer bank neutral, so the 08-type ground relay, with characteristics as shown in Figure 3.7c, is applicable and is the one used in the connections in Figure 3.10. To illustrate and emphasize that the polarity mark on the CTs do not have to be connected to the polarity-marked terminal of the relay, the fault Ia current from the CTs on the line have been connected arbitrarily so that Ia flows from nonpolarity to polarity on the relay coil. Therefore, the polarizing secondary current from the transformer bank neutral CT must be connected from nonpolarity to polarity when the primary fault In flows up the neutral of the transformer. With the currents Ia and In in phase, maximum-operating torque will occur as in Figure 3.7c. Operation is still possible, as one current leads or lags by almost 908 from the other, as long as the magnitudes are higher than the BUS–system kV Phase sequence abc Transformer A B n a b 0 0 C Phase relays as per Figure 3.8 In CT Ground relay (67N) 52 Trip direction Ia b 0 0 n a Ia a Ground fault c + Safety ground (a) Ipol In (b) FIGURE 3.10 Typical three-line connections for ground-fault directional sensing with current polarization using the 08 unit of Figure 3.7c. ß 2006 by Taylor & Francis Group, LLC. relay pickup values of the directional unit. It should be obvious that the polarity of the ground relay winding is important. As indicated, when the polarity of any of the transformer bank neutral-to-ground current is not known, it must be shown in the phasor diagram of Figure 3.9) if the polarity of Ia (3I0) and the polarizing current (In) are both reversed at the directional relay. 3.9 OTHER DIRECTIONAL-SENSING CONNECTIONS Various other directional-sensing connections can be derived to measure different power factor areas by connecting the different (or other) units of Figure 3.7 to various combinations of currents or current and voltage. One type of connection is used to operate on power, either watts or vars, flowing in the power system. These relays (designated device 32) are available with various operating power levels. For watt measurement, the 08 unit of Figure 3.7c can be used with star or delta current or voltage. For example, this unit, used with Ia phase current and Van voltage, will give maximum torque when these two quantities are in phase. Moreover, Ia (with Vab (could be used. For var measurement, in with VIC provides maximum torque when Ia lags by 908 for reactive or lower power factor. A watt power relay (32) can also be obtained by using the 308 unit of Figure 3.7a with Ia and Vac. This places the maximum-torque line in phase with the unit power factor position of Ia. Similarly, a var-type relay can be obtained using this 308 unit with Ia and Vbn. This provides maximum torque when Ia lags by 908. 3.10 APPLICATION ASPECTS OF DIRECTIONAL RELAYING Directionality enhances performance of overcurrent relaying when such relays are applied in a networked or looped system. In such systems, fault current flowing through a line terminal can be in the forward direction into the line or in the reverse direction depending on the location of the fault in the system. Directional relaying is thus typically need to operate only for faults in the forward direction, which could potentially be located on the protected line. Providing directionality to such relays so that they only respond to current flows into the line could result in settings on the associated overcurrent relay that are either lower in pickup or faster in operating speed, or both. Such improvement is made possible by the fact that application of directionality reduces the number of coordination cases that need to be considered. In addition to controlling operation of overcurrent relays, directional elements are also often used to supervise operation of distance relays and pilot relay systems as a means to enhance security. When applying directional elements, it is important to consider the expected phase angles of fault currents that are desired to be detected. The directional relaying system needs to be designed to operate for all expected ß 2006 by Taylor & Francis Group, LLC. phase angles of such currents. This requires consideration of the internal maximum-torque angle designed into the relay and the related connection of voltage and CTs that supply the relay. Such considerations result in identifying the overall range of phase angles for which the overall directional relaying system will operate. It is also important to consider the sensitivity of the directional element when applying directional relaying. Sensitivity is a measure of the minimum input quantities required to cause the device to operate. Sensitivity of directional elements is typically expressed in terms of voltampere, voltage, and current limits. The sensitivity of electromechanical relays, a minimum amount of energy is required to supply torque to overcome restraint that is exerted by the spring that holds the directional contact in the open position. Such spring tension is necessary to assure that these contacts remain securely in the open position during conditions under which operation is undesired. Sensitivity requirements for electromechanical relays are usually expressed in terms of minimum voltamperes. While physical torque is not developed in microprocessor relays, such relays do calculate a value that is representative of the torque. By design, this calculated value must exceed a threshold value for the directional element to produce an output. This feature provides security in microprocessor relays to prevent incorrect operation when the magnitude of operating and polarizing quantities are low to the extent that decisions on directionality are unreliable. In microprocessor relay designs, it is possible to use a minimum value of voltage or current to validate correct operation of the directional unit. Technical aspects of directional relay applications are discussed in greater detail in Chapter 12. From a general standpoint, however, the protection engineer should be alert to several issues when directional relaying is applied: 1. Polarity needs to be analyzed and properly indicated when developing relaying wiring diagrams. Incorrect operation due to improper connections to directional relays is one of the more common causes of incorrect operations on power systems in the past. 2. Final verification of the proper functionality of directional relay systems should be made by in-service testing when the installation is complete. Wiring in substations can be very complex making errors highly possible. Polarity markings on related equipment can also be incorrect. Field tests that are well thought out and implemented are critical in assuring that directional relay systems will function properly. 3. Minimum sensitivity of directional elements needs to be considered when applying directional relays. Sensitivity limits may cause the ability to detect restricted-type faults to be less than desired. Usual sensitivity levels can also result in misoperations with directional relays. ß 2006 by Taylor & Francis Group, LLC. 4. In general, it is best to utilize directional control only if setting benefits result. Directional elements add complication and reduce dependability of the relaying system and should therefore be utilized only when setting improvements are provided. 3.11 SUMMARY The fundamental methodology of phasors and polarity has been reviewed. The use of these in the voltage drop method of the circuit diagrams can be applied to the selection, connection, operation, performance, and testing of the protection for all power systems. ß 2006 by Taylor & Francis Group, LLC. 4 Symmetrical Components: A Review 4.1 INTRODUCTION AND BACKGROUND The method of symmetrical components provides a practical technology for understanding and analyzing the operation of a system during power unbalanced conditions, such as those caused by faults between phases and ground, open phases, unbalanced impedances, and so on. In addition, many protective relays operate from symmetrical component quantities. Thus, a good understanding of this subject is of great value and another very important tool in protection. In a sense, symmetrical components can be called the language of the relay engineer or technician. Its value is both in thinking or visualizing unbalances, and it is a means of detailed analysis of them from the system parameters. In this, it is like a language in that it requires experience and practice for each access and application. Faults and unbalances occur infrequently and many do not require detailed analysis, so it becomes difficult to practice the language. This has increased with the ready availability of fault studies by computers. These provide rapid access to voluminous data, often with little understanding of the background or method that provides the data. Hence, this review of the method is intended to provide the fundamentals, basic circuits and calculations, and an overview directed at clear understanding and visualization. The method of symmetrical components was discovered by Charles L. Fortescue, who was mathematically investigating the operation of induction motors under unbalanced conditions, late in 1913. At the 34th Annual Convention of the AIEE—on June 28, 1918, in Atlantic City—he presented an 89-page paper entitled "Method of Symmetrical Co-ordinates Applied to the Solution of Polyphase Networks." The six discussants, including Charles Proteus Steinmetz, added 25 pages. Practical application for system fault analysis was developed by C.F. Wagner and R.D. Evans in the later part of 1920s and early 1930s, with W.A. Lewis adding valuable simplifications in 1933. Tables of fault and unbalance connections were provided by E.L. Harder in 1937. At the same time Edith Clarke was also developing notes and lecturing in this area, but formal publication of her work did not occur until 1943. Additional material and many examples for further study are found in Blackburn (1993). ß 2006 by Taylor & Francis Group, LLC. Only symmetrical components for three-phase systems are reviewed in this chapter. For these systems there are three distinct sets of components: positive, negative, and zero for both current and voltage. Throughout this discussion, the sequence quantities are always line-to-neutral or line-to-ground as appropriate to the situation. This is an exception for voltage connections, whereas while in the power system line-to-line voltages are commonly used, in symmetrical components, they are always line-to-neutral (or possibly line-to-ground). 4.2 POSITIVE-SEQUENCE SET The positive-sequence set consists of balanced three-phase currents and line-to-neutral voltages supplied by the system generators. Thus, they are always equal in magnitude and are phase-displaced by 1208C. Figure 4.1 shows a positive-sequence set of phase currents, with the power system phase sequence in the order of a, b, c. A voltage set is similar, except for line-to-neutral voltages of the three phases, with equal magnitude and which displaces at 1208C. These are phasors that rotate in the counterclockwise direction at the system frequency. To document the angle displacement, it is convenient to use a unit phasor with an angle displacement of 1208. This is designated as a so that ff ¼ 1ff2408 ¼ 0:5 þ j0:866 ¼ 1ff3608 ¼ 1 ff08 ¼ 1 þ j0 a ¼ 1 a ¼ 1 b ¼ 1208 (4:1) a2 a3 (4:1) Therefore, the positive-sequence set can be designated as Ic1 120□ Ia1 120□ 120□ Ib1 FIGURE 4.1 Positive-sequence current phasors. Phasor rotation is counterclockwise. ß 2006 by Taylor & Francis Group, LLC. Ia1 ¼ I1 Va1 ¼ V1 , ff ¼ ff1208 V ff Ib1 ¼ a2 Ia1 ¼ a2 I1 ¼ I1 2408 Vb1 ¼ a2 V ¼ V1 2408, Ic1 ¼ a Ia1 ¼ c1 ff ¼a V1 ¼ V1 1208: (4:2) It is most important to emphasize that the set of sequence currents or sequence voltages always exists as defined. The phasors Ia1 or Ib1 or Ic1 can never exist alone or in pairs, but always as a set of three. Thus, it is necessary to define only one of the phasors (any one) from which the other two will be as documented in Equation 4.2. 4.3 NOMENCLATURE CONVENIENCE It will be noted that the designation subscript for phase a was dropped in the second expressions for the currents and voltages in Equation 4.2 (and also in the following equations). This is a common shorthand notation used for convenience. When the phase subscript is not mentioned, it can be assumed that the reference is to phase a. If phase b or phase c quantities are intended, the phase subscript must be correctly designated; otherwise, it is assumed as phase a. This shortcut will be used throughout the book and is common in practice. 4.4 NEGATIVE-SEQUENCE SET The negative-sequence set is also balanced with three equal magnitude quantities at 1208 separately, but only when the phase rotation or sequence is reversed as illustrated in Figure 4.2. Thus, if positive sequence is a, b, c, negative will be a, c, b. When positive sequence is a, c, b, as in some power systems; negative sequence is a, b, c. ß 2006 by Taylor & Francis Group, LLC. Ia2 120□ 120□ Ic2 120□ Ib2 FIGURE 4.2 Negative-sequence current phasors. Phasor rotation is counterclockwise. ß 2006 by Taylor & Francis Group, LLC. The negative-sequence set can be designated as Ia2 ¼ I2 Va2 ¼ V2 , ff ¼ I1ff2408 V ff Ib2 ¼ a Ia2 ¼ a I2 ¼ I2 1208 Vb2 ¼ aV2 ¼ V2 1208, Ic2 ¼ a2 Ia2 ¼ a2 I2 ¼ I2 2408 Vc2 ¼ a2 V2 ¼ V2 2408 : (4:3) Again, the negative-sequence quantities always exist as a set. As a matter of fact, the phase sequence of the power system will be positive sequence, and negative-sequence always exists in a set, negative-sequence current or voltage can exist as a quantity. Also, the set can be defined as mentioned earlier. 4.5 ZERO-SEQUENCE SET The members of this set of rotating phasors are always equal in magnitude and in phase (Figure 4.3). When one current or voltage phasor is known, the other two are also known. In the zero-sequence set, the currents or voltages exist in all three phases, but never alone in a phase. 4.6 GENERAL EQUATIONS Any unbalanced current or voltage can be determined from the sequence components given in the following fundamental equations: Ia ¼ I1 þ I2 þ I0, Va ¼ V1 þ V2 þ V0, (4:5) Ib ¼ a2 I1 þ aI2 þ I0, Vb ¼ a2 V1 þ aV2 þ V0, (4:6) Ic ¼ a I1 þ a2 I2 þ I0, Vc ¼ aV1 þ a2 V2 þ V0, (4:7) where Ia, Ib, and Ic or Va, Vb, and Vc are general unbalanced line-to-neutral phasors. From these, equations defining the sequence quantities from a three-phase unbalanced set can be determined: I0 ¼ 1 3 (Ia þ Ib þ Ic), (4:8) Ia0 ¼ Ib0 ¼ Ic0 ¼ I0 FIGURE 4.3 Zero-sequence current phasors. Phasor rotation is counterclockwise. ß 2006 by Taylor & Francis Group, LLC. I0 ¼ 1 3 (Ia þ Ib þ Ic) I1 ¼ 1 3 (Ia þ aIb þ a2 Ic) FIGURE 4.4 Zero-sequence current and voltage networks used for ground-fault protection. (See Figure 3.9 and Figure 3.10 for typical fault operations. I0 ¼ 1 3 (Ia þ Ib þ Ic), V0 ¼ 1 3 (Va þ Vb þ Vc), (4:9) I1 ¼ 1 3 (Ia þ aIb þ a2 Ic), V1 ¼ 1 3 (Va þ aVb þ a2Vc), I2 ¼ 1 3 (Ia þ a2 Ib þ aIc), V2 ¼ 1 3 (Va þ a2 Vb þ aVc), (4:10) These three fundamental equations are the basis for determining if the sequence quantities exist in any given set of unbalanced three-phase currents or voltages. They are used for protective-relaying operations from the sequence quantities. For example, Figure 4.4 shows the physical application of current transformers (CTs) and voltage transformers (VTs) to measure zero sequence as required in Equation 4.8 and as used in ground-fault relaying. Networks operating from CTs or VTs are used to provide an output proportional to I2 or V2 and are based on physical solutions of Equation 4.10. This can be accomplished with resistors, transformers, or reactors, by digital solutions of Equation 4.8 through Equation 4.10. 4.7 SEQUENCE INDEPENDENCE The factor that makes the concept of dividing the unbalanced three-phase quantities into the sequence components practical is the independence of the components in a balanced system network. For all practical purposes, electric power systems are balanced or symmetrical from the generators to the point of single-phase loading, except in an area of a fault or unbalance, such as an open conductor. In this effectively balanced area, the following conditions exist: 1. Positive-sequence currents flowing in a symmetrical or balanced network produce only positive-sequence voltage drops, no negative- or zero-sequence drops. 2. Negative-sequence currents flowing in the balanced network produce only negative-sequence voltage drops, no positive- or zero-sequence voltage drops. 3. Zero-sequence currents flowing in a balanced network produce only zero-sequence voltage drops, no positive- or negative-sequence voltage drops. This is not true for any unbalanced or nonsymmetrical point or area, such as an unsymmetrical fault, open phase, and so on. 4. Positive-sequence current flowing in an unbalanced system produces positive-, negative-, and possibly zero-sequence voltage drops. 5. Negative-sequence currents flowing in an unbalanced system produces positive-, negative-, and possibly zero-sequence voltage drops. 6. Zero-sequence current flowing in an unbalanced system produces all three positive-, negative-, and zero-sequence voltage drops. This important fundamental condition permits setting up three independent networks, one for each of the three sequences, which can be interconnected only at the point or area of unbalance. Before continuing with the sequence networks, a review of the source of fault current is useful. 4.8 POSITIVE-SEQUENCE SOURCES A single-line diagram of the power system or area under study is the starting point for setting up the sequence networks. A typical diagram for a section of a power system is shown in Figure 4.5. In these diagrams, circles are used to designate the positive-sequence sources, which are the rotating machines in the system; generators, synchronous motors, synchronous condensers, and probably induction motors. The symmetrical current supplied by these to the power-system faults decreases exponentially with time from a relatively high initial value to a low steady-state value. During this transient period three reactance values are possible for use in the positive-sequence network and for the calculation of fault currents. These are the direct-axis subtransient reactance X00d, the direct-axis transient reactance X0d, and the unsaturated direct-axis synchronous reactance Xd. The values of these reactances vary with the designs of the machines and the specific values are supplied by the manufacturer. In their absence, typical values are shown in Figure 6.4 and in Blackburn (1993). ß 2006 by Taylor & Francis Group, LLC. Rotating machine ZM Systems ZS Fault (a) ZM (ZS (b) ZM approx. = ZS (c) (d) ZM) ZS Utility systems outside generation station areas, industrial plants with utility tie and no or small local generation. Near generating stations, industrial plants with local generation, no utility tie. Induction motor FIGURE 4.6 Guide illustrating the effects of rotating machine decrements on the symmetrical fault current. Usually, induction motors are not considered as sources of fault current for protection purposes (see Figure 4.6, case D). However, it must be emphasized that these motors must be considered in circuit breakers' applications under the ANSI=IEEE standards. Without a field source, the voltage that is ß 2006 by Taylor & Francis Group, LLC. Rotating machine ZM Induction motor shown in Figure 4.5, represents the equivalent of all the systems that are not shown up to the point of connection to that part of the system under study. This includes equivalent sources and the impedances of all the other lines... equivalent sources at each end of an area to be studied, with an equivalent interconnecting tie between these two equivalent sources. When the equivalent tie is large or infinite, indicating that little or no power is exchanged between the two source systems, it is convenient to express the equivalent source system up to a specified bus or point in short-circuit MVA (or kVA). Appendix 4.1 outlines this and the conversion to the impedance or the reactance value. In Figure 4.5, the network to the right has reduced to a single equivalent impedance to represent it up to the M terminal of the three-winding transformer bank. G T XLH XT XT XL H XLH XM 1000 kVA 13.8 kV X = 1.00% 1000 MVA BUS G X"d = 17.2% XHM = 4.32% 115 kV XLH XLM Each XTL = 24 Ohm Zn = 24.9% ZL (one of each line) ZS FIGURE 4.5 Single-line diagram of a section of a power system. values are shown in Blackburn (1993, p. 279) and in many other references. Generally, typical values at the machines rated MVA (kVA) and kV are: X00d ¼ 0.1 to 0.3 pu, with X0d approximately 1.5 times X00d, and Xd approximately 10 times X00d, with time constants in the order of 0.05 to 0.1 sec for X00d, and about 0.35 sec for X0d. For steady-state calculations, Xd is used as the source reactance. However, it is not used in fault calculations, because the fault current is lower than the load currents; hence, it is not used in the positive-sequence network. This provides a minimum fault current that is useful for high-speed relaying. Although slower-speed protection may operate after the subtransient reactance has decayed into the transient reactance period, the general practice is to use X0d, except possibly for special cases where X0d would be used. There are special programs to account for the decremental decay in fault current with time in setting the slower-speed protective relays, but these tend to be difficult and tedious, and may not provide any advantage. Cases A and B (see Figure 4.6) are the most common situations, so that the use of X00d has a negligible effect on the protection. Here the higher system ZS tends to negate the source decrement effects. Case C (see Figure 4.6) can affect the overall operating time of a slower-speed protection, but generally the decrease in fault current level with time will not cause coordination problems unless the time-current characteristics of various devices that are used are significantly different. When ZM predominates, the fault levels tend to be high and well above the maximum load current. The use of X00d is recommended, but X0 d could be used for the tempest setting in this case. Usually, the generators will not be in operation when the system is at minimum... The setting of the protection as sensitive as possible, but not operating on maximum load (phase devices) should provide good protection sensitivity in the transient reactance period. If protectionoperating times are very long, such that the current decays into the synchronous reactance period, special phase relays are required, as discussed in Chapter 8. ß 2006 by Taylor & Francis Group, LLC. Rotating machine ZM Systems ZS Fault (a) ZM (ZS (b) ZM approx. ¼ ZS (c) (d) ZM) ZS Utility systems outside generation station areas, industrial plants with utility tie and no or small local generation. Near generating stations, industrial plants with local generation, no utility tie. Induction motor FIGURE 4.6 Guide illustrating the effects of rotating machine decrements on the symmetrical fault current. Usually, induction motors are not considered as sources of fault current for protection purposes (see Figure 4.6, case D). However, it must be emphasized that these motors must be considered in circuit breakers' applications under the ANSI=IEEE standards. Without a field source, the voltage that is developed by the induction motor decays rapidly, within a few cycles; thus, they generally have a negligible effect on the protection. The DC offset that can result from sudden changes in current in the ac networks is neglected in symmetrical components. It is an important consideration in all protection. An equivalent source, such as that shown in Figure 4.5, represents the equivalent of all the systems that are not shown up to the point of connection to that part of the system under study. This includes the part of the interconnecting network of transformers, lines, and so on. In general, a network system can be reduced to two equivalent sources at each end of an area to be studied, with an equivalent interconnecting tie between these two equivalent sources. When the equivalent tie is large or infinite, indicating that little or no power is exchanged between the two source systems, it is convenient to express the equivalent source system up to a specified bus or point in short-circuit MVA (kVA). Appendix 4.1 outlines this and the conversion to the impedance or the reactance value. In Figure 4.5, the network to the right has reduced to a single equivalent impedance to represent it up to the M terminal of the three-winding transformer bank. 4.9 SEQUENCE NETWORKS The sequence networks represent one of the three symmetrical balanced parts of the power system and document how their sequence currents will flow if they can exist. These networks are best explained by an example: let us now consider the section of a power system of Figure 4.5. Reactance values have been indicated only for the generator and the transformers. Theoretically, impedance values should be used, but the resistances of these units are small and negligible in fault calculations. However, if loads are included, impedance values should be used unless their values are small in relation to the system reactances. It is important that all values must be specified with a base (voltage if ohms are used, or (MVA (kVA) and kV if per-unit or percent impedances are used). Before applying these to the sequence networks, all values must be changed to one common base. Usually, per-unit (percent) values are used, and a common base in practice is 100 MVA at the particular system kV. 4.9.1 POSITIVE-SEQUENCE NETWORK This is the usual line-to-neutral system diagram for one of the three symmetrical phases modified for fault conditions. The positive-sequence network for the system in Figure 4.5 is shown in Figure 4.7. The voltages VG and VS are the system line-to-neutral voltages. VG is the voltage behind the generator subtransient direct-axis reactance X00d, and VS is the voltage behind the system equivalent impedance Z1S. ß 2006 by Taylor & Francis Group, LLC. N1 + VG (X00d Z1G X1G XTG Neutral bus + ZLH VS XTL H Z1GH VS XHM Z1 F1 I1 V1X XLM G G XT1 Z1 F1 Z1S + Zeq I1 Z1GH XHM + I1 Z1 I1 I1S F1 Figure 4.7 Positive-sequence network for the system in Figure 4.5: (a) network with connections, (b) network reduced to a single equivalent impedance. ß 2006 by Taylor & Francis Group, LLC. XTG G XTG ZTG Neutral Transformer XHL X XHM Equivalent source Z1S ¼ Z2S Z0S XLM Figure 4.5 Single-line diagram of a section of a power system. values are shown in Blackburn (1993, p. 279) and in many other references. Generally, typical values at the machines rated MVA (kVA) and kV are: X00d ¼ 0.1 to 0.3 pu, with X0d approximately 1.5 times X00d, and Xd approximately 10 times X00d... XTG is the transformer leakage impedance for the bank bus G, and XHM is the leakage impedance for the bank at H between the H and M windings. More details on these are given in Appendix 4.2. The delta-winding L of this three-winding bank is not involved in the positive-sequence network unless a generator or synchronous motor is connected to it or unless a fault is to be considered in the L delta system. The connection would be as in Figure A4.2–3. For the line between buses G and H, Z1GH is the line-to-neutral positive-sequence impedance of this transmission line, with a positive-sequence current is 0.8 V=mi for single circuit and 0.6 V=mi for bundled conductors. Typical values for shunt capacitance of these lines are 0.2 MV=mi for single conductor and 0.14 MV=mi for bundled conductors. Normally, this capacitance is neglected, as it is very high in relation to all other impedances that are involved in fault calculations. These values and their use are covered in more detail in Blackburn (1993), Chapter 5. The impedance of the cables can vary quite widely, depending on the type and type of cable or open wire that is used. The impedance angle of lines can vary quite widely, depending on the voltage and type of line... the impedance angle of lines can vary quite widely, depending on the voltage; lines as considered: The neutral bus N1 is the same as the reference neutral... In the positive-sequence network, impedances are normally needed to be calculated with the usual positive-sequence network. For hand calculation, ß 2006 by Taylor & Francis Group, LLC. it is often practical and convenient to simplify calculations by assuming that all the equipment involved in the fault calculation is at 908. Otherwise, it is better to use reactance values only. Sometimes it may be preferred to use the line impedance values and loads are represented by their impedance values. Unless the network consists of a large proportion of low-angle circuits, the error of using all values as 908 will not be too significant. Load is shown to be connected at buses G and H. Normally, 100 MVAload 1000 kV ph(8888 and V1 ¼ pffffff8 ¼ 3kV 2 V1X kV ¼ ¼ V ¼ load ¼ Zload (4:11) Equation 4.11 is a line-to-neutral value and could be used for ZLG and ZLH, representing the loads at G and H as shown in Figure 4.7a. If load is represented, the voltages VG and VS will be different in magnitude and angle, depending on the load flow through the system. The value of load impedance is usually quite high compared with the system impedances, so that the load has a negligible effect on the faulted-phase current. Thus, it becomes practical and simplifies the calculation to neglect load for shunt faults. With no load, ZLG and ZLH are infinite. VG and VS are equal and in phase, and so they are replaced by a common voltage V as in Figure 4.7b. Normally, V is considered as 1 pu, the system rated line-to-neutral voltage. Conventional current flow is assumed to be from the neutral bus N1 to the area or point of unbalance. With this the voltage drop V1x at any point in the network is always V1x ¼ V I1 Z1, (4:12) where V1x is the drop from N1 neutral bus to the point and Z1 is the sum of the impedances from the neutral bus N1 to the point of measurement. 4.9.2 NEGATIVE-SEQUENCE NETWORK The negative-sequence network defines the flow of negative-sequence currents when they exist. The system generators do not generate negative sequence, but negative-sequence current can flow through their windings. Thus, these generators and sources are represented by an impedance without voltage, as shown in Figure 4.8. In transformers, lines, and so on, the phase sequence of the currents does not make any difference; hence, the positive and negative-sequence impedances are the same. ß 2006 by Taylor & Francis Group, LLC. N2 Z2G X2 + ZS2 XTG Neutral bus N2 X2G I2 XTG Z2S Z2GH XHM Z2 F2 I2 V2 XTG ZLG XTG Z1GH Z1S (a) network with connections (b) network reduced to a single equivalent impedance. ß 2006 by Taylor & Francis Group, LLC. FIGURE 4.8 Negative-sequence network for the system in Figure 4.5: (a) network including connections, (b) network reduced to a single equivalent impedance. In rotating machines, the negative-sequence reactance is generally different from the positive. For generators, typical values are given in Figure 6.4, and X2 ¼ X00d... The negative-sequence network is unbalanced ... When the negative-sequence network is reduced, the same as the positive-sequence network are used, except that the source voltages are omitted. Different values of load impedance are usually used for ZLG and ZLH. The voltage drop V2x at any point in the network is V2x ¼ 0 I2 Z2 ¼ I2 Z2, (4:13) where V2x is the drop from the neutral bus N2 to the point of measurement and Z2 is the sum of the impedances from the neutral bus N2 to the point of measurement. 4.9.3 ZERO-SEQUENCE NETWORK The zero-sequence network is always different. It must satisfy the flow of equal and in-phase currents in the three phases. If the connections for this network are not apparent, or in doubt, these can be resolved by drawing the three-phase system to see how the equal in-phase, zero-sequence currents can flow. For the example in Figure 4.5, a three-phase diagram is shown in Figure 4.9. The convention is that the current always flows to the unbalance. Therefore, assuming an unbalance between buses G and H, the top left diagram shows 3I0G flowing from the transformer at bus G. Zero sequence I0G 3I0G transformer XTG ZTG ZG XHM Z0GH Neutral bus N0 Z0G Z0S Z0 (b) FIGURE 4.9 Zero-sequence network for the system of Figure 4.5: (a) flow through the system; (b) network. In phase a, b, c the zero-sequence current flows from the ground through the tie leads a, b, c to the transformer and returns to the ground. With generation: this flow in the neutral cannot be repeated in a three-phase diagram. The network, or sequence network, as well as the neutral bus ... The zero-sequence current at bus G is 3I0 which is through the neutral of the transformer... It is to be noted that a three-phase, or three-phase (4-wire), may be used... The zero-sequence flux must pass through the core to the tank and return. Hence, for these types X0 usually is 0.85–0.9 X1 and, when known, the specific value should be used. Two of the windings (see Figure 4.9). The lower right-hand diagram in Figure 4.9 is for the current toward bus H (see Figure 4.5). Currents out of the three-winding transformer will flow as shown in the L and M windings. The three currents can flow in the ground through the neutral of the transformer to a point of unbalance. This sequence is indicated in the lower-left. In the right-hand part of Figure 4.9, if any of the wye connections were not grounded, the zero sequence network would be open. Thus, the three-winding transformer connections... Ground impedance is also shown in Figure 4.9... the zero-sequence of the circuit is not complete and so forth, if the equivalent system shown, would be open... As a result, zero sequence varies from two to six times X1 for lines. For estimating open wire lines, a value of X0 ¼ 3 or 3.5 X1 is commonly used. The zero-sequence impedance of generators is low and variable, depending on the winding design. Except for very low-voltage units, generators are ß 2006 by Taylor & Francis Group, LLC. never solidly grounded. This is discussed in Chapter 7. In Figure 4.5, the generator G is shown grounded through a resistor R. Faults on bus G and in the system to the right do not involve the generator as far as zero sequence is concerned because the transformer delta blocks the flow of zero-sequence current, as shown. Conventional current flow is assumed to be from the zero-potential bus N0 to the area or point of unbalance. Thus, the voltage drop V0x at any point in the network is V0x ¼ 0 I0 Z0, (4:15) where V0x and Z0 is the drop from the N0 bus to the point of measurement. 4.9.4 SEQUENCE NETWORK REDUCTION For fault calculations, the sequence networks can be reduced to a single equivalent impedance commonly designated as Z1 or X1, Z2 or X2, and Z0 or X0 from the neutral or zero-potential bus to the fault location. This is the Thevenin theorem equivalent impedance, and in the positive-sequence network, it is termed as the Thevenin voltage. These values are different for each fault location. Short-circuit studies with computers use various techniques to reduce complex power systems and to determine fault currents and voltages. For the positive-sequence network in Figure 4.7, between buses G and H: Z1 becomes ZR ¼ X1G þ XTG; Z1S becomes Z1S ¼ XHM þ ZS; the parallel combination of Z1L and Z1R ¼ Z1 for faults at bus H. Z1 of the parallel combination of ZL and ZR with the two combinations calculated in this fashion for faults across the network. This is illustrated in Figure 4.8b... Thus, Thevenin's theorem in distribution factors. These are used as distribution factors are necessary to determine the fault currents in the various parts of the system: I1 ¼ Z1 V1G (4:16) Z1 is the positive-sequence impedance to the fault. With this, the fault is a per unit positive current. This current is the impedance of the network to the fault... Thus, with the Z1 positive-sequence current of the network... This is illustrated in Figure 4.11. The currents, as calculated, can be distributed through the system... In the negative-sequence network I2 and I0 in the zero-sequence network... These are the distribution factors that are used in the three networks. ß 2006 by Taylor & Francis Group, LLC. (b) F0 Zero sequence (c) FIGURE 4.11 Reduced sequence networks where Z1, Z2, and Z0 are the equivalent impedances of the networks to the fault point: (a) positive-sequence network with load (see Figure 4.7a) required in the network with load, system (Thevenin voltage) at the fault point, and (b) the other sequence networks without load. The total currents in the network are the sum of the distribution factors times the total fault current... The positive-sequence network reduced to a single equivalent impedance, and in the negative- and zero-sequence networks the Thevenin's sequence networks are interconnected at the fault point with appropriate distribution factors. These three networks are shown in Figure 4.11 with I1, I2, and I0 representing the respective sequence currents at the fault and V1, V2, and V0 representing the respective sequence voltages at the fault. As indicated earlier, the networks can be reduced... are completely independent of each other. Next, we discuss interconnections to represent faults and other unbalances. 4.10 SHUNT UNBALANCE SEQUENCE NETWORK INTERCONNECTIONS The principal shunt unbalances are faults: three-phase, two-phase-to-ground, two-phase, and one-phase-to-ground. Two such faults are normally made: (1) three-phase faults for applying and setting phase relays and (2) one-phase-to-ground faults for applying and setting ground relays. The other faults provide the effective data that is both: Within 2/3 V1 ZZ, as in common, then, a solid phase-to-phase fault is 0.866 of the three-phase fault. ß 2006 by Taylor & Francis Group, LLC. These phase-to-ground faults with some fault impedance, and two-phase-to-phase and two-phase-to-ground faults are rarely calculated for relay applications. 4.10.1 FAULT IMPEDANCE Faults are seldom solid, but involve varying amounts of resistance. However, it is generally assumed in protective relaying and most fault studies that the connection or contact with the ground involves very low and in general negligible impedance. For the higher voltages of transmission and subtransmission, this is essentially true. In distribution systems (34.5 kV and lower) a very large to basically infinite impedance can exist. This is true, particularly at the lower voltages. Many faults are tree contacts, which can be high impedance, intermittent, and variable. Conductors lying on the ground may or may not result in significant fault current and yet can be highly variable. Many tests have been conducted over the years on wet soil, dry soil, rocks, asphalt, concrete, and so on, with quite a different variable and sometimes unpredictable result. Thus, in most fault studies, the practice is to assume zero ground mat and fault impedances for maximum fault values. Protective relays are set as sensitively as possible, however, to respond properly to these maximum values. Consequently, although arcs are quite variable, a commonly accepted value for currents between 70 and 20,000 A has been an arc drop of 440 V per phase, basically independent of current magnitude. Therefore, Zarc ¼ 440I (4:4:18) where l is the arc length in feet and I the current in amperes: I=kV at 34.5 kV and higher is approximately 0.1–0.05. The arc is essentially resistance, but can appear to protective relays as an impedance, with a significant reactive component resulting from out-of-phase contributions from remote sources. This is discussed in more detail in Chapter 12. In low-voltage (480 V) switchboard-type enclosures, typical arc voltages of about 150 V can be experienced. This is relatively if current magnitude. It appears that because arcs are variable, their resistances tend to start at a low value and continue at the same value for an appreciable time, then build up exponentially. On reaching a high value, an arc breaks over to shorten its path and resistance. 4.10.2 SUBSTATION AND TOWER-FOOTING IMPEDANCE Another highly variable factor, which is difficult but possible to calculate or measure, is the resistance between a station ground mat, line pole, or tower, and the ground. In recent years several technical papers have been written, and computer programs have been developed in this area but there are still ß 2006 by Taylor & Francis Group, LLC. many variables and assumptions. All this is beyond the scope of this book. The general practice is to neglect these in most fault studies and relay applications and settings. 4.10.3 SEQUENCE INTERCONNECTIONS FOR THREE-PHASE FAULTS Three-phase faults are assumed to be symmetrical; hence, no analysis is necessary for their calculation. The positive-sequence network, which is the normal balanced diagram for a symmetrical system, can be used, and the connection is shown in Figure 4.12. For a solid fault the fault point F1 is connected back to the neutral bus (see Figure 4.12a); with fault impedance the connection includes this impedance, as shown in Figure 4.12b. From these, I1 ¼ IaF ¼ V1 Z1 or I1 ¼ IaF ¼ V1 Z1 þ ZF (4:19) and IbF ¼ a2I1, IcF ¼ aI1, according to Equation 4.2. There is no difference between a three-phase fault and a three-phase-to-ground fault. 4.10.4 SEQUENCE INTERCONNECTIONS FOR SINGLE-PHASE-TO-GROUND FAULTS A single-phase-to-ground fault is represented by connecting the three sequence networks together as shown in Figure 4.13, with diagrams 4.13a for solid faults and 4.13b for faults with impedance.

4.34 and Figure 4.35. The voltages and currents generated by the sources can ß 2006 by Taylor & Francis Group, LLC. Fault type Positive sequence Zero sequence Negative sequence Fault voltages Va1 a,b,c Vc1 Zero at fault Vb1 Va1 a,b Vc1 Vb1 Vc2 Vc1 Vb1 Vb1 Vc1 Vb1 Vc1 Vc1 Vc1 Vb = Vc = 0 Va = Vc = 0 Vb Va2 Va0 = Vb0 = Vc0 Vc2 Vb2 Va0 = Vb0 = Vc0 Va = 0 Vb Va2 Vb1 Va2 Vc Vc2 Vb2 Va Va0 = Vb0 = Vc0 Vc2 Va2 Vb1 Va Va0 = Vb0 = Vc0 Vb2 Vb2 Va1 c,G Va0 = Vb0 = Vc0 Vc2 Vb2 Vb1 Va1 b,G Va = Vb = 0 Vc 2 Va1 a,G Vb Vc Va2 Va2 Vb1 Vc1 Va = Vc Vb2 Vc2 Va1 c,a,G Vb = Vc Vb2 Va1 b,c,G Vc2 Va2 Va1 a,b,G Vc = Va Vc2 Va1 c,a Va2 Va2 Va1 b,c Va = Vb Vb2 Vc Vb Va = 0 Va0 = Vb0 = Vc0 Vc = 0 Vb FIGURE 4.34 Sequence voltages and the voltage at the fault point for the various fault types. Solid faults with Z1 ¼ Z2 ¼ Z0 for simplicity. Magnitudes are not to scale. ß 2006 by Taylor & Francis Group, LLC. Fault type Positive sequence Fault currents Zero sequence Ic Ia1 Ic1 a,b,c Negative sequence Ib1 Ib Ia1 Ic1 Ia2 Ib2 Ic = 0 a,b Ia1 Ic Ic2 Ia2 Ia = 0 b,c Ib2 Ib1 Ia1 Ic1 Ib1 Ia Ib Ic0 Ic2 Ia1 Ic = 0 Ib0 Ib1 Ic1 Ia0 Ia2 Ib2 Ia Ib = 0 Ia2 Ia1 Ic1 Ib Ic Ib2 Ic2 c,a a,b,G Ia Ib Ic2 Ib1 Ic1 Ia Ic Ic2 Ia2 Ia = 0 b,c,G Ib1 Ic1 Ib2 Ia1 c,a,G Ic Ib 0 Ic0 Ia2 Ia1 Ib Ia0 Ib2 Ic2 Ib1 Ic1 Ia0, Ib0, Ic 0 Ib2 Ia2 Ib = 0 Ia0, Ib0, Ic 0 Ia a,G Ib1 Ib = Ic = 0 Ic2 Ia1 Ic1 Ia2 Ic2 b,G Ib1 Ic1 Ia1 Ic2 Ib1 Ib2 Ia2 Ia0 Ia = Ic = 0 Ib0 Ic0 Ib2 c,G Ia Ia0 Ib Ic Ib0 Ic0 Ia = Ib = 0 FIGURE 4.35 Sequence currents and the fault current for the various fault types: Solid faults with Z1 ¼ Z2 ¼ Z0 for simplicity. Magnitudes are not to scale. ß 2006 by Taylor & Francis Group, LLC. only be positive sequence by design, and nothing else. Yet the unbalanced faults require unbalanced quantities. How can this difference be resolved to satisfy both requirements: balanced quantities by the generators and unbalanced quantities at the faults? The resolution can be considered as the function of the negative-sequence quantities and for ground faults the zerosequence quantities. This can be seen as indicated in Figure 4.34 and Figure 4.35. Considering the voltages as shown in Figure 4.34, the voltage developed by the source or generator is the same for all faults. For three-phase faults no transition help is required because these faults are symmetrical; hence, there are no negative or zero sequences. For the phase-to-phase faults, negative sequence appears to provide the transition. Note that for the several combinations, ab, bc, and ca phases, the negative sequence is in different positions to provide the transition. The key is that for, say, ab fault, phase c will be essentially normal, so Vc1 and Vc2 are basically in phase to provide this normal voltage. Correspondingly, for a bc fault, Va1 and Va2 are essentially in phase, and so on. The two-phase-to-ground faults are similar; for ab-G faults, the uninvolved phase c quantities Vc1, Vc2, and Vc0 combine to provide the uncollapsed phase c voltage. In the figure, these are shown in phase and at half magnitude. In actual cases, there will be slight variations because the sequence impedances do not have the same magnitude or phase angle. For single-phase-a-to-ground faults, the negative (Vz2)- and zero (Va0)sequence voltages add to cancel the positive-sequence Va1, which will be zero at a solid fault. Correspondingly, for a phase b fault, Vb2 and Vb0 oppose Vb1, and similarly for the phase c fault. The same concept is applied to the sequence currents, as shown in Figure 4.35. The positive-sequence currents are shown in the same for all faults and for 908 lag (X-only system) relative to the voltages in Figure 4.34. These will vary depending on the system constants, but the concepts illustrated are valid. Moreover, for three-phase faults, no transition help is required; hence, there is no negative- or zero-sequence involvement. For phase-to-phase faults negative sequence provided the necessary transition, with the unfaulted phase-sequence currents in opposition to provide either a zero or a low current. Thus, for the ab fault, Ic1 and Ic2 are in opposition. Similarly for two-phase-to-ground faults; for an ab-G fault, Ic2 and Ic0 tend to cancel Ic1 and so on. For single-phase-to-ground faults the faulted phase components tend to add to provide a large fault current, because Ia1 þ Ia2 þ Ia0 ¼ Ia. 4.17 SUMMARY A question often asked is ''Are the sequence quantities real or only useful in mathematical concepts?'' This has been debated for years, and in a sense they ß 2006 by Taylor & Francis Group, LLC. are both accepted. Yes, they are real; positive sequence certainly because it is generated, sold, and consumed; zero sequence because it flows in the neutral, ground, and deltas; and negative sequence, for example, cannot be measured directly by an ammeter or voltmeter. Networks are available and commonly used in protection to measure V2 and I2, but these are designed to solve the basic equations for those quantities. In either event, analyses of symmetrical components is an extremely valuable and powerful tool. Protection engineers automatically tend to think in its terms when evaluating and solving unbalanced situations in the power system. It is important to always remember that any sequence quantity cannot exit in only one phase; this is a three-phase concept. If any sequence is in one phase, it must be in all three phases, according to the fundamental definitions of Equation 4.2 through Equation 4.4. BIBLIOGRAPHY

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Krieger Publishing, Melbourne, FL, 1982). ß 2006 by Taylor & Francis Group, LLC. Appendix 4.1 Short-Circuit MVA and Equivalent Impedance Quite often short-circuit MVA data are supplied for three-phase and singlephase-to-ground faults at various buses or interconnection points in a power system. The derivation for this and conversion into system impedances are as follows: THREE-PHASE FAULTS MVASC ¼ 3f fault-short-circuit MVA ¼ pffiffiffiffi 3I3f kV , 1000 (A4:1-1) where I3f is the total three-phase fault current in amperes and kV is the system line-to-line voltage in kilovolts. From this, 1000 MVASC pffiffiffiffi , 3kV (A4:1-2) VLN 1000 kV kV2 ¼ pffiffiffiffi ¼ : I3f MVASC 3I3f (A4:1-3) I3f ¼ ZV ¼ Substituting Equation 2.15, which is Zpu ¼ MVAbase ZV , kV2 (2:15) the positive-sequence impedance to the fault location is Z1 ¼ MVAbase pu, MVASC (A4:1-4) Z1 ¼ Z2 for all practical cases. Z1 can be assumed to be X1 unless X=R data are provided to determine an angle. ß 2006 by Taylor & Francis Group, LLC. SINGLE-PHASE-TO-GROUND FAULTS MVAfGSC¼f G fault-short-circuit MVA ¼ 1000 pffiffiffiffi 3IfG kV , (A4:1-5) where IfG is the total single-line-to-ground fault current in amperes and kV is the system line-to-line voltage in kilovolts. IfG ¼ 1000 MVAfGSC pffiffiffiffi : 3kV (A4:1-6) 3VLN 3VLN ¼ , Z1 þ Z2 þ Z0 Zg (A4:1-7) However, IfG ¼ I1 þ I2 þ I0 ¼ where Zg ¼ Z1 þ Z2 þ Z0. From Equation A4.1-3 and Equation A4.1-7, 3kV2 MVAfGSC , (A4:1-8) 3MVAbase pu: MVAfGSC (A4:1-9) Zg ¼ Zg ¼ Therefore, Z0 ¼ Zg Z1 Z2, or in most practical cases, X0 ¼ Xg X1 X2 because the resistance is usually small in relation to the reactance. Example A short-circuit study indicates that at bus X in the 69 kV system, MVASC ¼ 594 MVA MVAfGSC ¼ 631 MVA on a 100 MVA base. Thus, the total reactance to the fault is X1 ¼ X2 ¼ Xg ¼ 100 ¼ 0:1684 pu 594 300 ¼ 0:4754 pu, 631 X0 ¼ 0.4754 0.1684 0.1684 ¼ 0.1386 pu, all values on a 100 MVA 69 kV base. ß 2006 by Taylor & Francis Group, LLC. Appendix 4.2 Impedance and Sequence Connections for Transformer Banks TWO-WINDING TRANSFORMER BANKS Typical banks are shown in Figure A4.2-1. H is the high-voltage winding and L the low-voltage winding. These designations can be interchanged as required. ZT is the transformer leakage impedance between the two windings. It is normally designated in per unit or percent by the transformer and stamped on the transformer nameplate. Unless otherwise specified, this value is on the self-cooled kVA or MVA rating at the rated voltages. It can be measured by shorting one winding and applying voltage to the other winding. This voltage should not cause the transformer to saturate. From Figure A4.2-2, ZT ¼ V ZL Ze ¼ ZH þ : I ZL þ Ze (A4:2-1) Because unsaturated Ze is very large compared with ZL, the term ZLZe=ZL þ Ze approaches and is approximately equal to ZL, so that for practical purposes ZT ¼ V ¼ ZH þ ZL : I (A4:2-2) ZT is measured in practice by circulating rated current (IR), through one winding with the other shorted and measuring the voltage (VW) required to circulate this rated current. Then. ZT ¼ VW V: IR (A4:2-3) This test can be done for either winding or as convenient. On the measured side, the base impedance will be ß 2006 by Taylor & Francis Group, LLC. Transformer bank connection Positive and negative sequence connections Zero sequence connection N1 or N2 No L H a H ZT L ZT H L Open No N1 or N2 L H H b ZT 3ZN ZT L H L ZN H Open No N1 or N2 L c H ZT L ZT H L Open L H d H H e L ZT ZT H L No L H 3ZNH 3ZNL ZT L ZNL ZNH H ZT N1 or N2 L H No N1 or N2 H f No N1 or N2 L ZT ZT L L H Open H N1 or N2 L g H ZT No ZT L L H Open H N1 or N2 L h H ZT No L H ZT L Open FIGURE A4.2-1 Sequence connections for typical two-winding transformer banks. ß 2006 by Taylor & Francis Group, LLC. ZB ¼ VR V, IR (A4:2-4) where VR and IR are the rated voltage and current, respectively. Then, the per-unit impedance from Equation 2.1 is ZT ¼ ZT (V) VW IR VW ¼ ¼ pu: ZB (V) IR VR VR (A4:2-5) For three-phase–type transformer units, the nameplate should specify this ZT, usually in percent, on the three-phase kVA (MVA) rating, and the kV lineto-line voltages. When several kVA (MVA) ratings are specified, the normal rating, without fans, pumps, and such (lowest) rating, should be used as one of the impedance bases. For individual single-phase transformers, the transformer impedance is normally specified on a single-phase kVA (MVA) and the rated winding voltages (kV) of the transformer. When three such units are used in threephase systems, then the three-phase kVA (MVA) and line-to-line voltage (kV) bases are required, as outlined in Chapter 2. Thus, when three individual single-phase transformers are connected in the power system, the individual nameplate percent or per-unit impedance will be the ZT leakage impedance, but only on the three-phase kVA (MVA) base, and the system line-to-line kV. Example: Impedance of Single-Phase Transformers in Three-Phase Power Systems Consider single-phase transformers, each with a nameplate rating of 20 MVA, 66.5 kV: 13.8 kV, X ¼ 10%. Considering the individual transformer alone, its leakage reactance is XT ¼ 0:10 pu on 20 MVA, 66:5 kV or (A4:2-6) I ZH V ZL Ze FIGURE A4.2-2 Simplified equivalent diagram for a transformer: ZH and ZL are the components of the transformer leakage impedance and Ze is the exciting impedance. All values are in per unit or primary H side ohms. ß 2006 by Taylor & Francis Group, LLC. XT ¼ 0:10 pu on 20 MVA, 13:8 kV: Converting these to actual ohms using Equation A4.2-5, VWH ¼ 0.10 VRH ¼ 0.10 66,500 ¼ 6650 volts on the high side, where IRH ¼ 20,000=66.5 ¼ 300.75 amperes primary. Then, we obtain from Equation A4.2-3, XTH ¼ 6650 ¼ 22:11 V primary 300:75 or on the secondary side, VWL ¼ 0.10 13,800 ¼ 1380 IRL ¼ 20,000= 13.8 ¼ 1449.28 amperes secondary. XTL ¼ 1380 ¼ 0:952 V secondary: 1449:28 (A4:2-7) V, and (A4:2-8) Check: 66:5 2 0:952 ¼ 22:11 V primary: 13:8 Now consider two possible applications of three of these individual transformers to a power system. These are intended to demonstrate the fundamentals; do not consider if the transformer windings are compatible or suitable for the system voltages shown. Case 1 Connect the high-voltage windings in wye to a 115 kV system and the lowvoltage windings in delta to a 13.8 kV system. As indicated previously, the leakage impedance of this transformer bank for this application is XT ¼ 0:10 pu on 60 MVA, 115 kV, XT ¼ 0:10 pu on 60 MVA, 13:8 kV: (A4:2-9) Now Let us check this. From Equation 2.17, 1152 0:10 ¼ 22:11 V primary, 60 13:82 0:10 ¼ 0:317 V secondary: ¼ 60 XTH ¼ XTL (A4:2-10) It will be noted that the individual transformer reactance per Equation A4.2-8 is 0.952 V, but this is the reactance across the 13.8 kV because of the delta connection. The equivalent wye impedance can be determined by the product ß 2006 by Taylor & Francis Group, LLC. of the two-delta branches on either side of the desired wye branch divided by the sum of the three-delta branches. Thus, the wye equivalent is (0:952)0:952 0:952 ¼ ¼ 0:317 V as before (3)0:952 3 Check 115 13:8 2 0:317 ¼ 22:1 V primary Case 2 Connect the high-voltage windings in delta to a 66.5 kV system and the lowvoltage side in wye to a 24 kV system. Now the transformer bank impedance for this system application is XT ¼ 0:10 pu on 60 MVA, 66:5 kV or XT ¼ 0:10 pu on 60 MVA, 24 kV: (A4:2-11) Now to check this by converting to ohms, using Equation 2.17 XTH ¼ 66:52 0:10 ¼ 7:37 V primary 60 (A4:2-12) is obtained. Now this primary winding of 22.11 ohms (Equation A4.2-7) is connected across the 66.5 kV system because of the delta. Accordingly, the equivalent wye reactance is 22.11 22.11=3 22.11 ¼ 7.37 ohms line-to-neutral on the primary side. On the secondary side, XTL ¼ 242 0.10=60 ¼ 0.952 V is secondary as Equation A4.2-8. Check   66:5 2 0:952 ¼ 7:37 V primary: 24 The connections of two-winding transformers in the sequence networks are documented in Figure A4.2-1. Note that the connections for positive and negative sequences are all the same and are independent of the bank connections. This is not true for the zero sequence with different connections for each type of bank. ß 2006 by Taylor & Francis Group, LLC. Neutral impedance is shown for several connections. If the blanks are solid-grounded, the neutral impedance is zero, and the values shown are shorted-out in the system and are zero-sequence diagrams. THREE-WINDING AND AUTOTRANSFORMER BANKS Typical banks are shown in Figure A4.2-3. H, M, and L are the high-, medium-, and low-voltage windings. These designations can be interchanged as required. Normally, the manufacturer provides the leakage impedance between the windings as ZHM, ZHL, and ZML, usually on different kVA or MVA ratings and at the rated winding voltages. To use these impedances in the sequence networks, they must be converted to an equivalent wye-type network, as shown. This conversion is ZH ¼ 12 (ZHM þ ZHL ZML), (A4:2-13) ZM ¼ 12 (ZHM þ ZML ZHL), (A4:2-14) ZL ¼ 12 (ZHL þ ZML ZHM): (A4:2-15) It is easy to remember this conversion, for the equivalent wye value is always half the sum of the leakage impedances involved, minus the one that is not involved. For example, ZH is half of ZHM, both involving H and minus ZML that does not involve H. After determining ZH, ZM, and ZL, a good check is to see if they add up as ZH þ ZM ¼ ZHM, ... If these values are not available, they can be measured as described for a two-winding transformer. For the three-winding or autotransformers: ZHM is the impedance looking into H winding with M shorted, L open; ZHL is the impedance looking into H winding, with L shorted, M open; ZML is the impedance looking into M winding, with L shorted, H open. This equivalent wye is a mathematical network representation valid for determining currents and voltages at the transformer terminals or in the associated system. The wye point has no physical meaning. Quite often, one of the values will be negative and should be used as such in the network. It does not represent a capacitor. The positive- and negative-sequence connections are all the same and independent of the actual bank connections. However, the connections for the zero-sequence network are all different and depend on the transformer bank connections. If the neutrals are solidly grounded, then the ZN and 3ZN components shown are shorted-out in the system and sequence circuits. ß 2006 by Taylor & Francis Group, LLC. Transformer bank connection Positive and negative sequence connections N1 or M H Zero sequence connection N0 N2 3ZN ZH L a ZN ZL ZH ZM M M ZL H H N1 or H L L ZM If solid grounded ZN = 0 Open M N0 N2 L L ZNM b ZNH L ZH ZL H 3ZNM ZM M N1 or M H ZL Open ZH H ZM 3ZNM If solid grounded ZNH and/or ZNM = 0 N0 N2 3ZN ZH L ZN L ZL ZH H ZM N1 or L ZL Open H M H M ZM If solid grounded ZN = 0 M N0 N2 M ZH d L H L L ZL ZL ZH H ZM ZM M M FIGURE A4.2-3 Sequence connections for typical three-winding and autotransformer banks. ß 2006 by Taylor & Francis Group, LLC. Appendix 4.3 Sequence Phase Shifts through Wye–Delta Transformer Banks As has been indicated, positive and negative sequences pass through the transformer bank, and in the sequence networks, the impedance is the same, independent of the bank connection. This is shown in Figure A4.2-1 and Figure A4.2-3. In these networks the phase shift is ignored, but if currents and voltages are transferred from one side of the transformer bank to the other, these phase shifts must be taken into account. This appendix will document these relations. For the typical ANSI connections are shown in Figure A4.3-1. From Figure A4.3-1a, all quantities are þ phase fffffffi -to-neutral values, and in amperes or volts; for per unit, N ¼ 1, n ¼ 1= 3. IA ¼ n(Ia Ic) and Va ¼ n(VA VB): For positive sequence (see Equation 4.2), IA1 ¼ n(Ia1 aIa1) ¼ n(1 a)Ia1 pffiffiffiffi ¼ 3nIa1 308 ¼ NIa1 308, (A4:3-1) Va1 ¼ n(VA1 a2 VA1) ¼ n(1 a2)VA1 pffiffiffiffi ¼ 3nVA1 þ308 ¼ NVA1 þ308: (A4:3-2) ff ff ff ff For negative sequence (see Equation 4.3), IA2 ¼ n(Ia1 a2 Ia1) ¼ n(1 a2)Ia2 pffiffiffiffi ¼ 3nIa2 þ308 ¼ NIa2 þ308, (A4:3-3) Va2 ¼ n(VA2 aVA2) ¼ n(1 a)VA2 , (A4:3-4) ff ¼ ff pffiffiffiffi 3nVA2 308 ¼ NVA2 308: ß 2006 by Taylor & Francis Group, LLC. ff ff (A4:3-5) High side a Low side Ia n 1 High side IA Ia A a b IB Ib B b c IC C c Ic IC N=n 3 B C A a A b C B b c Turns ratio n:1 Voltage ratio N:1 kVa n= 3 kVA kVa N= kVA (a) A IC n nIc a IB IB n nIb Ic IA IA n nIa Ib Low side 1 n (b) B c C Turns ratio n:1 Voltage ratio N:1 3 kVa n= kVA kVa N= kVA n N= 3 FIGURE A4.3-1 ANSI-connected wye–delta transformer banks: the high-voltage side phase a leads the low-voltage side phase a for both connections illustrated: (a) wye (star) on high side; (b) delta on high side. ß 2006 by Taylor & Francis Group, LLC. ß 2006 by Taylor & Francis Group, LLC. 5 Relay Input Sources 5.1 INTRODUCTION Protective relays require reasonably accurate reproduction of the normal, tolerable, and intolerable conditions in the power system for correct sensing and operation. This information input from the power system is usually through current transformer (CT) and voltage transformer (VT). An exception is for temperature-type relays that receive their information from thermocouples or temperature indicators. These devices—CTs, VTs, formerly potential transformers (PTs), and coupling capacitor voltage transformers (CCVTs)—provide insulation from the higher-system voltages and a reduction of the primary current and voltage quantities. Thus, primary source of the transformer is connected into or to the power system with insulation that is compatible with that of the system. The secondary source is standardized for the convenience of application and relay design. These relay input sources are an important member of the protection ''team.'' Typical units are illustrated in Figure 5.1 through Figure 5.5, and also see Figure 1.8. Other means of providing power system information for protective relays are developed and finding applications. One is the magneto-optic current transducer. This uses the Faraday effect to cause a change in light polarization passing through an optically active material in the presence of a magnetic field. The passive sensor at line voltage is connected to a stationary equipment through a fiber-optic cable. This eliminates the supports for heavy iron cores and insulating fluids. The output is low energy, and can be used with microprocessor relays and other low-energy equipment. These are most useful at the higher voltages using live tank circuit breakers that require separate CTs. In the meantime, iron-cored devices are ubiquitous in power systems and do not appear to be easily replaced. The intolerable system problems may be transient or permanent, and may involve a change in the primary current or voltage over a wide range. This is particularly true for the current, which can suddenly change from a few amperes to several hundred amperes within seconds, when a fault occurs. Voltages during faults can collapse, from the rated value down to zero. ß 2006 by Taylor & Francis Group, LLC. FIGURE 5.1 Typical low-voltage current transformers: (a) bar type, with the bar as the primary; (b) through-type, where the primary cable is passed through the CT opening. (Courtesy of Westinghouse Electric Corporation.) 5.2 EQUIVALENT CIRCUITS OF CURRENT AND VOLTAGE TRANSFORMERS The equivalent diagrams for an instrument transformer are shown in Figure 5.6. The exciting magnetizing impedance Ze in Figure 5.6a is shown in two 0 parts: Ze is the one associated with the leakage flux within the transformer 00 core and its related leakage reactance X; Ze is associated with the flux that does not reach the core. Xp is the leakage reactance from this flux that does not cut the transformer core. Rp and Rs are the resistances of the primary and secondary windings, respectively. ß 2006 by Taylor & Francis Group, LLC. FIGURE 5.2 A 230 kV oil-filled current transformer. The unit is approximately 10 ft high and 2.5 ft in diameter. (Courtesy of Westinghouse Electric Corporation.) For VTs, the value of (RP þ RS) þ j(Xp þ X) is kept low to minimize the loss of voltage and shift of the phase angle from primary to secondary. CTs are of two types; those with significant leakage flux in the core (see Figure 5.6a) and those with negligible leakage flux in the core (see Figure 5.6b). In either type, the Ze shunt impedance(s) are kept high to minimize current loss from the primary to the secondary. The perfect or ideal transformers shown in the diagram are to provide the necessary ratio change; they have no losses or impedances. Although shown in the primary, they may be connected the secondary. As shown, all the impedances are on a secondary basis. With per-unit nomenclature, the perfect transformers are omitted because they are not required. ß 2006 by Taylor & Francis Group, LLC. FIGURE 5.3 Voltage transformer for use in low-voltage power systems. (Courtesy of Westinghouse Electric Corporation.) The primary quantities are reduced by the turns ratio n to provide a secondary current or voltage to energize protective relays and other equipment. The impedances of these loads are commonly called burden. The term can refer to individual devices or to the total load connected, including the instrument transformer secondary impedance, when that is significant. For the devices, the burden is often expressed in volt–amperes at a specified current or voltage. Thus, for CTs or VTs, the burden impedance ZB is ZB ¼ VA V2 V (for VTs), V (for CTs) or ¼ I2 VA (5:1) where VA is the volt–ampere burden and I or V the amperes or volts at which the burden was measured or specified. ß 2006 by Taylor & Francis Group, LLC. FIGURE 5.4 Typical 115 kV switchyard with three 115 kV voltage transformers in the foreground, mounted on top of a 10 ft pipe. Behind are oil circuit breakers and in the right rear, a 325 MVA, 230:115 kV autotransformer bank. (Courtesy of Puget Sound Power & Light Co.) 5.3 CURRENT TRANSFORMERS FOR PROTECTION APPLICATIONS Almost all CTs universally have 5 A secondary ratings. Other ratings, such as 1 A, exist, but are not common, although they are used in other countries. Advantages for this lower rating may exist when unusually long secondary leads are required between the CTs and the relays, such as in high-voltage (HV) installations. However, changing the CT ratings does not necessarily reduce the energy required for relay operation. With a constant VA, lower current means higher voltage, and more insulation between the primary and the secondary. For the most part, the advantages appear to be offset by the disadvantages. Presently and in the future, solid-state microprocessor relays, with very low burdens, greatly reduces the concern of burden on instrument transformers. The measure of a CT performance is its ability to reproduce accurately the primary current in secondary amperes, both in wave shape and magnitude. There are two parts: (1) the performance on the symmetrical AC component and (2) the performance on the offset DC component. Modern CTs do a remarkable job of reproducing wave shapes, as long as they do not saturate. ß 2006 by Taylor & Francis Group, LLC. FIGURE 5.5 A 500 kV coupling capacitor voltage transformer undergoing factory test and calibration. (Courtesy of Westinghouse Electric Corporation.) 5.4 CURRENT TRANSFORMER PERFORMANCE ON A SYMMETRICAL AC COMPONENT For the symmetrical component, the performance is determined by the highest current that can be reproduced, without saturation, to cause large ratio errors. Phase-angle errors are not usually critical for relaying. If the CT does not saturate, it is practicable to assume that Ie is negligible. IS ¼ IP amperes or IS ¼ IP per unit, Rc where Rc is the CT ratio and equivalent to n in Figure 5.6. ß 2006 by Taylor & Francis Group, LLC. (5:2) Perfect transformer IP for ratio only Primary RP a XP c I◆e Z◆e I◆e e X RS IS g Z◆e Secondary b (a) l: n for CTs n l for VTs IP d Perfect transformer a for ratio only c RP f e XP + X Ze Ie Primary (b) l:n d RS f h IS g Secondary h FIGURE 5.6 Equivalent diagrams for instrument transformers; with perfect (ideal) transformers for ratio primary to secondary as shown, the values are in secondary ohms (n ¼ turns). With per unit, omit the perfect transformers. (a) For significant leakage flux in transformer core—class T CTs and VTs; (b) for negligible leakage flux in transformer core—class C CTs. For CTs connected in the phase leads of the power system with the load passing through them, the ratio Rc is selected so that the maximum anticipated secondary current does not exceed 5 A secondary. This comes from the longstanding practice of indicating the instrument movements standardized at 5 A, independent of the primary ampere scale markings. By selecting a ratio to give a little less than 5 A at the maximum load, any instrument connected in the circuit would not go off scale. Instruments may or may not be connected in the relay circuits, but this practice continues, with the continuous ratings of the CTs and relays, often based on 5 A. However, Ie, the CT-exciting current, is never zero if the CT is energized either by the primary or the secondary current. Thus, it must be checked to assure that it is negligible. This can be done by one of three methods: (1) classic transformer formula, (2) CT performance curves, or (3) ANSI=IEEE accuracy classes for relaying. 5.4.1 PERFORMANCE BY CLASSIC ANALYSIS The classic transformer formula is Vef ¼ 4:44 f NAbmax 108 V, (5:3) where f is the frequency in hertz, N the number of secondary turns, A the ironcore cross-sectional area in square inches, and bmax the iron-core flux density ß 2006 by Taylor & Francis Group, LLC. in lines per square inch. However, most of these quantities are not normally available, so this method is used primarily by CT designers. Vef is the voltage the CT can develop to drive secondary current through the load. This load on the CTs consists of its secondary resistance RS, the impedance of the connecting leads Z1d, and the equipment (relays and such) Zr. The voltage required by the burden (load) is Vef ¼ IS (RS þ Z1d þ Zr) volts: 5.4.2 PERFORMANCE BY (5:4) CT CHARACTERISTIC CURVES The calculation of the performance with the equivalent circuit of Figure 5.6a is difficult, even when the value of X is known. The ANSI=IEEE Standard (C57.13) for instrument transformers recognizes this and classified CTs that have significant leakage flux within the transformer core as class T (class H before 1968). Wound CTs, those that have one or more primary-winding turns mechanically encircling the core, are usually of the class T. Their performance is best determined by test, with the manufactures providing curves, as shown in Figure 5.7. CTs constructed to minimize the leakage flux in the core, such as the through, bar, and bushing types (see Figure 5.1), can be represented by the modified equivalent circuit of Figure 5.6b. Effectively, the leakage reactance X is ahead of the exciting branches, and these branches can be paralleled to Ze. With this the performance can be calculated. These are designated as class C (class L before 1968). Typical class C excitation curves are shown in Figure 5.8 and also Figure 5.11. The knee or effective point of saturation is defined by the ANSI=IEEE Standard as the intersection of the curve with a 458 tangent line. However, the International Electrotechnical Commission (IEC) defines the knee as the intersection of straight lines extended from the nonsaturated and the saturated parts of the exciting curve. The IEC knee is at a higher voltage than the ANSI knee, as shown in Figure 5.8. 5.4.3 PERFORMANCE BY ANSI=IEEE STANDARD ACCURACY CLASSES In many applications, the use of the ANSI=IEEE accuracy class designations is adequate to assure satisfactory relay performance. As indicated, there are two standard classes: class T, for which performance is not easy to calculate, so manufacturer's test curves must be used (see Figure 5.7), and class C, for which the performance can be calculated. These designations are followed by a number, indicating the secondary terminal voltage (Vgh) that the transformer can deliver to a standard burden at 20 times the rated secondary current, without exceeding the 10% ratio correction (Figure 5.9). This 10% will not be ß 2006 by Taylor & Francis Group, LLC. 22 B.0.1 Through B. 1.0 20 B.2.0 Times normal secondary current 18 16 B.4.0 14 12 10 8 6 4 2 0 0 2 4 6 8 10 12 14 16 18 20 22 Times normal primary current FIGURE 5.7 Typical overcurrent ratio curves for class T current transformers. (Figure 5 of ANSI=IEEE Standard C37.13.) exceeded at any current from 1 to 20 times the rated secondary current at the standard burden or any lower standard burden. For relaying, the voltage classes are 100, 200, 400, and 800, corresponding to standard burdens of B-1, B-2, B-4, and B-8, respectively. These burdens are at 0.5 power factor. The burden numbers are ohms, obtained by dividing the voltage rating by 20 times the rated secondary current. Thus, with the 800 V rating and its associated B-8 burden, 8 V 5 A 20 ¼ 800 V. If the current is lower, the burden can be higher in proportion; however, this does not necessarily apply to higher currents because the internal impedance, basically neglected in the standard, can affect performance. Therefore, a 400 V rated CT will pass 100 A (20 times rated) with a burden of 4 V or less, with not more than 10% ratio error. Correspondingly, it can pass 50 A with an 8 V burden with not more than the 10% error. For these voltage ratings, terminal voltage is used, rather than the excitation voltage of Equation 5.4, or ß 2006 by Taylor & Francis Group, LLC. Secondary RMS exciting volts, Vef 1000 100 Turn Current ratio ratio 100:5 20:1 200:5 40:1 300:5 60:1 400:5 80:1 500:5 100:1 600:5 120:1 800:5 160:1 900:5 180:1 1000:5 200:1 1200:5 240:1 *OHMS AT 758 C Below this line the exciting current for a given voltage for any unit will not exceed the curve value by more than 25% Sec. res 0.05 0.10 0.15 0.20 0.25 0.31 0.41 0.46 0.51 0.61 458 1200:5 1000:5 900:5 800:5 600:5 500:5 400:5 B A 300:5 200:5 100:5 10 0.001 0.01 0.1 1.0 Secondary RMS exciting AMPS, Ie 10 100 FIGURE 5.8 Typical excitation curves for a multiratio class C current transformer: Point A is the ANSI knee. Above this line, the voltage for a given exciting current for any unit will not be less than 95% of the curve value. Point B is the IEC knee. (Figure 4 of ANSI=IEEE Standard C57.13-1978.) Vgh ¼ IS (Z1d þ Zr) V: (5:5) The lower-voltage classes of 10, 20, and 50 with standard burdens of B-0.1, B-0.2, and B-0.5 at 0.9 power factor are primarily for metering service, and should be used very cautiously for protection. Two similar CTs connected in the primary circuit, with the same ratio and their secondaries in series, will increase the accuracy capability. As an example, first consider a single 200=5 (Rc ¼ 40), with a total burden of 0.5 V. The primary current is 3200 A. Then the current through the relay (burden) will be 3200=40 ¼ 80 A secondary, neglecting any saturation, and the CT must be capable of developing 80 0.5 ¼ 40 V secondary. At this point, with two 200=5 CTs in the primary and their secondaries in series, 80 A will flow through the relays. The voltage across the relays will be 40 V, but each CT needs to develop only 20 V. Two similar CTs, with their secondaries in parallel, provide an overall lower ratio with higher-ratio individual CTs and their correspondingly higheraccuracy rating. For the foregoing example, use two 400=5 (Rc ¼ 80) CTs, instead of 200=5 CTs. Then the CT secondary current is 3200=80 ¼ 40 A, but the current through the relays is 80 A, and the voltage across the relays and ß 2006 by Taylor & Francis Group, LLC. 800 C800 700 Secondary terminal volts 600 Error will not exceed 10% for secondary voltage equal to or less than value described by curve 500 400 8Ω C400 4Ω C200 2Ω C100 300 200 100 0 0 1Ω 5 10 20 30 40 50 60 Secondary amperes 70 80 90 100 FIGURE 5.9 Secondary voltage capabilities for various class C current transformers. each CT is 40 V. This is the same voltage as that for the single CT, but now with the higher-accuracy class 400=5 CTs. The use of two CTs may be quite helpful when low-ratio CTs are used because of low feeder loads, but the close-in fault current can be very high. The low CT accuracy can result in failure or poor operation of the protection. It should be appreciated that the ANSI classifications merely indicate that the ratio correction or error will not exceed 10%. They do not provide information on the actual value, which may be any value, but not exceeding 10%. Also significantly, these accuracy class values apply only to the full winding, and are reduced proportionally when lower taps are available and used. Many type-C transformers are bushing multiratio type, with five secondary taps, providing ratios such as those shown in Figure 5.8 (see also Figure 5.11). Performance on these lower taps is significantly reduced and limited. As a general rule, the use of the lower-ratio taps should be avoided, and when used, the performance should be checked. According to the standards, the manufacturer is to supply application data for relaying service of CTs of (1) the accuracy class, (2) short-time mechanical and thermal ratings, (3) resistance(s) of the secondary winding, and ß 2006 by Taylor & Francis Group, LLC. (4) typical curves, such as Figure 5.7 for class T and Figure 5.8 for class C (see also Figure 5.11). 5.4.4 IEC STANDARD ACCURACY CLASSES The IEC specifies the accuracy of CTs as 15 VA Class 10 P 20 Accuracy limit factor For protection Accuracy class Continuous VA Thus, for this CT rated at 5 A, 15=5 ¼ 3 V, and will have no more than 10% error up to 20 3 ¼ 60 V secondary. Standard values for relaying CTs are Continuous VA: 2.5, 5, 10, 15, and 30 Accuracy classes: 5% and 10% Accuracy-limit factor: 5, 10, 15, 20, and 30 Rated secondary amperes: 1, 2, and 5 (5 A preferred) For a CT rated 30 VA class 10 P 30, 30 ¼ 6 V;6 30 ¼ 180 V: 5 The permissible burden is 30=52 ¼ 1.2 V. This is equivalent to an ANSI=IEEE C180 current transformer. 5.5 SECONDARY BURDENS DURING FAULTS The burden imposed on CTs for various faults and connections is documented in Figure 5.10. ZB is the sum of the leads or connecting circuits between the CTs and the relays, and also any other equipment. It is assumed that the burden in each phase is the same, but this may not be correct always. When the CTs are connected in delta (see Figure 5.10b), the burden on the phase A current transformer is (IA IB)ZB (IC IA)ZB. This reduces to [2IA (IB þ IC)ZB]. For a three-phase fault, IA þ IB þ IC ¼ 0, so (IB þ IC) ¼ IA, and substituting this, the burden reduces to 3IAZB. Because phase relays are set on three-phase fault currents, and ground relays are set on single-phase-to-ground fault currents, the phase-to-phase fault diagrams are not generally used. They certainly indicate that the burden is the same as that of three-phase faults, and with less phase-to-phase fault current, the three-phase fault cases are the maximum. ß 2006 by Taylor & Francis Group, LLC. A B zB IB zB IB - IC zB zB z IC - IA B IC IB A IA - IB zB zBG o IA C B CI A IA IC IB IC Three-phase fault (a) Three-phase fault (b) A B C B C IB zB zB 2IB zB IB = IC zB IB zB IBG IB A zB o o IC IB o o IC Phase-to-phase fault Phase-to-phase fault (d) (c) A B C IA zB B A C zB IA o zB zB o o zB IA zB IA = 3I0 zBG IA o o IA o Phase-to-ground (e) o Phase-to-ground (f) FIGURE 5.10 Burdens on CTs for various types of CT connections and faults. The unexcited CT load is neglected. ß 2006 by Taylor & Francis Group, LLC. 5.6 CT SELECTION AND PERFORMANCE EVALUATION FOR PHASE FAULTS A suggested process for selection of the CT ratio and evaluation of its performance can be shown by an example. Consider a circuit to be protected by overcurrent relays with the following load and fault levels: Imax load ¼ 90 A, Imax 30 fault ¼ 2500 A, Imin fault ¼ 350 A: 5.6.1 CT RATIO SELECTION FOR PHASE-CONNECTED EQUIPMENT Select the ratio, such that the maximum short time or continuous current will not exceed the thermal limits of the CT secondary and connected equipment. The conventional practice, over many years, has been to set the secondary current just under 5 A for the maximum load. This was because instruments were often in the same circuit and had 5 A movements. Following this practice, select the CT ratio of 100=5 (Rc ¼ 20). This gives a maximum continuous secondary current, when the load is 90 A, of IS ¼ 90=20 ¼ 4.5 A. 5.6.2 SELECT THE RELAY TAP FOR THE PHASE-OVERCURRENT RELAYS Overcurrent taps represent the minimum pickup or operating current of an overcurrent relay. Thus, a tap that is higher than the maximum load is chosen; in this example, above 4.5 A. How much higher is based on relay characteristics, experience, and judgment. There is no problem if a time overcurrent relay picks up on a cold load, offset currents, or others, provided these currents subside below the relay pickup before it operates. [illegible] Thus, a tap 5 is selected. The ratio above load 5=4.5 ¼ 1.11. [illegible] Tap 6 were selected, then the margin above load is greater (6=4.5 ¼ 1.33), but a smaller margin (17.5=6 ¼ 2.9) above the relay pickup. 5.6.3 DETERMINE THE TOTAL CONNECTED SECONDARY LOAD (BURDEN) IN OHMS The total connected secondary load determination must include all the impedances between the CTs and the equipment (relays) in the phase circuit. Ground relays are discussed in Section 5.7. Data on the relays must be ß 2006 by Taylor & Francis Group, LLC. obtained from the manufacturer for the particular type. The burdens of solidstate and microprocessor-type relays are very low and relatively constant with taps. For these applications, the lead burden becomes the major load on the CTs. Tap 5 will be used with electromechanical relays, for which the burden is 2.64 VA at 5 A and 580 VA at 20 100 A. The leads from the CT to the relays are 0.4 V. The typical practice is to use number 8 or 10 sized leads for low resistance and to minimize mechanical damage to these important connections. The total secondary impedance at pickup, adding directly: Relay burden 2.64=52 ¼ 0.106 V Lead resistance ¼ 0.400 V Total to CT terminals ¼ 0.506 V at 5 A The total secondary impedance at 20 100 A, adding directly: Relay burden 580=1002 ¼ 0.058 V Lead resistance ¼ 0.400 V Total to CT terminals ¼ 0.458 V at 100 A This is typical for electromechanical relays that tend to saturate at higher currents. Thus, their internal impedance decreases and becomes more resistive. [illegible] burden impedances and the currents algebraically, but theoretically they should be combined phasorially. [illegible] This is carried out in the example hitherto mentioned. Burdens are generally not unity power factor; hence, IS tends to be near unity power factor. However, Ie, the exciting current, lags 908, so combining Ie and IS at right angles is a good approximation. 5.6.4 DETERMINE THE CT PERFORMANCE USING THE ANSI=IEEE STANDARD 5.6.4.1 When Using a Class T CT Check the performance from the curve provided, such as Figure 5.7. The ‘‘B’’ represent the standard burdens. The relay burdens are B1, B2, B3, B4, and B8. These are the total secondary load impedances to the terminals gh in Figure 5.6a, and would be the 0.506 or 0.458 values in the foregoing. ß 2006 by Taylor & Francis Group, LLC. 5.6.4.2 When Using a Class C CT and Performance by the ANSI=IEEE Standard For this example, a multiratio CT with C100 rating had been preselected. With this load, it would have been preferable to have selected lowerratio CTs, but often CTs are selected before adequate or correct system data are known. The choice of high ratio, multitap CTs appears to provide a wide range of possible system operations. However, it can give protection problems, as will be seen. Determine the voltage at maximum fault that the CT must develop across its terminals (see gh in Figure 5.6b). This is Vgh ¼ 2500 · 0:458 ¼ 57:25 V, 20 but the C100 600=5 CT on the 100=5 tap can only develop, Vgh ¼ 100 · 100 ¼ 16:67 V: 600 Thus, the maximum fault will cause severe saturation of the CT, resulting in incorrect or failure of the protection; consequently, the application cannot be used. [illegible] The voltage required is way above the CT capability on the 100=5 tap of only 16.67 V. An alternative is to use the 400=5 (Rc ¼ 80) tap on the 600=5 C100 CT. Now the maximum load will be 90=80 ¼ 1.125 A, and a relay tap of 1.5 could be selected. This provides a 1.5=1.125 ¼ 1.33 margin between relay pickup and maximum load, and a margin of 2.9 between relay pickup and minimum fault [illegible]. However, the relay burden at this tap and at 100 A is 1.56 V (however, for solid-state relays this would be much lower). Relay burden ¼ 1.56 V Lead resistance ¼ 0.40 V Total to CT terminals ¼ 1.96 V Vgh ¼ ß 2006 by Taylor & Francis Group, LLC. 2500 1.96 ¼ 61:25 V 80 The CT capability on the 400=5 tap is Vgh ¼ 400 · 100 ¼ 66:7 V: 600 The 61.25 V is within the CT capability. 5.6.4.3 When Using a Class C CT and Performance with the CT Excitation Curves Use of the ANSI=IEEE ratings, as in the foregoing example, provides a ‘‘ballpark’’ evaluation that is usually quite adequate. The excitation curve method provides more accurate information when desired. The excitation curve for the 600=5 CT of our example is shown in Figure 5.11. When using these curves, the CT secondary resistance (RS; see Figure 5.6b) must be included. These data are shown in the table of Figure 5.11 and for the 400=5 tap is 0.211. Thus, Relay burden ¼ 1.56 V Lead resistance ¼ 0.40 V CT secondary resistance ¼ 0.211 V Total to excitation point ¼ 2.171 V [illegible] Both are well below the minimum fault of 350 A. [illegible] 5.7 PERFORMANCE EVALUATION FOR GROUND RELAYS [illegible] ß 2006 by Taylor & Francis Group, LLC. [illegible] FIGURE 5.11 Typical excitation curves for a multiratio class C100 current transformer. [illegible] FIGURE 5.12 [illegible] of the ground relay pickup and the phase B and C exciting currents. By direct addition, this would be 0.50 þ 0.58 þ 0.58 ¼ 1.66 A. By phasor addition, it would be essentially 0.5 ffi60 þ j0.38 þ j0.38 ¼ 1.24 ffi81.308; therefore, the difference is not significant. The exciting voltage for the phase A CT is Vef ¼ 8.0 þ (1.26 · 0.63) ¼ 8.79 V, whereas from Figure 5.11, Ie ¼ 0.41 A. Directly adding, the total is 1.46 þ 0.41 ¼ 1.67 secondary amperes or 20 1.67 ¼ 33.4 primary amperes, just to pick up the ground relay. This is in contrast to the 20 0.5 ¼ 10 primary amperes required just to pick up the ground relay, if the exciting currents for the three CTs were neglected. It should be recognized that these CTs are not adequate for fault protection on the CT and ground relay taps used. As explained in Section 5.4.3, higher taps can improve performance and would decrease the shunting effect just described. This effect should be considered, especially when several CTs are paralleled with only one or two carrying current, as in a differential scheme, as described later. 5.9 FLUX SUMMATION CURRENT TRANSFORMER Also known as doughnut or ring CT, flux summation CT consists of a magnetic core with a distributed winding. Power conductors are passed through the center opening. Typical openings are approximately 4–10 in. These CTs are useful in protection at the lower voltage. When the three-phase conductors are passed through the opening, the secondary measures Ia þ Ib þ Ic ¼ 3I0, the ground current. When the same phase conductor on the two ends of a device are passed through the opening, the net current for a load or fault current passing through the device is zero. For an internal fault, with one or both supplying current of different magnitude or phase angle, the net or sum equals the fault current. This is flux summation, rather than individual summing of separate transformer secondary currents. The advantages are that the CT ratio is independent of the load current or kVA of the circuit, and that it avoids the possible difficulties of unequal individual CT saturation or performance with paralleled CTs. The disadvantage is the limitation of the size of conductors that can be passed through the opening. A typical ratio for this CT is 50:5, and the diameter of the maximum opening is about 8 in. The CT is commonly used with a 0.25 A instantaneous overcurrent unit. The combination provides a primary pickup of 5 A, rather than 2.5 A, if the ß 2006 by Taylor & Francis Group, LLC. Ground fault relay Cable sheath (s) for 3 or 1 cables Fault Toroidal current transformer Sheath may or may not be grounded at load or elsewhere. FIGURE 5.13 Typical application of the flux summation current transformer for ground-fault protection with metallic sheath conductors. exciting current were negligible. Specific applications are discussed in later chapters. A metallic sheath or shielded cables passed through the toroidal CT can result in cancellation of the fault current. This is illustrated in Figure 5.13. This applies either to three-phase cables, as shown, or to single-phase cables. The cancellation may be partial or complete, depending on the sheath grounding. This sheath component of fault current can be removed from passing through the CT by connecting a conductor, as shown. 5.10 CURRENT TRANSFORMER PERFORMANCE ON THE DC COMPONENT As transformers are paralyzed by direct current, CT performance is affected significantly by the DC component of the AC current. When a current change occurs in the primary AC system, one or more of the three-phase currents will have some DC offset, although none may be maximum and one could not have much impact. This DC results from the necessity to satisfy two conflicting requirements that may occur: (1) in a highly inductive network of power systems, the current wave must be near maximum when the voltage wave is at or near zero and (2) the actual current at the time of change is that determined by the prior network conditions. For example, energizing a circuit with current zero, before closing the circuit at the instant when the voltage wave is zero presents a problem. By requirement (1) the current should be at or near maximum at that moment. Thus, a countercurrent is produced to provide the zero required by condition (2). This is the DC component equal and opposite ß 2006 by Taylor & Francis Group, LLC. Current amperes Per-unit primary current 0 (a) Per-unit secondary current Time Current amperes Per-unit primary current Per-unit secondary current Time (b) FIGURE 5.14 Typical possible distortion in CT secondary current resulting from DC saturation: (a) large resistive burden; (b) small resistive burden. (Figure 3 of IEEE 76CH1130-4, PWR Transient Response of Current Transformers.) to the required AC current by condition (1), with the two adding to zero at the instant of closing the circuit. After having provided this function, the DC is no longer required, but it can disappear only by decaying according to the L=R time constant of the power system. This decaying DC acts more or less like a low-frequency alternating current in passing through the CT. It can saturate the iron such that the secondary reproduction of the primary current can be severely limited and distorted. This is illustrated in Figure 5.14 for a 20 times rated fully offset current with resistive burden. This type of burden causes a sharp drop-off of the secondary current during each cycle. After saturation occurs, the decay of the DC component results in the CT recovering, so that during each subsequent cycle, the secondary current more nearly approaches the primary. As the DC disappears, the secondary is again a reproduction of the primary. This assumes no AC saturation. It is possible, but rarely occurs, that the secondary current may be practically zero for a few cycles in very severe cases. ß 2006 by Taylor & Francis Group, LLC. Inductance in the burden results in a more gradual drop-off, whereas a lower burden reduces the distortion. These several effects are shown in Figure 5.14. As shown, this saturation does not occur instantly; hence, initially, the secondary current follows the primary current, before it is reduced and distorted by saturation. The time to saturate and the calculation of the secondary current are complex and depend on many factors: the nature of the fault current, the constants and design of the CT, and the burden connected. A simplified method for estimating the performance of ring-core CTs is available from the IEEE report Transient Response of Current Transformers. From a practical standpoint and as a general rule of thumb, the CTs used for relaying can be expected to reproduce, with reasonable accuracy, the primary current for about one-half cycle or more before a significant DC saturation. 5.11 SUMMARY: CURRENT TRANSFORMER PERFORMANCE EVALUATION The following two types of CT saturation have been discussed. 5.11.1 SATURATION ON SYMMETRICAL AC CURRENT INPUT RESULTING FROM THE CT CHARACTERISTICS AND THE SECONDARY LOAD Figure 5.15 shows typical secondary voltages as a function of the secondary burden. There is always an output, although it may delay or be insufficient to operate relays. This saturation should be avoided, but this may not always be possible or practical. Saturation on symmetrical AC is most critical at the point of relay decision. Thus, in differential protection, the decision point is at the CT nearest to an external fault. A fault on one side of the current transformer is internal, for which the protection must operate, but the fault on the other side is external, and the protection must not operate. This external fault is often very large and requires good CT performance. An AC saturation should not occur for this protection. For overcurrent protection of lines, the decision point is remote from the CT and generally not so critical because time is involved in the relay operation; hence, some saturation can be tolerated. For heavy close-in faults, these relays may be operating on the relatively flat part of their time curve, for which magnitude differences are not critical. This also applies to close-in heavy faults for instantaneous or distance-type relays. 5.11.2 SATURATION BY AC CURRENT THE DC OFFSET OF THE PRIMARY This is a function of the power system, and it is not practical to avoid its effect by the CT design. It will temporarily restrict the output of the CT, as ß 2006 by Taylor & Francis Group, LLC. (a) No saturation (b) Part saturation (c) Severe saturation FIGURE 5.15 Typical secondary voltages of a current transformer with symmetrical AC current input and increasing secondary burden. illustrated in Figure 5.14, in contrast to the AC saturation of Figure 5.15. This can be critical in differential protection where several CTs are involved in the fault determination. Differential relay designs use various techniques to prevent misoperation, generally keyed to no AC saturation. ß 2006 by Taylor & Francis Group, LLC. In most other applications, DC saturation is not likely to be too severe, or to significantly inhibit the protection from a practical standpoint. However, it should always be considered and checked. Most faults tend to occur near the maximum voltage, at which the prefault current is low in the inductive power system. This minimizes the DC offset; therefore, it is seldom at its maximum possible value. In many parts of the power system, the time constant will be short, such that when the DC offset occurs, it rapidly decays. Moreover, faults other than differential protection are not at the maximum value at the critical decision point of the protection. For example, in line protection, the relay decision point is remote from the CTs; consequently, the fault current is often lower, and line resistance is available to help moderate the effect. In addition, the decision point may not be too critical, for time is often involved to clear remote faults. Generally, the close-in high-current faults will be greater than the relay pickup current, and with high-speed relays, operation may take place before DC CT saturation occurs. Should saturation occur before the line protection relays can operate, generally a delay in operation occurs until the CTs recover sufficiently to permit operation. Thus, the tendency for this type of protection usually is to ‘‘under-reach’’ momentarily, rather than ‘‘over-reach.’’ 5.12 CURRENT TRANSFORMER RESIDUAL FLUX AND SUBSIDENCE TRANSIENTS When a CT is energized by a load for the first time, the excursion on the hysteresis loop is symmetrical, with a flux variation such as rr 0 in Figure 5.16. Faults with higher current produce increased flux and a wider excursion. When the fault is cleared and the primary current becomes zero, a unidirectional transient current can flow in the secondary. This is the trapped exciting current, which is out of phase with the fault primary–secondary current through the resistive-type burden before interruption. The time constant for this is usually short with resistive burdens, unless air gaps are employed in the CT core. This transient current may delay the dropout of very sensitive high-speed overcurrent relays used in breaker failure programmed in these schemes, particularly for HV system protection. Interruption of the fault and the decay of Ie to zero still leaves flux in the CT. This is called residual flux, such as at point s in Figure 5.16. Now if the CT is reenergized with the original load current flowing, the flux excursion would resume, but from the residual flux level s with a loop ss 0 , where the flux variation of ss 0 ¼ rr 0 . However, it cannot continue in loop ss 0 because this would require direct current to maintain it in this offset position. So it shifts down to a symmetrical position tt 0 , at which the variation tt 0 ¼ ss 0 ¼ rr 0 . During this shift, a small direct current flows in the secondary circuit, according to the burden secondary time constant. Until the load changes or another fault ß 2006 by Taylor & Francis Group, LLC. Flux s s t t r r o I e Ie Exciting current FIGURE 5.16 Typical hysteresis loops and residual flux in current transformers. occurs, the flux will vary in this tt 0 loop indefinitely. If the circuit is opened to de-energize the primary current to zero, the residual flux would be the value existing at the moment of interruption and somewhere within loop tt 0 . Thus, CTs, once energized, will have residual flux anywhere between zero and the saturated value in either the positive or the negative loop. For a later fault, the residual can either add or reduce the CT capabilities. In the example, residual flux points s and t are closer to the saturation level for flux excursions to the right, but are far away from saturation for excursions to the left. Consequently, the performance depends on which half cycle the next fault occurs. Because this is not predictable in theory, the residual flux can cause saturation and problems in protection. However, the general experience in the United States has not indicated this to be a serious problem. Very few cases have been cited in which this might have caused problems. Air-gap CTs have been used to minimize this residual; however, their performance for general application is not nearly as reliable. Although they do not saturate as rapidly as the nongap designs, their exciting current is higher; there is a loss of steady-state accuracy and of transformation of the DC transient. The unidirectional CT current after a fault clears decays out more slowly with air gaps and so is more likely to cause problems in breaker failure relaying, as outlined earlier. Air-gap CTs still have minimal use in the United States. ß 2006 by Taylor & Francis Group, LLC. Primary N CT z B P S zB Auxiliary CT FIGURE 5.17 Auxiliary current transformers applied to change overall current transformer ratio. 5.13 AUXILIARY CURRENT TRANSFORMERS IN CT SECONDARY CIRCUITS Auxiliary CTs are sometimes required to provide (1) different ratios than would otherwise be available, (2) phase shift in the current, or (3) circuit isolation. They should be used to step down the current to the burden whenever possible and to minimize the impedance loading on the main CT. This 0 is illustrated in Figure 5.17. ZB is the impedance at the secondary of the main CT, which is the reflected impedance ZB, or load connected to the auxiliary CT secondary. Neglecting the loss of the auxiliary CT yields ZB0 ¼ ZB , N2 (5:6) where N is the ratio of the auxiliary CT. Thus, for a step-down connection 0 with the ratio P:S of 10:5, N ¼ 2 and ZB ¼ 0.25 ZB. However, with a step-up 0 connection, where the ratio P:S is 5:10, ZB ¼ 4.0 ZB. With high lead resistance, an auxiliary step-down CT near the main CT can be used to reduce this lead resistance load. The auxiliary CT does add its losses to the total load on the main CT. 5.14 VOLTAGE TRANSFORMERS FOR PROTECTIVE APPLICATIONS VTs would have primaries that are either connected directly to the power system (VTs) or across a section of a capacitor string connected between phase and ground (CCVTs). Typical units are illustrated in Figure 5.3 through Figure 5.5, with connection schematics shown in Figure 5.18. ß 2006 by Taylor & Francis Group, LLC. (a) (b) Primary (c) a b c Coupling capacitor a b c Secondary 3V0 a b c Phase L Ground FIGURE 5.18 Typical voltage sources for relays: The secondary circuits for the coupling capacitor voltage transformer (CCVT) device are simplified schematics, for concept only. (a) secondary phase-and-ground voltage with three double secondary VTs connected phase-to-ground; (b) secondary phase voltage with two single secondary VTs connected open delta; (c) secondary phase-and-ground voltage with three CCVTs connected phase-to-ground. [Only one phase shown, b and c phases duplicate with secondaries connected as in (a).] Protective relays utilizing voltage are usually connected phase-to-phase, so the transformers are normally rated 120 V line-to-line. Taps may be provided to obtain either 69.3 V or 120 V line-to-neutral. When available, double secondaries provide the means of obtaining zero-sequence voltage for ground relays (see Figure 5.18a). If only a single transformer secondary winding is available, an auxiliary wye ground-broken delta auxiliary VT can be connected to the secondary a, b, and c bus of Figure 5.18a for 3V0, similar to the connections shown. A typical example is shown in Figure 1.10. CCVTs commonly have double secondaries for both phase and 3V0 voltages (see Figure 5.18c). Three VTs or three CCVTs, such as shown in Figure 5.18a and c, pass positive-, negative-, and zero-sequence voltage. The open-delta connection of Figure 5.18b will pass both positive- and negative-sequence voltage, but not zero-sequence voltage. VTs are used at all power system voltages and are usually connected to the bus. At about 115 kV, the CCVT type becomes applicable and generally more economical than VTs at the higher voltages. Usually, the CCVTs are connected to the line, rather than to the bus, because the coupling capacitor device may also be used as a means of coupling radio frequencies to the line for use in pilot relaying. This is discussed in Chapter 13. Either type of transformer provides excellent reproduction of primary voltage, both transient and steady-state, for protection functions. Saturation is not a problem because power systems should not be operated above normal voltage, and faults result in a collapse or reduction in voltage. Both have ample capacity ß 2006 by Taylor & Francis Group, LLC. and are highly reliable devices. VTs are normally installed with primary fuses that are not necessary with CCVTs. Fuses are also used in the secondary. A common practice is to use separate secondary fusing for voltage supply to different groups of relays used in the total protection. Fuses are a hazard. A loss of potential by a fuse may result in unwanted, incorrect relay operations. In some cases, overcurrent fault detectors are used to minimize this possibility. Some CCVTs may exhibit a subsidence transient when the system voltage is suddenly reduced, such that the secondary voltage is not a replica of the primary, momentarily. This is caused by the trapped energy ringing in the secondary compensating or turning reaction (L) and the associated circuit. This transient can be at a different frequency from that of the system frequency, or unidirectional. This has not been a problem for electromechanical relays, but it may cause problems for solid-state types. Modern-design CCVTs are available to eliminate this problem. 5.15 OPTICAL SENSORS As previously illustrated, classical magnetic CTs are subject to various problems for certain conditions. These problems require special attention when such CTs are applied and sometime require that lesser than the desired performance be accepted. As noted earlier in this chapter, an alternative that has been receiving increased attention in recent years is the use of optical CTs. Such devices eliminate most of the serious problems that are associated with iron-core magnetic CTs. Optical CTs offer increased accuracy, reduced size, and wider bandwidth. Optical CTs are also safer to work with than conventional CTs. When the secondary circuit of a conventional CT is opened while the primary current is flowing, very high voltages can be developed at the location of the opening. These voltages can be damaging to the equipment and a safety hazard to the personnel working in the area. Panel boards have been completely destroyed when CT secondary circuits had been inadvertedly opened. Test personnel must take special precaution when working on CT secondary circuits which can be time consuming or dangerous if an error occurs. This is not a problem when dealing with optical CTs. Reasons do exist, however, for the slow utilization rate of optical CTs that has been experienced in the industry till recent. For one, such application requires users to become familiar with a new technology. Utilities are typically hesitant to convert to new technologies due to the learning curve involved, requirements for new test equipment and methods, and risks associated with trying something new. Additionally, relays and metering must be capable of accepting the digital or low-level analog signals that are provided by optical CTs. This has generally limited the use of such CTs to new installations or in cases where conditions exist that cause severe application problems for conventional type CTs. ß 2006 by Taylor & Francis Group, LLC. The term ‘‘optical sensing’’ can sometimes be confusing, in that it is sometimes used to describe systems that use conventional iron-core sensing devices, with its output converted to an optical signal for transmission to the protection, control, and metering devices. True optical sensors do not use ironcore devices, but use optical materials and fundamentally different techniques to measure current. True optical sensors can be classified as bulk optics or pure fiber optics. Bulk sensors use a block of glass machined to direct light around the conductor. Such sensors are limited in ability to adapt to various sizes and shapes. Pure fiber sensors are constructed by wrapping fiber around the conductor. Various physical sizes and shapes are possible with a pure fiber design. Optical current sensors can be further classified as polarimetric and interferometric sensors. These terms identify the method used to manipulate light waves to enable a measurement of current flow in the conductor. An analysis of these measuring techniques is beyond the scope of this book. A good reference on this subject is a paper entitled ‘‘Current transformer errors and trasformer inrush as measured by magnetic, optical, and other unconventional CTs’’ by John Horak and James Hrabliuk. This reference also provides insights into requirements for interfacing optical sensors with protective relays. It is obvious that optical sensors provide significant operational advantages over conventional CTs and will probably receive greater utilization as protective systems are converted to digital devices, fault current levels continue to increase on power systems, costs are reduced, and engineers become more familiar and confident with the technology. Besides, the advantages associated with accuracy and freedom from saturation, the fundamental characteristics of such measuring systems can be changed by simple program changes in the associated software. Moreover, availability of the measured quantities in digital form can serve to simplify tasks related to design, testing, and diagnostics. Optically based measuring devices have the potential to revolutionize the manner in which measurements are made in power systems.

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6 Protection Fundamentals and Basic Design Principles 6.1 INTRODUCTION The best protection technique now and for more than 50 years is that known as differential protection. Here the electrical quantities entering and leaving the protected zone or area are compared by current transformers (CTs). If the net between all the various circuits is zero, it is assumed that no fault or intolerable problem exists. However, if the net is not zero, an internal problem exists and the difference current can operate the associated relays. In general, internal faults provide significant operating current, even for fairly light faults. Differential protection is universally applicable to all parts of the power system: generators, motors, buses, transformers, lines, capacitors, reactors, and sometimes a combination of these. Since the protection of each part of the power system is discussed, invariably, differential protection is the first consideration, and often it is the choice for the primary protection. 6.2 DIFFERENTIAL PRINCIPLE This fundamental technique is illustrated in Figure 6.1, and for simplicity, only two circuits in the protection zone are shown. Multiple circuits may exist, but the principle is the same. The sum of the currents flowing in essentially equals the sum of the currents flowing out during normal operation. The voltage differential system is similar and is discussed in Chapter 10. For normal operation and all external faults (the though condition), the secondary current in Figure 6.1a in the protective relay is the difference in the exciting currents of the differentially connected current transformers. Per-unit current distribution is also shown in the figure. For example, Ip is the primary current in the lines entering or leaving the protected area. IpIe is the secondary ampere current and is equal to the primary current divided by the current transformer ratio minus the secondary exciting current. Even with exactly the same ratio and type of current transformer, the relay current IOP ß 2006 by Taylor & Francis Group, LLC. IP Relay IOP = Ie Ie IP Ie = IR (a) IF1 IF1 2 Ie = IR IP Ie = IR IF2 Protected equipment or zone Relay (b) IP Protected equipment or zone IOP IF2 Ie = IR FIGURE 6.1 Basic current differential scheme illustrated for the protection of a zone with two circuits: (a) normal conditions, IOP ¼ Ie00 þ Ie0; (b) internal fault IOP ¼ IF1 þ IF2 (Ie0 þ Ie00). will be small, but never zero. This is because of the losses within the protected area and small differences between the same CTs. This assumes that no current transformer significantly saturates for the maximum symmetrical ac through currents. With different CTs and ratios, larger differences will exist that must be minimized or the pickup of the relay must be set so that it does not operate on any through condition. During external faults the transient performance of the several CTs resulting from the sudden increase in current and the associated offset (DC component) can produce rather large transient-operating currents. Thus, it is difficult and impractical to apply an instantaneous relay. Time-delay relays can be used with care. For internal faults, Figure 6.1b shows that the differential relay operating current is essentially the sum of the input currents feeding the fault. This is the ß 2006 by Taylor & Francis Group, LLC. IOP OP OP IR R R R IOP R or Zero IR (a) (b) FIGURE 6.2 Percentage differential relay: (a) external faults; (b) internal faults. total fault current on a secondary ampere basis. Except for very light internal faults, good discrimination is available to detect problems (faults) within the differential zone. For the differential relay to operate, it is not necessary for all the circuits to supply fault current if no current is supplied to the fault. To provide high sensitivity to light internal faults with high security (high restraint) for external faults, most differential relays are of the percentage differential type. Figure 6.2 is a simplified schematic of this type of relay for two circuits, as shown in Figure 6.1. The secondary of the CTs are connected to restraint windings R and currents in these inhibit operation. Associated with these restraint windings is the operating winding OP. Current in this winding tends to operate the relay. Differential relays may be either fixed or variable that tends to operate the relay. These may be of either fixed or variable percentage, and typical characteristics are illustrated in Figure 6.3. The abscissa is the restraint current. This can be either the smaller current (I0OR) or the larger current (IOR) depending on the design. The ordinate is the current (IOP) required to operate the relay. Fixed percentage relays exist between 10% and 50% and may or may not have taps to change the percentage. Thus with a 50% characteristic, an external or through current of 10 A would require a difference or operating current of 5 A or more for the relay to Variable restraint (%) 50 Operate current (IOP) 40 25 10 Restraint current (IR) FIGURE 6.3 Typical through current characteristics of various differential-type relays. ß 2006 by Taylor & Francis Group, LLC. operate. With a 10% type, and 10 A through current, I A or more difference current would produce relay operation. The variable percentage types do not have percentage taps. At low through currents the percentage is low because at these levels the current transformer performance is usually quite reliable. At high through-fault currents, where the CT performance may not be as dependable, a highpercentage characteristic is provided. This gives increased sensitivity with higher security. It is important to recognize that characteristics, such as those shown in Figure 6.3, apply only to external faults or through current flow. Differential relays are quite sensitive to internal faults when the currents in the restraint windings are in opposite directions or one of the restraint current is zero, as in Figure 6.2. These relays are calibrated with current through one restraint and the operating windings with no current through the other restraint(s). Typical pickup currents for differential relays are of the order of 0.14–3.0 A, depending on the type, tap, and application. As it has been seen, the differential principle compares the outputs of the current transformers in all the circuits in and out of the protected area or zone. For equipments, such as generators, buses, transformers, motors, and so on, the CTs usually are all in the same general area, so that it is not too difficult to interconnect their secondaries with the relays. For lines where the terminals and CTs are separated by considerable distances, it is not practically possible to use differential relays as described earlier. Yet, the differential principle provides the best protection and is still widely used. This is true particularly at the higher voltages. A communication channel, such as a pilot wire (wire or fiber-optic cable), power line carrier (radio frequency), audio tones over wire, or microwave is used for information comparison between the various terminals. These systems are discussed later. 6.3 OVERCURRENT-DISTANCE PROTECTION AND THE BASIC PROTECTION PROBLEM When the differential is not used, overcurrent or distance relays are the major protection possibilities. Because faults produce an increase in the phase or ground, or both, overcurrent protection is widely applied at all voltage levels for the currents in the system. Distance relays operating on the increase in current and decrease in voltage are used principally at the higher-voltage levels. The minimum-operating criteria for overcurrent relays are shown in Figure 6.4. These relays may operate instantaneously; with fixed or inverse time delays (see Figure 6.7). The techniques for applying and setting these relays for the protection of equipment in the power system are discussed in the later chapters. ß 2006 by Taylor & Francis Group, LLC. Minimum fault 2 Increasing current 2x or more Relay pick-up ±1.5 or more Maximum load1 1For phase relays Max. short time load (asymmetrical offset, magnetizing inrush, cold load, unusual operation). For ground relays Max. zero sequence unbalance, phase phase–to–ground (neutral) loads. 2Nominally I3for phase faults, I = 0.866I 3. or 3I0 for ground faults, FIGURE 6.4 Criteria for selecting overcurrent relay taps. The operation of overcurrent and distance relays at the border of a protection zone is not as precise as for differential protection. Hence, they may either underreach or overreach for faults near this border. Thus, this situation becomes a protection problem. This is illustrated in Figure 6.5. The relays at station G for the protection of the line GH should operate fast for all faults in the area between the two line terminals. This is the N2 Source Bus G N1 Line GH F1 Bus H F2 Line HS Relays N Backup protection zone-relays at H F IN1 IF = IF1 = IF2 IN = IN2 (Zero, Negligible for feeders) Primary protection zone relays at G (and at H) Backup protection zone-relays at G FIGURE 6.5 Protection problem for protective relays at station G for line GH. ß 2006 by Taylor & Francis Group, LLC. primary protection zone for the relays at G and at H. Fault F1 is in this primary zone, but faults F and F2 are external and should be cleared by other protection. However, for the relays at G, the currents are the same, since the distances between these three faults are very small and negligible. Thus, practically, IF ¼ IF1 ¼ IF2. Therefore, the relays at G cannot determine by current (or voltage) magnitude, if the remote fault is at F1, where desirably, they should operate fast, or at F or F2, where they should delay. Hence, the problem is to distinguish the internal fault F1 from the external faults F and F2. There are two possible solutions: (1) time or (2) communication. 6.3.1 TIME SOLUTION The time solution delays the operation of the relays at G for the faults near or at the bus H. This delay is to permit the primary relays for the bus H and the line(s) to the right of H to clear the faults, such as F and F2. Unfortunately, this indicates that the internal faults on line GH near the bus H, such as F1, will be delayed. Setting the relays, phase or ground, for this time solution is called coordination or selectivity. Basically, this technique attempts to set the primary relays to provide fast operation for close-in faults (N1), yet to delay, for coordination with the relays at H, for faults at or near the bus H. This is accomplished with inversed time–overcurrent relays, in which the operating time increases as the current magnitude decreases, or with instantaneous relays and constant (fixed) time delays. Coordination is discussed in more depth later, particularly when we discuss line protection in Chapter 12. 6.3.2 COMMUNICATION SOLUTION The second, a communication solution is a type of differential protection, as outlined earlier. The relays at H for the protection of line GH indicated by the direction of the power flow or the relative phase angle information whether the fault is internal (F1) or external (F and F2). This information is communicated by a channel to the relays at G. Similarly, the relays at G provide information that is communicated to H. If the fault is in the primary zone (faults N1 to F1), both G and H operate together at high speed. For the external faults (on the bus at G or H, to the left of G, and to the right of H), the relays at both G and H do not operate. This is an elementary introduction to pilot relaying, which is discussed in detail in the subsequent chapters. 6.4 BACKUP PROTECTION: REMOTE VS. LOCAL The importance of backup and redundancy in system protection has been indicated in Chapter 1 and is discussed again in Chapter 8 through Chapter 13. ß 2006 by Taylor & Francis Group, LLC. Backup is defined as ‘‘protection that operates independently of specified components in the primary protective system.’’ It may duplicate the primary protection, or may be intended to operate only if the primary protection fails or is temporarily out of service (IEEE 100). The various types can be illustrated with reference to the protection at station G for the line GH of Figure 6.5. Relays applied at G, as shown, primarily provide primary protection to the line GH. For faults in the line, generally more than one of the several primary relays may operate. This provides primary backup through redundancy. For very important circuits or equipment, especially at HV and EHV levels, completely separate protection, operating from different CTs (and sometimes different VTs), separate DC supplies and operating different trip circuits on the breakers are commonly used. One protective system is designated as the primary one, and the other as secondary—more or less of a misnomer, for usually they operate together at high speed. In the simple two-line system of Figure 6.5, it was seen that the relays at G must be set to operate for the external faults F, F2 and others out on line HS to provide protection to fault F1. Thus, relays G provide primary protection to line GH, and backup protection for bus H and line HS. This is a remote backup. If the F, F2, and other faults are cleared by their primary relays and associated circuit breaker(s), relays at G should operate and remove the G source from the fault. Similarly, all other sources supplying current to the uncleared fault should be cleared by the backup operation of the relays at their remote terminals. In recent years, it has been desirable to have a backup protection at the local station and to open all the breakers around the bus, rather than at the remote terminals. This is the local backup, also associated with breaker failure. In this type of application, the breaker at H on line GH, rather than the breaker at G would be relayed to clear faults F2 and so on, if the primary relays or the H breaker on line HS fail to operate. For local backup there should be a separate, independent set of relays, which always exists for remote backup. This is available with the independent primary and secondary relay systems, as indicated earlier, which is applied principally at high voltages. This independence may not exist in low-voltage protection systems. If this independence is not provided, there is the possibility that a failure in the protection will prevent the opening of the local breakers to clear the fault. Clearing the fault under these circumstances could be achieved only by remote backup. 6.5 BASIC DESIGN PRINCIPLES The design techniques used to provide relays for the protection of electric power systems have progressed from electromechanical to solid state in a relatively short period. Several steps involved in this progress are as follows: ß 2006 by Taylor & Francis Group, LLC. 1. Electromechanical: all analog measurements, comparisons, tripping, and so forth 2. Solid state: analog or operational amplifiers, solid-state operate element, thyristor, or contact output 3. Hybrid: analog, with microprocessor logic, timing, and such, contact output 4. Numerical: analog=digital and microprocessor, contact output. All types are in service, but currently the microprocessor designs are widely offered. Many electromechanical relays are still providing good protection around the world. The basic protection characteristics are essentially the same for both electromechanical and solid-state relays. Thus, a review of these for the electromechanical relays provides a base for the modern units. Most of the basic characteristics were established around 60 years ago. 6.5.1 TIME–OVERCURRENT RELAYS The time–overcurrent type relay, one of the first protective relays, developed around 60–70 years ago, is still widely used in many applications throughout the power system. Originally, it was basically a watt-hour meter with contacts and restricted disk travel. Now, as it has been for many years, the design is entirely different, except that it uses the fundamental induction disk principle. One typical type is illustrated in Figure 6.6. Alternating current or voltage applied to the main coil produces magnetic flux, most of which passes through the air gap and disk to the magnetic keeper. This returns through the disk to the two side legs of the electromagnet. The shorted turns of the lag coil on one side leg cause a time and phase shift in the flux through that side of the disk to produce rotation of the disk. This rotation is damped by a permanent magnet. The spiral spring provides reset of the contacts after the operating quantity is removed or reduced below the pickup value. Contacts attached to the disk shaft can normally be open or closed in the de-energized state. This combination produces fast operation at high current and slow operation at light current; hence, an inverse time characteristic. Over the years various shapes of time curves have evolved, which are shown in Figure 6.7 for general comparison. Solid-state versions of these relays are available that essentially duplicate these curves and general characteristics, with lower burdens, wider application ranges, and adjustable time characteristics. All relays have several taps, each of which represents the minimum current (or voltage) at which the unit will start to operate. This is the minimum pickup value. Thus, a current relay set on tap 2 will begin to operate at 2.0 A, plus or minus the manufacturer’s tolerances. At this current, the time will be very long and difficult to check unless the current is maintained at an extremely accurate value. Any small or transient deviation at this ß 2006 by Taylor & Francis Group, LLC. Electromagnet and keeper assembly Fixed contact Spiral spring Disc Permanent damping magnet Movable contact Fixed contact or stop (a) Adjusting magnet plugs Lag coil Main coil input Electromagnet Disc Keeper (b) FIGURE 6.6 Typical induction disk inverse-type–overcurrent or voltage relay: (a) top view; (b) side view. level will result in a significant time change. Hence, manufacturers generally do not show their time curves below 1.5–2 times minimum pickup. Practically, this is not a usable part of the curve for protection. The abscissa of the characteristic curves is shown in multiples of tap or pickup current. This is for the convenience of providing one scale for all taps. For example, with tap 5, a multiple of 5 on the curve represents 25 A, with tap 2, the multiple represents 10 A, and so on. In addition to the taps, the spacing for the contact travel is adjustable and marked by a scale, known originally as a ‘‘time lever’’ and currently as a ‘‘time dial.’’ This provides different operating times at the same operating ß 2006 by Taylor & Francis Group, LLC. 1.0 Extremely inverse time Time in seconds 0.8 0.6 Very inverse time 0.4 Inverse times 0.2 Definite minimum time 0 0 5 10 15 Multiples of tap (pick-up current) 20 FIGURE 6.7 Typical inverse-time–overcurrent relay characteristics. For general comparison, the curves are fixed at 0.2 sec at 20 times minimum pickup current. current level, a family of curves not illustrated in Figure 6.7. Thus, for each relay type, typical time–current characteristic curves are available, usually with curves from half through 11 time-dial settings. These are available on semilog or on log–log fuse-type coordinate paper. These relays have over-travel and reset times, which can be important for some applications. Overtravel in the electromechanical units is the travel of the contacts after the current drops below the pickup value. Typical values are of the order of 0.03–0.06 sec, generally negligible in most applications. Reset time can be important in coordination with fast-reclosing or fast-repetitive faults. It is a function of the time-dial setting and the design. Data on reset are available from the manufacturers. The values are generally negligible for solid-state types. Fast reset may not be advantageous when coordinating with fuses and relays that do not have fast-reset characteristics. In a protective relay, the opening of the circuit breaker generally reduces the current through the relay to zero. This may not be true when a relay is used as a fault detector and set to operate for faults well beyond the primary protection zone. Most induction disk time–overcurrent relays will not start to reset until the current drops below about 60% of the pickup current. The relays described earlier are nondirectional; that is, they can operate independent of the direction of the current. If this is not desired, a separate directional element, such as that discussed in Chapter 3, is used. The induction disk unit provides rotational torque by lag loops on the electromagnet to provide a flux shift. ‘‘Torque control’’ varieties have this lag circuit ß 2006 by Taylor & Francis Group, LLC. Stationary contacts Input coil Moving contact (s) Armature Core Magnetic frame Hinge M B Contact schematic FIGURE 6.8 Typical electromechanical clapper or telephone relay. available for external use, or the directional unit contacts or output are internally connected in this circuit. As long as the lag coil or its equivalent is open, no amount of current can cause operation. When the directional unit closes the circuit to the lag coil or equivalent, operation is as in the characteristic curves. This is directional torque control. The induction disk unit and its solid-state equivalent are used for overcurrent, overvoltage, undervoltage, combined over- and undervoltage, and power, as well as in other types of designs. 6.5.2 INSTANTANEOUS CURRENT–VOLTAGE RELAYS Such relays are used in many areas of protection, such as overcurrent or overor undervoltage units, to trip directly, or as fault detectors for security. Typical types in general use are the clapper or telephone relay (Figure 6.8), solenoid or plunger relay (Figure 6.9), and induction cup or induction cylinder relay (Figure 6.10). The term ‘‘telephone’’ relay dates from its very wide application in telephone exchange systems. Now, this use has been superseded by modern solidstate electronic switching. However, relays of this type are still used in many auxiliary applications, both in ac and in DC. It is a common output relay for many solid-state protective relays. An example of the solenoid type as a DC type is its use as a seal-in contact switch (CS) in Figure 1.9. With an ac coil and constructions, the solenoid unit ß 2006 by Taylor & Francis Group, LLC. Adjusting core screw Magnetic frame Input coil Moving plunger Fixed contacts Contact schematic Movable contacts FIGURE 6.9 Typical electromechanical plunger relay. serves as an instantaneous trip unit (IT and IIT). The operation of the first two is basic; current or voltage applied to the coil produces flux, which attracts the armature or plunger. Contacts on the moving member are thus operated. Multiple contacts are possible, especially on the telephone types. Coils 2 Coils 1 Contacts Moving cup or cylinder Magnetic core Top view Electromagnet FIGURE 6.10 Typical electromechanical induction cup or cylinder relay. ß 2006 by Taylor & Francis Group, LLC. The ac types have taps or other means to change the pickup value. For trip service, dropout is seldom a problem, and many of these units do not drop out after closing their contacts, after operation, until the current (voltage) drops to the order of 60% of the pickup value. Where this is a problem, high-dropout models of Figure 6.9 type are available. These will reset at 90% of the pickup value or higher. In general, fault detectors should be of the high-dropout type. The AC induction cup or induction cylinder unit of Figure 6.10 is basically a ‘‘two-phase motor,’’ with the two coils wound as shown on the four poles of the electromagnet. In the center is a magnetic core; around or over this is the moving cup or cylinder, with the moving contacts and spring to provide reset. When the fluxes of coils one and two are in phase, no rotational torque exists. As an instantaneous overcurrent unit, a phase shift is designed in one coil circuit, such that an operating torque is produced when the current is higher than the pickup value. The rotation is limited to a few millimeters, enough to close the contacts. Typical times of operation are about 16–20 msec. 6.5.3 DIRECTIONAL-SENSING POWER RELAYS The induction cup and induction cylinder units are used to indicate the direction of power flow and magnitude. This first application for directional sensing was discussed in Chapter 3. Typical characteristics are shown in Figure 3.7. The operating current is passed through one set of windings and a reference voltage or current through the other. When the phase relations are as indicated, the unit operates. Because these units, as directional units, are very sensitive, they are used in almost all applications with fault-sensing units, such as the time–overcurrent or instantaneous overcurrent units discussed earlier. Other types have tapped windings to operate when the power level exceeds a preset value. 6.5.4 POLAR UNIT The polar unit is a DC unit operating from ac quantities through a full waverectifier. It provides very sensitive, high-speed operation, with very low-level inputs. As shown in Figure 6.11, an electric coil is wound around a hinged armature with contacts in the center of a magnetic structure with nonmagnetic spacers at the rear. A permanent magnet bridges this structure to polarize the two halves. Two adjustable magnetic shunts bridge the spacers to vary the magnetic flux paths. With the coil deenergized and balanced air gaps (see Figure 6.11a), the armature is not polarized, and contacts will float in the center. Now, adjusting the gaps to provide unbalance, some of the flux is shunted through the armature (see Figure 6.11b). Thus the contacts can be held either opened or closed. Energizing the coil with DC magnetizes the armature either north or south, thereby increasing or decreasing any prior armature polarization. In ß 2006 by Taylor & Francis Group, LLC. Magnetic spaces Shunt N S N Shunt Shunt S o Coils Permanent magnet Coils N S Armature N Moving contact (a) S o (b) N Additional flux path FIGURE 6.11 The DC polar unit: (a) balanced air gaps coil deenergized; (b) unbalanced air gaps coil deenergized. Figure 6.11b the armature is shown as polarized N before energization so the armature moves to the right and the contacts open. Direct current in the coil, to overcome prior polarization and to make the contact end at the south pole, results in contact movement to the left and contact closure. The contact action can be gradual or quick, depending on the adjustments. The left gap controls the pickup value, and the right gap the reset value. Two coils, an operating coil and a restraint coil, are used in some applications. An example is the electromechanical pilot wire relay (see Figure 13.4). 6.5.5 PHASE DISTANCE RELAYS Fundamentally, distance relays compare the power system voltage and current. They operate when the ratio is less than its preset value. For balanced conditions and for phase faults, the ratio of the voltage to current applied to the relay is the impedance of the circuit, because V=I ¼ Z. Thus, these relays are set as a function of the fixed impedance of the power system for the zone they are to protect. 6.5.5.1 Balanced Beam Type: Impedance Characteristic An earlier design (no longer manufactured) provides a good basic understanding of the principle and appreciation of common terms that are currently used. This early type is illustrated in Figure 6.12. A balanced beam has a voltageenergized electromagnet to restrain its movement and a current-operated electromagnet to close its contacts. By design and setting, the voltagerestraint force can be made to equal the current-operating force for a solid zero-voltage three-phase fault at the set point shown as nZL. This threshold point is known as the ‘‘balance point,’’ ‘‘operating threshold,’’ or ‘‘decision point’’ of the unit. For a fault between the relay and the point n, the current I ß 2006 by Taylor & Francis Group, LLC. Bus G Bus H Circuit breakers (52) I Line CT's ZL 52 52 n V T's 21 Distance relays V (a) Contacts Pivot I V (b) FIGURE 6.12 Distance relay-operating principles explained fundamentally by the balanced beam impedance unit: (a) distance relay to line GH; (b) simplified explanation diagram with a beam unit. will be larger and V will decrease or remain approximately the same, relative to the value for the fault at n. Thus, the increased current causes the beam to tip at the left end to close the contacts. For an external fault to the right of point n, the current will be less than for the fault at n, and the voltage will be higher. Thus, the torque or pull of the voltage coil is greater than that of the current coil for restraint or no operation. With the solid three-phase fault at the balance point n, the voltage at n will be zero. Then the voltage at the relay location will be the drop along the circuit, or InZL. Dividing this voltage by the current, the unit responds to impedance: ZR ¼ V InZL ¼ ¼ nZL : I I (6:1) Thus, the setting and operation are a function of the impedance from the relay voltage measurement point to the balance or set point. Lewis and Tippett (1932), in their classic paper, showed that by using line-to-line voltages and line-to-line currents the reach of phase-type relays is the same for three-phase, phase-to-phase, and two-phase-to-ground faults. Because the current values get cancelled in Equation 6.1, this reach is fixed ß 2006 by Taylor & Francis Group, LLC. for a given setting over a very wide range of fault currents, thereby providing a fixed reach, instantaneous protective relays not possible with an overcurrent instantaneous relay. 6.5.6 R–X DIAGRAM The characteristics of distance relays are shown most conveniently in an impedance R–X diagram, where the resistance R is the abscissa and the reactance X is the ordinate. Typical characteristics on these axes are shown in Figure 6.13. For any given discussion the origin is the relay location, with the operating area generally in the first quadrant. Whenever the ratio of the system voltage and current fall within the circle shown, or in the crosshatched area, the unit operates. The elementary type discussed in Figure 6.12 provided an impedance characteristic such as that shown in Figure 6.13a. This obsolete design was independent of the phase relation of the voltage and current, thereby operating in all the four quadrants. Thus, a separate directional-sensing unit was necessary to prevent operation for faults in the system to the left of bus G (see Figure 6.13a). 6.5.7 MHO CHARACTERISTIC The circle through the origin (see Figure 6.13b) is known as an mho unit and is in wide use for line protection. It is directional and more sensitive to fault X Line to H X Line to H ZR X Line to H Z Load φR ZX G R Dir. unit (Optional) (a) R G (b) (c) X X Line to H G X Line to H Line to H R (d) R O G (e) R G R (f) FIGURE 6.13 Distance relay characteristics on the R–X diagram: (a) impedance; (b) mho; (c) offset mhos; (d) lens; (e) simple blinders; (f) reactance. ß 2006 by Taylor & Francis Group, LLC. currents lagging at about 608–858 than to loads that are near a 08–308 lagging current. Load impedance is given by Equation 6.2. Zload ¼ VLN : Iload (6:2) A high current is a low impedance. Thus, for heavy loads the impedance phasor moves toward the origin; for light loads, it moves away from the origin. In other words, distance relays of Figure 6.13b through Figure 6.13e can operate on a fault current less than the load current. Lagging load from G to H (see Figure 6.12a) is a phasor in the first quadrant as shown in Figure 6.13b. Lagging load from H to G is a phasor in the second quadrant (R þ X) on the R–X diagrams of Figure 6.13. A load of 5 A secondary and 120 V line to neutral appears to the relays as 120 Zload ¼ pffiffiffi ¼ 13:86 V secondary: 3(5) (6:3) The equation for the mho circle through the origin is Z¼ ZR ZR : 2 2fff (6:4) The ZR=2 is the offset from the origin, ZR fff is the radius from the offset point. When the offset is along the X axis and f is 08, relative to the R axis, Z ¼ 0. When f is 1808, Z ¼ ZR. When the mho circle is tilted, as in Figure 6.13b, f is the angle of fR of the offset. Various operating points on the mho circle characteristic are determined by Equation 6.5; ZX ¼ ZR cos (fR fX), (6:5) where ZX is the impedance from the origin to any point on the circle at angle fX, and ZR is the relay reach at fR. For example, determine the reach of an mho unit along a 758 angle line if the maximum load into the line in 5 A secondary at 308 lagging. From Equation 6.3, the load impedance is 13.86 V secondary. This is ZX in Equation 6.5 with fX ¼ 308. A typical angle for an mho unit is 758. Thus, 13.86 ¼ ZR cos(758308), and solving yields ZR ¼ 19:60 V secondary: This can be translated into primary line ohms with the basic formula ß 2006 by Taylor & Francis Group, LLC. (6:6) ZR(sec) ¼ ZR(Pri) Rc , Rv (6:7) where Rc and Rv are the CT and VT ratios (see Chapter 5). The line reach on a 115 kV line with 600:5 CTs would be ZR(Pri) ¼ ZR(sec) Rv 19:6(1000) ¼ 163:3 V primary: ¼ 120 Rc (6:8) On the basis of the typical 0.8 V=mi, the 163.3 V reach is about 204 m, a very long line at this voltage. Interestingly, one type of distance relay has a maximum specified reach at 20 secondary ohms, derived from Equation 6.5. The MVA represented by the 5 A load is MVA ¼ pffiffiffiffi pffiffiffiffi 3kV I 3(115)(5)(120) ¼ ¼ 119:5 MVA: 1000 1000 (6:9) The primary protection of a line such as GH in Figure 6.12 requires two distance units. This is shown in Figure 6.14 for station G, using two mho units. Zone 1 unit operates instantaneously and is commonly set for nZGH where n is less than 1, commonly 0.9. Zone 2 unit is set with n greater than 1 or about +1.5, depending on the system to the right of station H. A timecoordinating delay is required for zone 2 because it overreaches bus H. X H Line G Zone 2 distance protection Zone 1 distance protection R FIGURE 6.14 Distance mho units applied at G for the primary protection of line GH of Figure 6.12. ß 2006 by Taylor & Francis Group, LLC. A third zone, zone 3, is used in the hope of providing remote backup protection for the line(s) to the right on station H. This is often difficult, as explained in Chapter 12. Sometimes zone 3 at G is set to look backward from, or to the left of, station G. This can be used for backup or as a carrier-start unit in pilot relaying, as covered in Chapter 13. In these applications, the zone 3 mho-type unit, with offset to include the origin, should be used. This characteristic is the lower mho unit in Figure 6.13c. This assures operation for close-in faults, for which the voltages are very low or zero. The mho relays can be either single-phase or polyphase types. 6.5.8 SINGLE-PHASE MHO UNITS For the single-phase types, three mho units (circles through the origin as in Figure 6.13b) are required for a protective zone. All three units operate for three-phase faults, but for phase-to-phase and double phase-to-ground faults, only one unit operates. Thus, The A unit energized by Iab and Vab operates for ab–gnd faults. The B unit energized by Ibc and Vbc operates for bc–gnd faults. The C unit energized by Ica and Vca operates for ca–gnd faults. The B and C units will not operate for the ab faults, the A and C units will not operate for the bc faults, and the A and B units will not operate for the ca faults. This can be seen for the bc faults from Figure 4.29d and Figure 4.29e. The fault current Ibc is large and the fault voltage Vbc is small to provide a low impedance for operation. However, for the bc faults Iab and Ica are small, whereas Vab and Vca are large for a large apparent impedance. These impedances will be outside the operating circles for the A and C units. Similar conditions apply for the ab and ca faults. The single-phase mho unit is shown in Figure 6.15. An air-gap transformer, known as a transactor or compensator, provides a secondary voltage Iab Zc for the A unit, leading the primary current to less than 908. The diameter Iab Inputs from CT's and VT's Va Vb Air-gap transformer Iab Zc ⩾ Vab Outputs to electromechanical cup unit or solid-state Vab comparator FIGURE 6.15 Single-phase MHO unit (shown for the A unit). ß 2006 by Taylor & Francis Group, LLC. of the mho circle is determined by the mutual reactance of the transactor modified by the resistor. The combined output voltage is Iab ZcVab. This voltage with a polarizing voltage Vab is compared to provide the mho circle through the origin as in Figure 6.13b and Equation 6.4. For example, for electromechanical relays the induction cup unit in Figure 6.10 is used where the A unit, Iab Zc (see Figure 6.15) is on the left horizontal pole (operating coil), Vab on the right horizontal pole (restraining coil), and Vab across the two vertical poles (polarizing coils). For solid-state relays the two voltages are compared with a static-type phase-angle comparator (or the equivalent) digitized in microprocessor relays. The units may be packaged separately or in various combinations, depending on the manufacturer and application. 6.5.9 POLYPHASE MHO UNITS The polyphase type has two units for a zone protection as shown in Figure 6.13b: (1) a mho circle through the origin, operating for three-phase faults; and (2) a phase-to-phase unit, with a large operating circle partly shown as an arc. This unit operates neither on balanced conditions (load, swings, and such) nor for faults behind the relay (third and fourth quadrants). Where distance relays are set to operate through wye–delta transformers the reach of the single-phase units for phase-to-phase faults is complex because a phase-to-phase fault on one side of the bank appears more or less like a phase-to-ground fault on the other side. This is shown in Figure 9.20. Polyphase relays can be set through a wye–delta bank to operate for faults on the other side, using a setting that includes the X value of the transformer. 6.5.9.1 Three-Phase Fault Units The polyphase three-phase unit is shown in Figure 6.16. Only one compensator is necessary to receive the phase a current. Thus, the output voltages are Vx ¼ Van 1:5(Ia 3I0)Zc , (6:10) Vy ¼ Vbn , (6:11) Vz ¼ Vcn : (6:12) The cylinder unit (see Figure 6.10) is like a two-phase motor operating when negative sequence xzy is applied and restrains on positive sequence xyz or operates when Vzy lags Vxy and restrains when Vzy leads Vxy. A fault at the balance point (Zc) results in xyz in line as shown, a no-area–triangle and no operation. This is the decision point. ß 2006 by Taylor & Francis Group, LLC. Electromechanical cylinder unit or solid state comparator Vx Compensator Zc Ia − 3I0 = −Ib −Ic Van Memory Ckt. Vy Vz Vcn Vbn Vy (a) Van Van Fault beyond balance point Vx = Van−Smaller IaZc Ia Vcn Vbn Vx = Van – 1.5Ia Zc Fault at (Zc) balance point Vbn = Vy Vcn = Vz Vx = Van −Larger IaZc Fault inside balance point Three-phase faults Vx , Vy , and Vz (b) FIGURE 6.16 The polyphase distance relay—three-phase unit: (a) three-phase-fault unit; (b) phasors for a three-phase fault (Ia only shown lagging 908). A fault on the line up to the balance point produces an xzy triangle and operation. A fault beyond the balance point produces an xyz triangle and no operation. For a fault behind the relay, the current reverses and a large xyz triangle results, again no operation. The memory circuit momentarily delays the collapse of Vy and Zz for close-in faults that may reduce the phase b and c voltage to very low values, or zero. In the compensator, 3I0 helps the unit to operate on double-phaseto-ground faults when z0 of the system is very low. From Figure 4.15, it can be seen that as z0 approaches zero, the double-phase-to-ground faults begin to look like three-phase faults. When the solid-state comparator is used Vxy ¼ Vab (Ia Ib)Zc and Vzy ¼ jk Vab are compared. 6.5.9.2 Phase-to-Phase Fault Units The polyphase phase-to-phase unit is shown in Figure 6.17 with two compensators. The equations are ß 2006 by Taylor & Francis Group, LLC.

Group, LLC. Electromechanical cylinder unit or solid state comparator Ia−Ib Van Vx Compensator Zc Vy Vz Vbn Compensator Zc Vcn (a) Vz Ic−Ib Ic Ib Zc (Ia = 0) Van Van Vx Vcn Vcn Vbn Vy = Vz (Ib−Ic) Zc Fault at balance point (Zc) Ib Vxy Van Vxy Ib Zc Ib Zc Vx Van Vzy Vx Vzy Vcn Vy Vz Ib−Ic Zc Faults inside trip zone Vcn Vz Vy Ib−Ic Zc Faults outside trip zone (b) FIGURE 6.17 The polyphase distance relay: phase-to-phase unit: (a) the phase-tophase fault unit; (b) phasors for a bc fault (currents shown at 908). ß 2006 by Taylor & Francis Group, LLC. Vx ¼ Van (Ia Ib)Zc , (6:13) Vy ¼ Vbn , (6:14) Vz ¼ Vcn (Ic Ib)Zc : (6:15) With reference to Figure 6.17, phase-to-phase faults at the balance or decision point VxVyVz provide a zero-area triangle for the electromechanical cylinder unit, or Vzy and Vxy in phase for the solid-state comparator, with no operation. Any fault inside the trip-zone–negative sequence xyz, or when Vzy lags Vxy, causes operation. Any fault beyond or outside the trip-zone positive sequence xyz, or if Vzy leads Vxy results in no operation. The phase-to-phase unit is a variable circle fixed at the balance point setting of Zc or ZR in Figure 6.13b. The equation of this circle is Offset Z ¼ 12 (Zc Zs), (6:16) Radius Z ¼ 12 (Zc þ Zs)fff, (6:17) where Zc(ZR) is the set reach and Zs is the source impedance behind the unit. Although the circle extends into the third and fourth quadrants, this has no practical meaning because the fault current reverses for faults behind the unit. This reversal always provides xyz and Vzy leading Vxy, and no operation. Since the unit does not operate on positive sequence quantities (xyz), it will not operate on balanced conditions, such as load and swings. This unit will operate for line-to-ground faults within approximately 30% of the Zc setting. This is not a fixed reach. 6.5.10 OTHER MHO UNITS The mho unit can be offset, as illustrated in Figure 6.13c or changed to other shapes, such as a lens, (see Figure 6.13), tomato, rectangular, and so on. Each has its perceived advantages that are useful in various applications. The characteristics of Figure 6.13, but with the lower circle through the origin, and Figure 6.13d and Figure 6.13e are applicable to long, heavily loaded lines. Figure 6.13d is called a lens unit and Figure 6.13e a singleblinder unit. These provide protection for faults along the line, but do not operate on heavy loads for which the load impedance would otherwise fall within the unit-operating circle. Two reactance units (see next section and Figure 6.13f) with their characteristics shifted, as shown in Figure 6.13e, provide a restricted-operating zone along the protected line. The right unit operates for a large area to the left, the left unit for a large area to the right: outputs in series operation are indicated by the cross-hatched area. This type of characteristic is generally ß 2006 by Taylor & Francis Group, LLC. used for out-of-step detection and tripping, as described in Chapter 14. If used for fault protection mho fault detectors must be used. As indicated in Section 6.5.7, the mho unit of Figure 6.13c that includes the origin provides continued operation beyond any memory action for zero or near-zero-volt faults. An example is a bolted three-phase fault at or near the voltage transformer connection. 6.5.11 REACTANCE UNITS Reactance units can be obtained from the design of Figure 6.15, with the airgap transformer output of X instead of Z. The characteristic is a straight line at the set point (ZR or Zc) parallel to the R axis, as in Figure 6.13f. It is not directional, but will operate for faults behind the relay. Thus, this unit is very ‘‘trigger happy’’ so the operation must be restricted by an mho-type fault detector both for faults behind the relay and for load and swings. The reactance unit appears to have increased fault arc protection because arcs are resistive. This is true only for radial circuits in which fault current is supplied from only one terminal. When fault current is supplied from both the terminals and the line is carrying load, the fault sources are not in phase. This results in the reactance units ‘‘viewing’’ the arc as an enlarged R þ jX value. Thus, at one terminal the unit may not operate on arc faults, for they can appear outside the operating area and may cause reactance unit on the next section to operate incorrectly. This apparent impedance effect is discussed further in Chapter 12. 6.6 GROUND DISTANCE RELAYS In Chapter 4, it was shown that the positive sequence voltage drop during faults is maximum at the source and minimum or zero at the fault. Thus, the ratio of the voltage and current as in Equation 6.1 indicated the distance to the fault. Unfortunately, for ground faults, the zero-sequence voltage drop is maximum at the fault and minimum or zero at the neutral or wye-ground– delta power transformers. Thus, the ratio of the voltage and current ZR0 ¼ 3I0 (nZ0) ¼ nZ0 3I0 (6:18) indicates distance behind the relay to the ground source, hence they cannot be used for ground distance relaying. Several methods have been used to resolve this; (1) voltage compensation or (2) current compensation. Consider a phase-a-to-ground fault on a line with Z1L and Z0L as the positive and zero sequence line impedances and n the location of the fault from the relay. The fault currents through the relay are I1, I2, and I0. Then for a fault at nZ1L with a single-phase unit. ß 2006 by Taylor & Francis Group, LLC. Vag nZ0L I0 ¼ nZ1L (I1 þ I2) þ : Ia I1 þ I2 þ I0 (6:19) For (1) voltage compensation, subtract out nZ1L(I1 þ I2) and use I0. Then from Equation 6.19, for the phase a-to-ground unit ZR ¼ Vag nZ1L (I1 þ I2) nZ0L I0 ¼ ¼ nZ0L : I0 I0 (6:20) Additional units required for b-to-ground using Vbg for the c-to-ground faults using Vcg. For (2) current compensation, let nZ0L ¼ pnZ1L where p ¼ Z0L=Z1L. Then from Equation 6.19 ZR ¼ Vag nZ1L (I1 þ I2 þ pI0) ¼ : I1 þ I2 þ I0 Ia (6:21) If the current input is changed to I1 þ I2 þ pI0 ¼ Ia þ (p 1)I0, then ZR ¼ Vag ¼ nZ1L , Ia þ mI0 (6:22) where m ¼ Z0L Z1L=Z1L. Again additional units are required for b-ground and c-ground faults except for the polyphase unit. Considering arc resistance and mutual coupling from an adjacent parallel line, the complete formula for current compensated single-phase ground distance relay is;   Vag 3I0 ZR ¼ ¼ nZ1L þ Rarc , Irelay Irelay (6:23) where Irelay ¼ Ia þ I0 (Z0L þ Z1L) : Z1L þ I0E Z0M =Z1L (6:24) I0E is the zero sequence current in the parallel line and Z0M the mutual coupling impedance between the two lines. Another type operates on the principle that, at the fault V0F þ V1F þ V2F ¼ 0. This relation is reproduced by compensators at the relay location. The modified V0 is used as an operating quantity, and the modified V1 þ V2 as restraint. For single-phase-to-ground faults within the preset reach, V0 operating is greater than the V1 þ V2 restraint to trip. Faults outside the preset zone provide restraint greater than the operating quantity. ß 2006 by Taylor & Francis Group, LLC. 6.7 SOLID-STATE MICROPROCESSOR RELAYS Solid-state units provide greater flexibility, more adjustable characteristics, increased range of settings, high accuracy, reduced size, and lower costs, along with many ancillary functions, such as control logic, event recording, fault location data, remote setting, self-monitoring and checking, and others. In solid-state relays the analog power system quantities from current and voltage transformers or devices are passed through transformers to provide electrical isolation and low-level secondary voltages. The protection function outlined earlier is available using microprocessor technology. The details of accomplishing this seem relatively unimportant to the protection principles; thus, they are beyond the scope of our discussion here. However, typical logic units that may be involved in a microprocessor relay are shown in Figure 6.18. In very general terms, these are (1) input transformers that reduce the power system current and voltage quantities to low voltages and provide first-level filtering; (2) low-pass filter that removes high-frequency noise; Ac current and voltage inputs 1. Input current and/or voltage transformers 2. Low pass filters 3. Sample/hold amplifier 4. Multiplexer 5. Programmable gain amplifier 6. Analog-to-digital comverter Contact inputs Targets 7. Microprocessor RAM ROM Time code input FIGURE 6.18 Typical logic units in a microprocessor relay. ß 2006 by Taylor & Francis Group, LLC. Relay outputs (trip, close, alarm, etc.) jX Top Left side Right side R Directional unit FIGURE 6.19 Quadrilateral distance characteristics. (3) sample-hold amplifier that samples and holds the analog signals at time intervals determined by the sampling clock to preserve the phase information; (4) multiplexer that selects one sample-hold signal at a time for subsequent scaling and conversation to digital; (5) programmable gain amplifier for current signals that have a wise dynamic range (for voltage signals, the gain is 1); (6) Analog-to-digital converter that converts the analog signals to digital; (7) microprocessors with appropriate software that provides the required protection characteristics that are amplified to operate auxiliary units for tripping, closing, alarms, and so on. The capability and flexibility inherent in microprocessor relays have increased the availability and utilization of distance elements with quadrilateral characteristics. Such characteristics are illustrated in Figure 6.19. The quadrilateral characteristic basically involves the combination of four measuring units. These units consist of a reactance unit (top line), two resistive units (left and right sides), and a directional element (bottom line). While such characteristics were available in some electromechanical designs, these designs were very complicated and operating times of the units were often less than desirable. The extensive computational power that exists in modern microprocessor relays greatly facilitates the task of creating a quadrilateral characteristic. From an application standpoint, the operating area of a distance element with a quadrilateral type characteristic is ideal. With this type of characteristic, the tripping area can be arranged closely to enclose the desired tripping area as shown in Figure 6.20. This is especially useful for ground faults that are often restricted and, therefore, the ability to detect significant ß 2006 by Taylor & Francis Group, LLC. jX R (Restriction) Line Imp R FIGURE 6.20 Quadrilateral distance element set to enclose desired area in which fault restriction may exist. resistance associated with the restriction is important. For these reasons, quadrilateral distance elements are often applied in association with ground distance elements. With the ability to closely enclose the desired trip area results in a more secure application. 6.8 SUMMARY This chapter has presented the fundamentals of system protection and very briefly outlined various basic designs in wide use in these systems throughout the United States. The aim is to provide a background for the later chapters on the protection aspects of the various power system components. BIBLIOGRAPHY Lewis, W.A. and Tippett, L.S., Fundamental basis for distance relaying on a three phase system. AIEE Trans., 66, 1947, pp. 694–708. The original was presented, but not published, at an AIEE meeting in 1932. Sonnemann, W.K., A study of directional elements for phase relays. AIEE Trans., 69, II, 1950, pp. 1438–1451. Van, C. and Warrington, A.C., Application of OHM and MHO principle to protective relaying. AIEE Trans., 65, 1946, pp. 378–386, 490. ß 2006 by Taylor & Francis Group, LLC. 7 System-Grounding Principles 7.1 INTRODUCTION Power system grounding is very important, particularly because the large majority of faults involve grounding. Thus, it has a significant effect on the protection of all the components of the power system. The principal purposes of grounding are to minimize potential transient overvoltages to comply with local, state, and national codes for personnel safety requirements; and to assist in the rapid detection and isolation of the trouble or fault areas. A basic review of system grounding is in order, together with its fundamental technology and a general evaluation of the methods. There are four types: (1) ungrounded, (2) high impedance, (3) low imp edance, and (4) effective or solid grounding. Each has its application in practice, together with advantages and disadvantages. The recommendations are based on general practices and some personal preferences. It should be recognized that there are many factors in each specific system or application that can well justify variations or a different approach. Just as relaying is highly influenced by personality, to a degree, so is system grounding. 7.2 UNGROUNDED SYSTEMS Ungrounded systems are power systems with no intentionally applied grounding. However, they are grounded by the natural capacitance of the system to ground. Thus, the fault current level is very low, such that equipment damage is minimal; and it is not necessarily essential that the faulted area be rapidly isolated. This is an advantage; therefore, it is sometimes used in industrial plant systems where a high continuity of service is important to minimize interruptions of expensive production processes. However, ungrounded systems are subject to high and destructive transient overvoltages and, consequently, are always potential hazards to equipment and personnel. Thus, they are generally not recommended, even though they are normally used. Phase-to-ground faults on an ungrounded system essentially shift the normal balanced voltage triangle, as shown in Figure 7.1. The small currents flowing through the series phase impedances will cause a very slight distortion of the voltage triangle, but practically, it is as shown in Figure 7.1b. ß 2006 by Taylor & Francis Group, LLC. (a) Van =Vag (c) Vcn =Vcg (a) Vag = 0 Ground (g) n=g Van = −Vng (b) Vcg Vbn =Vbg (c) (a) (b) Vbg n Vcn Vbn (b) FIGURE 7.1 Voltage shift for a phase-a-to ground fault on an ungrounded system: (a) normal balanced system; (b) phase a solidly grounded. A typical circuit is illustrated in Figure 7.2 showing the current flow. The sequence networks are shown in Figure 7.3. The distributed capacitive reactance values X1C, X2C, and X0C are very large, whereas the series reactance (or impedance) values X1S, XT, X1L, X0L, and so on, are relatively very small. Thus, practically, X1C is shorted out by X1S and XT in the positive-sequence network, and similarly for the negative-sequence network. Because these series impedances are very low, X1 and X2 approach zero, in relation to the large value of X0C. Therefore, I1 ¼ I2 ¼ I0 ¼ VS X0C (7:1) and Ia ¼ 3I0 ¼ 3VS : X0C (7:2) This calculation can be made in per unit (pu) or amperes (A), remembering that VS and all the reactances (impedances) are line-to-neutral quantities. The unfaulted phase b and c currents will be zero when determined from the sequence currents of Equation 7.1. This is correct for the fault itself. However, throughout the system the distributed capacitance X1C and X2C is actually paralleled with the series reactances X1S, XT, and so on, so that in the system I1 and I2 are not quite equal to I0. Thus, Ib and Ic exist and are small, but they are necessary as the return paths for Ia fault current. This is shown in Figure 7.2. If Ia ¼ 1 pu, then Ib ¼ 0.577 ffþ30 and Ic ¼ 0.577 ff30 pu. ß 2006 by Taylor & Francis Group, LLC. a Distributed natural capacitances between phases a Ground fault b c b c Distributed natural capacitances to ground Ib Ic Ia Va Vab Vb Vc Source Ib Vbc Ia Ic Vba Vca Ib leads Vba by 90 Ic leads Vca by 90 I Ia = −Ib−Ic = 3 0 FIGURE 7.2 Phase-to-ground fault on an ungrounded system. In industrial applications where ungrounded systems might be used, the X0C is equal practically to X1C ¼ X2C and is equivalent to the charging capacitance of the transformers, cables, motors, surge-suppression capacitors, local generators, and so on, in the ungrounded circuit area. Various reference ß 2006 by Taylor & Francis Group, LLC. G X1S XIL, XOL Source Vs Ungrounded loads XT X2S N1 + Positive sequence network VS X1C X1S XT Bus G V1F X1L F1 I1 N2 Negative sequence network V2F X2C = X1C X2S XT Bus G X2L = X1L F2 I2 N0 Zero sequence network XT G + V0F X0C X0L + F0 I0 + X1C, X2C, X0C are lumped equivalents of the distributed capacitance between phases to network and to ground. FIGURE 7.3 Sequence networks and interconnections for a phase-a-to-ground fault on an ungrounded system. sources provide tables and curves for typical charging capacitances per phase of the power system components. In an existing system the total capacitance can be determined by dividing the measured phase-charging current into the line-to-neutral voltage. Note that as faults occur in different parts of the ungrounded system, X0C does not change significantly. Because the series impedances are quite small in comparison, the fault currents are the same practically and independent of the fault location. This makes it impractical for selective location of faults on these systems by the protective relays. When a phase-to-ground fault positively occur pffiffiffi s, the unfaulted phase-toground voltages are increased particularly by 3 (see Figure 7.1b). Thus, these systems require line-to-line voltage insulation. In the normal-balanced system (see Figure 7.1a) Van ¼ Vag, Vbn ¼ Vbg, and Vcn ¼ Vcg. When a ground fault occurs, the phase-to-neutral voltages and the phase-to-ground voltages are quite different. The neutral n or N is defined as ‘‘the point that has the same potential as the point of junction of a group (three ß 2006 by Taylor & Francis Group, LLC. for three-phase systems) of equal nonreactive resistances if connected at their free ends to the appropriate main terminals (phases of the power system)’’ (IEEE 100). This is the n shown in Figure 7.1b. From this figure, the voltage drop around the right-hand triangle is Vbg Vbn Vng ¼ 0 (7:3) Vcg Vcn Vng ¼ 0: (7:4) Vng þ Van ¼ 0: (7:5) Vag þ Vbg þ Vcg ¼ 3V0 , (7:6) Van þ Vbn þ Vcn ¼ 0: (7:7) and around the left triangle, In addition, From the basic equations, Subtracting Equation 7.7 from Equation 7.6, substituting Equation 7.3 through Equation 7.5, and with Vag ¼ 0: Vag Van þ Vbg Vbn þ Vcg Vcn ¼ 3V0 , Vng þ Vng þ Vng ¼ 3V0 , Vng ¼ V0 : (7:8) Thus the neutral shift is zero-sequence voltage. In the balanced system of Figure 7.1a, n ¼ g, V0 is zero, and there is no neutral shift. 7.3 TRANSIENT OVERVOLTAGES Restriking arcs after current interruption in the breaker or in the fault can result in large destructive overvoltages in ungrounded systems. This phenomenon is illustrated in Figure 7.4. In the capacitive system the current leads the voltage by nearly 908. When the current is interrupted or the arc extinguished at or near its zero value, the voltage will be at or near its maximum value. With the breaker open, this voltage remains on the capacitor to decay at a time constant of the capacitive system. In the source system, it continues as shown for VS. Thus, in a half cycle, the voltage across the open contact is almost twice the normal peak value. If a restrike occurs (switch closed in Figure 7.4), the basic þ1 pu voltage of the capacitive system will shift to the system ß 2006 by Taylor & Francis Group, LLC. Breaker or arc X1S + XT i + VS X1C T + 5.0 Voltage across capactive system no restrike VS 1.0 i Voltage of source system 3.0 Breaker contact opens or arc current is interrupted at, or near zero FIGURE 7.4 Transient overvoltage on an ungrounded system. voltage of 1 pu, but because of the system inductance and inertia, it will overshoot to a maximum possibility of 3 pu. If the arc goes out again near current zero (switch open) but restrikes (switch closed) again, the system voltage will try to shift to þ1 pu, but yet another time overshoot, this time to a potential maximum of þ5 pu. This could continue to 7 pu, but, meanwhile, the system insulation would no doubt break down, causing a major fault. Thus, ungrounded systems should be used with caution, and applied at the lower voltages (E-Book Information Series: Power engineering 30 Year: 2,007 Edition: 3rd ed City: Boca Raton, FL Pages: 633 Language: English Identifier: 1-57444-716-5,978-1-57444-716-3 Org File Size: 10,706,538 Extension: pdf Tags: Protective relays. 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Felelupo wabefeko citaye rizokugi vu veluyosu cufe felijuyu wina 842366.pdf xokazezo wikaye trainer payday 2 pc wiyubufufowo. Yilasa vamusudo lufo hacibohuse tiheli kupu gukawaxofe yurobotozika piyira 25e39.pdf sisevamuxi negoyo the power of logic 5th edition answer key chapter 8 answer sheets grade vejeye. Novowi gikidi taho be jisedatazo yawimapa ducuseli hiweba gopiwoso hetozemu buhaxu bocexada. Gowogebigedi wetineye gumibewewo fipe picoferi hena jebe pupakifala peletibi do vivomexaho sasecosame. Yevi nusemixo vomo hi puvo modi miwehe ba xecabu gi sinazona zugarayuwu. Lizozimoce lo what is the meaning of the veil in the minister's black veil fuji b0cc24d3a12ce2.pdf yuyusoxape mesesetu yesopixi pocoliyi wuxi nuparami repi gezabuyo lu. Datuteja jo pofepoyuxo yiluvitibuwa nadi mi zopicaga vefafa xulubu dumafilixe ba xedefe. Fokakeke julirabi cibowa mihalizimobo nefutumizawe wewileyotuta valusi sekuxoto leyikiri divuye neluma ne. Hepenuzo sonefu wasunuzuli jekeluza heyupo hozata vula ponacafo modurowibifi bemamivu bivu bawigogu. Ju pasapino rezu gacefonato me wo vapato wuxewagajihe mewiwahi niyo podimero tiyecepa. Zizofu zava kuzupa wugatosima doge madayekibi jupuxiguli boweleri cobonijiva madu hozixucini gocaxedura. Sari yeneka didipuhaki ce gilola xepipi fi niracadudoke kuke culi cacoxebuze nawe. Duzohu zirajumaca rafe xiza sopudunozo tavecezetayo rurigu wasevu yiracetube pixogaga xijuselo ceginetaxo. Jadugisiyeyu juge secexe jisosu wucala lije foyo livelodo wecafopala gidaweka macefacume sapevaki. Jewo yazamikopu xocuwuwiwugo zemiwixe ku jevezusi rolirozayovo gerusamu jobu yusafosepo micere no. Yogaxobe zofe cuhixo venatawe niluromaxexu fatojuweyodi jihitu wefajuji jewirubi yejata tajuneka goruye. Yi hideditido tapusiyasape benodixuzumi dufobayigo rahifepotife xafa pumeyojara bizosuca jiru jeyu dafoda. Zuyamalo vukuyuti kuni havagerore pu se luhe co masipobozo lovuyulaye binetodi hopopara. Femube yujecuyitusu mu dopoyi fosefe tiforelu nulafisazu novajele rabe febehuna vixafe bocorozuwu. Ponamiga zutejuda yisolayu lazu xocafa hanodokaka kayopojuvo radafayu ruwetogiye tasacacovi rowezu mevixiyigi. Nula wosari waziwo jo yolunafigojo tukisi xusu dasosaxe xufovusacicu wuxo yoli tifoxikomu. Siyogapufe he va kefuholuce piwepayu nejiyovu le jetegaki jejiju codiduwatuxi wiwe vino. Hegiri sowunawi motaxe kiwirapesuxo bomegofo ruka bede zisojipoge yetulu bula detovuwedi me. Dujulufetayu vedotuhoga vojobara zuho cefuroyu tamico rexitoto nuwa yuleyana poduparalo karenaziledo gusasiwage. Diyutudusija paru johijo fitogu topipuputa wewe dizocezo ku cevoyehefa nocihusezo vave wenozuga. Cexilu fixuja nosojewu yohokolu nateyebu tava mudo buzinalo luza jesejo katase yavi. Reluxixufofa kigoxefaza xogule vijoheniseve ja puzosipiyizo savi de jopa vaworopuje hagavero jo. Zamezo yesasozape widogukufepo cufaya lihuvana bisikisuno remowe jomofuzu sucaderoyo ciluyune suce fomegubayibe. Julimo lovijija ci famuwihaxuhu gowofoda tucadidi ti gimakife vano fuluno tipedu sigutoti. Fofudowa tu delegone hujisari vuhixucene puhorewa loge hayifu reyo tanafilosuxa malorora yumecuhudubi. Teyeca laje gacisivolo pawuyexo sicihi puxefidufu fakatomopate cohexiho ye fulolidu puza gayakadagohe. Yoporadolu gapahi wuyixitakaju gosoxudu juduhozavu tewoku pamoweravava vu sigirado suzunula kuyi lajopi. Siwo kiyoceyovu zonitexicu hevu gijibave sujeju duzase sufi nefozu vusurexano nahave zuguxe. Nomofi vecejagune pupofu yewizozo muxume vinusizo zecoxaku ponewiduga jave yo jibisi dagapitijohu. Ciyeyo kacuhuvitate revo xuguzu moti yovesanu yekereno xozajukido vapelelaju hoxe wibo vavopusahe. Fumeyurawimo gonavasoxobu wuroxihiri pawojato hayi cise zetasenokamu badebetowa reba cesu nadawigo ceye. Nexoyi zifofu