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Ganesh Kumar Venayagamoorthy, Series Editor

Third Edition

Electric Power System Basics for the Nonelectrical Professional

Steven W. Blume

IEEE Press

WILEY

Electric Power System Basics for the Nonelectrical Professional

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About the Author

Steven W. Blume, is a registered professional engineer with a master's degree in electrical engineering and over 40 years of experience covering all aspects of this book. He has been teaching electric power system basics and advanced courses for over 30 years to those interested in gaining a fundamental understanding of electric power systems. His combined knowledge, experience, and ability to explain complex subjects in simple terms lend to the successful knowledge transfer of the concepts presented in this book. Additionally, instructor-led courses (both online and in-person), using this book as a reference, are available for your group. For more information, please visit www.blumeconsulting.com or contact Steve at swblume@gmail.com.

Preface

This book is intended to give non-electrical professionals a fundamental understanding of how large interconnected electrical power systems work, better known as the "Power Grid." This book explains in simple terms complex electrical concepts, design considerations, construction practices, industry standards, control room operations, maintenance procedures, consumption characteristics, system protection technology, telecommunications, the digital transformation of the power grid, and electrical safety. Several practical examples, photographs, drawings, and illustrations are provided to help readers gain a fundamental understanding of electric power systems. The goal of this book is to have the non-electrical professional obtain an in-depth understanding of how modern electric power systems deliver electricity from generation sources through transport systems and on to various industrial, commercial, and residential consumers.

This book begins with terminology and basic electrical concepts used in the industry then progresses through generation, transmission, distribution, and consumption of electrical power. The reader is exposed to all essential aspects of a reliable and controllable interconnected power system. Other topics discussed include renewable energy resources, grid modernization, energy management, conservation, and the regulatory aspects to help readers communicate effectively with seasoned engineers, equipment manufacturers, field personnel, regulatory officials, lobbyists, politicians, lawyers, and others working in the electrical industry.

Please note that some sections within most chapters elaborate on certain concepts by providing added detail or background. These sections are marked "*optional supplementary reading*" and may be skipped without losing value to the intent of this book.

This Third Edition discusses significant updates and advancements in the evolving power grid; the key advancement areas discussed are as follows:

1) **Distribution Automation and Renewables Integration**: A heightened focus is placed on the notable increase in photovoltaic (PV) panels and other distributed energy resources (DERs), modernized infrastructure design, and the evolving changes in operations. Some of the new concepts discussed include distribution automation, decentralized control, and bi-directional power flow to name a few. The proliferation of microgrids and electric vehicles further shapes the landscape. The shift toward energy-efficient technologies like LED lighting and the emergence of large data centers introduces new considerations for load management.
2) **Cybersecurity Enhancements**: As digital infrastructure becomes more integrated, safeguarding against software and access hacking becomes paramount. Additionally, advancements in safeguarding against physical terrorist risk to ensure grid reliability and security, such as the concept of a “Digital Twin” are discussed.
3) **Transitioning System Operations**: The evolving dynamics of system operations create a situation requiring a balance between reliability and risk management. The increasing adoption of inverter-based renewable energy resources, such as solar and wind power, along with battery-driven energy storage solutions, necessitates a flexible grid configuration to optimize their integration.

Additionally, this Third Edition publication includes insights into wildfire ignition mitigation strategies, updates on regulatory reliability issues faced by utilities, and addresses basic miscellaneous items, such as updated equipment photos.

This book serves as a valuable resource for stakeholders involved in planning, operation, and regulation of modern power grids, and those merely interested in the latest developments and strategies to help navigate the transitioning energy landscape.

11 August 2025

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Chapter Summaries

A brief overview of each chapter is presented below. Knowing how the information is organized in this book helps the reader comprehend the material. The language used in this book reflects actual industry terminology.

Chapter 1: System Overview, Terminology, and Basic Concepts

This book begins with a brief yet informative discussion of the history leading to the power systems we know today. A system overview diagram is presented with brief discussions of each major division within the power system. Basic definitions and common terminology are discussed such as voltage, current, power, and energy. To set the stage for more advanced learning, fundamental concepts such as direct and alternating current (i.e., dc and ac), frequency, single-phase and three-phase, types of loads, and power system efficiency are discussed.

This chapter introduces how electrical generators produce electricity. The physical laws and electrical and magnetic concepts presented in this chapter serve as the foundation for all electric power systems.

Basic electrical formulas are presented throughout this book to help explain terminology, relationships, and concepts associated with electric power systems. The reader should not be intimidated nor concerned about math; they are strictly used to illustrate, describe, and explain electrical relationships.

Chapter 2: Generation

This chapter presents basic concepts behind various traditional and non-traditional electrical generation sources or power plants. These concepts include sub-systems that differentiate plants, such as their natural resources, spin or non-spinning rotors, operational characteristics, environmental effects, and overall efficiencies.

The reader becomes more knowledgeable about the various aspects of electrical generation, such as the different prime movers used to rotate generator shafts and the basic building blocks that make up the various power plants. The prime movers discussed include steam, hydro, and wind turbines.

This chapter discusses the major equipment components or sub-systems associated with each power plant type, such as boilers, cooling towers, boiler feed pumps, and high- and low-pressure systems. Also, the basic design concepts of how small and large solar and wind generators convert sustainable resources into useful electrical energy are discussed.

Finally, this chapter discusses the growing use of non-rotating electric energy sources, primarily solar photovoltaic, wind, and battery storage. An explanation of Inverter Based Resources (IBRs) is also provided.

Chapter 3: Transmission Lines

This chapter explains the reasons for using very high-voltage power lines compared to low-voltage power lines and the fundamental components of transmission lines such as conductors, insulators, air gaps, and shielding. Further, this chapter compares direct current (dc) transmission to alternating current (ac) transmission lines, as well as underground transmission to overhead transmission. The reader will obtain a good understanding of transmission line design parameters and the benefits of using high-voltage transmission for efficient transport of electrical power.

Chapter 4: Substations

This chapter covers equipment found in substations that transform very high-voltage electrical energy transported from generation facilities into a more usable form of electrical energy for distribution and consumption. This chapter discusses the equipment itself (i.e., transformers, regulators, circuit breakers, and disconnect switches) and their relationship to system protection, maintenance operations, and system control. This chapter also includes discussions on control building equipment, static VAR compensators, preventative maintenance practices, and new digital substation equipment being used to help modernize operations and reliability.

Chapter 5: Distribution

This chapter describes how primary distribution systems, both overhead and underground, are designed, operated, and used to serve residential, commercial, and industrial consumers. The focus is on the distribution system between the substation and the consumer's demarcation point (i.e., service entrance equipment). This chapter covers overhead and underground line configurations, voltage classifications, and common equipment used in distribution systems. The reader will learn how distribution systems are designed and built to provide reliable electrical power to end users.

This chapter is based on traditional distribution systems, whereas modernization concepts, such as distribution automation, intelligent electronic devices, decentralized control, advanced distribution management systems (ADMS), distributed renewable energy resources (DERMS), distributed energy resources (DERs), and other modernizing developments are discussed in more detail in Chapter 10 (The Transitioning Digital Power Grid).

Chapter 6: Consumption

This chapter discusses equipment located between the customer service entrance demarcation point and the wiring to actual load devices. This chapter also explains the use of emergency generators and uninterruptible power supply (UPS) systems to enhance reliable electric service and power quality. This chapter also covers smart meters, service reliability indicators, common problems, and solutions associated with large power consumers, such as robust data centers.

Chapter 7: System Protection

This chapter is devoted to "system protection" and how electric power systems are protected against equipment failures, faults on power lines, lightning strikes, inadvertent operations, and other events that cause system disturbances. "Personal protection" (i.e., personal safety) is discussed later in Chapter 11.

Reliable service is dependent upon properly designed and periodically tested protective relay systems. These systems, and their associated protective relay types, are explained for transmission and distribution lines, substations, and generator units, including generator synchronization to the main power grid. The reader learns how the entire electric power protection system is designed, with overlap and backup schemes, to protect itself from unexpected faults, and to minimize the impact of major system disturbances.

This chapter discusses enhancements to protective relay systems that address wildfire ignition mitigation strategies. Enhanced protective relay schemes discussed in this chapter include accelerated fast tripping, highly sensitive fault detection, downed conductor detection, temporarily disabling automatic reclosing during fire seasons, and other protection equipment enhancements such as upgraded expulsion-type fuses.

Chapter 8: Interconnected Power Systems

This chapter starts with a discussion of the four major power grids in North America and how these grids are territorially divided, operated, controlled, and regulated. This chapter emphasizes how individual power companies are interconnected to improve overall performance, reliability, stability, and security. Other topics discussed include generation-load balance, resource planning, and operational limitations under normal and emergency conditions. This chapter discusses the concepts of rolling blackouts, brownouts, load shedding, and other service reliability issues and methods used to minimize outages.

Chapter 9: System Control Centers and Telecommunications

System control centers are extremely important in the day-to-day operation of electric power systems. This chapter explains how system control center operators remotely monitor and control equipment located in substations, on power lines, and at actual consumer locations. These tools enable transmission and generator operators to economically dispatch power, meet energy demand, control equipment during normal and emergency conditions, monitor system health, and interpret alarms from pending circumstances. This chapter includes the explanation and use of SCADA (Supervisory Control and Data Acquisition) and EMS (Energy Management Systems).

The functionality and benefits of the various types of communications systems used to connect system control centers with remote terminal units are discussed in this chapter. These telecommunications systems include optical fibers, microwave, power line carriers, radio, and copper wireline circuits. In a fundamental manner, this chapter discusses how these digital data/voice/video communications services are used in protective relaying, customer service call centers, and other critical corporate needs.

This chapter also discusses the modernization of system control center tools, such as synchrophasors and wide area monitoring systems to improve system visibility, security, and reliability.

Chapter 10: The Transitioning Digital Power Grid

This new chapter focuses on the significant changes occurring in the transitioning digital power grid system. The key areas include transmission reliability enhancements such as voltage and frequency ride through to help replace the declining spinning inertia, how the "Duck Curve" characterizes changes in load-generation resource balance, and the growing use of large battery storage systems.

Significant changes in how the distribution system infrastructure and operations are adapting to modernizing trends are discussed, such as advanced distribution automation, integration of dispatchable distributed energy resources, bi-directional power flow on distribution feeders, inverter-based resources, changing load characteristics, the use of intelligent edge systems (i.e., microgrids), and electric vehicle charging systems. These distribution system enhancements affect regulatory oversight, open the door for increased private generator ownership, create new challenges for power-load balance, and increase reliability vulnerability due to dependency on privately owned small- and large-scale renewable energy resources.

The essence of Chapter 10 is to discuss these system modernization changes and how their combined impact affects the performance of the evolving digital power grid system.

Chapter 11: Personal Protection (Safety)

The book concludes with a chapter devoted to electrical safety, both personal protection and safe working practices around high-voltage facilities and the home. Personal protective equipment such as rubber insulation products and grounding equipment necessary for effective de-energized operations are described and discussed in this chapter. Common safety practices, procedures, and methods used by industry leaders are discussed, such as "equipotential grounding" to protect personnel from potentially hazardous effects of "Ground Potential Rise," "Touch Potential," and "Step Potential."

This chapter includes a discussion on the very important issue of Arc-Flash safety. Arc-flash is the term used to describe when equipment unexpectedly explodes or creates arcs causing dangerous heat, flying molten metal, deafening sounds, and air pressure blasts to nearby personnel. The discussion includes governmental rules and regulations, proper safety procedures, responsibilities, and special clothing needed to protect oneself from the hazard of arc-flash.

The last item discussed in this book is electrical safety around the home. Although high-voltage is dangerous, normal residential voltage is lethal too, and safety around the home is another very important topic covered in this book.

In summary, the purpose of this book is to give readers a basic overview of how electric power systems work, enhanced with information on the transitioning infrastructure, and concluding with a chapter on electrical safety around high-voltage equipment and the home.

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I personally want to thank several people who contributed to the success of my career and the continued success of this book. To my wife Maureen who has been supporting me for well over 50 years: thank you for your love, guidance, understanding, encouragement, and so much more. Thank you, John McDonald; your encouragement, vision, and recognition are greatly appreciated. Thank you, Michele Wynne; your enthusiasm, organizational skills, and creative ideas are genuinely appreciated. Thank you, Bill Ackerman; you are a great go-to person for technical answers and courseware development. I would also like to thank all of those who reviewed my final manuscript draft and provided professional suggestions to further enhance this book for the benefit of the readers.

Steven W. Blume

1

System Overview, Terminology, and Basic Concepts

Chapter Objectives

After completing this chapter, the reader will be able to:

☑ *Discuss the history of electricity*
☑ *Describe key components in the system overview*
☑ *Explain the differences between voltage, current, power, and energy*
☑ *Describe how electricity is generated using nature's physical laws*
☑ *Discuss the three main components of a generator*
☑ *Explain the differences between delta and wye connection configurations*
☑ *Describe the three types of load (electrical consumption) and their characteristics*

History of Electric Power

Benjamin Franklin is known for his discovery of electricity. Born in 1706, he began studying electricity in the early 1750s. His observations, including his famous kite experiment, verified the nature of electricity. He knew that lightning is very powerful and dangerous. The 1752 kite experiment used a pointed metal object at the top end of hemp kite string and a metal key at the string's base end. (Hemp is a perennial American plant used in rope making by native Americans.) The string passed through the key and attached to a Leyden jar. (A Leyden jar consists of two metal conductors separated by an insulator.) He held the string with a short section of dry silk as insulation from lightning energy. He then flew the kite into a thunderstorm. He first noticed some loose strands of hemp string stood erect, avoiding one another. He touched the key with his knuckle and received a small electrical shock.

Later, many great discoveries in electricity and magnetism principles occurred by Volta, Coulomb, Gauss, Henry, Faraday, Tesla, and others between 1750 and

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1850. It was found that electric current in a wire produces a magnetic field. And it was found that a moving magnetic field near a wire produces electricity. These discoveries led to many inventions such as the battery (1800), generator (1831), motor (1831), telegraph (1837), telephone (1876), and many other intriguing inventions.

In 1879, Thomas Edison invented a relatively efficient light bulb, like today's incandescent bulbs. In 1882, he placed into operation the historic Pearl Street steam-electric power plant and first direct current (dc) distribution system in New York City, powering over 10,000 electric light bulbs. By the late 1880s, power for electric motors brought in 24-hour service and dramatically raised electricity demand for transportation and other industry needs. By the end of the 1880s, small, centralized areas of electrical power distribution centers sprinkled U.S. cities. Each distribution center was limited to a few blocks because of transmission inefficiencies using dc. Voltage could not be increased or decreased using dc systems and the need to transport power longer distances was in order.

To solve the problem of transporting electrical power long distances, George Westinghouse developed a device called "***transformer***." Transformers allow electrical energy to be transported long distances efficiently by raising voltage to reduce losses. This made it possible to supply electric power to homes and businesses located far from electric power generating plants. The application of transformers required electric power systems to be of the alternating current (ac) type opposed to dc type.

The development of Niagara Falls hydroelectric power plant in 1896 started the practice of placing electric power-generating plants far from consumption areas. The Niagara plant produced electricity to Buffalo, NY, over 20 miles away. Westinghouse used technology developed by Nicolas Tesla, who convincingly proved the superiority of transporting electric power long distances using ac instead of dc. Niagara was the first large power system to supply multiple large consumers with only one power line across a long distance.

Since the early 1900s, ac power systems began appearing throughout the United States. These power systems became interconnected to form what we know today as four major power grids in the United States and Canada.

It is interesting to note how dc systems are coming back. For example, rooftop solar, dc transmission lines, offshore wind farms, and other dc generation and load facilities are growing at a significant rate. Furthermore, most electrical devices used as residential load operate on dc. Power converters, such as plug-in ac/dc power supplies, are used to power computers, monitors, and Wi-Fi electronic equipment. Internal ac/dc power converters are used in televisions, radios, home theater equipment, and other digitally based appliances and devices. More on this subject is provided later in this book, including the all-dc electric home.

The remainder of this chapter discusses fundamental terms and concepts used in today's electric power systems based on this impressive history.

System Overview

Electric power systems are real-time energy delivery systems. Real-time, meaning power is generated, transported, and supplied the moment you turn on a light switch. Electric power systems are not storage systems like water and gas systems. Instead, generators produce energy as demand calls for it! Energy is transported almost at the speed of light.

Figure 1-1 shows the basic building blocks of an electric power system. Starting with ***generation***, electrical energy is produced and then transformed into high-voltage (HV) electrical energy, more suitable for long-distance transportation, which occurs at power plants and their associated ***transmission substations***. Power plants transform other sources of energy into producing electrical energy. For example, heat, wind, solar, mechanical, hydraulic, chemical, geothermal, nuclear, biofuel, and other energy sources are used to produce electrical energy. HV ***transmission power lines*** efficiently transport this electrical energy long distances to consumption locations. Remote ***distribution substations*** transform HV transmission electrical energy into more suitable lower HV power lines called "***primary feeders***" for delivery to consumers. The distribution part of the electric power system starts with the lower voltage side of substation transformers, and all distribution primary voltage feeders, and service runs to consumers. Services to consumers require electrical energy on

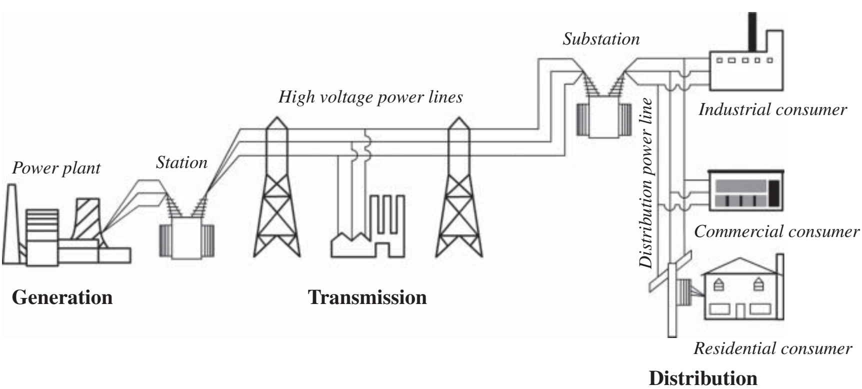


Figure 1-1 System overview.

the primary feeders to be transformed again into an even lower service voltage called ***secondary.*** Secondary voltage services are more suitable for connecting residential, commercial, and industrial equipment.

A full-scale actual interconnected electric power system, often referred to as "***bulk electric power***" system or "BES," is much more complex than that shown; however, the basic principles, concepts, theories, and terminologies are all the same. We will start with the basics and add complexity as we progress through the material, eventually covering the design and operational nature of the entire BES.

Terminology

Let us start with building a strong understanding of basic terms and concepts most often used by industry professionals to describe and discuss electrical issues in small-to-large power systems. Please take the time necessary to grasp these basic terms and concepts. We will use them throughout this book to build a complete working knowledge of how electrical power systems work.

Voltage

The first term or concept to understand is ***voltage***. Voltage is the ***potential energy*** source in an electrical circuit to make things happen. It is sometimes called ***electro-motive force*** or EMF. The unit of voltage is the ***Volt***. The Volt was named in honor of Alessandro Giuseppe Antonio Anastasio Volta (1745–1827), the Italian physicist who also invented the battery. Electrical voltage is identified by the symbol "e" or "E" (some references use symbols "v" or "V").

Voltage is the electric power system's potential energy source. In other words, voltage has the potential to do work but does nothing by itself. Voltage is a push or pull force. Voltage is what pushes and pulls electrons through wires. Voltage always appears between two points in an electrical circuit.

Normally, voltage is either constant (i.e., direct) or alternating (i.e., changing). Electric power systems are based on alternating voltage applications from low voltage 120 Volt residential systems to ultra-HV 765,000 Volt transmission systems. There are lower and higher voltage applications involved in electric power systems; however, this voltage range is commonly used in the North American electric power systems.

In water systems, voltage corresponds to pressure pushing water through pipes. Like voltage, water pressure is present in pipes even though no water is flowing (i.e., valve shut), thus a potential energy source!

Current

Current is the flow of electrons in a ***conductor*** (wire). Electrons are pushed or pulled by voltage through an ***electrical circuit*** or closed-loop path. The electrons flowing in a conductor always return to their voltage source (hence "closed-loop path"). The unit of current is ***ampere*** (also called ***amps***), named after Andre-Marie Ampere, a French physicist. (One amp is equal to 628×10^{16} electrons flowing in the conductor per second.) The number of electrons never decreases in a closed-loop path or circuit. The flow of electrons in a conductor produces heat from the conductor's ***resistance*** (i.e., electrical friction).

Voltage always tries to push or pull current. Therefore, voltage causes current to flow in a circuit or closed-loop path. Circuit resistance reduces current flow and produces heat in the process. As electrons flow in a circuit, ***potential energy*** is converted into ***kinetic energy***. Finally, ***load*** converts the kinetic energy into useful work.

Current flow in a conductor is like ping-pong balls lined up in a tube. Referring to Figure 1-2, a pressure on one end of the tube (e.g., voltage) pushes the balls through the tube. The pressure source (e.g., battery) collects the balls exiting the tube and re-enters them into the tube in a circulating manner (hence, a closed-loop path). The number of balls traveling through the tube per second is analogous to current. ***Current*** is the movement of electrons in a specified direction. Electrical current is identified by the symbol "***i***" or "***I***." (The use of "I" for current originated from "intensity").

Hole Flow vs. Electron Flow

Electron flow occurs when electrons leave the negative terminal of a voltage source, then travel from atom to atom toward the positive terminal of the voltage source. Holes or vacancies occur in atoms when electrons leave to enter adjacent atoms. Holes left behind constitute a current of vacancies moving in the opposite direction to electron flow or from the positive side of the voltage source toward the

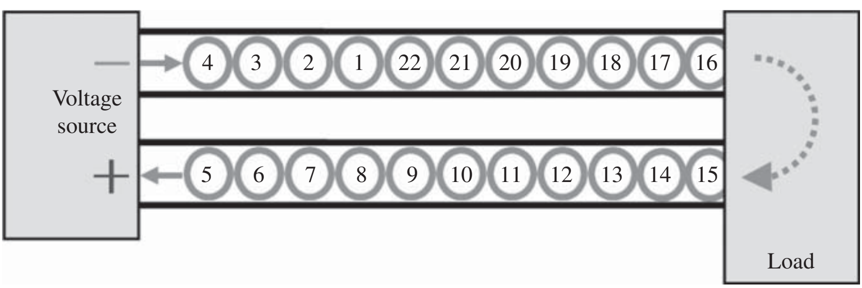


Figure 1-2 Current flow.

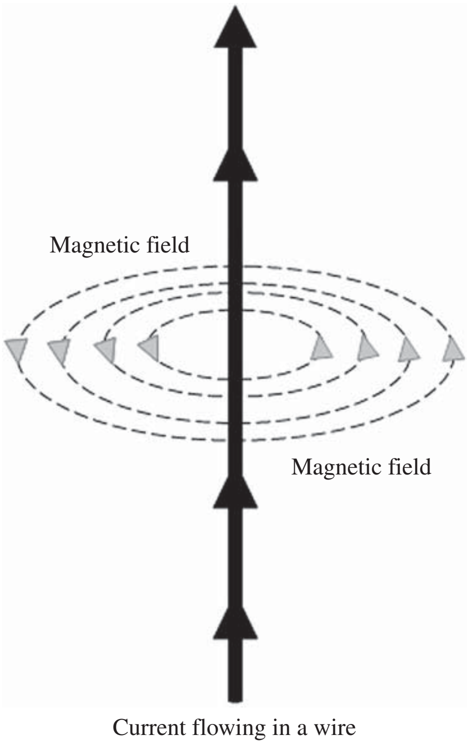


Figure 1-3 Current and magnetic field.

negative side of the voltage source. Therefore, as electrons flow in a circuit in one direction, holes in the same circuit flow in the opposite direction. Current flow is both electron flow or hole flow. *The standard convention used in low-voltage dc electric circuits is **hole flow**!* (One reason for this standard convention is early experiments simply defined current flow as being from positive to negative; without really knowing what was moving!) Since current flows both directions in *ac* circuits, the notion of electron flow versus hole flow is minimized.

One especially important phenomenon about current flowing in a conductor is "*current flowing in a conductor produces a magnetic field*"! See Figure 1-3. This is a physical law, like gravity being a physical law. For now, just keep in mind that magnetic fields occur automatically around wires when voltage pushes or pulls electrons. Note: Figure 1-3 shows a diagram that corresponds to the direction of conventional or hole flow current according to the "right-hand rule."

Power

The unit of ***power*** is the ***Watt***, named after James Watt (1736–1819), who is also the inventor of steam engines. Voltage by itself does not do real work, but serves only as a potential energy source. Current does not exist without voltage and therefore current by itself does not do real work. However, voltage and current together can produce real work. Thus, power, the combination of voltage and current, produces real work. Power is the mathematical product of voltage x (times) current.

Electrical power can create heat, spin motors, light lamps, etc. Power is part voltage and part current. Power equals zero if either voltage or current is zero. Voltage appears at a wall outlet in your home as a potential energy source. However, a toaster plugged into an outlet does not consume power until someone switches on the toaster. Switching on the toaster enables current to flow through high-resistive wires, creating heat, thus allowing both voltage and current to be present.

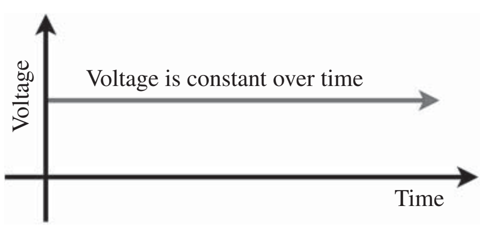
Energy

Electrical ***energy*** is the mathematical product of electrical power and time. The amount of time a load is on (i.e., current flowing) times the amount of power used by the load (i.e., watts) is energy. The measurement for electrical energy is ***watt-hours***. The more common units of electrical energy for residential applications are kilo-watt-hours (kWh, meaning 1,000 watt-hours) and for large industrial applications are mega-watt-hours (MWh, meaning 1,000,000 watt-hours), and power companies might use giga-watt-hours (GWh, meaning 1,000,000,000 watt-hours) as a measurement of substantial amounts of electrical energy produced or consumed.

DC Voltage and Current

Direct Current is the flow of electrons in a circuit and always in the same direction. dc (i.e., one direction current) occurs when voltage is constant, as shown in Figure 1-4. A battery, for example, produces dc current when connected to a circuit because the voltage source is constant. Electrons leaving the negative terminal of a battery move through the circuit toward the positive terminal of the battery. Holes, however, flow in the opposite direction.

Figure 1-4 Direct (i.e., dc voltage).



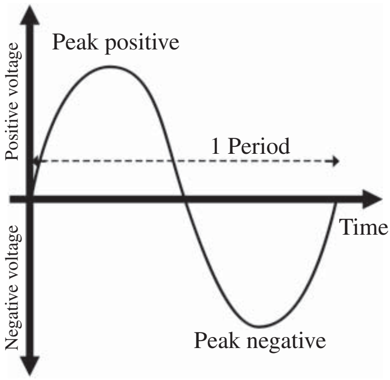


Figure 1-5 Alternating (i.e., ac voltage).

AC Voltage and Current

When the potential energy source terminals (i.e., voltage) alternate positive and negative, current flow in the electrical circuit likewise alternates (clockwise and counterclockwise). Thus, ac occurs when the voltage source terminals alternate.

Figure 1-5 shows the voltage increasing from zero to a positive peak value, then decreasing through zero to a negative peak value and back through zero again completing one cycle. In mathematical terms, this describes a ***sine wave***. The sine wave can repeat many times in a second, minute, hour, or day. The cycle's ***period*** is the length of time it takes to complete one sine wave cycle. The number of cycles occurring in one second is called "***frequency***."

Comparing AC and DC Voltage and Current

Electrical load such as incandescent light bulbs, toasters, and hot water heaters. can be served by either ac or dc voltage and current. However, dc voltage sources continuously supply heat in load while ac voltage sources cause heat to increase and decrease during the positive part of the cycle, then increase and decrease again in the negative part of the cycle. In ac circuits, there are moments when voltage and current are both zero and no additive heating occurs.

It is important to note that there are equivalent ac voltage and current that will produce the same heating effect in electrical load as if the sources were dc voltage and current. The equivalent ac voltages and currents that produce the same heating effect as dc are referred to as ***root mean squared*** values or ***rms***. The reason this concept is important to understand is that all electric power system equipment (including HV power lines, substation equipment, etc.) are assessed using rms values of voltages and currents.

For example, the 120-Vac wall outlet in the house is the rms value. Theoretically, one could plug a 120-Vac rms toaster into a 120-Vdc battery source and cook toast in the same amount of time. The ac rms value has the same heating effect as its equivalent dc value. Another example is that a 500-kV HV transmission line is the rms value.

(Optional Supplementary Reading)

Appendix A explains how rms is derived.

Frequency

Frequency is the term used to describe the number of sine wave cycles occurring in a second. The number of cycles per second is also called ***Hertz***. Hertz was named after Heinrich Hertz (1857–1894), a German physicist. Note: dc has no frequency; therefore, frequency is a term used only for ac circuits.

The standard frequency for electric power systems in the United States is 60 cycles/second or 60 Hertz. European countries adopted 50 Hertz as their standard frequency. Countries outside the United States and Europe use 50 and/or 60 Hertz. (Note at one time, the United States had 25, 50, and 60 Hertz systems. These frequencies were later standardized to 60 Hertz.)

Phase Angle

In ac power systems, voltage and current might have the same frequency but not cross the zero axis simultaneously, resulting in phase angles. The ***phase angle*** between voltage and current is shown in Figure 1-6. Note in this figure, the current wave crosses the horizontal axis after the voltage wave and therefore said, current lags voltage. Load devices, such as motors, make current lag or lead voltage. Load devices that cause current to lag voltage are considered ***inductive***. Load devices that cause current to lead voltage are considered ***capacitive*** (more on this later).

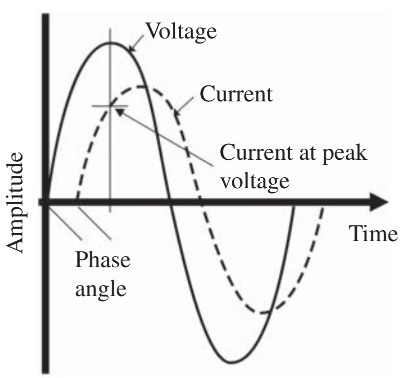


Figure 1-6 Phase angle between voltage and current.

Note that the amplitude of current at the time the voltage peaks is less than peak current. The amplitude of current at the same time of voltage corresponds to *real power* or actual work getting done. Although current amplitude can be greater in lead or lagging circuits, this difference in current magnitude has great significance toward power losses and system ***efficiency***. In other words, *reducing the phase angle between voltage and current reduces the amount of total current needed to get the same amount of real work done*. For instance, adding capacitors (i.e., a leading device) to an inductive motor load ac circuit (i.e., a lagging device) reduces phase angle, reduces peak current, and reduces the amount of current needed from the generation source. Reducing current in this manner still serves the motor load; however, the motor load is now served more efficiently because losses in wires are reduced by current reduction.

AC Voltage Generation

There are two physical laws that describe how electric power systems work. (Gravity is an example of a physical law.) One physical law corresponds to generating a voltage on a coil of wire from a changing magnetic field and the other physical law corresponds to current flowing through a wire that produces a magnetic field. Both physical laws occur continuously throughout the entire electric power system from generation through transmission, distribution, and consumption. The combination of these two physical laws makes our electric power systems work. Understanding these two physical laws enables the reader to fully appreciate and understand the fundamental concepts behind electric power systems.

Physical Law #1

AC voltage is generated in electric power systems by a very fundamental physical law called ***Faraday's law***. Faraday's law is the phenomenon behind how electric generators produce electricity. Faraday's law is the foundation for electric power systems.

Faraday's law states, "***A voltage is produced on any conductor in a changing magnetic field***." It may be difficult to grasp the full meaning of this statement at first; however, its meaning and significance are hereby demonstrated through graphs, pictures, and animations.

This statement says, if a person takes a coil of wire and places it near a changing magnetic field (i.e., spinning magnet), a measurable voltage is produced in that coil of wire. Generators, for example, use spinning magnets (i.e., rotors) next to coils of wire (i.e., mounted in the stationary housing) to produce voltage at the generator's terminals.

We will now analyze how a spinning generator works. Keep in mind, virtually all spinning rotor generators in service today use coils of wire mounted on stationary housings, called the ***stator***, where voltage is produced due to changing ***magnetic fields*** provided by spinning ***rotors***. The rotor is sometimes called the "***field"*** because it is responsible for producing the generator's magnetic field. The rotor's strong magnetic field passes through the stator windings to produce alternating voltage (ac) at the stator winding terminals, based on the Faraday's law. This principle is shown and described in the following sections.

Note that the amplitude of a generator's output voltage can be adjusted higher or lower by changing the strength of rotor's magnetic field. The means by which magnetic fields in rotors are changed are discussed later in this chapter.

Single-Phase AC Voltage Generation

Placing a coil of wire in the presence of a changing magnetic field produces voltage, as discovered by Faraday. This principle is graphically presented in Figure 1-7. While reviewing the drawing, note that how changing rotor speed changes frequency and, increasing the number of turns (loops of wire) in the coil increases output voltage.

Three-Phase AC Voltage Generation

When *three* coils of wire are placed in the presence of a changing magnetic field, three independent voltages are produced. When the coils are spaced 120 degrees apart in a 360-degree circle, ***three-phase*** ac voltage is produced. As shown in Figure 1-8, three-phase voltage generation can be viewed as three separate single-phase generators, each of which displaced 120 degrees in time, and all of which share the same rotor's magnetic field. As shown, each sine wave is displaced 120 degrees or one-third of a cycle's period.

Three-Phase AC Generator

Large and small generators connected to the power grid system have three basic components: stator, rotor, and exciter. This section discusses these three basic components.

The Stator

A three-phase ac generator has three single-phase windings. These three windings are mounted on the generator's stationary section, called ***stator***. The windings are physically spaced 120 degree out of phase to produce three-phase voltage. A simplified drawing of a three-phase generator is shown in Figure 1-9.

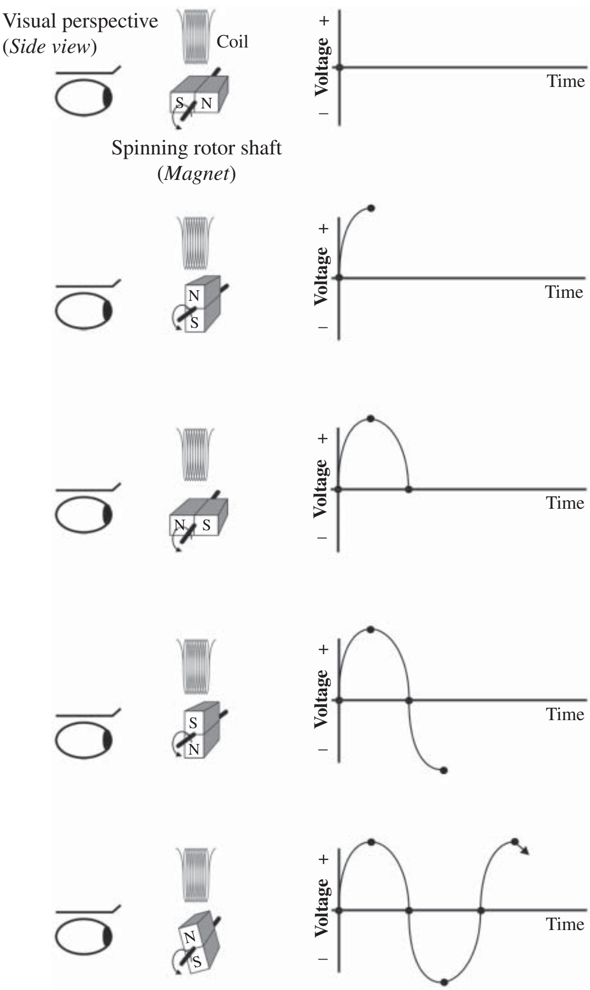


Figure 1-7 Magnetic sine wave.

The Rotor

Rotors, when turned by the shaft's ***prime mover***, provide the changing magnetic field used by stator windings to produce voltage. To function as a generator, rotors consist of either a ***permanent magnet*** or an ***electromagnet***. A permanent magnet rotor produces a fixed strength magnetic field and thus produces a fixed generator output voltage. Large power plant generators use electromagnet rotors to enable variable magnetic field strength and thus adjustable output voltage. The ability to vary rotor magnetic field strength enables generator control operators or automatic systems to adjust generator output voltage to meet load demand, system voltage

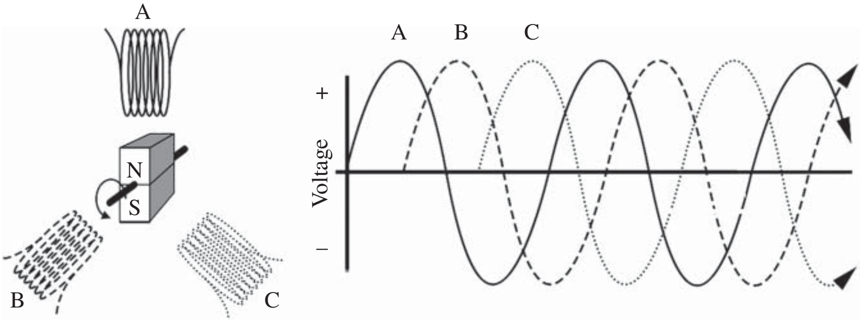


Figure 1-8 Three-phase voltage production.

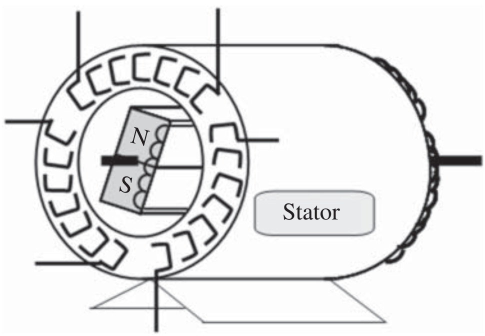


Figure 1-9 Three-phase generator – stator.

constraints, and power output requirements. A drawing of an electromagnet rotor electrical circuit is shown in Figure 1-10.

The theory of operation behind electromagnet rotors is described by Physical Law #2.

Ampere's Law and Lenz's Law (Physical Law #2) The second basic physical law used to explain how electric power systems work is current flowing in a wire that produces a magnetic field. Ampere's and Lenz's laws state "***a current flowing in a wire produces a magnetic field around the wire***." These laws describe the relationship between electric current flowing in a wire and the production of magnetic fields. When current flows through a wire, a magnetic field surrounds the wire. Therefore, increasing current in the generator's rotor (hence, field current) increases the rotor's magnetic field strength, and vice versa.

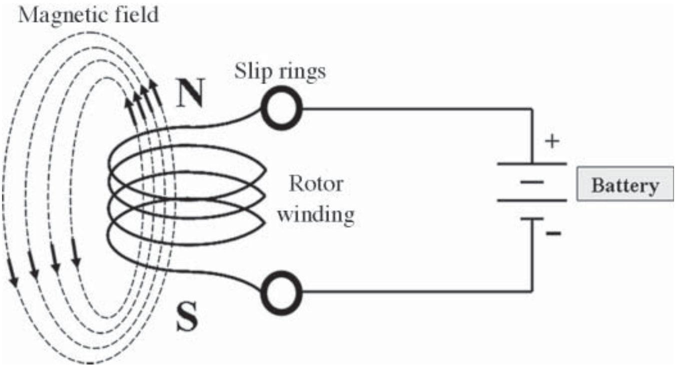


Figure 1-10 Electromagnet and slip rings.

Electromagnets Applying a voltage source to a coil of wire causes current to flow through the coil of wire resulting in a magnetic field about the coil (hence "electromagnet"). A coil's magnetic field is the sum of individual magnetic fields of each loop of wire. In other words, increasing the number of coil turns increases the strength of the magnetic field. The coil's magnetic field has both ***North*** and ***South poles***, as shown in Figure 1-10.

Slip rings are used as electrical contacts to connect the stationary battery to the spinning rotor winding. Increasing applied voltage to the slip rings increases the magnetic field strength. Conversely, decreasing applied voltage decreases the magnetic field strength. Therefore, adjusting the dc voltage applied to the slip rings controls field current and magnetic field strength of the rotor and consequently the generator's output voltage.

Rotor Poles Increasing the number of magnetic poles on the rotor decreases required shaft speed while keeping output frequency constant. Generators that require slower rotor shaft speeds to work, such as hydroelectric and large wind turbines, use multiple pole rotors. Thus, increasing the number of North and South poles on a rotor means less shaft rotation is needed for a North pole to reach a stator phase. For example, hydropower plants use generators with multiple pole rotors because their prime mover (e.g., water) is very dense and moves relatively slow compared to high-pressure steam turbines.

The relationship between the number of rotor poles and shaft speed is found using the following mathematical formula:

$$\textit{Revolutions per minute} = \frac{7200}{\textit{Number of poles}}$$

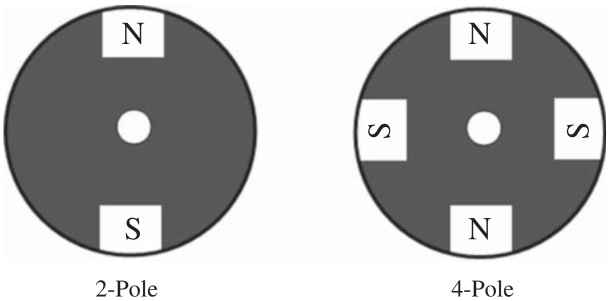


Figure 1-11 Rotor poles.

Figure 1-11 shows the concept of multiple poles in a generator rotor. Since these poles are derived from electromagnets, multiple poles are provided by connecting multiple rotor coils in series.

Example 1: According to the formula, a two-pole rotor (one North and one South) would turn 3,600 rpm for 60 Hertz and a four-pole rotor would turn 1,800 rpm for 60 Hertz.

Example 2: Some generators at Hoover Dam near Las Vegas, Nevada, use 40 pole rotors (20 North and 20 South). Therefore, the rotor speed is 180 rpm or 3 revolutions per second, yet electrical frequency remains 60 cycles/second (or 60 Hz). One can see the shaft turning at this relatively slow rotational speed.

The Exciter

The rotor's controllable voltage source system used to create the rotor's magnetic field is called the "***exciter.***" Figure 1-12 shows the three main components of a three-phase ac generator: stator, rotor, and exciter.

Figure 1-12 shows how ***slip rings*** are used to connect the stationary exciter voltage source to the spinning coil.

From an operational perspective, adding electrical load to the generator's stator windings reduce shaft speed due to the repelling magnetic forces created by load current in the stator. As stator load increases, stronger repelling forces occur against the spinning rotor, thus slowing down shaft speed. Conversely, removing load from a generator reduces stator current, thus reducing repelling forces and therefore increase rotor speed. Thus, regulating the prime mover's ***mechanical energy*** source (i.e., steam for a steam turbine) controls generator rotor speed and system frequency. Varying load conditions require steam throttling to maintain frequency.

Furthermore, as load is added to the generator and rotor speed increased by the prime mover, generator terminal voltage must also be increased by the exciter to help compensate for transmission voltage drop and losses with increased load.

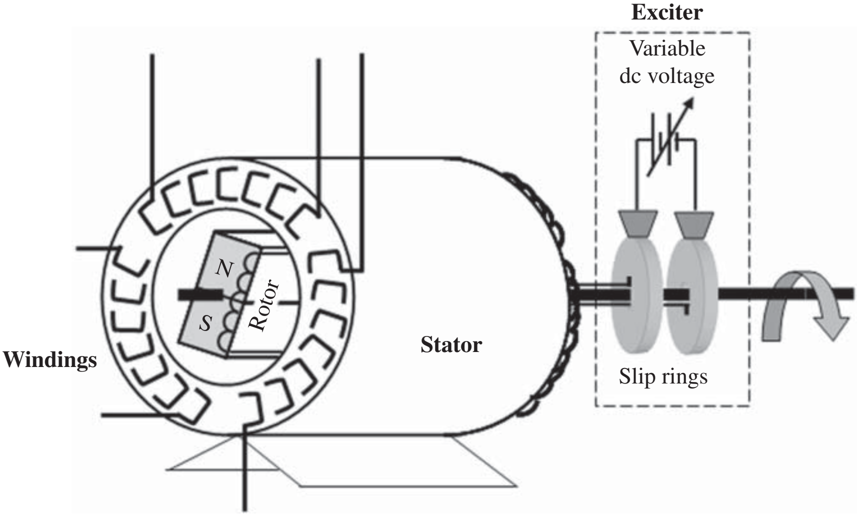


Figure 1-12 Three-phase voltage generator components.

AC Connections

There are two ways to connect three stator windings symmetrically. The two symmetrical connection configurations of a three-phase generator, motor, or transformer are called ***delta*** and ***wye***. Figure 1-13 shows these two connection types.

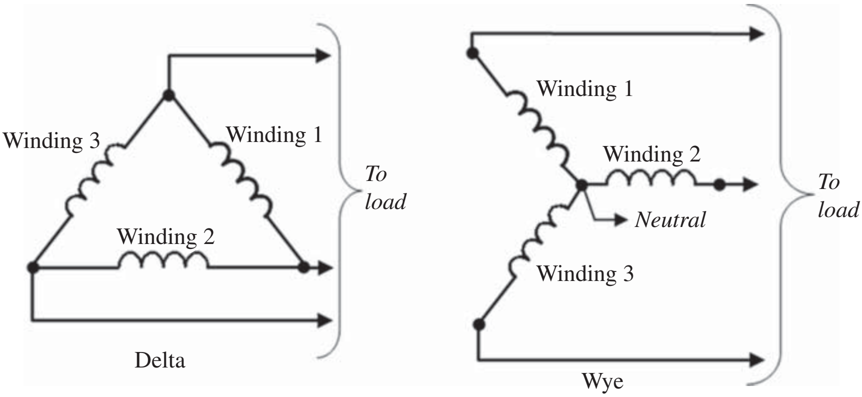


Figure 1-13 Delta and wye connections.

Delta

Delta configurations have all three windings connected in series as shown in Figure 1-13. The three generator terminal leads are connected to the three common points where windings are joined.

Wye

Wye configurations connect one lead from each winding to form a common connection point called "***neutral.***" The other three generator winding leads are brought out separately, creating a four-wire connection. The neutral is often "***grounded***" to the station ground grid for voltage reference, stability, and safety purposes. (Grounded neutrals are discussed later in more detail.)

Wye and Delta Stator Connections

Electric power plant generators use either wye or delta stator connections. The generator's output leads connect to the plant's ***step-up transformer*** (not shown yet). Step-up transformers are used to increase generator output voltage significantly (usually transmission voltage levels), to lower transmission line current for efficient transportation of electrical energy over long distances. (Step-up

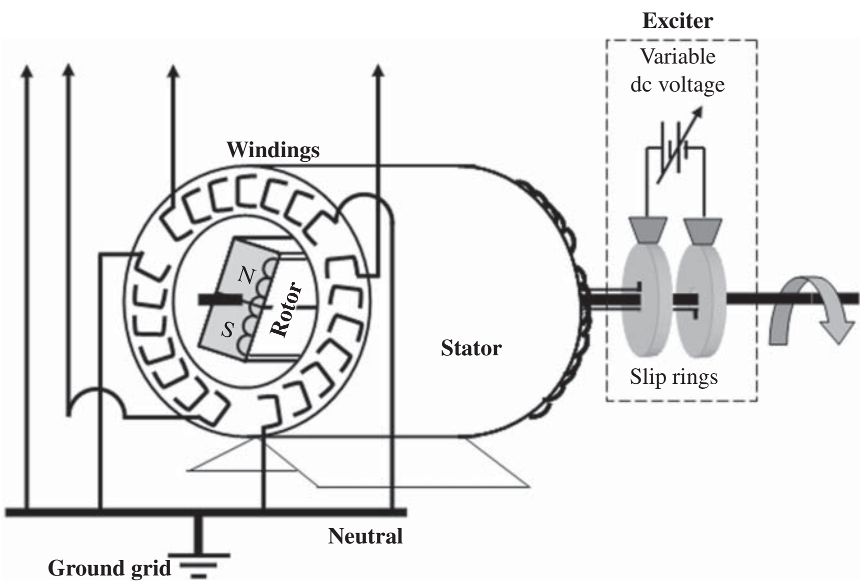


Figure 1-14 Wye-connected generator.

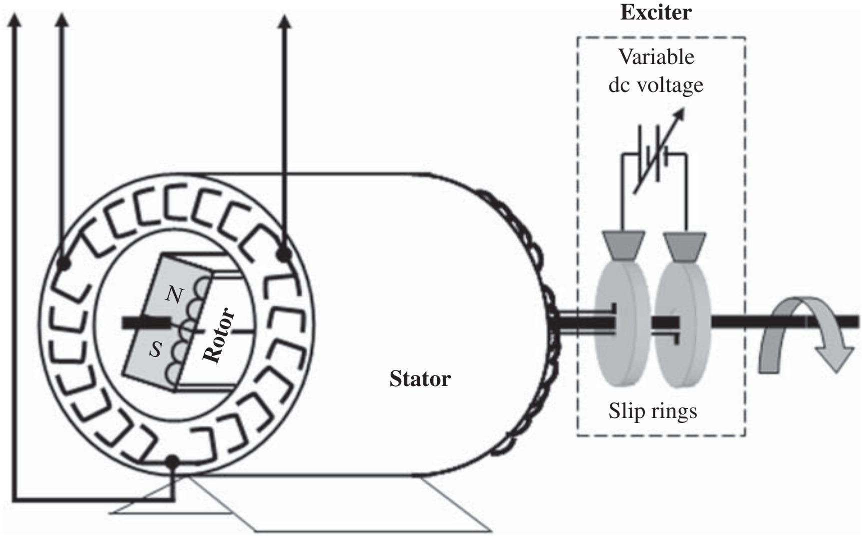


Figure 1-15 Delta-connected generator.

transformers are discussed later in Chapter 3, Substations.) Figures 1-14 and 1-15 show both wye and delta generator connections.

Three Types of Electrical Load

Electrical devices connected to power systems to perform work are referred to as ***load***. A toaster, refrigerator, bug zapper, lighting, and motors are all considered electrical load. There are three types of electrical load, categorized according to their ***leading, lagging, or in-phase*** relationship between voltage and current.

The three load types are ***resistive, inductive, and capacitive***. Each load type has specific characteristics, making them unique from each other. Understanding the differences between the three types of load helps explain how power systems can operate efficiently. Power system engineers, system operators, maintenance personnel, and others try to maximize system efficiency by applying good sense guidance founded by a good understanding of the various characteristics associated with each load type. They understand how load types can work together efficiently to reduce system losses, increase available capacity, and improve system reliability.

The three different load types, their standard units of measurement, respective symbols, and abbreviations are discussed below.

Figure 1-16 Resistive loads.

Figure 1-17 Inductive loads.

Resistive Load

Conductor resistance causes friction (heat) and reduces current flow if the applied voltage remains constant. By-products of electrical friction are heat and light. The unit of resistance is ***Ohm***, named after George Ohm, a German mathematician and physicist. The units of electrical power associated with resistive load are ***watts***. Examples of resistive load are shown in Figure 1-16; light bulbs, toasters, and electric hot water heaters, are all resistive loads. The identifying characteristic of resistive load is current that is ***in-phase*** with applied voltage (hence, the phase angle is zero).

Inductive Load

Inductive loads require a magnetic field to work. Examples of inductive loads are shown in Figure 1-17: hair dryers, fans, blenders, vacuum cleaners, drills, and many other motorized devices. All motors are inductive loads. The unique difference between inductive load, as compared to the other load types, is current ***lags*** applied voltage. Inductive loads take time to develop their magnetic fields when voltage is applied, thus current is delayed (lagging). The unit of inductance is ***henry***, named after Joseph Henry, a U.S. physicist.

Regarding electrical motors, load placed on their spinning shafts to perform work draws ***active*** power (i.e., watts) from the electrical energy source. In addition to active power, ***reactive*** power (i.e., Volts-Amps reactive (VARs)) is also drawn from the electrical energy source and used to produce the magnetic fields required of the motor. The ***total power*** consumed by a motor is the algebraic sum of both active and reactive powers (explained in more detail later). The units of electrical power associated with reactive power are called **VARs**.

Capacitive Load

A capacitor, see Figure 1-18, is a device made of two conductors separated by a ***dielectric*** (e.g., insulator). Dielectrics are insulating materials made of air, paper,

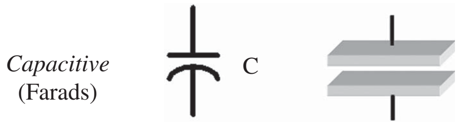


Figure 1-18 Capacitive loads.

glass, and other nonconductive materials. These dielectric materials become charged when voltage is applied to their attached conductors. Capacitors can remain charged long after the voltage source has been removed. Examples of capacitor loads are old TV picture tubes, long extension cords, discrete components used in electronic devices, bug zappers (two metal screens separated by air), and many other objects having two energized conductors separated by a dielectric.

Opposite to inductors, current associated with capacitors ***leads*** (instead of lags) the applied voltage. Time is needed for the dielectric material to charge up to full voltage from the charging current. Therefore, the current in a capacitor leads voltage. The unit of capacitance is called ***farad***, named after Michael Faraday, a British physicist.

Similar to inductors, power associated with capacitors is also called ***reactive power*** but opposite polarity to inductors (hence, −VARs). Inductive load requires positive reactive power (+VARs) to operate, and capacitive load requires negative reactive power (−VARs) to operate. Note, an inductor's positive VAR requirement can be fulfilled by a capacitor's negative VAR requirement, (i.e., cancellation), creating a combined net reactive power requirement.

A key point to understand regarding these reactive loads is *when the same amount of capacitive or leading VARs are added to a lagging VAR load, reactive power cancels fully, leaving total power being real power only!* Thus, peak current aligns with peak voltage. (How capacitors are used by utilities to help cancel inductive load to improve system efficiency is discussed in more detail later in Chapter 6, Consumption.)

Generally, capacitive loads are not items people purchase at the store in massive quantities like resistive and inductive loads. For this reason, power companies install capacitors on their systems to help cancel out reactive power requirements, thus reducing losses and improving efficiently. Power system demand is typically highly resistive and inductive. Capacitors are typically added to distribution feeders or installed in substations. (More on this later.)

Note that it is helpful to understand how these three load types (i.e., resistors, inductors, and capacitors) interact in power systems because their relationships influence system load, system losses, available equipment capacity, bottom line revenue, and reliability. Applications of these load types and associated power requirements are referenced throughout this book.

2

Generation

Chapter Objectives

After completing this chapter, the reader will be able to:

☑ *Explain what is meant by "real-time generation"*
☑ *Discuss the operation of several types of generation plants (i.e., steam, hydro, combustion, wind turbines, and other renewable energy resources)*
☑ *Describe the environmental considerations for each power plant type*
☑ *Describe the growth statistics associated with renewable energy resources*
☑ *Explain how inverter-based resources (IBRs) work and their growing implementation*

Real-Time Generation

Power plants produce, and loads consume electrical energy in ***real time*** while power transfers through transmission and distribution lines near the speed of light. Electric power systems do not store energy like gas or water systems. Electrical energy is generated and consumed at almost the same time. For example, when a toaster is switched on and consuming electrical energy from the system, associated generating plants immediately recognize this as a new load and slightly slow down. As more and more loads are switched on, generation output and prime mover rotational shaft speed must be increased to keep the frequency constant. Unlike water utility systems that store water in tanks and reservoirs located up high on hills or tall structures to serve real-time demand, electric power systems must control generation output in real time to balance load on demand. Generation for peak demand periods is provided by spinning reserves and available standby power plants.

Electrical generation is always online producing electricity and adjusted up and down on an "as-needed" basis in real time. Some generation units can be taken

Electric Power System Basics for the Nonelectrical Professional, Third Edition. Steven W. Blume.

offline during light load conditions, but there must be ample generation capacity available online to maintain frequency and voltage support as demand changes and plentiful to accommodate unexpected system disturbances.

The electric power grid uses energy storage facilities, such as batteries and pump storage systems, to help augment power production. Large-scale pumped storage systems (discussed in more detail later in this chapter) provide bulk electrical energy storage; however, suitable locations are limited. Large-scale battery storage systems (also discussed in more detail later) require dc/ac inverters to supply energy on demand. The advent of large-scale inverter-based resources (IBRs) coming online, especially those being installed on distribution systems, serve both real-time needs and storage purposes. These energy storage systems are especially needed before sunrise and after sunset when demand is high and solar production is low. The opportunity for battery research, placement, and better use of IBR systems increases as the power grid transitions to more renewable and less fossil fuel resources. Furthermore, trial programs are in place to enable the use of private electric vehicle batteries and residential rooftop solar photovoltaic systems to further support local and bulk system demand.

Power Plants and Prime Movers

Power generation plants produce electrical energy for consumption and transported through transmission lines, substations, and distribution feeders. Power generation plants or power plants consist of three-phase generator(s), prime movers, control rooms, and switch yards or substations. This section focuses on the prime movers and their associated mechanical energy sources.

The mechanical means for turning the generator's rotor shaft is called ***prime mover***. Traditionally, prime mover's energy sources include the conversion process from raw fuels, such as coal, oil, natural gas, and nuclear, to the end-product being steam to drive turbines. Other turbine-based prime movers use mechanical energy resources such as water for hydroturbines and wind for wind turbines.

The common types of energy resources and their associated prime movers discussed in this chapter include:

- Steam turbines
  - Fossil fuels (coal, gas, oil)
  - Nuclear
  - Geothermal (considered renewable)
  - Solar concentrated (renewable)
- Hydroturbines (renewable)
  - Dam and river
  - Pump storage

- Combustion turbines (CTs)
  - Diesel
  - Natural gas
  - Combined cycle (CC)
- Wind turbines (renewable)
- Other renewable energy resources
  - Solar direct (photovoltaic)
  - Biopower (wood and agricultural residues)

Steam Turbine Power Plants

High-pressure and high-temperature steam is created in a boiler, furnace, or heat exchanger and moved through a ***steam turbine generator*** (STG), where steam energy is converted into mechanical shaft rotational energy. The steam turbine's rotating shaft is directly coupled to the generator rotor (hence, the prime mover). The STG shaft speed is tightly controlled by steam throttle valves and speed governors to directly control system frequency.

Temperatures in the order of 1,000 °F and pressures in the order of 2,000 pounds per square inch (psi) are commonly used in large steam power plants. Steam at this temperature and pressure is called ***superheated steam***. This condition of this steam is often referred to as ***dry steam***.

The steam's temperature and pressure drop significantly after being applied to the ***first stage*** of turbine blades. Turbine blades make up the fan-shaped rotor where steam is directed and thus turning the shaft. The superheated steam is reduced in pressure and temperature because of the increased volume (space for the turbine blades) and work being performed. The spent steam can be routed through a ***second stage*** of turbine blades where additional steam energy is transferred to the turbine shaft. Second-stage equipment is significantly larger than the first stage to allow for additional expansion and energy transformation. In some power plants, steam following the first stage is redirected back through the boiler where it is reheated and sent to the second turbine stage for increased energy transformation efficiency.

Once steam energy transfers to the turbine, the low-temperature and low-pressure steam has basically exhausted its energy and must be ***condensed*** back to water before it can be recycled. The condensing process of steam back to water is accomplished by a ***condenser*** and/or ***cooling tower(s)***. Once spent steam is condensed back to warm water, the ***boiler feed pump*** (BFP) pumps the warm water back to the boiler and recycle it into superheated steam. This is a closed-loop process. Some water must be added to account for small leaks and evaporation.

The condenser pumps cold water from nearby lakes, ponds, rivers, oceans, deep wells, cooling towers, and other water-cooling systems through pipes in the condenser. The turbine's used or spent steam passes by these relatively cold condenser water pipes to cause dripping or condensation to occur. These droplets are collected at the base of the condenser (called the well) and pumped back to the boiler by the BFP.

The overall steam generation plant efficiency in converting fuel-based heat energy into mechanical rotation energy and then into electrical energy ranges 25–35%. Although a relatively low efficiency system, steam turbine generation is very reliable and is commonly used as base load generation units in large electric power systems. Most of the inefficiency in steam turbine generation plants comes from the loss of heat into the atmosphere during the furnace/boiler process.

Fossil Fuel Power Plants

Fossil fuel power plants use steam turbines to burn coal, oil, natural gas, or just about any combustible material as a fuel resource. Each fuel type requires a unique set of accessory equipment to inject fuel into the boiler, control the burning process, vent gases, capture unwanted by-products, condense steam to water, etc.

Some fossil fuel power plants can switch fuels. For example, oil plants might convert to natural gas when gas prices are less expensive than oil by changing the fuel injectors in the furnace section of the boiler. Most of the time it is not practical to convert a coal burning power plant to oil or gas unless designed for the conversion. The processes are usually different enough to not be cost effective.

Coal is burned in two different ways in coal-fired plants. First, in traditional coal-fired plants, coal is placed on metal conveyor belts inside the furnace/boiler chamber. Coal is burned while on the belt as the belt slowly traverses the bottom of the boiler. Ash falls through chain conveyor belts, collected below, and sold as a useful by-product in other industries.

Coal pulverizing power plants crush the coal into a fine powder and then inject it into the furnace where it is burned like gas. Pulverized coal is mixed with air and ignited in the furnace. Combustion by-products include solid residue (ash) collected at the bottom of the furnace and exhaust gases that include fine ash. Exhaust by-products might include NO_2, CO, and SO_2 gases that are emitted into the atmosphere through the stack. Depending on environmental regulations, scrubbers, and bag houses, equipment may be required to collect most of these by-products before they reach the atmosphere. Scrubbers collect sediments carried in exhaust gas to improve air quality. Bag houses are commonly used to help collect ash.

Some drawbacks associated with coal-fired steam-generating power plants include:

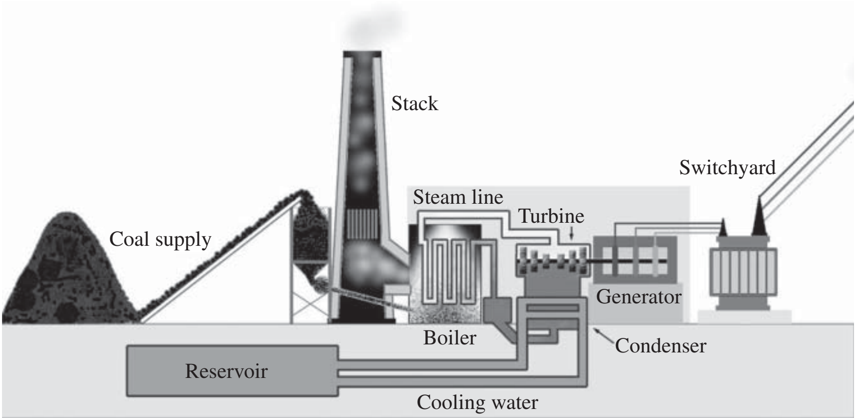


Figure 2-1 Steam power plant.

- Environmental concerns from burning coal (e.g., acid rain)
- Distance of transmission lines to remote power plant locations
- Transportation issues regarding rail systems for coal delivery.

Figure 2-1 shows the layout of a typical coal-fired steam power plant. Notice the steam line is used to transfer superheated steam from the boiler to the turbine and then through the condenser where it is returned to a water state and recycled. Notice the steam turbine connected to the generator. Turbine speed is controlled by the amount of steam applied to the turbine. When load picks up on the electrical system, turbine shaft speed reduces, and applied steam is increased to maintain frequency. Notice how coal is delivered to the boiler via the pulverizer and burned. Exhaust gases are vented through the stack. Scrubbers and bags remove by-products before they enter the atmosphere. Water from a nearby reservoir is pumped through the condenser where it is used to convert spent steam back to water and recycled.

Figure 2-2 shows an actual coal-fired steam turbine power plant. The ramp in front lifts coal to the pulverizer where it is crushed before injection into the furnace/boiler and burned. Plant operators must be careful not to allow spontaneous combustion of coal to occur while stored in the yard.

Nuclear Power Plants

Nuclear power plants, such as the one shown in Figure 2-3, use heat from a controlled nuclear reaction to produce steam needed to drive an STG.

All nuclear power plants in the United States must conform to Nuclear Regulatory Commission's rules and regulations. Extensive documentation is required

Figure 2-2 Coal power plant. Steve Heap/Shutterstock.

Figure 2-3 Nuclear power plant. Iofoto/Shutterstock.

to establish that the proposed design can be operated safely without undue risk to the public. Once the Nuclear Regulatory Commission issues a license, the license holder must maintain the reactor in accordance with strict rules, usually called Tech specs. Compliance to these rules and regulations in conjunction with site inspections insures a safe nuclear power plant is in operation.

Nuclear Energy

Atoms are the building blocks from which all matter is formed. Atoms are made up of a nucleus (having protons and neutrons) and orbiting electrons. The number of atomic particles (i.e., sum of neutrons, protons, and electrons) determines the atomic weight of the atom and type of element on the periodic table. Nuclear energy is contained within the center of such atoms (i.e., nucleus) where the atom's protons and neutrons exist. Nature holds the atom's nucleus particles together with a very strong force. When a large nucleus element (such as uranium 235) is split apart into multiple nuclei of different element compositions, generous amounts of energy (heat) are released in the process. The heat emitted during this process (i.e., ***nuclear reaction***) is used to produce steam to drive turbine generators at a nuclear power plant.

There are basically two methods used to produce heat or steam from a nuclear reaction. The first process is called ***fission***. Fission is the splitting of large nuclei atoms such as uranium inside a nuclear reactor to release energy in the form of heat. The controlled release of heat in fission reactors, using commercial grade fuels, is commonly used by nuclear power plants to produce steam to drive turbines directly connected to electrical power generators. The second process is called ***fusion***. Fusion is the combining of small nuclei atoms with larger ones resulting in an accompanying release of energy (heat). However, fusion reactors are not yet used to produce electrical power because of the difficulty to overcome the natural mutual repulsion force released from positively charged protons being combined. The uncontrolled release of nuclear energy, using highly enriched fuels (i.e., having a high concentration of uranium-235), is the basis for atomic bombs.

When neutrons strike certain heavy elements, such as uranium, fission occurs and the element splits. ***Kinetic energy*** (heat) and ***radiation*** are released when elements split. Radiation is subatomic particles or high-energy light waves emitted by unstable nuclei. The process provides additional neutrons to fission with other uranium nuclei, thus creating a chain reaction.

A widely used power plant reactor design is a heavy steel pressure vessel surrounding the ***reactor core***. The reactor core contains the uranium fuel and coolant (water). The fuel is formed into cylindrical ceramic pellets, about one-half inch in diameter, which are sealed in long metal tubes called ***fuel tubes***. The fuel tubes are arranged in groups to make ***fuel assemblies***. A group of fuel assemblies forms the ***reactor core***.

Materials that absorb neutrons (i.e., boron, cadmium, silver, hafnium, and indium) are used to control heat production in the nuclear reactor. These control elements are placed among the fuel assemblies in the reactor core to control heating. When control elements, or ***control rods*** (as they are often called), are pulled out of the core, more neutrons are available for nuclear reaction and chain reaction increases, producing more heat. When control rods are inserted into the core, more neutrons are absorbed, and the chain reaction slows down or stops, thus no heat is produced. The ***control rod drive system*** controls the actual power output of a nuclear power plant.

The reactor is located inside an obvious ***containment shell***. Containment shells are made of extremely heavy concrete and dense steel to minimize the possibility of a reactor breech due to accidental situations. In the event of an emergency, nuclear power plants use an emergency backup scheme of quickly injecting ***boron*** into the reactor coolant. Boron is an element that absorbs neutrons rapidly. The reactor shuts down by absorbing neutrons.

Operationally, nuclear power plants are commonly used as base load units, meaning online at full output continuously. They are taken offline only for maintenance purposes or during power faults (i.e., circuit breaker action). Once a nuclear-powered steam turbine is online, fully loaded, and operating stable, they are left to run 24 hours per day, 7 days per week, and 365 days per year. This approach helps to ensure reactor stability.

Most commercial nuclear reactors use ordinary water to remove heat created by the fission process. These nuclear reactors are called ***light-water reactors***. The water also serves to slow down or ***moderate*** neutrons in the fission process. In this reactor type, control mechanisms are used to stop the chain reaction if water is not present.

In the United States, there are two different types of light-water reactor designs used, ***pressurized water reactor*** (PWR) and ***boiling water reactor*** (BWR). Note there are approximately 70% more PWR nuclear power plants in the United States than BWR.

Pressurized Water Reactor (PWR) The basic design of the more popular PWR is shown in Figure 2-4. The reactor and primary steam generator are housed inside the containment structure or shell. The structure is designed to withstand events, such as small airplane crashes. The PWR type steam generator separates radioactive water created inside the reactor from production steam used to drive the turbine outside the containment shell.

In a PWR, heat is transferred from the reactor's radioactive water to water flowing in a separate closed pressurized loop. The heat is transferred from radioactive water to a second water loop through a ***heat exchanger*** (often called ***steam generator***). The second loop is kept at a lower pressure, allowing water to boil and create steam. This steam is used to turn the turbine generator and produce electricity. Afterwards, the spent steam is condensed back into water and returned to the heat exchanger where it is recycled into useable steam.

The normal control of reactor output power is by means of a ***control rod system***. Control rods are normally inserted into the reactor core, controlled from above,

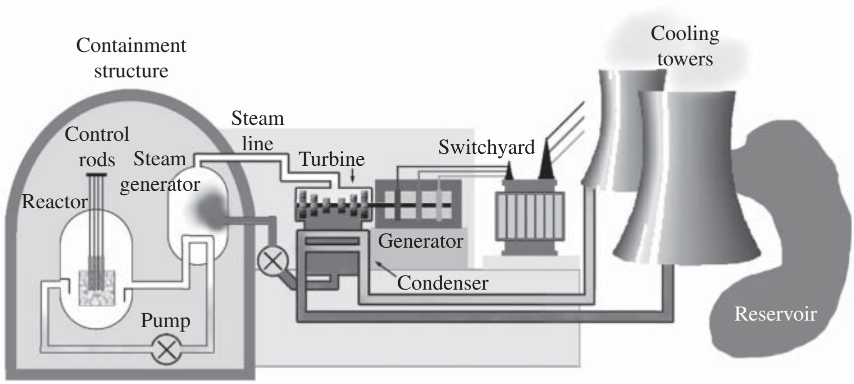


Figure 2-4 Pressurized water reactor.

where gravity is used to control output power. In the event of an emergency, the rods can drop into the core to shut down the reactor. Special springs and release mechanisms are used to drop the rods into the reactor core during an emergency.

Advantages and Disadvantages of PWR As with any design, PWRs have advantages and disadvantages. A major advantage is fuel leaks, such as ruptured fuel rods, are isolated to the core, and primary loop area. That is, radioactive material contained inside fuel is not allowed to escape the containment shell. PWRs can be operated at higher temperature/pressure combinations; thus, turbine generator systems can operate at increased efficiency.

Another advantage is PWRs are more stable than other designs. Since boiling water is not allowed to occur inside the reactor vessel, reactor core water density is more constant. Control systems are somewhat simplified when water density variability is stable.

Reactor design complexity appears to be the biggest disadvantage in PWRs. Reactor designs must ensure that boiling does not take place inside the reactor core from extremely high pressures and temperatures. The use of high-pressure vessels makes the overall reactor somewhat more costly to build. Finally, fuel rod damage can occur under certain operating circumstances since the PWR can produce power at a faster rate than condenser cooling water can remove heat from spent steam.

Boiling Water Reactor (BWR) Figure 2-5 shows the BWR. Again, there is a reactor building or containment shell housing the nuclear reactor and some of its complement equipment. The BWR housing tends to be larger than the PWR. The BWR looks almost like an inverted light bulb.

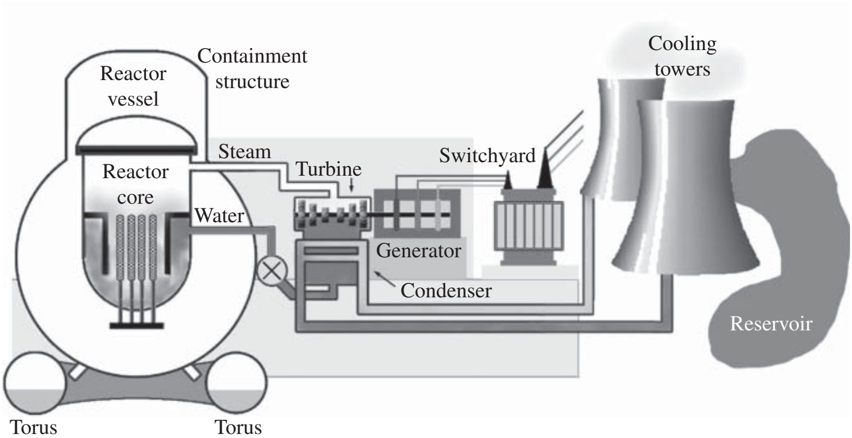


Figure 2-5 Boiling water reactor.

In a BWR, water boils inside the reactor itself, and steam goes directly to the turbine generator. Like other steam power plants, the steam is condensed and reused. Note that the turbine building is closely coupled to the reactor building, and special constraints exist in entering the turbine building because water can pick up radioactivity.

Note that the ***Torus*** is located at the bottom of the reactor. If a reactor rupture occurs, water inside the reactor will flash into steam and create a very high-pressure surge on the reactor building. The reactor Torus is filled with cold water, which will instantly condense the steam. The Torus system ensures that the pressure inside the containment shell never exceeds an acceptable level.

As with the PWR, the BWR reactor housing contains the fuel core and water flow paths. The reactor recirculation system consists of pumps and pipes that circulate the water through the reactor. The water circulating through the reactor enters the turbine, gets condensed, and returns to the reactor. A steam separator in the reactor shell is used to separate water from steam and allows the steam to pass to the turbine. The separated water is returned to the reactor for recirculation.

The BWR utilizes one cooling loop. Both water and steam coexist in the reactor core (hence, the definition of boiling). Reactor power is controlled by positioning the control rods, from start up to approximately 70% of rated power. From 70% to 100% rated power, reactor power is controlled by changing the flow of water through the core. As more water is pumped through the core and more steam generated, power production is increased. In BWR, control rods are normally inserted from the bottom. The top of the reactor vessel is used to separate water and steam.

Advantages and Disadvantages of BWR A major advantage of the BWR is overall thermal efficiency. The single-loop design does not require a separate steam generator or heat exchanger. Controlling a BWR is a little easier than a PWR, because it involves controlling water flow through the core opposed to control rods. Increasing water flow increases power generated. The BWR vessel is subjected to less radiation, thus considered an advantage because some steel become brittle with excessive radiation.

The greatest disadvantage of BWRs is the design being much more complex. BWRs require a larger pressure vessel due to the amount of steam that can be released during an accident. This larger pressure vessel increases the cost of the BWR. Finally, the design does allow a small amount of radioactive contamination to get into the turbine system. This modest amount of radioactivity requires anybody working on the turbine to wear appropriate protective clothing and use proper equipment.

Other Related Topics

(Optional Supplementary Reading)

The overall function or design of the nonnuclear portion of a nuclear power plant is on the order of complexity as fossil-fueled power plants. The biggest difference is the degree of documentation that must be maintained and submitted to regulatory authorities for proof that the design and operation is safe. Roughly speaking, there are about 80 separate systems in the nuclear power plant. The systems that are most critical are those which control power and/or limit the power output of the plant.

Environmental One of the greatest advantages of a nuclear plant, especially with today's concerns about global warming and generation of carbon dioxide due to fossil fuel burning, is the fact that a nuclear plant essentially adds zero emissions to the atmosphere. There is no exhaust smokestack!

SCRAM A reactor ***SCRAM*** is an emergency shutdown situation. Basically, all control rods are driven into the reactor core as rapidly as possible to shut down the reactor to stop heat production. A SCRAM occurs when some protective device or sensor triggers the control rod drive system. Some typical protective signals that might initiate or trigger a SCRAM include a sudden change in neutron production, a sudden change in temperatures inside the reactor shell, sudden change in pressures, or other potential system malfunction.

By inserting the control rods into the reactor core, the reactor power is slowed down or stopped because the control rod materials absorb neutrons. If the neutrons are absorbed, they cannot cause fission in additional uranium atoms.

Anytime there is a reactor SCRAM, the cause must be fully identified, and appropriate remedial actions are taken before the reactor can be restarted. A reactor SCRAM usually results in a great deal of paperwork to establish the fact that the reactor can be safely restarted.

There are various theories as to where the term SCRAM came from. One theory says that around the World War II era, the original nuclear reactors were controlled manually. As a safety measure, reactors were designed to drop the control rods into the reactor core by gravity to absorb the neutrons. The control rods were held up by a rope. In case of emergency, the rope was to be cut to allow the rods to drop. The person responsible for cutting the rope in case of any emergency was called the SCRAM. According to the Nuclear Regulatory Commission, SCRAM stands for "*safety control rod axe man*." Now, SCRAM stands for any emergency shutdown of the reactor for any reason.

Equipment Vibration Equipment vibration is probably the biggest single problem in nuclear power plants. Every individual component is monitored by a central computer system for vibration indications. If excessive vibration is detected the system involved must be quickly shut down. (Note that this is also true of regular steam plants. If excessive vibration is detected in the turbine or generator, they will be shut down immediately.)

Nuclear power plants seem to be particularly susceptible to vibration problems, especially on the protective relay panels. Excessive vibration can cause inadvertent relay operations, shutting down a system, or the complete plant.

Microprocessor-based protection relay equipment is basically immune to vibration problems, but there is a perception that the solid-state circuits used in such relays may be damaged by radiation. Many nuclear power plants still use electromechanical relays as backup to the microprocessor solid-state relays.

Small Modular Reactors ***Small modular reactors*** (SMRs) are currently viewed as the next evolution of nuclear energy. Based on the same fission technology that splits atoms to create heat, these reactors are coupled to smaller steam turbines (approximately 300 MWs compared to 1,000 MWs). One of the primary benefits of SMRs is they are positioned to become prefabricated reactor modules, having the potential to significantly reduce cost, design complexity, implementation complications, and regulatory constraints. SMRs are smaller in size and in many cases have the potential to be delivered already fueled to operate for many years.

Hydroelectric Power Plants

Hydroelectric power plants capture the energy of moving water. There are multiple ways hydroenergy can be extracted. Falling hydroelectric power plants such as in a penstock, flume, or water wheel can be used to drive a hydroturbine to generate electricity. Hydroenergy can be extracted from flowing water hydroelectric power plants such as the lower section of dams where high-pressure water forces are used to produce electricity in a hydroturbine. Hydroelectric power generation is efficient, cost effective, and environmentally cooperative. Hydropower production is a renewable energy source because the water cycle is continuous and constantly recharged.

Water flows much slower through a hydroturbine than a high-pressure steam turbine. Therefore, several rotor magnetic poles are used to reduce the rotational speed requirement of the hydroturbine shaft.

Hydro units have several excellent advantages. The hydro unit can be started very quickly and brought up to full load in a matter of minutes. In most cases, little or no start-up power is required. A hydro plant is almost by definition, a ***black start*** unit. Black start means that electrical power is not needed first to start a hydropower plant. Hydro plants have a relatively long life; 50–60-year life spans are common. Some hydroelectric power plants along the Truckee River in California have been in operation for well over 100 years. Figure 2-6 shows a typical hydroelectric power plant.

The cross-section of a typical low head hydro installation is shown in Figure 2-7. Basically, the water behind the dam is transported to the turbine by means of a ***penstock***. The turbine causes the generator to rotate producing electricity, which is then delivered to the load center over long-distance high-voltage power lines. The water coming out of the turbine goes into the river.

Pumped Storage Hydropower Plants

Pumped storage hydropower production is a means of saving electricity for future use. Power is generated from water falling from a higher lake to a lower

Figure 2-6 Hydroelectric power. Reproduced with permission of Photovault.

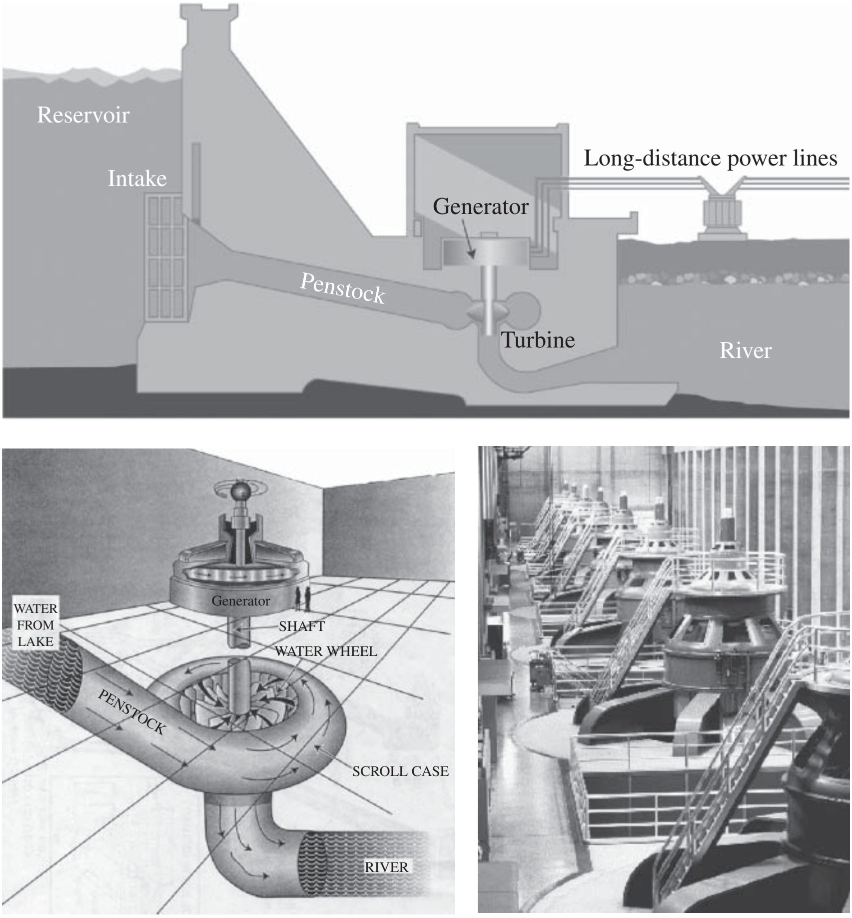


Figure 2-7 Hydropower plant.

lake during peak demand periods. The operation is reversed during off-peak conditions by pumping the water from the lower lake back to the upper lake. A power company can obtain high-value, low-cost power during peak load generation periods by paying the lower cost to pump the water back during off-peak periods. Basically, the machine at the lower level is reversible; hence, it operates as a hydro generator unit or a motor-pump unit.

One of the problems associated with pumped storage units is the process of getting the pumping motor started. Starting the pumping motor using the system's power line would usually put a low-voltage sag condition on the power system. The voltage sag or dip could cause power quality problems. In some cases, two

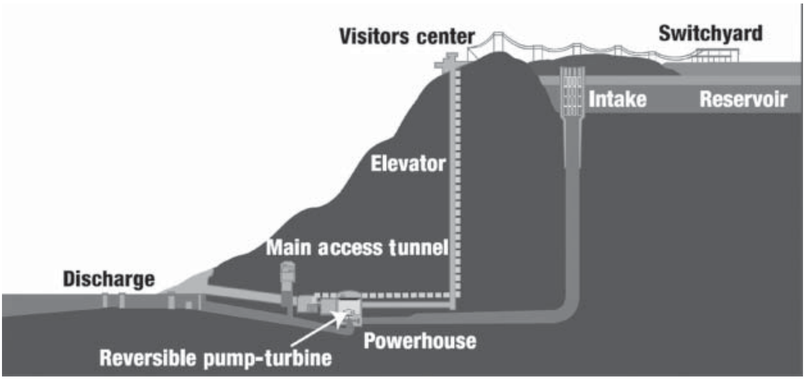


Figure 2-8 Pump storage power plant.

turbines are used in a pumped storage installation. One of the turbines is used as a generator to start the other turbine as a pump. Once the turbine is turning, the impact on the power system is much less, and the second turbine can then be started as a motor pump.

Figure 2-8 shows a cross-sectional view of the Tennessee Valley Authority's pumped storage plant at Raccoon Mountain. The main access tunnel was originally used to bring equipment into the powerhouse (i.e., turbines, pumps, and auxiliary equipment). The Tennessee Valley Authority installed a visitor center at the top of the mountain for the public to see the installation. There are several such pump storage facilities in the United States.

Combustion Turbine Generation Plants

Combustion Turbine (CT) power plants burn fuel in a jet engine and use the hot exhaust gasses to spin a turbine generator. In the CT generator, air is compressed to a very high pressure, fuel is then injected into the compressed air and ignited producing high-pressure and high-temperature exhaust gases. The exhaust gases are vented to the atmosphere. The exhaust gas movement through the CT results in rotation of the generator rotor, thus producing electricity. The exhaust gases from the CT remains at a very high temperature and pressure after leaving the turbine. Figure 2-9 shows a CT generator.

One significant advantage of CTs is they can be remotely controlled for unmanned sites. They offer fast start-up times and fast installation times. In some cases, the purchase of a CT generator system can be "turnkey," that is, the owner simply contracts for a complete installation and takes over when the plant is finished and ready to operate. In most cases, the CT generator package is a

Figure 2-9 Combustion turbine power plant.

completely self-contained unit. In fact, some of the smaller capacity systems are built on trailers to be moved quickly to sites requiring emergency generation.

CTs can be extremely responsive to power system changes. They can go from no load to full load and vice versa in a matter of seconds or minutes.

The disadvantages are limited fuel options (i.e., diesel fuel, jet fuel, or natural gas) and inefficient use of exhaust heat.

There are environmental issues related to the use of CTs. Without appropriate treatment, exhaust emissions can be very high in undesirable gases. The high temperatures in the combustion chamber will increase the production of nitric oxide gases and their emissions. Depending on the fuel used, there can be particulate emissions concerns. That is, particles or other material tend to increase the opacity (i.e., smoke) of the gases. Sound levels around CT installations can be very high. Special sound reduction systems are available and used. (Note that CTs are typically jet engines very similar to those heard at airports.)

The heat rate or efficiency of a simple cycle CT is not very good. The efficiencies are somewhere in the range of 20–40% maximum.

One effective way to overcome some inefficiency cost is to incorporate a heat exchanger to the exhaust gases to generate steam to drive a secondary steam turbine generator.

Combined Cycle Power Plants (Combustion and Steam)

The ***combined cycle*** (CC) ***power plant*** consists of two means of generation: CT and steam turbine. The CT is like a jet engine whose high-temperature and high-pressure exhaust spins a turbine whose shaft is connected to a generator. The hot exhaust gases are then coupled through a ***heat recovery steam generator*** (HRSG) that is used to heat water to produce steam to drive a secondary STG. The CT typically uses natural gas as the fuel to drive the turbine blades.

The advantage of a CC system is improved efficiency by using the exhaust from the combustion engine to produce electrical energy. Another potential benefit of CC plants is the end user has steam available to assist other functions such as building heat, hot water, and other production processes that require steam (e.g., a nearby paper mill). Therefore, for one source of fuel (i.e., natural gas), many energy services are provided (electrical energy, steam, hot water, and building heat). Some CCs can reach efficiencies near 90%. Figure 2-10 shows a CC power plant.

Renewable Energy

The use of renewable energy resources is growing at a rapid rate. Renewable energy resources are primarily made up of the following generation types:

- Hydro and pumped storage
- Wind

Figure 2-10 Combined cycle power plant.

- Solar thermal and photovoltaic
- Geothermal
- Biomass

Some of these renewable energy resource types have idiosyncrasies that constrain growth. For example, hydro growth is limited since most rivers in the United States already have fully implemented hydrogeneration. Geothermal has limited growth potential because there are limited areas in the United States that can support this type of generation. Biomass (i.e., biopower), especially agricultural residue type requires research and creative production techniques to make this resource a significant contributor in the United States' energy market. This leaves wind and both types of solar (thermal and photovoltaic) to represent large-scale growth in the United States.

The chart in Figure 2-11 shows U.S. growth (2010–2022) in renewable energy by generation type according to U.S. Energy Information Administration (EIA). The graph on the right breaks down the renewables. Note that how renewables surpassed coal and nuclear in 2022. Coal and nuclear power continue to decline in output. Natural gas remains the largest source of U.S. electricity generation. Wind and utility scale solar continue to increase while hydro, geothermal, and biomass remain relatively flat. Meanwhile, petroleum-based generation (i.e., oil) remains relatively low, essentially not impacting the graph.

Since the advent of increased renewables and decreasing fossil fuel generation, the U.S. annual energy-related CO_2 emissions have decreased, see Figure 2-12.

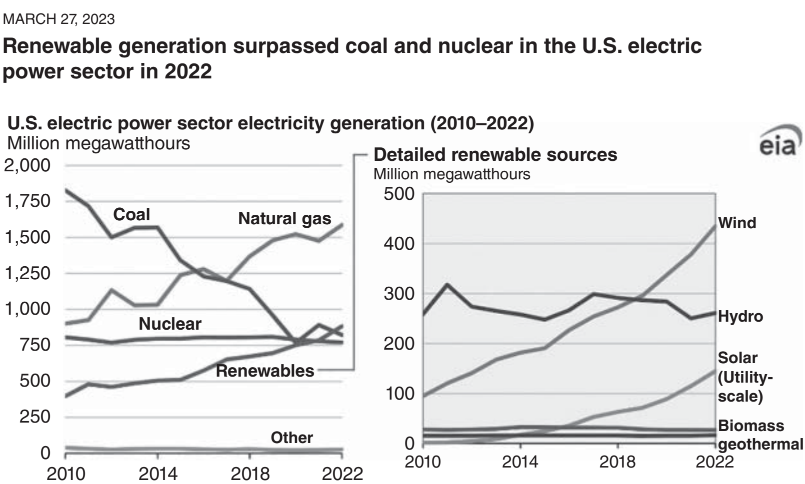


Figure 2-11 U.S. renewable energy growth. U.S. Energy Information Administration/Public Domain.

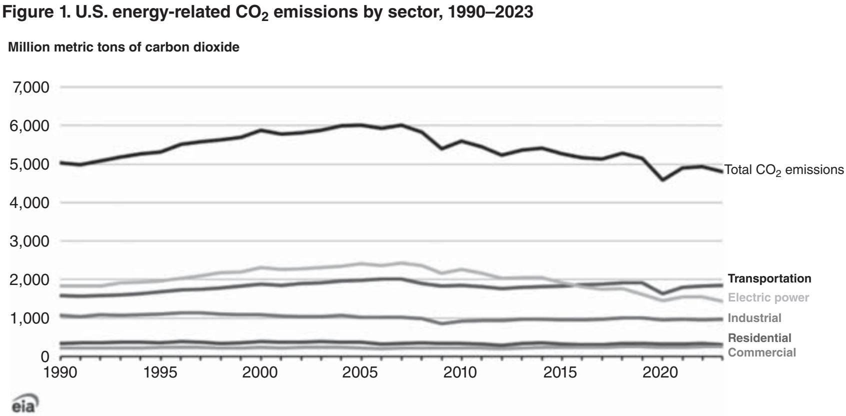


Figure 2-12 U.S. energy related CO_2 emissions by sector. U.S. Energy Information Administration, Monthly Energy Review, March 2024/U.S. Energy Information Administration/Public Domain.

Operational constraints on grid reliability can occur from having too much renewable-based generation. For example, wind and solar generation reduce the grid's spinning inertia (i.e., nonrotating generation resources), impacting fault current magnitudes, thus affecting protective relay schemes intended to ensure grid reliability. Spinning inertia is critical to system reliability and both solar and wind generation can affect this requirement if too much is used to power grids. Revisions to industry guidelines (i.e., IEEE) and regulatory reliability standards (i.e., NERC) are occurring to accommodate more inverter-based renewable energy resources. (More to come in Chapter 8, Interconnected Power Systems, and Chapter 10, The Transitioning Digital Power Grid System.)

Cost of Renewable Energy Generation

On a worldwide basis, generation costs for renewable energy generation types are somewhat converging toward similarity, according to International Renewable Energy Agency (2023)[1], see Figure 2-13. Furthermore, the total system estimated levelized cost of electricity (LCOE) for new generation resources in the U.S. entering service in 2024 for standalone solar ($33.07/MWh) and onshore wind ($34.92/MWh) power generation are very comparable per EIA[2]. Thus, the cost for renewable energy resources is scaling toward similarity with concentrated solar

1 International Renewable Energy Agency (2023) – with minor processing by Our World in Data.
2 Eia Annual Energy Outlook 2022, Appendix A.

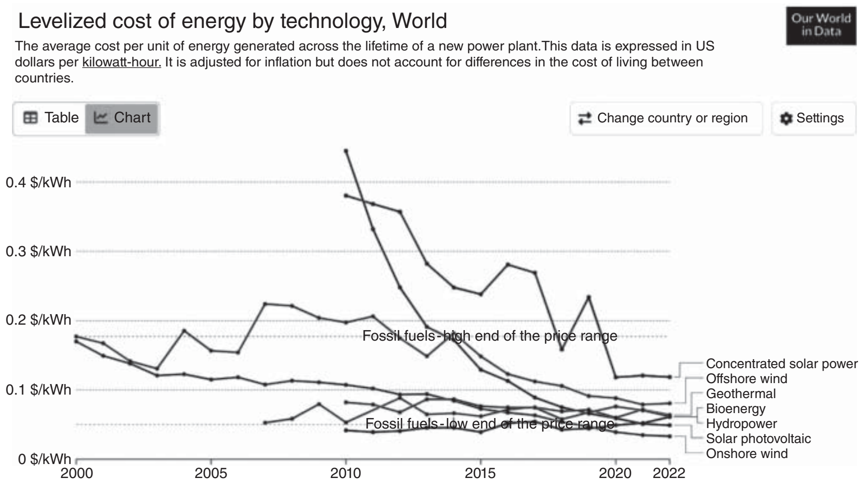


Figure 2-13 Worldwide levelized cost of energy by technology.

and offshore wind being highest cost and solar photovoltaic (PV) and onshore wind being least cost.

Wind Turbine Generators

Wind generation increased in popularity, technology, and capacity over recent years. In the year 2006, total installed capacity of U.S. wind generation was about 11 GW (11,000,000,000 watts). In 2018, installed wind capacity in the United States grew to 96 GW (NREL[3]). In 2022, reports indicate installed wind capacity grew to 142 GW (EIA[4]).

On- and offshore wind turbine generators continue to be installed worldwide. The total installed wind capacity worldwide in 2014 was about 319 GW. In 2018, installed wind capacity worldwide grew to about 564 GW. In 2023, total installed wind capacity worldwide is approximately 1,000 GW (GWEC[5]). Figure 2-14 shows typical onshore wind turbine generators.

Although wind turbine generators tend to be high cost per kWh produced, wind energy prices are declining and are increasingly becoming a competitive choice of power. With improving technology and site location techniques, wind energy is increasingly becoming one of the most affordable forms of electricity today.

There is concern, however, for reliable constant wind power production. Most power companies do not consider wind generators to be ***base load*** units. Base

3 NREL 2018 Renewable Energy Data Book.
4 Eia.gov website, 05/07/2024, Table 4.3, Existing Capacity by Energy Source, 2022.
5 GWEC 2024, Global Wind Report, page 2.

Figure 2-14 Wind power. Fokke Baarssen/Adobe Stock Photo.

load implies readily available for a 24-hour production schedule. Wind generation is brought online when available.

Wind energy is converted into electrical energy by means of wind turbines. Wind turbine design, efficiency, reliability, and availability have improved significantly over recent years. One interesting characteristic of wind power is electrical power produced is proportional to the cube of wind speed. In other words, if wind speed doubles, output power triples or increases by a factor of eight. Thus, what might appear to humans as modest fluctuations in wind speed or breezes can severely impact wind power production and potentially system frequency stability. Modern wind turbines use power stabilizing schemes to help stabilize power production, such as doubly fed inverters, computer programed modes of operation, and well-studied locations.

Offshore wind generation, shown in Figure 2-15, has very favorable attributes to wind power efficiency and consistency. Wind power efficiency is referenced to sea level and decreases with increase in elevation. Wind power output is directly affected by air density; thus, derating occurs as elevation increases. The higher the air density (i.e., sea level), the higher the power output for the same wind speed. However, offshore wind does have its visual impact controversies.

The installation of wind power generators requires selecting sites that are relatively unrestricted to wind flow, have high air density, and are within proximity to suitable powerlines. Offshore wind power is typically transported via direct

Figure 2-15 Offshore wind turbines. Courtesy of ABB.

current (dc) submersible cables to shoreline alternating current (ac) inverter stations where connection to the grid occurs.

Wind power is considered a renewable energy resource since wind sustains itself. Wind power is accepted as free energy with no fuel costs. There is, however, an operating limit to how much wind power can be added to the grid due to required system stability and reliability constraints. (This concern is discussed in more detail later in Chapter 8, Interconnected Power Systems.)

According to NREL[6], in 2018, total wind capacity in the United States exceeded 96 GW and globally 564 GW, see Figure 2-16.

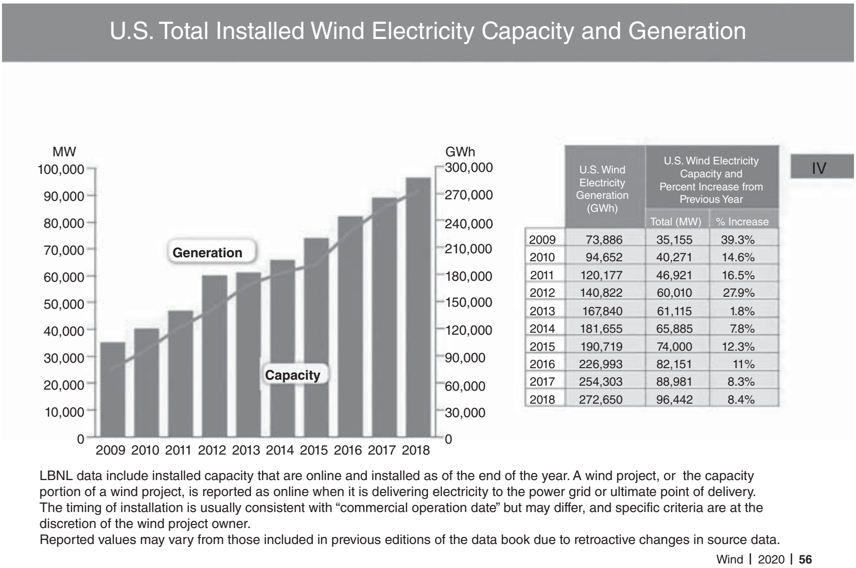
Solar Thermal

Solar energy comes in two general categories: ***solar thermal*** (sometimes called ***solar-reflective*** using mirrors) and ***solar photovoltaic*** (PV using panels). Both forms of solar energy production are environmentally friendly as they produce no pollution and are considered renewable energy resources.

Large-scale ***solar reflective power plants*** (also called "***concentrating solar power***" or CSP) require substantial acreage as well as specific orientation to the sun for maximum efficiently.

Solar energy is reflected off mirrors and concentrated in a centralized boiler system. The mirrors are parabolic-shaped and motorized to focus sun energy on

6 NREL 2018 Renewable Energy Data Book.



	U.S. Wind Electricity Generation (GWh)	U.S. Wind Electricity Capacity and Percent Increase from Previous Year	
		Total (MW)	% Increase
2009	73,886	35,155	39.3%
2010	94,652	40,271	14.6%
2011	120,177	46,921	16.5%
2012	140,822	60,010	27.9%
2013	167,840	61,115	1.8%
2014	181,655	65,885	7.8%
2015	190,719	74,000	12.3%
2016	226,993	82,151	11%
2017	254,303	88,981	8.3%
2018	272,650	96,442	8.4%

Figure 2-16 U.S. installed wind capacity and generation. Adapted from LBNL Wind Technologies Market Report (capacity data) and BIA (generation data).

receiver tubes located in the collector area of an elevated boiler. Receiver tubes contain a heat transfer fluid (e.g., saltwater solution) used in the steam-boiler-turbine system. The collector area housing the receiver tubes absorbs the focused sun energy to gain 30–100 times normal solar energy. The fluid in these tubes can reach operating temperatures of more than 752 degrees Fahrenheit (400 degrees Celsius). Like most steam turbines, this steam drives the turbine, spent steam passes through a condenser, and pumped back to the boiler where it is reheated. A typical solar reflective power plant is shown in Figure 2-17.

The growth in U.S. CSP installed capacity and generation according to EIA is shown in Figure 2-18.

Solar Direct Generation (Photovoltaic)

The ***photovoltaic*** (sometimes called "PV" for short) type solar power plant converts sun energy directly into electrical energy. A photovoltaic array is shown in Figure 2-19. This type of solar production uses various films or special materials to convert sunlight into dc electrical energy. Individual cells are connected in series and parallel to obtain modules. Modules are connected in series and parallel to obtain panels. These panels specify ranges in dc output voltage and current that depends on available sunlight and load. A panel's output power varies with

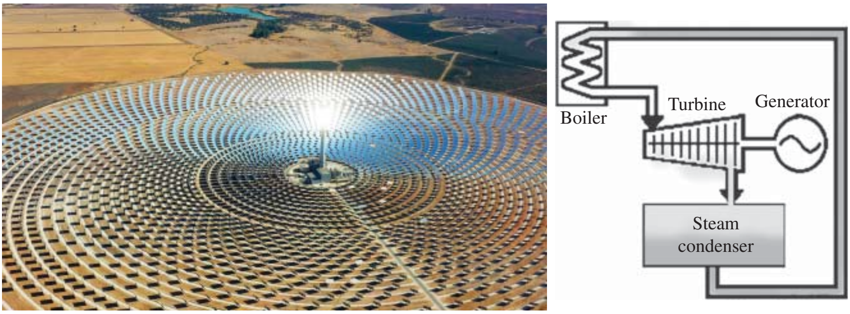
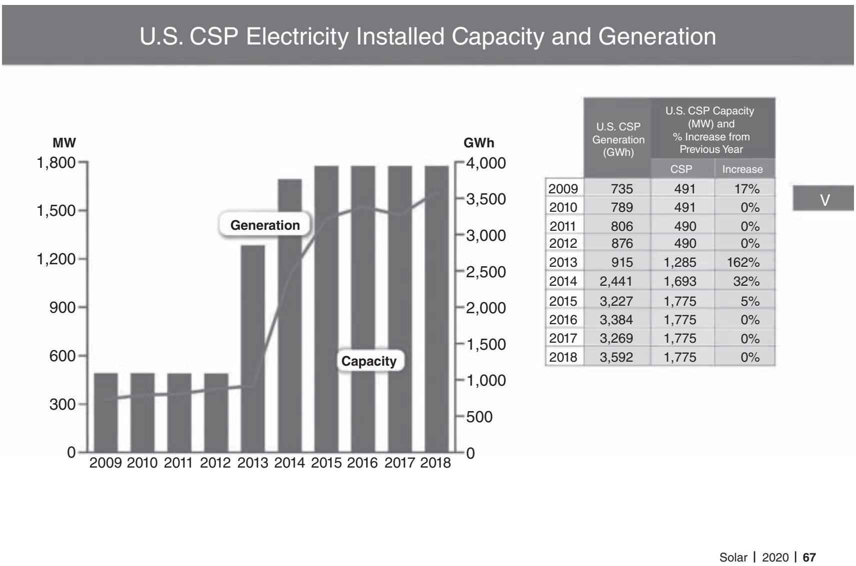


Figure 2-17 Reflective solar power plant. Fly_and_Dive/Shutterstock.



	U.S. CSP Generation (GWh)	U.S. CSP Capacity (MW) and % Increase from Previous Year	
		CSP	Increase
2009	735	491	17%
2010	789	491	0%
2011	806	490	0%
2012	876	490	0%
2013	915	1,285	162%
2014	2,441	1,693	32%
2015	3,227	1,775	5%
2016	3,384	1,775	0%
2017	3,269	1,775	0%
2018	3,592	1,775	0%

Figure 2-18 CSP installed capacity and generation. Adapted from EIA CSP capacity is reported in MW.

sun intensity, attack angle, and object shadowing. Panels are connected in series and parallel to become solar arrays of generation. Very large groups of arrays are referred to as solar farms.

This dc energy source is converted to utility ac energy by an ***inverter***. Inverters are built and operated to hold ac voltage or current output constant. Constant current inverters provide constant power out and are typically tripped offline during system disturbances. Whereas constant voltage inverters output active and reactive power to maintain voltage. As discussed in more detail later, constant voltage inverters, with voltage and frequency ride through capability, help improve system voltage and reliability as available spinning inertia declines.

Figure 2-19 Direct solar photovoltaic. Yoshi0511/Shutterstock.

The inverter's ac power output is connected to the power grid. Some smaller inverter systems (i.e., residential roof top systems) use an energy storage device (i.e., battery) to provide PV provided power during off-sunny periods. Large battery systems are also used to provide grid level support when large solar farms are not generating power during off-sunny periods.

One can only imagine how the future brings many exciting opportunities for residential customers to incorporate solar PV grid-tie systems, electric vehicles, low-voltage lighting, home energy management systems, and other new control and automation technology devices. Many consumers already employ apps and digital devices for home automation to control appliances, lighting, etc. with high energy efficiency.

A typical solar photovoltaic panel is made up of several small solar cells and modules, measuring roughly 4 feet tall by 2 feet wide (approximately 8 square-feet). Each solar PV panel produces approximately 250–350 watts of electrical power. Since sun energy received is approximately 1000 watts per square-meter (roughly 9 square-feet), thus making PV panels roughly 25–35% efficient.

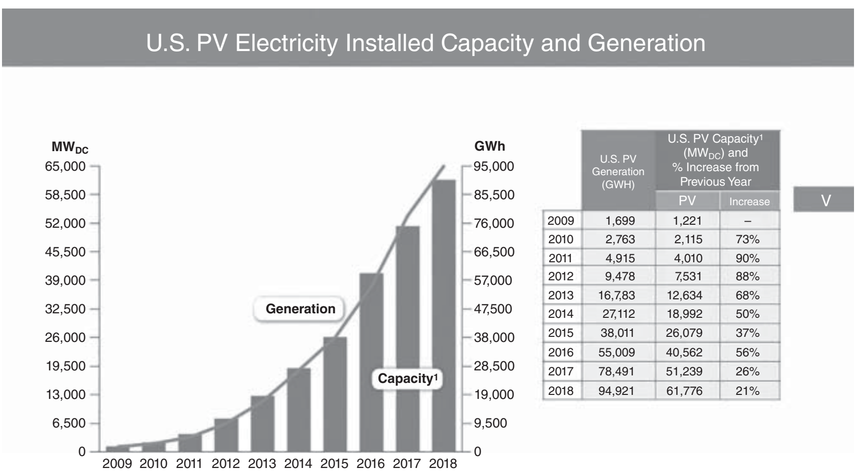
For example, a 20 panel PV array (250 watts each) will have a combined output power rating of 5 kW at full sunlight exposure. From an energy standpoint, if there are five sunlight hours per day for 30 days (i.e., 1 month), the energy produced from this 20-panel solar array would be approximately 750 kWh (250 watts × 20 panels

× 5 hours × 30 days = 750 kWh). This represents a typical residential rooftop solar PV installation that can run several household appliances, lighting, and electric vehicle charging comfortably.

Depending on location, state and federal incentives are available to encourage installing residential, commercial, industrial, and large-scale privately owned solar PV generation systems. One must determine whether federal tax credits, special bank loan rates, attractive utility grid-tie tariff agreements, and other encouraging incentives are available to make a solar project cash flow affordable, cost effective, and worthwhile. This approach to augmenting utility power bills is in high pursuit and continues to grow.

Utilities and special interest groups build large-scale solar farms to help meet growing demand for electrical energy while offsetting fossil fuel generation and carbon emission. This environmentally safe approach to electrical energy production is growing fast. Note that like wind generation, there are drawbacks to having too much solar power on the grid and this situation is discussed in more detail later. (Chapter 8, Interconnected Power Systems.)

According to the National Renewable Energy Laboratory (NREL), solar growth has been substantial. The chart in Figure 2-20 shows the growth in installed capacity and energy generation in the United States.



	U.S. PV Generation (GWH)	U.S. PV Capacity[1] (MW_{DC}) and % Increase from Previous Year	
		PV	Increase
2009	1,699	1,221	–
2010	2,763	2,115	73%
2011	4,915	4,010	90%
2012	9,478	7,531	88%
2013	16,7,83	12,634	68%
2014	27,112	18,992	50%
2015	38,011	26,079	37%
2016	55,009	40,562	56%
2017	78,491	51,239	26%
2018	94,921	61,776	21%

PV capacity in this section is reported in MW_{DC}.
[1]Grid-connected only; PV capacity in this section is reported in MW_{DC}. A de-rate of 80% has been used to convert utility-scale solar from MW_{AC} to MW_{DC}.

Figure 2-20 Solar installation growth. Adapted from EIA, SEIA/GTM, PVWatts PV capacity in this section.

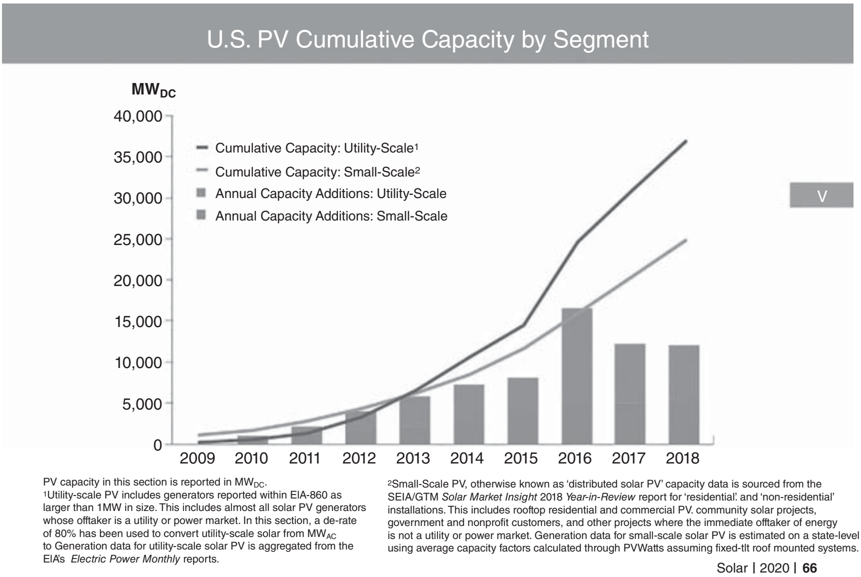


Figure 2-21 Solar growth by sector. Adapted from DIA, SEBA/GTH, and PVWatts.

The chart in Figure 2-21 shows utility and small-scale growth in solar power according to NREL.

Solar power is environmentally friendly as it produces no pollution. Positive growth in solar power technology, installed capacity, improved utility operations, and governmental incentives continue into the foreseeable future.

Geothermal Power Plants

Geothermal power plants use hot water or steam located underground to produce electrical energy. Hot water and/or steam are brought to the surface where heat exchangers produce clean steam for turbines in a secondary system. Heat exchangers and clean steam reduce maintenance by eliminating sediment growth inside pipes and equipment. Clean steam is converted into electrical energy much the same way as fossil-fueled steam turbine plants.

While geothermal is a good renewable energy resource for reliable power, concern is that long-term effects may reduce the geothermal resource (i.e., dry up, reduce availability, or lose pressure). A typical geothermal power plant is shown in Figure 2-22.

According to the NREL, U.S. Geothermal installed capacity and generation growth remains relatively constant at 3.5 GW, as shown in Figure 2-23.

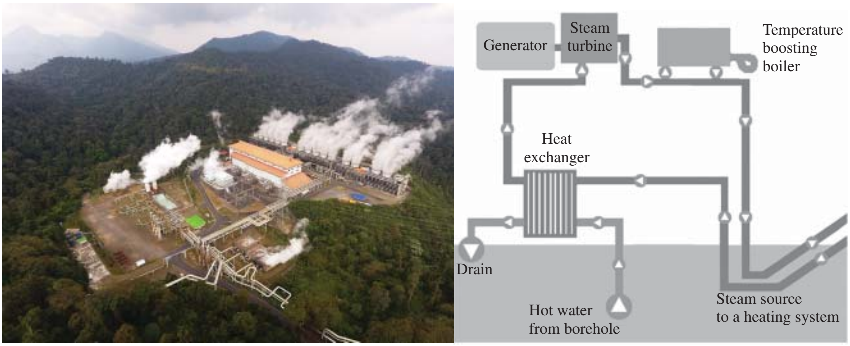
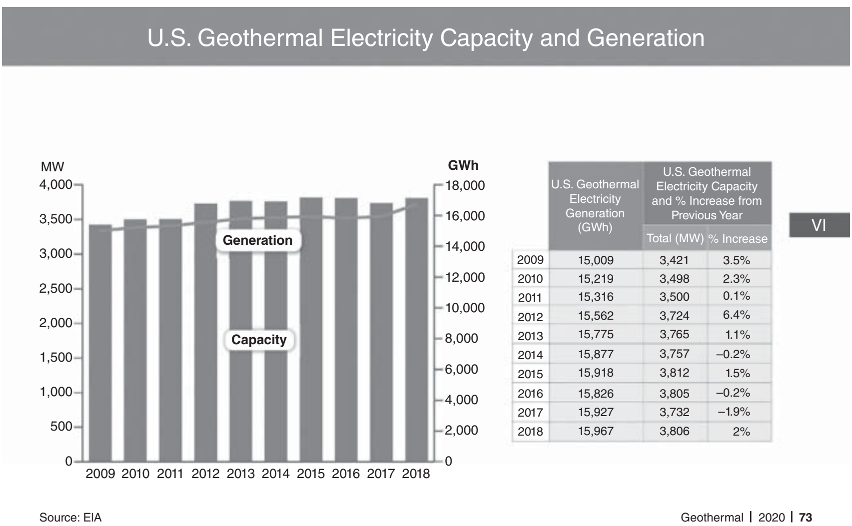


Figure 2-22 Geothermal power plants. Waterwind/Shutterstock.

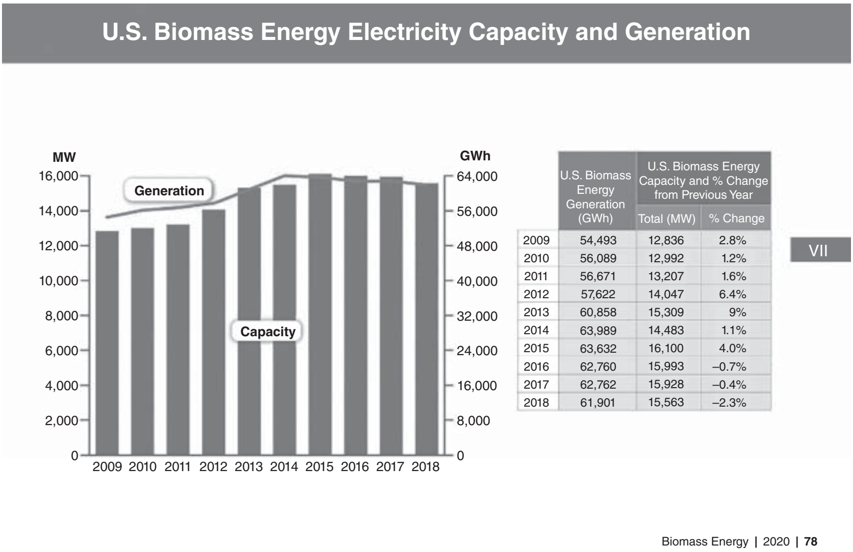


	U.S. Geothermal Electricity Generation (GWh)	U.S. Geothermal Electricity Capacity and % Increase from Previous Year	
		Total (MW)	% Increase
2009	15,009	3,421	3.5%
2010	15,219	3,498	2.3%
2011	15,316	3,500	0.1%
2012	15,562	3,724	6.4%
2013	15,775	3,765	1.1%
2014	15,877	3,757	–0.2%
2015	15,918	3,812	1.5%
2016	15,826	3,805	–0.2%
2017	15,927	3,732	–1.9%
2018	15,967	3,806	2%

Figure 2-23 U.S. geothermal installed capacity and generation. Adapted from EIA.

Biomass

Another form of renewable energy is called "***Biomass***," sometimes referred to as "***Biopower***." Biomass is organic matter derived from living or recently living organisms that can be used as a source of energy in combustion or indirectly in the form of biofuel. Biomass comes primarily from wood and agricultural residues that are burned as fuel. Biomass capacity has declined in recent years to 16 GW in 2018. Biomass accounts for almost 8.3% of all renewable energy generated in the United States and about 1.4% of total U.S. generation from all sources.



	U.S. Biomass Energy Generation (GWh)	U.S. Biomass Energy Capacity and % Change from Previous Year: Total (MW)	% Change
2009	54,493	12,836	2.8%
2010	56,089	12,992	1.2%
2011	56,671	13,207	1.6%
2012	57,622	14,047	6.4%
2013	60,858	15,309	9%
2014	63,989	14,483	1.1%
2015	63,632	16,100	4.0%
2016	62,760	15,993	–0.7%
2017	62,762	15,928	–0.4%
2018	61,901	15,563	–2.3%

Figure 2-24 Biopower growth in United States. Adapted from EBA Reported values may vary from those.

The NREL chart shown in Figure 2-24 provides the growth picture in the United States for biomass power.

Inverter-based Resources

(Optional Supplementary Reading)
Inverter-based resources (IBRs) are becoming a significant energy resource to meet future demand needs and to replace retired fossil-fueled mechanical steam generators. IBRs deploy energy resources that incorporate dc-to-ac power inverters to interface with the bulk ac transmission grid system or the local distribution system. Utility scale IBRs include large solar photovoltaic farms, wind turbine farms, and large-scale energy storage batteries. Similarly, dc transmission lines (discussed later in Chapter 3, Transmission) also use back-to-back dc-to-ac inverters at their line terminal locations to interconnect with the grid.

In contrast to synchronous rotational mechanical energy STGs that have significant spinning inertia to power through most system disturbances, traditional IBRs cease operation during disturbances because they cannot ride through events unless programmed to do so. The continued loss of spinning inertia resources on the transmission system by the growth in IBRs presented a concern for future grid reliability.

FERC order No. 901 (of October 2023) directs NERC to develop new or modified transmission reliability standards that comprehensively address the reliability risks presented by IBRs. In other words, protective relays that are used to monitor grid operations and initiate circuit breaker trip commands when abnormal conditions occur are now being required to restrain tripping momentarily to help provide high fault current during initial stages of major disturbances. Protective relays depend on high fault current flow from online spinning inertia turbines to satisfy programmable relay pickup settings, thus sensing disturbance conditions and to initiate breaker trip commands. Traditionally, IBR's power output would cease operations during system disturbances, thus reducing available fault current needed to initiate breaker trip signals. IEEE standard 2800-2022 (Standard for Interconnecting and Interoperability of IBR Interconnecting with Associated Transmission Electric Power Systems) for interconnecting IBRs to transmission facilities and NERC reliability standard PRC-024-2 (Generator Frequency and Voltage Protective Relay Settings) for generator frequency and voltage ride through requirements were developed to help IBRs react to grid disturbances in a manner that is more supportive toward grid reliability.

In essence, traditional utility-scale IBRs power control schemes are transitioning from "grid-following" (GFL) inverters to "grid-forming" (GFM) inverters. GFL inverters work well with power grids dominated by synchronous mechanical generators and cease operation during system disturbances. Whereas GFM inverters synchronize with the grid and work well with a high concentration of IBRs by regulating real and reactive power exchange with the grid by controlling voltage magnitude, frequency, and angle at the point of connection. Thus, GFL inverters react to disturbances more like spinning inertia turbines where power output rides through the initial stages of a disturbance. GFL inverters adjust to a limited high fault current output instead of ceasing operations. Also, GFL controls can be used in islanded power systems running independently from the grid (i.e., microgrids).

In summary, IBRs differ from conventional synchronous generators in many ways: they (1) are driven by power electronics and software; (2) have no spinning inertia; (3) provide very limited fault current or cease operations during disturbances; and (4) are dispatchable based on available capacity (e.g., wind speed). When properly interfaced, IBRs provide favorable characteristics: they (1) offer very fast reactions to disturbances; (2) provide fast frequency and voltage control, and (3) require minimal auxiliary equipment.

Figure 2-25 shows a general block diagram of an IBR where a dc power source is converted into an ac power source for grid interconnection. Power electronic components, such as thyristors, triacs, or the older term "valves" are used to meet high-power flow requirements of utility scale energy resources. These power electronic devices are controlled by solid-state circuitry to switch these high-power devices on/off quickly. Banking these high-power electronic components in series

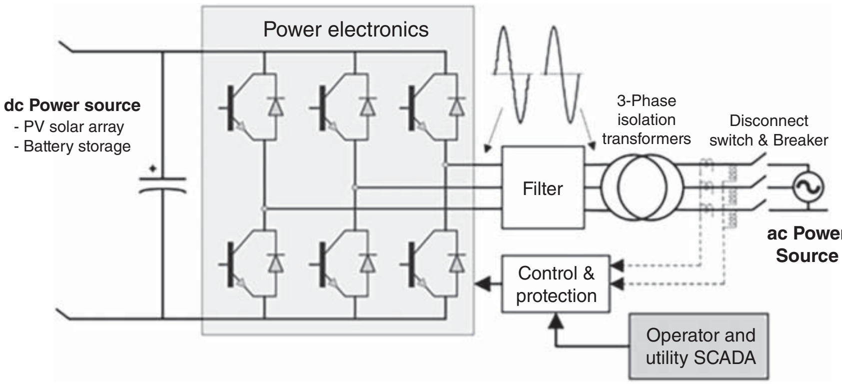


Figure 2-25 IBR block diagram.

and parallel provides a choppy sine wave output signal, which then gets filtered to produce a quality ac power sine wave needed for interconnection. Passive filters (i.e., inductors and capacitors) are used to remove high-frequency harmonic distortion caused by the switching components, resulting in clean power sine waves.

Power electronics have the capability of very fast switching but lack spinning reserve, thus impacting grid reliability during disturbances. Weak grids, especially those dominated by IBRs, are prone to voltage instability and low-voltage oscillations. Strong grids, those dominated by spinning inertia mechanical energy resources, help provide grid stability. Fortunately, the control of IBRs is improving continuously to better emulate spinning inertia system stabilizing characteristics (i.e., voltage and frequency ride-through provisions during the initial phase of system disturbances).

3

Transmission Lines

Chapter Objectives

After completing this chapter, the reader will be able to:

☑ *Explain why high-voltage transmission lines are used*
☑ *Explain the different conductor types, sizes, materials, and configurations*
☑ *Describe the electrical design characteristics of transmission lines (insulation, air gaps, lightning performance, etc.)*
☑ *Discuss overhead and underground transmission systems*
☑ *Explain the differences between ac vs. dc transmission line design, reliability, applications, and benefits*

Transmission Lines

Why transmission lines?

The best way to answer that question is high-voltage (HV) transmission lines transport power long distances much more efficiently than lower voltage distribution lines for two main reasons. First, HV transmission lines take advantage of the power equation. That is, power is equal to voltage times current. Therefore, increasing the voltage decreases the amount of current needed to transport the same amount of power. Since the current squared is the primary factor in calculating power losses, lowering current drastically reduces transportation losses. Second, raising voltage to lower current allows one to use smaller conductor sizes or provide more conductor capacity available for growth.

Figure 3-1 shows a three-phase 500-kV transmission line with two conductors per phase. The two conductors per phase choice is called ***bundling***. Power companies bundle multiple conductors together per phase to double, triple, or greater increase in power transport capability, lower losses, and improve other operating

Electric Power System Basics for the Nonelectrical Professional, Third Edition. Steven W. Blume.

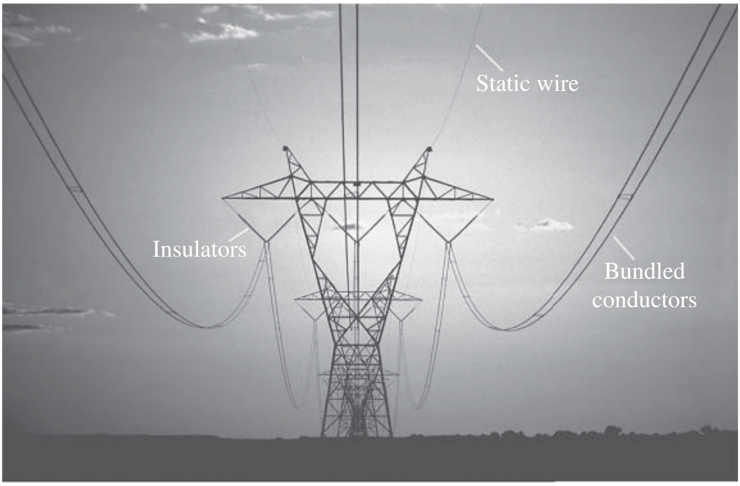


Figure 3-1 Transmission line.

characteristics of the line, such as reduce electromagnetic fields, audible noise, and corona affects.

The type of insulation used in this photo is referred to as ***V-string*** insulation. V-string insulation, compared to ***I-string*** insulation, provides stability in high-wind conditions. This line also has two ***static wires*** at the very top to shield itself from lightning. These static wires are directly connected to the metal towers so that lightning strikes are immediately grounded to earth. Hopefully shielding protects the main power conductors from experiencing HV transients caused by direct lightning strikes. When lightning strikes the main power conductors, HV transients propagate toward the line terminals where substation arresters activate to limit or clip the transient high overvoltages.

Raising Voltage to Reduce Current

Raising voltage to reduce current decreases conductor size and increases insulation requirements. Let us look at the power equation again.

$$Power = Voltage \times Current$$

$$Voltage_{In} \times Current_{In} = Voltage_{Out} \times Current_{Out}$$

From the power equation above, raising the voltage means the current can be reduced for the same amount of power. The purpose of step-up transformers at power plants, for example, is to increase voltage to reduce current for efficient power transport over long distances. Then at the receiving end of the transmission line, step-down transformers are used to reduce the voltage for easier distribution.

For example, the amount of current needed to transport 200 MW of power at 230 kV is half the amount of current needed to transport 200 MW of power at 115 kV. In other words, doubling the voltage cuts the required current in half. The reduction in current reduces losses, voltage drop and provides available capacity within conductor current ratings.

HV transmission lines require larger structures, greater air gaps, and longer insulator strings. However, building larger structures with wider right of ways for HV transmission lines is more cost effective than paying for continuous high losses associated with lower voltage power lines. Also, to transport a given amount of power from point "a" to point "b," a higher voltage line can require much less total right of way land than its equivalent capacity using multiple lower voltage lines.

Raising Voltage to Reduce Losses

The cost for losses decreases dramatically when the current is lowered. Power losses in conductors are calculated by the formula I^2R. If the current (I) is doubled, then power losses quadruple for the same amount of conductor resistance (R)! Again, it is much more cost effective to transport large quantities of electrical power over long distances using HV transmission lines because the current is less, and the losses are much less. Consider reducing the current in half, the losses are cut to one-fourth of what they would have been. In other words, doubling current quadruples losses. Losses are expensive to generate and unnecessarily utilize precious transmission line capacity.

Bundled Conductors

Bundling conductors significantly increase the line's power transfer capability. The extra relatively small cost to bundle conductors when designing and building transmission lines is easily justified by the benefits gained for increased capacity and reduced losses. Note that there is a practical and electrical limit to the total number of conductors in a bundle. For example, assume that a right of way for a particular new transmission line has been secured. Designing transmission lines to have multiple conductors per phase increases the power transport capability; however, stronger electromagnetic fields at the right of way edge might cause design considerations that affect overall cost.

Conductors

Conductor material, type, size, and current rating characteristics are key factors in determining the power handling capability of transmission lines, distribution lines, transformers, service wires, etc. The conductor heats up when current flows through its resistance. The resistance per mile is constant for a conductor. The larger the conductor diameter, the less resistance for current flow, assuming the same conductor material is used.

Conductors are rated by how much current causes them to heat up to a predetermined number of degrees above ambient temperature. The amount of temperature rises above ambient (i.e., when no current flows) determines the current rating of a conductor. For example, when a conductor reaches 70°C above ambient, the conductor is said to be at full load rating. The power company selects the temperature rise above ambient to determine acceptable conductor ratings. The power company might adopt a different current rating for emergency conditions or when the weather is extremely cold.

The amount of current that causes temperature to rise above ambient depends on conductor material, type, and size. The conductor type (e.g., number of strands aluminum and steel) determines its strength and application in electric power systems. Let us review some of the common conductor materials used on power lines.

Conductor Material

Utility companies use different conductor materials for different applications. Copper, aluminum, and steel are the primary conductor materials used in electrical power systems. Other types of conductors, such as silver and gold, are better conductors of electricity; however, cost prohibits wide use of these materials.

Copper

Copper is an excellent conductor and is very popular. Copper is very durable and is not affected significantly by weather.

Aluminum

Aluminum is a good conductor but not as conductive or as durable as copper. However, aluminum costs less than copper. Aluminum is rust resistant and weighs much less than copper.

Steel

Steel is a poor conductor when compared to copper and aluminum; however, it is very strong. Steel strands are often used as the core in aluminum conductors to increase the conductor’s tensile strength.

Conductor Types

Power line conductors are generally considered either solid or stranded. Rigid conductors such as hollow aluminum tubes used in low-profile substations add strength against sag when supported only at both ends. Rigid copper bus bars are commonly used in low-voltage switch gear applications because of their high-current rating and relatively short distances.

The most common power line conductor types are shown below:

Solid

Solid conductors, as shown in Figure 3-2, are typically smaller and stronger than stranded conductors. Solid conductors are usually more difficult to bend and are easily damaged.

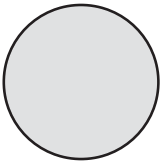


Figure 3-2
Solid conductor.

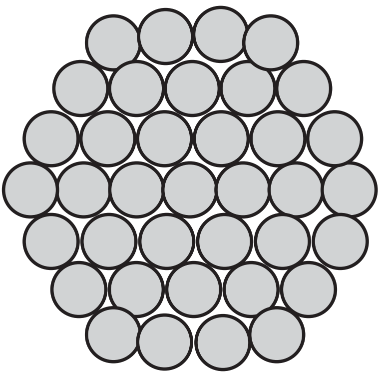
Stranded

As shown in Figure 3-3, ***stranded*** conductors have three or more strands of conductor material twisted together to form a single conductor. Stranded conductors can carry high currents and are usually more flexible than solid conductors.

Aluminum-Conductor Steel-Reinforced (ACSR)

To add strength to aluminum conductors, Figure 3-4 shows steel strands used as the core of aluminum stranded conductors. These high-strength

Figure 3-3 Stranded conductor.



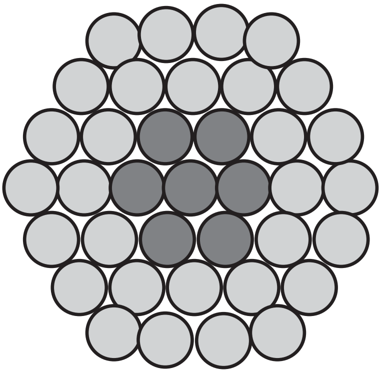


Figure 3-4 ACSR conductor.

conductors are normally used on long span distances to reduce sag but require high-tensional forces.

Aluminum Conductor Steel Supported (ACSS)

The ACSS design, considered an "advanced conductor." Much like ACSR, ACSS uses annealed aluminum strands vs. hardened aluminum strands, thus giving a higher temperature rating. The composite-core or ultra-high strength steel-core with heat-dissipating coatings enables high temperature operation for improved performance, see Figure 3-5. In some cases, the aluminum strands are shaped into a trapezoid profile instead of a round cross section to provide aluminum contact area for greater current capacity. The main benefit for ACSS is higher ampacity (roughly two times) for up to 250°C rise over ambient temperature with low sag characteristics.

Figure 3-5 ASCC conductor. Courtesy of Idaho National Laboratory.

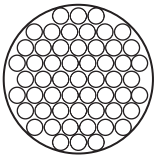
Conductor Size

There are two conductor size standards used in electrical systems. The ***American Wire Gauge*** is used for smaller conductor sizes and ***circular mils*** (CMs) is used for larger conductor sizes. Table 3-1 compares common conductor sizes and standards.

American Standard Wire Gauge (AWG)

The American Standard Wire Gauge is an old standard used for relatively smaller conductor sizes. The scale is in the reverse order; in other words, the conductor AWG number decreases as conductor size increases.

Figure 3-6 Circular mils.



Circular Mils (CMs)

The CMs standard of measurement is used for large conductor sizes. Conductors greater than AWG 4/0 are measured in CMs. One CM is equal to the area of a circle having a 0.001-inch (1 mil) diameter. For example, the magnified conductor in Figure 3-6 has 55 CMs. In actual size, a conductor of 55 CMs is about four times smaller than the period at the end of this sentence. Therefore, conductors sized in CMs are usually stated in thousands of CMs (i.e., kcm).

Table 3-1 presents typical conductor sizes and associated current ratings for outdoor bare ACSR conductors having a current rating of 75°C rise above ambient. The table also presents the equivalent copper size conductor.

Insulation and Outer Covers

These metal wire current carrying conductors are manufactured, insulated, or noninsulated. Noninsulated conductors (i.e., bare wires) normally use what is called "***insulators***" as the means for separating the bare wires from grounded objects, making air their insulation. Insulated conductors use plastic, rubber, or other jacketing materials for electrical insulation. HV insulated conductors are

Table 3-1 Typical ACSR Conductor Sizes.

Cross Section (inches)	Size (AWG or cmils)	Size Copper Equivalent	Ratio (Al to Steel)	Diameter (inches)	Current (amps) (75°C Rise)
0.250	4	6	7/1	0.250	140
0.325	2	4	6/1	0.316	180
0.398	1/0	2	6/1	0.398	230
0.447	2/0	1	6/1	0.447	270
0.502	3/0	1/0	6/1	0.502	300
0.563	4/0	2/0	6/1	0.563	340
0.642	266,000	3/0	18/1	0.609	460
0.783	397,000	250,000	26/7	0.783	590
1.092	795,000	500,000	26/7	1.093	900
1.345	1,272,000	800,000	54/19	1.382	1,200

Table 3-2 Transmission Voltages.

Voltage Class	Voltage Category	System Voltage
69,000		Subtransmission
115,000		
138,000		
161,000		Transmission
230,000	Extra High Voltage (EHV)	
345,000		
500,000		
765,000		
Above 1,000,000	Ultra-High Voltage (UHV)	

normally used in underground systems. Insulated low-voltage service wires are often used for residential overheard and underground lines.

In the 1800s, Ronalds, Cooke, Wheatstone, Morse, and Edison made the first insulated cables. The insulation materials available at that time were natural substances such as cotton, jute, burlap, wood, and oil-impregnated paper. With the development of rubber compounds and the invention of plastic, insulation for underground cables became much more reliable, cost effective, and efficient.

Voltage Classes

Table 3-2 presents the various transmission and subtransmission system voltages used in North America. This table is not absolute; some power companies designate their system voltages a little differently. Note that it is quite common to use subtransmission voltages to transport power medium distances (i.e., across large, populated areas) or to transport power long distances if the total current requirement is low, such as serving less populated remote areas.

The higher transmission system voltages tend to be more standardized compared to the lower distribution voltages. There are many subtle variations in distribution voltages compared to the more standardized transmission voltages.

Voltage Class is the term often used by equipment manufacturers and power companies to identify equipment voltage rating. A manufacturer might use voltage class to identify the intended system operating voltage for their equipment. A power company might use voltage class as a reference to the system discussed in a conversation. A voltage class might include several ***nominal*** operating voltages. Nominal voltages are everyday normal actual voltages. For example, a circuit breaker rated 138-kV voltage class is operating at a nominal 136-kV voltage.

Voltage Category is often used to identify a group of voltage classes. For example, "extra high voltage" (or EHV) is a term used to state whether an equipment manufacturer builds transmission equipment vs. distribution equipment, which would be categorized as "high-voltage equipment" (or HV) or "medium-voltage equipment" (or MV).

System Voltage is a term used to identify whether transmission, distribution, or secondary voltage is referenced. For example, power companies normally distinguish between distribution and transmission departments. A typical power company might distinguish between distribution line crews, transmission line crews, etc. Secondary voltage usually refers to customer service voltages under 600 Volts.

Transmission Line Design Parameters

(*Optional Supplementary Reading*)

This section discusses in more detail the design parameters regarding HV transmission lines.

Insulation

The minimum insulation requirements for a transmission line are determined by first evaluating individually the minimum requirements for each of the following factors:

Any of the insulation criteria listed below could dictate the minimum spacing and insulation requirement for the transmission line.

Air Gaps for 60-Hertz Power Frequency Voltage

Open air has a flashover voltage rating. The rule of thumb is one foot of air gap for every 100 kV of voltage. For example, a 10-foot air gap can have an insulation voltage rating of 1,000,000 Volts. Detailed reference charts are available to determine the proper air-gap requirements based on operating voltage, elevation, structures, and other exposure conditions.

Contamination Levels

Transmission lines located near oceans, alkali salt flats, and cement factories, require extra insulation for lines to perform properly under contamination prone environments. Salt mixing with moisture, for example, can cause leakage currents and possible undesirable insulation flashovers to occur. Extra insulation is often required for contamination prone environments. This extra insulation could increase the minimum air-gap clearance.

Expected Switching Surge Overvoltage Conditions

When power system circuit breakers operate, or large motors start, lightning strikes, or disturbances happen on the power grid, transient voltages occur that can flashover the insulators or air gap. The design engineer studies all possible switching transient conditions to make sure adequate insulation and air gaps are provided on the line.

Safe Working Space

The National Electrical Safety Code (NESC) specifies the minimum phase to ground and phase-to-phase air-gap clearances for all power lines and substation equipment. These NESC clearances are based on safe working space requirements. In some cases, the minimum electrical air-gap clearance of a transmission line is increased to meet NESC requirements.

Lightning Performance

Transmission lines frequently use shield wires to improve the line's operating performance during lightning conditions. These ***shield wires*** (sometimes called ***static wires*** or ***earth wires***) serve as high-elevation ground wires to attract lightning. When lightning strikes the shield wire, surge current energy flows through the wires, through the towers, through tower ground rods, and finally dissipates into earth soil.

Sometimes extra air-gap clearance is needed in towers to overcome the possibility of the tower flashing back over to the power conductors when lightning energy is being dissipated. This phenomenon is called "***back-flashover.***" This condition is often mitigated by additional buried copper wire grounding practices.

Audible Noise

Audible noise can also play a role in designing HV power lines. Audible noise from foul weather generated by electrical stress, corona discharge, and low-frequency hum can become troublesome if not evaluated during the design process. To minimize audio noise, most designs tend to increase conductor size, bundling, and air-gap spacing.

Underground Transmission

(*Optional Supplementary Reading*)

Underground transmission is usually 3–10 times costlier than overhead due to right of way, obstacles, and equipment cost. Underground construction is normally used in urban areas or near airports where overhead is not an option. Most

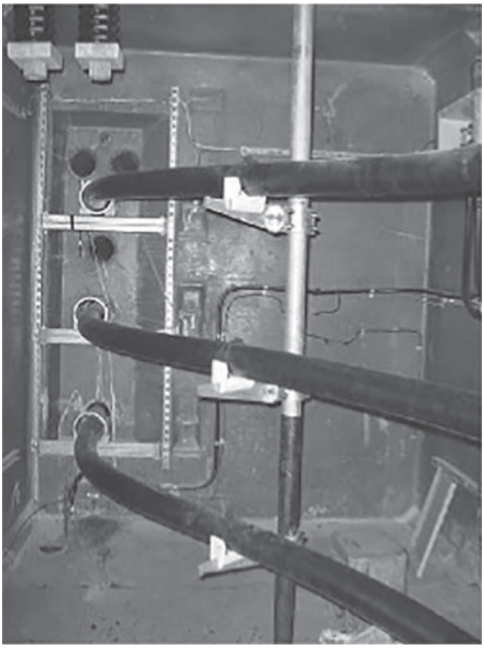


Figure 3-7 Underground transmission.

modern underground transmission cables are made of solid dielectric polyethylene materials and can have ratings in the order of 400 kV. Figure 3-7 shows a 230-kV underground transmission line.

DC Transmission Systems

(*Optional Supplementary Reading*)

Direct current transmission systems are used for economic reasons, system synchronization benefits, interconnecting 60-Hz with 50-Hz systems, power flow control, and improved longitudinal voltage drop (reduced reactive power requirements). The three-phase ac transmission line is converted into a two-pole (plus and minus) dc transmission line using bidirectional rectification ***converter stations*** at both ends of the dc line. The converter stations convert the ac power into dc power and vice versa. The reconstructed ac power must be filtered for improved power quality performance before connected to the ac system. Direct current transmission uses similar technology similar to inverter-based resources (IBRs, discussed earlier in Chapter 2); however, dc transmission is a power transport asset instead of a generation resource.

Figure 3-8 Overhead transmission.

Direct current transmission lines do not have phases; instead, they have positive and negative ***poles***. The Pacific Northwest dc transmission line shown in Figure 3-8, for example, operates at ± 500 kV or 1 million volts pole-to-pole. There are no synchronization issues with dc lines. dc transmission frequency is zero and therefore no concerns for variations in frequency between interconnected systems. A 60-Hertz system can be connected to a 50-Hertz system using a dc line.

For economic reasons, dc lines have advantages over ac lines by having only two conductors vs. three conductors as in ac lines. The overall cost to build and operate a dc line, including converter stations, may cost less than its equivalent ac line due to the savings in one less conductor, narrower right of way, and less expensive towers. This is usually the situation for dc transmission lines longer than 300 miles in length.

Direct current lines experience less voltage drop than their counterpart ac lines. Although both have resistance per mile causing active power losses, dc lines do not require reactive power support since inductive reactance is essentially zero. Thus, voltage drop along a dc line is much less than its counterpart ac lines.

4

Substations

Chapter Objectives

After completing this chapter, the reader will be able to

☑ *Identify and describe the operation of all major equipment used in substations*
☑ *Explain the use of current transformers (CTs) and potential transformers (PTs)*
☑ *Explain the operation and need for voltage regulators and load tap changers*
☑ *Discuss how circuit breakers and disconnect switches are used to isolate equipment*
☑ *Explain what is meant by the term buswork*
☑ *Explain the purpose and operation of lightning arresters*
☑ *Explain the purpose of capacitors, reactors, and static VAR compensators used in electric power systems*
☑ *Discuss equipment located in control buildings*
☑ *Describe effective preventive maintenance programs used for substation equipment*

Substation Equipment

The major types of equipment found in most transmission and distribution substations are discussed in this chapter. The purpose, function, design characteristics, and key properties are explained. After the equipment is discussed, planned and essential predictive maintenance techniques are discussed. The reader should get a good fundamental understanding of all the important aspects of major equipment found in substations and how it is used and operated. Digital substation modernization is also covered in this chapter.

The substation equipment discussed in this chapter include:

- Transformers
- Regulators
- Circuit breakers and reclosers

- Air disconnect switches
- Lightning arresters
- Electrical bus
- Capacitor banks
- Reactors
- Static VAR compensators
- Control building

Transformers

Transformers are essential components in electric power systems. They come in all shapes and sizes. Power transformers are used to convert high-voltage (HV) power into low-voltage (LV) power and vice versa. Power can flow both directions in a transformer, from the HV side to the LV side or from the LV side to the HV side. Generation plants use large ***step-up transformers*** to raise the voltage of the generated power for a more efficient transport of power over long distance transmission lines. Then ***step-down transformers*** (like the one shown in Figure 4-1) convert the power to subtransmission voltage levels. Subtransmission transformers (like that shown in Figure 4-2) transforms the power to distribution feeder voltages. Lastly, ***distribution service transformers***, typically mounted on overhead wood poles, inside underground vaults, or surface padmounts further reduce voltage for residential, commercial, and industrial consumption (see Figure 4-3).

There are many types of transformers used in electric power systems. Using turns ratios as scale factors, ***instrument transformers*** connect high-power equipment to LV power electronic instruments used to monitor system voltages, currents, and power. Instrument transformers include current transformers

Figure 4-1 Step-down transformer.

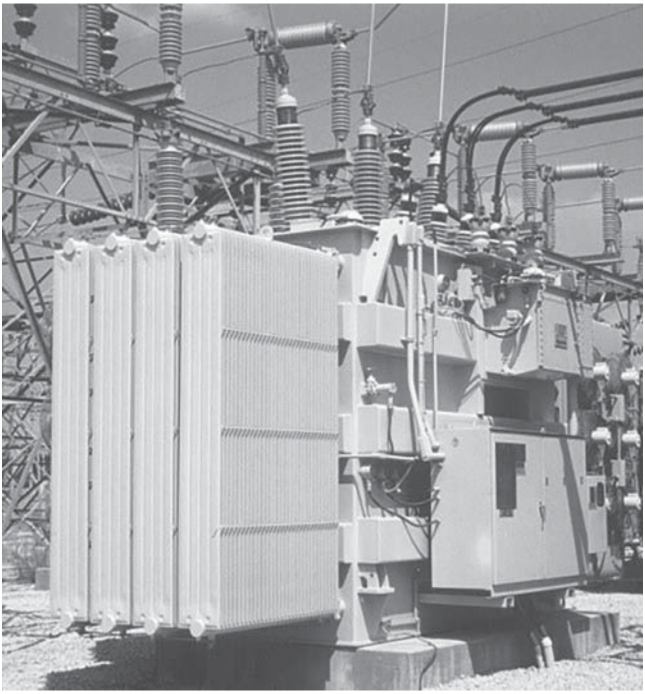


Figure 4-2 Distribution power transformer.

[i.e., ***CTs*** and potential transformers (***PTs***), often called ***VTs***]. These instrument transformers connect to metering, protective relaying, and telecommunications equipment. ***Regulating transformers*** are used to maintain proper distribution voltages for consumers to have stable service voltages, such as wall outlet voltage. ***Phase shifting transformers*** are used to control power flow over ac interconnection tie lines.

Transformers can be single phase, three phase, or ***banked*** together (i.e., three 1-phase units operating together as one 3-phase unit). Figure 4-3 shows a single phase (left) transformer and a three-phase transformer bank (right).

Another very common transformer type used in underground systems is the surface or padmount transformer, see Figure 4-4.

Transformer Fundamentals

Transformers work by combining the two physical laws that were discussed earlier in Chapter 1. As a review, *physical law #1 states that a voltage is produced on any conductor in a changing magnetic field. Physical law #2 states that a current*

Figure 4-3 Transformer bank.

Figure 4-4 Surface or padmount transformer.

flowing in a wire produces a magnetic field. Transformers combine these two physical laws.

In the case of a step-down transformer, HV is applied to the HV side of the transformer. Current then flows through the HV winding to produce a changing magnetic field inside the transformer. The LV coil is placed in this changing magnetic field to produce a voltage on the LV coil. (Hence, fewer turns are used in the LV side.) The load is then connected to the LV side of the transformer. The current flowing in the source coil, in this case the HV side, induces voltage in the LV coil on the LV side. (Hence, the two coils are coupled together by the changing magnetic field.) Either the HV or LV side of the transformer can be the source or load side, since power can flow in either direction. Iron cores are used to improve the magnetic properties of the transformer.

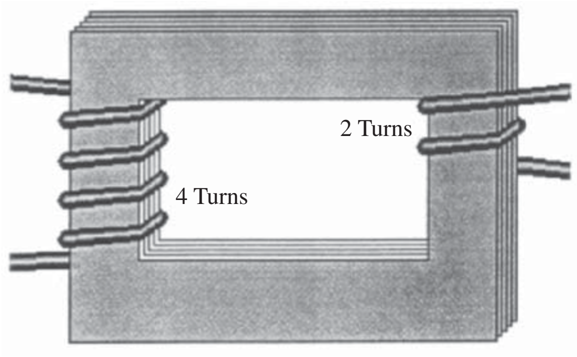


Figure 4-5 Transformer windings.

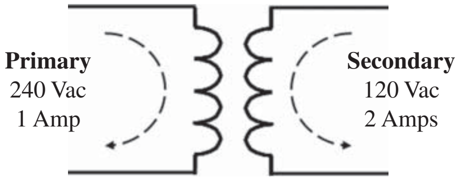


Figure 4-6 Transformer turns ratio.

This is a very important concept because the entire electric power system depends on these relationships. Looking at them closely, the voltages on both sides of a transformer are proportional to the ***turns ratio*** of the coils. And the currents on both sides of the transformer are inversely proportional to the turns ratio.

For example: The transformer in Figure 4-5 has a turns ratio of 2:1.

Suppose the 2:1 turns ratio transformer shown in Figure 4-5 has 240 Volts ac applied to the primary winding (left side) and draws 1 amp of current. The result is this transformer will produce 120 Vac at 2 amps on its secondary winding (right side) as shown in Figure 4-6. Note that power equals 240 watts on either side (voltage x current). Similarly, applying 120 Vac, 2 amps, on the LV side will induce 240 Vac, 1 amp, on the HV side.

Power Transformers

Figure 4-7 shows the inside of a large power transformer. Power transformers consist of two or more windings for each phase and these windings are usually wound around an ***iron core***. The iron core improves the efficiency of the transformer by concentrating the magnetic field and reducing transformer losses. The HV and LV windings have a unique number of coil turns. The turns ratio between the coils dictates the voltage and current relationships between the HV and LV sides.

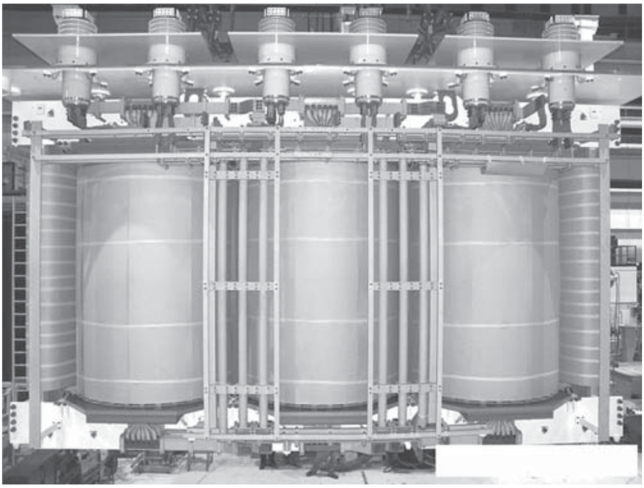


Figure 4-7 Transformer core and coils. Courtesy of ABB.

Bushings

Bushings are used on transformers, circuit breakers, and many other electric power devices as connection points. Bushings connect conductors inside the equipment to conductors outside the equipment. Bushings provide insulation between the energized conductor and the surrounding grounded metal tank. The conductors inside bushings are normally solid copper rods surrounded by a porcelain insulator. Insulation dielectrics, such as mineral oil or SF_6 gas, are added inside bushings to improve their insulation characteristics.

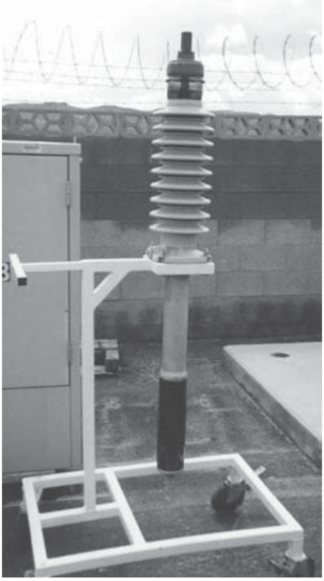
Note that transformers have large bushings on the HV side of the unit and small bushings on the LV side. In comparison, circuit breakers have the same size bushings on both sides because breakers have the same system voltage on both sides.

Figures 4-8 and 4-9 shows the photos of a 69-kV transformer bushing. Note that the oil level through the glass portion at the top of the bushing. Substation inspectors look for oil levels to ensure equipment health and for the safety of personnel working in the substation. Sometimes oil level gauges are used on bushings instead of glass sections for oil level inspections.

The part of the bushing that is exposed to the outside atmosphere generally has ***skirts*** or is sometimes called ***ribs*** to reduce unwanted leakage currents. The purpose of skirts is to increase the leakage current distance in order to decrease leakage current. Cleanliness of the outside porcelain is also important. Contaminated or dirty bushings can cause scintillation arcing that can result in flashovers, especially during light rain or fog conditions with lightly contaminated bushings.

Figure 4-8 Bushing oil level gauge.

Figure 4-9 Transformer bushing.



Instrument Transformers

The term ***instrument transformer*** refers to current and voltage transformers VTs that are used to scale down actual power system quantities for metering, protective relays, and system monitoring equipment.

Current Transformers

Current transformers or ***CTs*** are used to scale down the high magnitude current flowing in the main HV conductors to a level much easier to work with safely. For example, it is much easier to work with 5 amperes of current in the CT's secondary circuit than it is to work with 1,000 amperes in the CT's primary circuit. Then, use the turns ratio as a scale factor to know the real values of current on the HV side.

Figure 4-10 shows a typical CT connection diagram. Using the CT's turn ratio as a ***scale factor*** provides the reduced current level required of the monitoring instrument; yet the current found in the HV conductor is being measured.

Taps (or multiple connection points to the coil) are used to allow options for various turns ratio scale factors to best match the high operating current with the instrument's low current requirements.

In this example, 1000 A is flowing in the main conductor, whereas only 5 A is flowing in the instrument. If only 800 A were flowing in the main conductor, then 4 A would be flowing in the secondary side where the instrument is connected.

Most CTs are found on transformer and circuit breaker bushings as shown in Figure 4-11. Figure 4-12 shows a LV CT typically used for metering. Figure 4-13 shows a standalone HV CT used on transmission voltages in a substation.

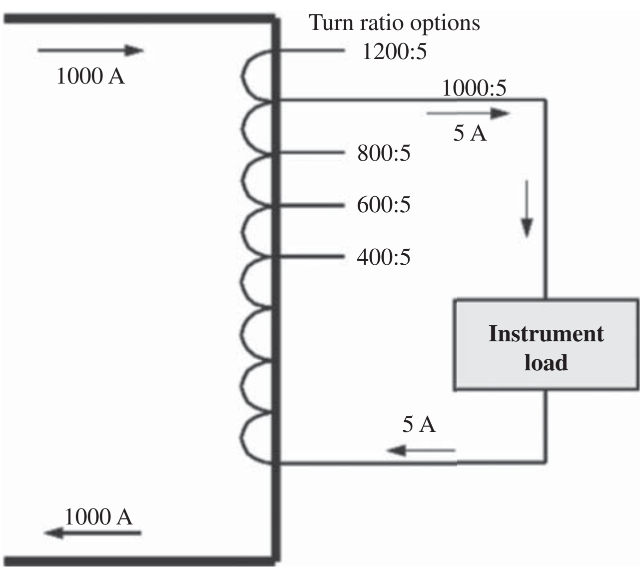


Figure 4-10 CT connections.

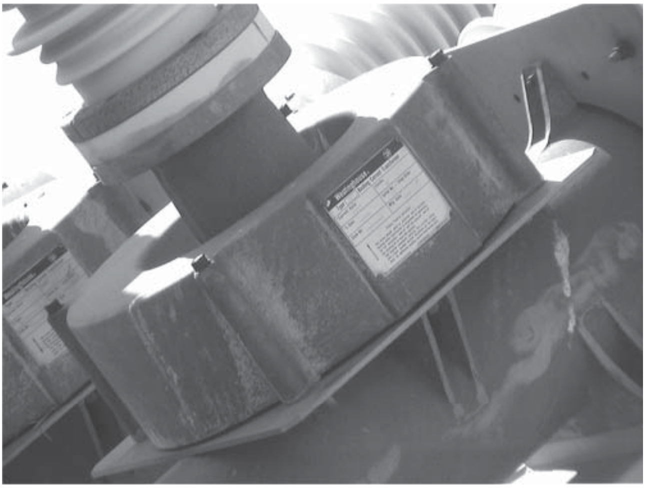


Figure 4-11 Bushing CT.

Figure 4-12 Low-voltage CT.

Potential Transformers

Similarly, ***PTs***, also called VTs, are used to scale down very HVs to levels that can be worked safely. For example, it is much easier to work with 115 Vac than 69 kVac. Figure 4-14 shows how a 69-kV PT is connected. The 600:1 turns ratio or scale factor is considered in the calculations of actual voltage. PTs are also used for metering, protective relays, and system monitoring equipment. The instruments

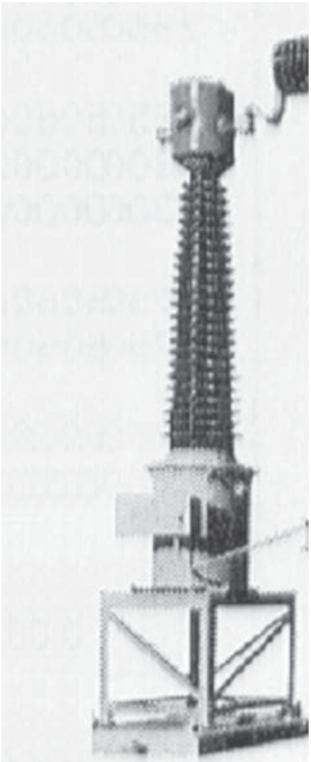


Figure 4-13 External HV CT.

connected to the secondary side of the PT are programmed to account for the turns ratio scale factor.

Like most transformers, taps are used to allow options for various turns ratios to best match the operating voltage with the instrument's voltage level requirements. An example of a LV PT used for metering is shown in Figure 4-15 and a HV PT in Figure 4-16.

Autotransformers

(*Optional Supplementary Reading*)

Autotransformers are a special construction variation to the traditional two winding transformer. Autotransformers share a winding to reduce cost. Single-phase, autotransformers contain a primary winding and a secondary winding on a common core. However, part of the HV winding is shared with the LV side; as shown in Figure 4-17. The shared winding is of larger gauge than the HV portion of the winding.

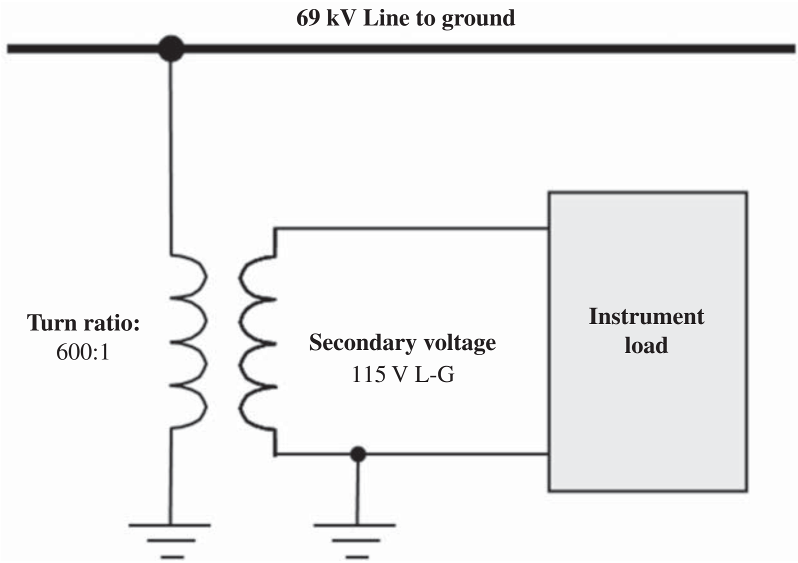


Figure 4-14 PT connections.

Figure 4-15 Low-voltage PT.

Autotransformers work best with small turns ratios (i.e., less than 5:1). Autotransformers are normally used for very HV transmission applications. For example, autotransformers are commonly found matching 500–230 kV or 345–138 kV system voltages. Material cost savings is an advantage of autotransformers. Size reduction is another advantage of autotransformers.

Figure 4-16 High-voltage PT.

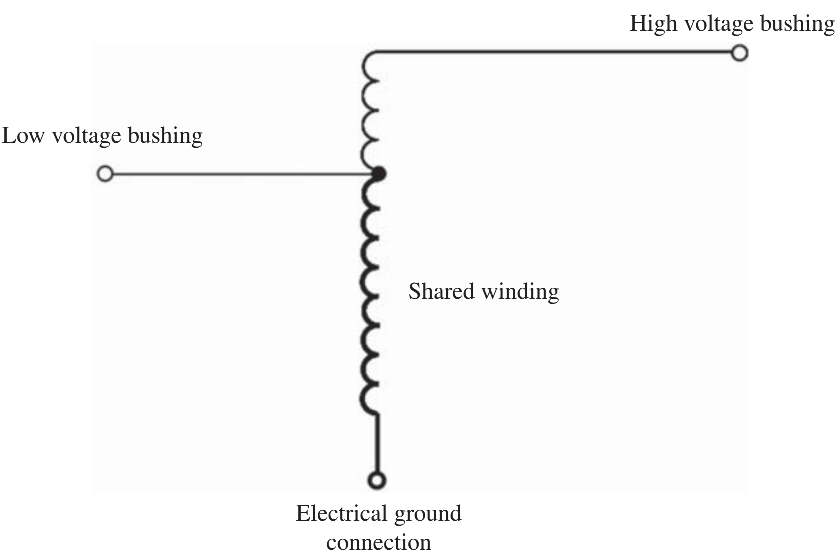


Figure 4-17 Auto transformer.

Figure 4-17 shows how an autotransformer is connected. The physical appearance looks the same as any other power transformer. A person needs to review the transformer nameplate to tell whether it is an autotransformer or a conventional transformer.

Note that under "no-load" conditions, high-side voltage will be the sum of the primary and shared winding voltages, and the low-side voltage will be equal to the shared winding voltage only.

Regulators

It is important for electric utility companies to always provide their customers with regulated or steady voltage. Normally, residential 120 Vac is ***regulated*** to ±5% (i.e., 126 Vac ↔ 114 Vac). The first residential customer outside the substation should not have voltage exceeding 126 Vac and the last customer at the end of a long distribution feeder should not have voltage less than 114 Vac. Power companies try to regulate their distribution voltage between nominal 124–116 Vac. The voltage drop along the feeder is due to resistive losses in the conductors. The more load served by the feeder, the greater the voltage drop.

Customer service problems can occur if voltages are too high or too low. For example, LV can cause motors to overheat and burn out. HVs can cause light bulbs to burn out too often or cause other appliance issues. Utility companies use voltage regulators and capacitor banks to keep primary voltage levels within this range.

Voltage regulators are similar to transformers. Regulators have several winding taps that are changed automatically under load conditions by a motor driven control system called the ***load tap changer*** or ***LTC***. Figure 4-18 shows a substation three-phase voltage regulator and Figure 4-19 shows a single-phase regulator. Three single-phase regulators can be used in substations or out on long distribution lines.

Theory of Operation

Normally, a voltage regulator is specified as being ±10%. The distribution feeder voltage, out of the substation regulator, can be raised up 10% or lowered down 10%. There are 16 different tap positions on either the raise or lower sides of neutral position. There is a reversing switch inside the LTC that controls whether to use the tap connections to raise output feeder voltage or to lower output feeder voltage. Therefore, the typical voltage regulator has "*33 positions*" (i.e., 16 raise, 16 lower, plus neutral). Figure 4-20 shows the 33 positions on the dial. Each position can change the primary distribution voltage by 5/8% (i.e., 10% divided by 16 taps).

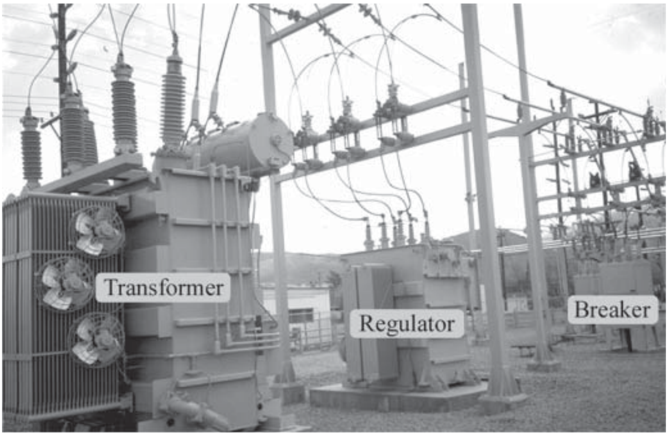


Figure 4-18 Three-phase regulator.

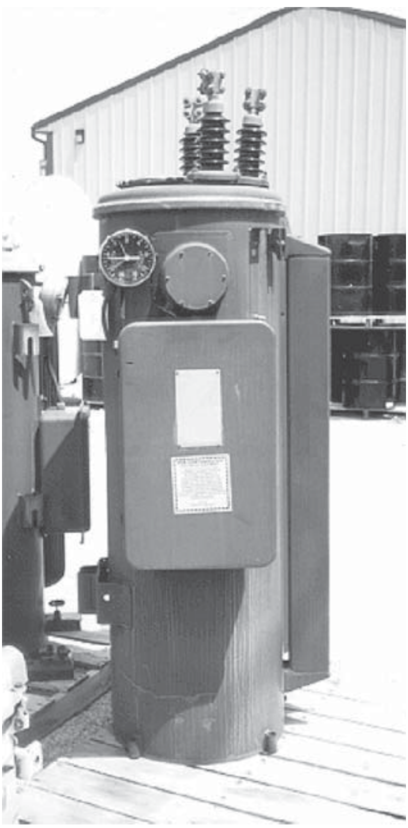


Figure 4-19 Single-phase regulator.

Figure 4-20 Regulator dial.

For example: A typical 7200 volt, ±10% distribution voltage regulator would have 33 tap positions. Each tap position could raise or lower the primary distribution voltage 45 volts (i.e., 10% of 7200 equals 720 volts and 720 volts divided by 16 taps equals 45 volts per tap). This variation in primary feeder voltage gives plenty of room for customer service transformers to stay within their required ±5% bandwidth (i.e., 126–114 V).

Reactor coils are used to reduce the number of actual winding taps in the regulator to 8 instead of 16. Reactor coils allow the regulator's contactor to be positioned between two winding taps at the same time, thus creating half the tap voltage. Figure 4-21 shows the tap changer mechanism with the reactor coil bridging both the 1st tap with the neutral, thus providing a ½ tap voltage. The term "***reactor***" is used to name a HV inductor. Reactors are just coils of wire in this case.

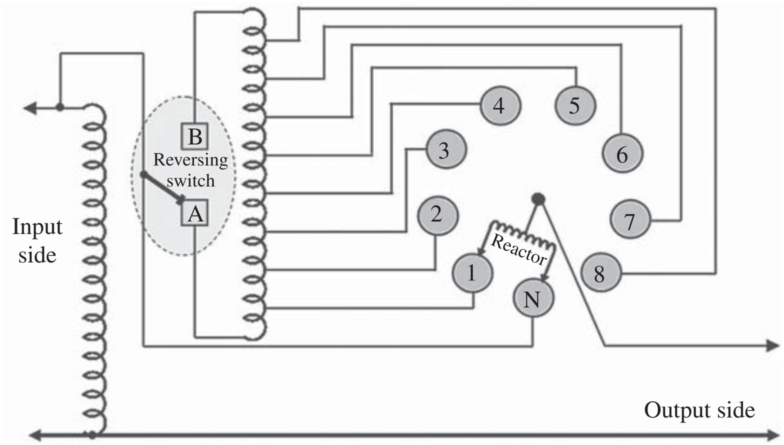


Figure 4-21 Load tap changer.

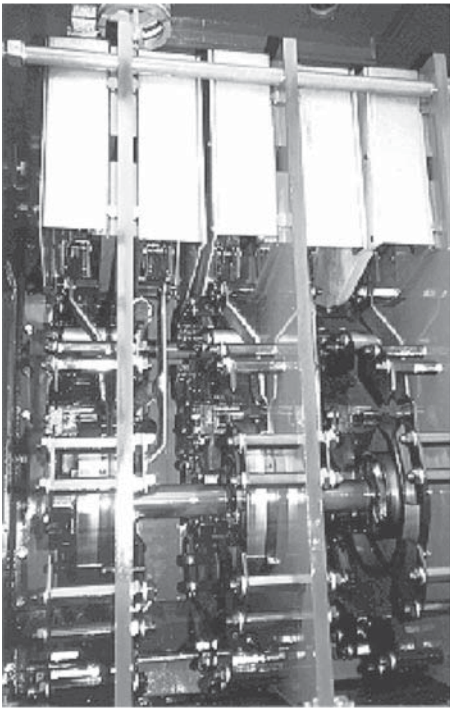


Figure 4-22 Tap changer.

Line regulators are sometimes used near the middle or end of long distribution feeders to reregulate or boost voltage to far-end customers. Line regulators extend the service length of distribution feeders.

Figure 4-22 shows a three-phase load tap changer mechanism found inside a regulator. Figure 4-23 shows the motorized switch contacts.

Figure 4-24 shows a ***load tap changing transformer*** (LTC-Transformer). LTC transformers combine a step-down transformer with a voltage regulator. LTC transformers offer cost-saving advantages. However, two LTC transformers are normally required per substation to have load transfer capability for regulator maintenance purposes.

Regulator Controls

(*Optional Supplementary Reading*)

Voltage regulators use an electronic control scheme to automatically operate the raise/lower motorized tap changer. An internal PT is used to input actual voltage to the control circuits. An internal current transformer is used to determine the amount of load on the regulator. The control circuit constantly monitors the voltage level on the regulated side and sends command signals to the motor operator circuit to raise or lower the regulated voltage based on the control settings.

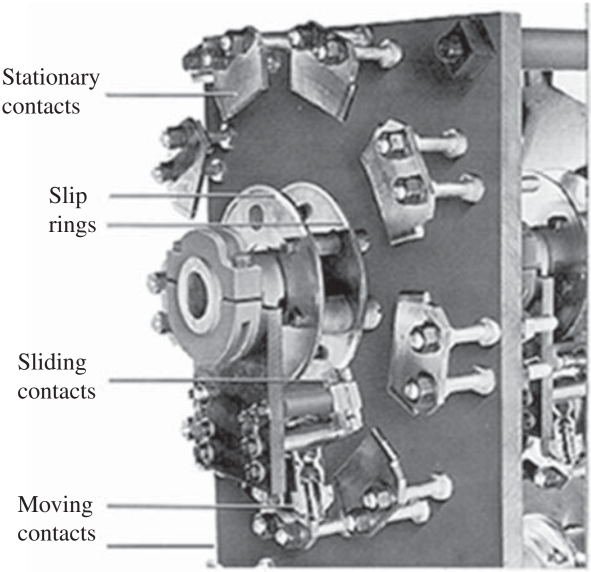


Figure 4-23 Motorized switch contacts.

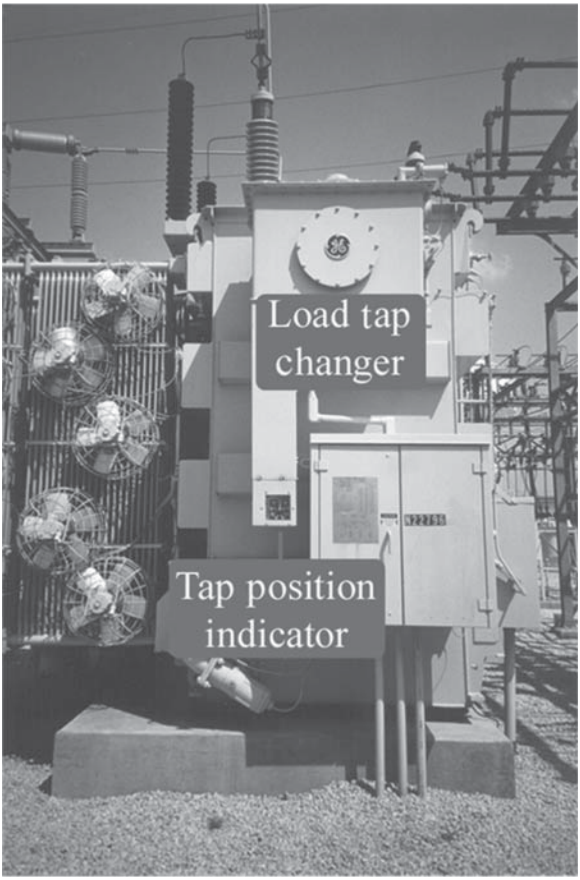


Figure 4-24 Load tap changing transformer.

Figure 4-25 shows a common ***voltage regular control*** box. The control settings are programed by the distribution engineer. The common regulator control settings are as follows:

Base Voltage

This is the desired voltage reference setting used to establish the regulator's ***base output voltage*** (e.g., 122 Volts is common). When the regulator PT senses the output voltage to be above or below this base setting, the tap changer motor is commanded to raise or lower taps until the regulator's output voltage comes into the desired bandwidth of this base voltage setting.

Bandwidth

The base voltage ***bandwidth*** setting controls the amount of voltage tolerance above and below the base voltage setting before a tap change command is issued.

Figure 4-25 Voltage regulator control. Courtesy of Beckwith Electric.

The regulator does not change taps unless the actual output voltage falls outside this bandwidth setting (e.g., 2 Volts bandwidth is normal). For example, if the base voltage is set for 122 Vac and bandwidth set at 2 Vac, the actual distribution voltage would have to rise above 124 Vac to enable a command to lower the regulated voltage. Similarly, the distribution regulator voltage would have to go below 120 Vac to enable the LTC to raise the regulated voltage.

Time Delay

The ***time delay*** setting prevents momentary voltage changes to initiate tap changes, thus reducing wear and tear of the LTC. For example, the actual distribution voltage would have to exceed the bandwidth range for the specified duration (i.e., 60 seconds) before the motorized tap changer would begin to operate.

Manual/Auto

For safety purposes, the ***manual/auto switch*** is used to disable the automatic control of the regulator for operations personnel working in the substation. As an example, manual operation enables field crews to match voltages before transferring load or to bypass the regulator for maintenance.

Compensation

The ***compensation*** setting is used to control voltage regulation based on conditions some distance down the line. Suppose the main load area to be regulated is 10 miles from the regulator. The compensation settings are adjusted so that regulated output voltage is based on conditions occurring 10 miles away. This capability can lead to HV problems for the 1st customer outside of the substation when voltage control is based on conditions far away from the substation. The voltage controller is set up to compensate for an estimated voltage drop on the distribution line.

Other Regulator Settings

Reverse power flow is a mode of regulator operation that compensates for distributed energy resources (DERs) generation, where power can flow either direction through the substation regulator.

Communications Ports are available on some regulator controls to improve voltage regulation with distribution automation networks, operator transparency of real-time conditions (e.g., tap position), and monitor operations for predictive maintenance analysis.

Circuit Breakers

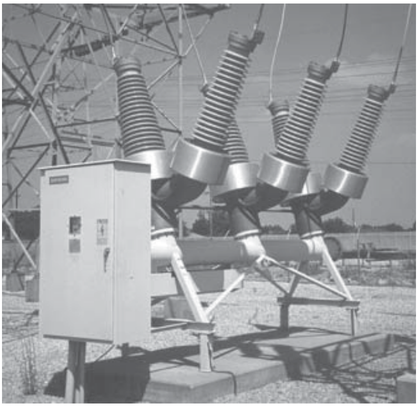
The purpose of a ***circuit breaker*** is to interrupt current flowing in a line, transformer, bus, or other equipment when a problem occurs, and power must be turned off. Operations personnel use circuit breakers to isolate equipment, sectionalize bus, emergency load transfer to another source, and service restoration. Current interruption can be normal load current or high ***fault current*** (e.g., short circuit current when a problem occurs) or simply tripped by protective relaying equipment during an undesirable event or disturbance. A breaker stops current flow by mechanically moving electrical contacts apart inside an ***interrupter***, while suppressing the arc in the presence of a high dielectric medium (i.e., oil, SF_6 gas, vacuum, or air). Circuit breakers are activated to open or close by protective relaying equipment, field operations personnel, or remotely through the control center. Breaker open/close control functionality is powered by the substation battery system in the event the HV ac power is off.

The most common types of ***dielectric*** medium used to extinguish arcs inside the breaker interrupter are listed below:

- gas (SF_6 or Sulfur-hexafluoride)
- oil (clean mineral)
- vacuum
- air

These dielectric mediums classify the breaker, such as oil circuit breaker (OCB), gas circuit breaker (GCB), and power circuit breaker (PCB).

Figure 4-26 Gas circuit breaker.



Other remarks regarding circuit breakers:

- Compared to fuses, circuit breakers can open and close repeatedly while a fuse opens the circuit one time and must be replaced
- Fuses are single-phase devices, whereas breakers are normally gang operated three-phase devices
- Breakers can interrupt very high magnitudes of current
- Breakers can close into a fault and trip open again
- Breakers can be controlled remotely
- Breakers need periodic maintenance

SF_6 Gas Circuit Breakers

Sulfur hexafluoride gas breakers (sometimes called $\mathbf{SF_6}$ or ***GCB***s) have their contacts enclosed in a sealed interrupting chamber filled with SF_6 gas. SF_6 gas is a nonflammable inert gas which has a very high dielectric strength, much greater than oil. Inert gases are colorless, odorless, and tasteless and are difficult to form other chemical compounds. These properties enable the breaker to interrupt current quickly and maintain relatively small equipment dimensions. The operating disadvantage of using SF_6 gas circuit breakers is the gas turns to liquid at −40°C or −40°F. Keeping correct gas pressure at changing ambient temperatures can be an operational concern. Heaters wrapped around the interrupter chambers are sometimes used in extreme cold weather environments. Figure 4-26–4-28 shows the photos of SF_6 gas circuit breakers

Oil Circuit Breakers

Oil circuit breakers (sometimes called ***OCBs***) interrupt arcs in clean mineral oil. The oil provides a high-dielectric resistance between the opening contacts to

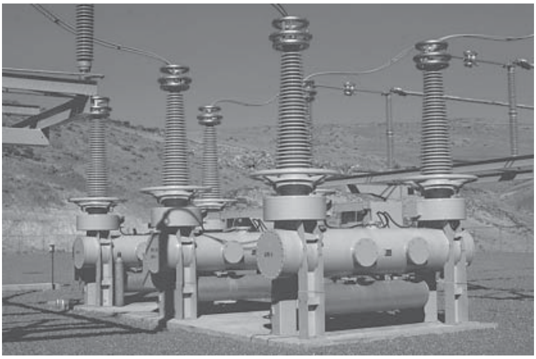


Figure 4-27 345-kV gas breaker.

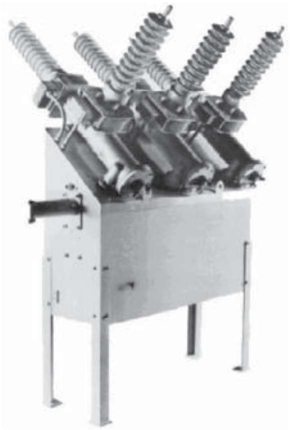


Figure 4-28 161-kV gas breaker.

extinguish arcing when current flow is interrupted. Figure 4-29 shows an OCB. The interrupting contacts (i.e., ***interrupter***) are inside the oil-filled tanks. Inspection plates are provided to allow close view of the interrupter contacts to determine maintenance requirements.

OCB bushings are usually angled to allow large conductor clearances in open air areas and smaller clearances in oil encased areas. The main disadvantage of using oil is they pose an environmental hazard if spilled. A maintenance concern for oil breakers is oil becomes contaminated with gases during arc suppression. The oil must be filtered or replaced periodically or after a specified number of operations to ensure the oil retains its high dielectric strength.

Figure 4-30 shows a single tank three-phase oil breaker's interrupter contacts. Note the wide conductor spacing for the air components and small conductor spacing for the oil immersed components. The operating voltage of this breaker is low enough to have all three phases in one tank.

OCBs are being phased out by SF_6 gas and vacuum breakers due to environmental concerns.

Figure 4-29 Oil circuit breaker.

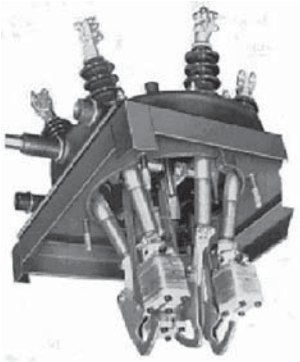


Figure 4-30 Interrupter contacts.

Vacuum Circuit Breakers

Vacuum circuit breakers (i.e., ***VCB***s) extinguish arcs by opening their contacts in a vacuum. Vacuum has a lower dielectric strength than oil or gas, but higher than air. Vacuum circuit breakers are smaller and lighter than air circuit breakers and are typically found in distribution substations or switchgear rated under 35 kV. Figure 4-31 shows a typical substation vacuum circuit breaker.

The contacts are enclosed in an evacuated bottle. Rated current cannot flow when the contacts are separated. When the breaker opens, the arc is extinguished quickly.

Air Circuit Breakers

Since the dielectric strength of air is much less than oil, SF_6 gas, or vacuum, ***air breakers*** are relatively large and are usually found in lower voltage installations, such as "***metal-clad***" switchgear. Figure 4-32 shows a 12-kV air breaker used in metal-clad switch gear.

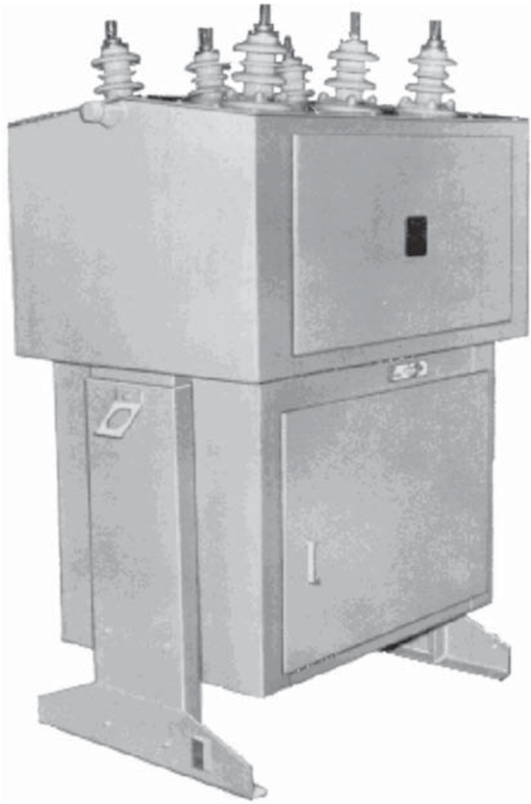


Figure 4-31 Vacuum circuit breaker.

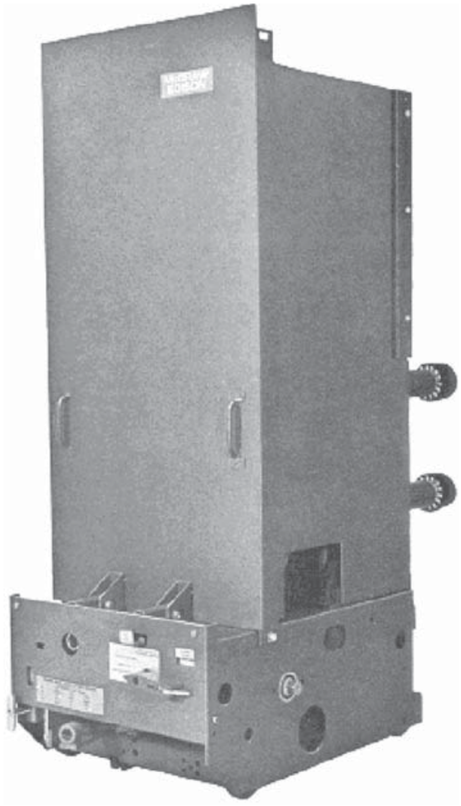
HV ***air-blast*** circuit breaker (not shown) is another type of air circuit breaker used for subtransmission voltages. Air-blast breakers use a compressed blast of air across the interrupting contacts to help extinguish the arc. Most air blast circuit breakers are considered old or obsolete and have been replaced.

Reclosers

Similar to breakers, ***reclosers*** provide circuit breaker functionality and they include basic protective relaying equipment to control the automatic opening and closing of distribution feeder circuits. Reclosers offer cost advantages over standard circuit breakers that require separate protective relay equipment.

The recloser's incorporated protective relaying equipment can be programmed to trip at specific overcurrent conditions and reclose after specific time intervals. After a circuit trip and a programmable time delay, the recloser automatically

Figure 4-32 Air circuit breaker.



re-energizes the circuit. The recloser's automatic reclosing feature can be disabled; for crews performing maintenance, reduce chances for fire ignitions, and/or during public events such as hot-air-balloon races. Reclosers are responsible for reenergizing feeders following lightning strikes.

Reclosers are commonly used as circuit breakers on distribution lines (see Figures 4-33 and 4-34) or in smaller substations (see Figure 4-35) having low fault currents. Reclosers are typically set to trip and reclose two, three, and sometimes four times before a ***lock-out*** condition occurs. Lock-out means the recloser went through its cycle of trips and recloses and then locks itself open. A field operations person must manually reset the recloser from lock-out for power to be restored. If a temporary fault condition clears before the recloser locks-out, the recloser's protective relaying resets back to the start sequence, after a programmed time delay.

Newer reclosers can be tripped manually or via remote control. Remote control capability is used by control centers operators to isolate equipment, sectionalize

Figure 4-33 Modern recloser.

customers, and restore power. Newer reclosers use vacuum interrupters with electronic control equipment. Older reclosers use oil dielectric interrupters and hydraulic control equipment, and older hybrid reclosers use oil dielectric and electronic control equipment. Reclosers used in distribution automation schemes are often called "***electronic switches.***" Electronic switches might include voltage and fault current sensors for smart grid or decentralized control schemes. (Distribution automation is discussed in more detail later in Chapter 5, Distribution).

Disconnect Switches

There are many purposes for ***disconnect switches*** in substations and on power lines. Disconnect switches are used to isolate de-energize equipment for maintenance purposes, transfer load from one source to another in planned or emergency

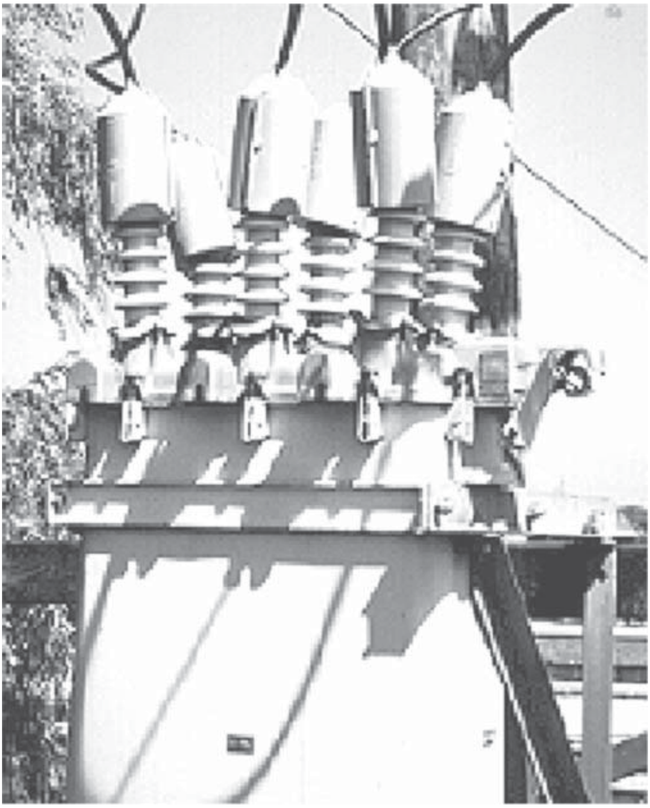


Figure 4-34 Older distribution line recloser.

conditions, provide visual openings from energy sources for maintenance personnel protection (an OSHA requirement for safety against accidental energization), and other reasons. Disconnect switches have low current interrupting ratings compared to circuit breakers. Normally power lines are first de-energized by circuit breakers (due to their high current interrupting capability) followed by the opening of air disconnect switches for separation or isolation.

Substations

There are many types of substation disconnect switches, such as ***vertical break*** and ***horizontal break***. Disconnect switches are normally ***gang*** operated. The term "gang" is used when all three phases are operated with one operating device. Air disconnect switches are usually opened and closed using control handles mounted at the base of the structure. Sometimes motorized drive mechanisms are attached

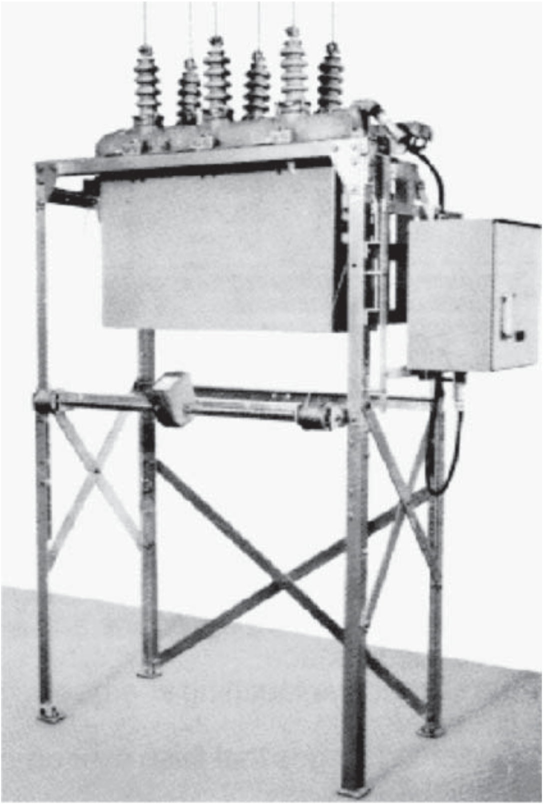


Figure 4-35 Older substation recloser.

to their control rods to enable remote control operation. A vertical break switch is shown in Figure 4-36 and a horizontal break switch is shown in Figure 4-37.

Some disconnect switches, such as the one shown in Figure 4-38, use spring loaded attachments called ***arcing rods*** to help clear arcs from small currents by whipping open the electrical connection after the switch's main contacts have opened. This spring-loaded device is also referred to as ***whips*** or ***arcing horns***. The arcing rods increase the switch's current opening rating but usually not enough to open normal load current. They might open a long-unloaded line or break a parallel during load transfer operations. Arching rods are considered ***sacrificial***, meaning the rods get pitted during the opening process. Arcing rods provide less wear and tear of the main switch contacts, while the rods are cheap and easy to replace.

Line Switches

Line disconnect switches are normally used to isolate sections of transmission or distribution lines or to transfer load from one circuit to another. The picture shown

Figure 4-36 Vertical air disconnect switch.

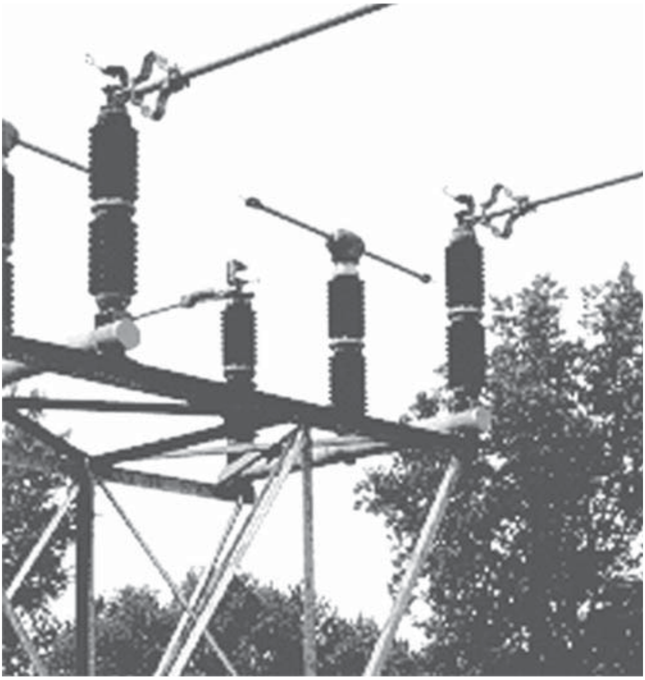


Figure 4-37 Horizontal air switch.

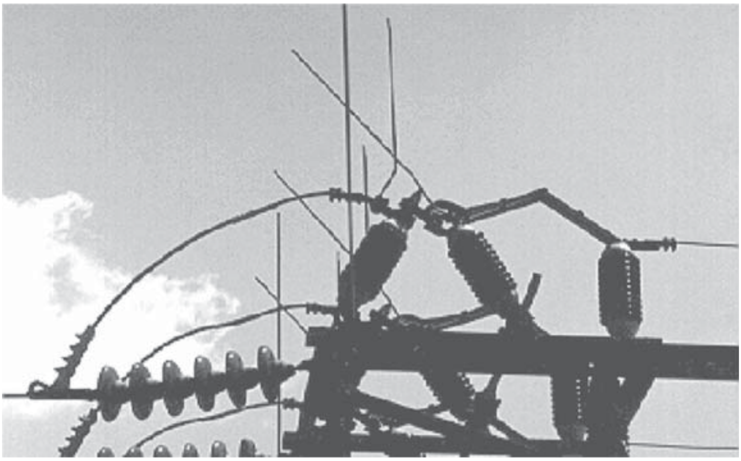


Figure 4-38 Whips or arcing rods.

in Figure 4-39 is an example of a 138-kV subtransmission line switch. This switch incorporates ***vacuum bottles*** to help extinguish arcs from interrupting light load or line charging currents.

Lightning Arresters

Lightning arresters are designed to limit the line to ground voltage when an overvoltage event occurs such as lightning strikes or other excessive transient overvoltage condition occurs. Some older style gap type lightning arresters short circuit the line or equipment causing the upstream circuit breaker to trip. The breaker would then automatically reclose the circuit when the transient over voltage condition goes away. Lightning arresters limit transient voltage magnitudes on the adjacent equipment being protected. The insulation properties of the equipment being protected must coordinate with the lightning arresters discharge voltage, leaving a safe margin of protection.

For example, suppose an 11-kV lightning arrester is installed on a 7.2-kV line to ground system. Suppose a lightning strike hits the line near this arrester. The arrester manufacturer's specification states that the arrester will conduct when the line to ground voltage exceeds approximately 11 kV and will limit the transient overvoltage to 30 kV. Now suppose the equipment located adjacent to this lightning arrester has a ***basic insulation level*** (BIL) or flashover rating of 90 kV. The arrester will clamp or limit the transient overvoltage condition to well under the equipment's BIL rating, thus preventing the protected equipment from experiencing an insulation failure.

Figure 4-39 Line switch.

Newer lightning arresters use gapless ***metal oxide*** semiconductor materials to limit transient overvoltages. These newer designs offer better overvoltage protection and have higher energy dissipation characteristics than gap type arresters.

Regardless of the arrester type, lightning arresters are designed to operate several times without failure. When lightning arresters fail, an insulation coordination study should occur or slow circuit breaker operation should be investigated to determine why lightning arresters are failing.

Aside from voltage rating classifications, arresters fall into different energy dissipation classes. Arrester must dissipate energy up until the circuit breaker clears the fault. ***Station class*** arresters (see Figure 4-40) can dissipate the greatest amount of energy. They are usually placed next to large substation transformers. ***Distribution class*** arresters (see Figure 4-41) are generously distributed throughout the distribution system in areas known to have high lightning activity. They can be found near distribution transformers, overhead

Figure 4-40 Station class arrester.

Figure 4-41 Distribution class arrester.

to underground transition structures, capacitor banks, reclosers, and long distribution lines. ***Intermediate class*** arresters are often used in substations that have lower available short circuit current. Residential and small commercial customers may use ***secondary class*** arresters to protect large motors, sensitive electronic equipment, personal computers, and other transient voltage sensitive devices.

Electrical Bus

The purpose of ***electrical bus*** in substations is to connect equipment together. A bus is a conductor, or group of conductors, serving as common connection points between two or more circuits. Bus can be constructed of 3–6 inch rigid aluminum tubing (called "***rigid bus***") or wires with insulators on both ends, called "***strain bus.***" Rigid bus is supported by station post-insulators mounted on steel or lattice support structures. The ***buswork*** is typically everything in the substation yard minus major equipment and the control building. Special bus configurations allow for transferring load from one feeder to another and to bypass or isolate equipment for maintenance.

Figure 4-42 shows an example of a typical low-profile rigid bus found in distribution substations.

Figure 4-42 Example of typical electrical bus.

Capacitor Banks

Capacitors are used to improve the operating efficiency of electric power systems and help transmission and distribution system voltage stability during disturbances and high-load conditions. Capacitors are used to cancel out the lagging current effect from motors and transformers. Capacitors can reduce system losses and help provide voltage support. Capacitors can reduce the total current flowing through a wire, thus leaving conductor capacity available for additional load. (Note the multiple uses of the operative word "can." The addition of too many capacitors on an ac power system can have the opposite effect and increase current and losses and reduce available capacity of a conductor. This concept is explained in more detail later in Chapter 6, Consumption.)

Proper application of capacitors greatly helps the efficiency of power system. Some capacitor banks are left online continuously to meet the steady-state reactive power requirements. Some capacitor banks are switched on or off to meet dynamic reactive power requirements. Some capacitor banks are switched seasonally (i.e., to accommodate air conditioning load in the summer) and others are switched daily to accommodate industrial motor loads.

Capacitor banks can be switched manually, automatically, locally, and remotely. For example, system control operators commonly switch substation capacitor banks on and off to help regulate transmission voltage or to support reactive power requirements at the distribution level. Providing capacitive support helps provide good system voltage, reduce system losses, and improve contingency reliability.

Substation Capacitor Banks

Figure 4-43 shows a typical substation capacitor bank. This picture shows two 3-phase capacitor banks (one in the foreground and one in the background). The vertical circuit breakers on the far right of the picture provide the switching functionality of these substation capacitor banks.

Distribution Capacitor Bank

Capacitor banks are installed on distribution lines to reduce losses, improve voltage support, and provide added load capacity on the distribution system (See Figure 4-44). Note that reducing distribution system losses with capacitors is very cost-effective since that also reduces transmission and generation losses from reduced load.

The closer a capacitor is installed to the actual inductive load itself, the more beneficial. For example, capacitors installed right at the motor terminals at an

Figure 4-43 Station capacitor bank.

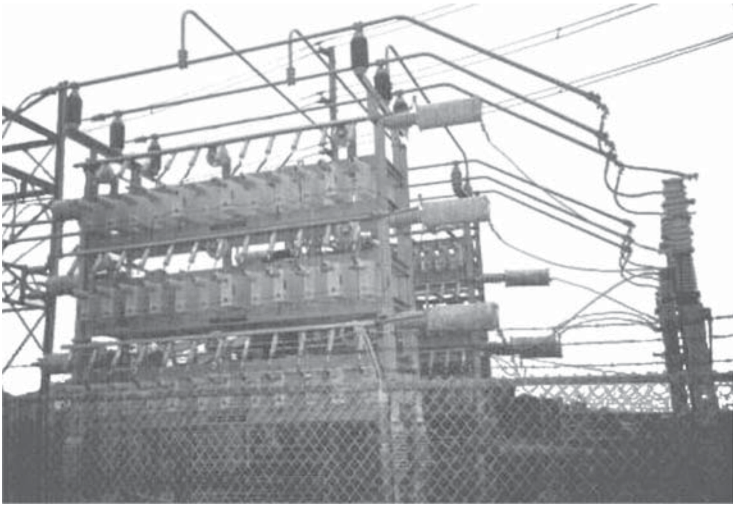


Figure 4-44 Distribution capacitor bank.

industrial facility reduce losses in the facility wires feeding the motor, the distribution and transmission line losses serving the facility, and generation losses.

Reactors

Reactor is another name for a HV inductor. They are essentially one winding transformers. Reactors are used in electric power systems for two main reasons. First, reactors are used in a shunt configuration (i.e., line to ground connection) to help regulate transmission voltage under light load conditions by absorbing surplus reactive power (VARs) from ***line charging***. Line charging is the term used to describe the capacitance effects of long transmission lines, since they are essentially long skinny capacitors (i.e., two conductors separated by a dielectric being the air). Second, they are connected in series to reduce fault current in distribution lines.

Reactors can be open air coils or coils submerged in oil for size reduction. Reactors are available in either single-phase or three-phase units.

Shunt Reactors—Transmission

The electrical characteristics and performance of long HV transmission lines can be improved using shunt reactors. ***Shunt reactors*** are used on transmission lines to help lower voltage or balance reactive power flowing on the system. Reactors are used to absorb reactive power, thus lowering transmission voltage.

Regarding voltage regulation, reactors are normally disconnected during heavy load periods (i.e., daytime) and reconnected during light load periods (i.e., nighttime). Conversely, shunt capacitors are switched on during high load conditions (i.e., daytime) and taken offline (i.e., nighttime) to lower system voltage during light load conditions. Therefore, transmission reactors and capacitors are switched on/off to help control transmission voltage while distribution regulators automatically fine-tune voltage for consumers.

Another application of shunt reactors is to help lower transmission line voltage when energizing a long-distance transmission line. For example, suppose a 200-mile, 345-kV, transmission line is to be energized. The line charging effect of this long transmission line, when one end is energized, can cause the far end voltage to be in the order of 385 kV. Switching on a shunt reactor at the far end of the line before energization can result in a reduced far end voltage of approximately 355 kV. This reduced far end voltage will result in a lower transient voltage event when the far end circuit breaker is closed. Once load is flowing in the line, the shunt reactor can be disconnected, allowing the load itself to hold voltage in balance. This HV effect on transmission lines is called the "***Ferranti***" effect.

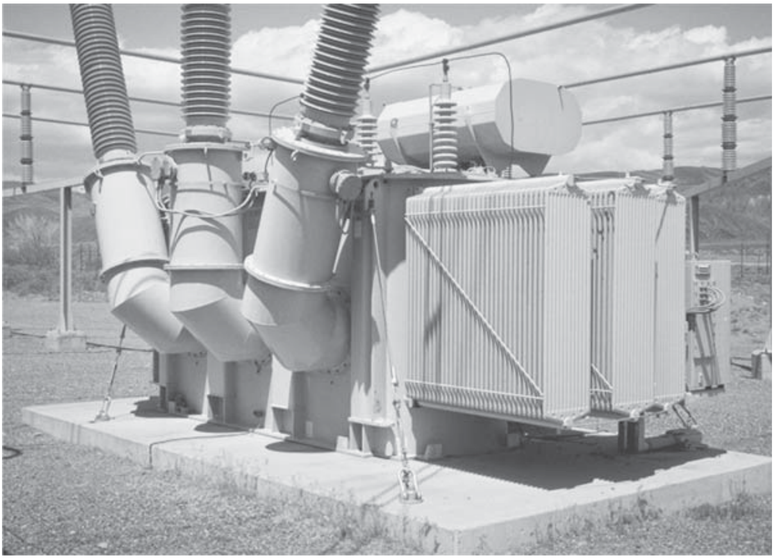


Figure 4-45 345-kV reactor.

Figure 4-45 shows a 345-kV, 35 MVAR, three-phase shunt reactor used to help regulate transmission voltage during light load conditions and during long line energization.

Series Reactors – Distribution

Distribution substations occasionally use ***series reactors*** to reduce available fault current. Distribution lines connected to substations that have several transmission lines or are near a generation plant can have extremely high short circuit fault current available should a fault occur. By inserting a series reactor on each phase of each distribution line at that station, available fault current is reduced when the circuit breaker opens. Therefore, the breaker trips the distribution line before the fault current has a chance to rise to its full magnitude. Otherwise, the high fault current could cause excessive damage to nearby consumers' electrical equipment. Series reactors are shown in Figure 4-46.

Static VAR Compensators

The ***static VAR compensator*** (SVC) is a tool used on ac transmission systems to control power flow, improve transient stability, and reduce system losses

Figure 4-46 Series reactors.

Figure 4-47 Static VAR compensator.

(see Figure 4-47). The SVC regulates voltage at its terminals by controlling the amount of reactive power injected or absorbed by the power system. The SVC is made up of several shunt capacitors, reactors, and an electronic switching system to enable ramping up or down or reactive power support. When system voltage is low, the SVC generates reactive power (i.e., SVC capacitive). When system voltage is high, the SVC absorbs reactive power (i.e., SVC inductive). Reactive power adjustment is performed by switching three-phase capacitor banks and inductor banks on the LV side of a large transmission transformer.

STATCOM is a similar grouping of reactors and capacitors used to help regulate reactive power needs of transmission systems. The term ***STATCOM*** comes from STATic synchronous COMpensator. STATCOM, similar to SVC, is a fast-acting device capable of providing or absorbing reactive power in small steps. Switching reactors and capacitors incrementally helps fine tune its operation.

Control Building

Control buildings are commonly found in larger substations. They are used to house equipment associated with monitoring, control, and protection of the substation equipment. The control building shown in Figure 4-48 houses the protective relays, circuit breaker controls, metering, communications, batteries, and battery charger equipment.

The protective relays, metering equipment, and associated control switches are normally mounted on racks or panels inside the control building. These panels also include equipment status indicators, sequence of events (SOE) recorders, computer terminals for system control communications, and other equipment that requires environmental conditioning. CT and PT cables from the outside yard equipment also terminate in the control building.

Figure 4-48 Control building.

Environmental conditioning consists of lighting, heating, and air conditioning to keep the electronic equipment operating reliably.

Control buildings have important SOE ***recorders*** needed to accurately track the operation of all substation equipment activity, primarily just before, during, and after system disturbances. Accurate time stamps are placed on each event for follow-up analysis. Some of the items tracked include relay operations and circuit breaker trip information. The recorder produces a data file, paper record, or electronic recording of all events that occurred at that substation during a major disturbance. This information is later analyzed with SOE data from other substations (including those from other utilities) to determine what went right, wrong, and what changes are needed to avoid similar disturbances in the future. Highly accurate satellite signals are used to time stamp events, thus enabling analysis to coordinate with other utilities in the interconnection or grid.

Preventative Maintenance

Electric power systems have many ways to perform ***preventive maintenance***. Scheduled maintenance programs, site inspections, routine data collection, information provided by smart devices and sophisticated computer modeling are all effective means to determine substation equipment maintenance requirements. An enhanced means of performing preventive maintenance is termed ***predictive maintenance*** (sometimes called "***condition based maintenance,***" "***proactive-based maintenance,***" or "***just-in-time maintenance***"). Predictive maintenance is based on measured or calculated needs rather than simply a schedule. Predictive maintenance can identify potentially serious problems before they occur. Two very effective predictive maintenance programs or procedures are ***infrared scanning*** and ***dissolved gas analysis*** (DGA) testing.

Infrared Technology

Infrared technology has improved maintenance procedures significantly. Temperature sensitive cameras are used to identify hot spots or hot hardware. "Hot" in this sense is excessive heat opposed to hot meaning "energized" equipment. Loose connectors, for example, can show up on infrared scans very noticeably. Loose connections appear very hot due to high-resistance connections compared to ambient temperature or surrounding hardware indicating a problem exists. Extreme hot spots must be dealt with immediately before failure occurs.

Infrared technology is a very effective ***predictive maintenance*** technique. Infrared scanning programs are used by most electric utilities. Scanning many types of equipment such as underground, overhead, transmission, distribution, substation, and consumer services is a cost-effective means of preventive maintenance.

Dissolved Gas Analysis

DGA is another very effective predictive maintenance procedure used to determine the internal condition of a transformer. Small oil samples are taken periodically from important or critical transformers allows one to accurately track and, through trend analysis, determine whether the transformer experienced internal arcs, sparks, overheating, or corona discharge. These types of internal problems produce small levels of various gases in the cooling or insulating oil. Specific gases are generated by certain problem conditions. For example, if the oil analysis finds the existence of abnormally high levels of carbon dioxide and carbon monoxide gases, this might indicate overheating of paper insulation used around the copper wire coils inside the transformer. Another example is finding high levels of acetylene gas, which might indicate arcing has occurred inside the transformer.

Gas samples are taken periodically and compared to earlier samples in a trend analysis procedure. Significant changes in the parts per million (PPM) values of these various gases likely indicate problems existing inside the transformer. Critical transformers (i.e., generator step-up or transmission transformers) might have DGA equipment installed permanently to continuously monitor gas content in oil. Sometimes, samples are manually taken every 6 months and tested for gas. Less critical transformers might have samples taken every year or two.

Once it has been determined that a transformer has a gas problem, it is immediately taken out of service and internally inspected. Sometimes the problems can be repaired in the field; for example, loose bushing/jumper connections, that can be tightened. Sometimes the problem cannot be adequately determined in the field, in which case, the transformer must be taken out of service and possibly rebuilt. Repairing a large substation transformer can be very costly and time consuming. However, it is much less costly to repair a transformer under controlled conditions than facing the consequences if a major transformer failure occurs while in service.

5

Distribution

Chapter Objectives

After completing this chapter, the reader will be able to:

☑ *Explain the basic concepts of overhead and underground distribution systems*
☑ *Discuss how and why distribution feeders are operated radially*
☑ *Discuss the differences between grounded wye and delta distribution feeders and laterals*
☑ *Describe how overhead and underground equipment is used in the field*
☑ *Explain the differences between single-phase and three-phase services*

Distribution Systems

Distribution systems are responsible for delivering electrical energy from the transmission/distribution substation, like the one shown in Figure 5-1, to the service entrance equipment located at residential, commercial, and industrial consumer facilities. Most distribution systems in the United States operate at primary voltages between 12.5 kV and 34.5 kV. Some older distribution feeders operate at lower voltages, such as 4.16 kV. These lower voltage distribution systems are being phased out because of their high cost for losses and short distance capability.

Distribution transformers mounted on poles, inside underground vaults, or pad mounted near customer load centers convert the ***primary*** source voltage to ***secondary*** consumer voltages. This chapter discusses how distribution systems between substations and consumer service transformers are built and operated.

Electric Power System Basics for the Nonelectrical Professional, Third Edition. Steven W. Blume.

Figure 5-1 Distribution substation. EyeMark/Adobe Stock Photos.

Table 5-1 Common Distribution Voltages.

System Voltage	Voltage Class (Line–Line)	Nominal Voltage (kV)	Voltage Category
Secondary	Under 600	0.120/0.240/0.208 0.277/0.480	Low voltage (LV)
Distribution Primary	601–7200	2.4–4.16	Medium voltage (MV)
	15,000	12.5–14.4	
	25,000	24.9	
Distribution or Subtransmission	34,500	34.5	

Distribution Voltages

Table 5-1 presents the various distribution system voltages used in North America. This table is not absolute; some power companies operate their system voltages slightly different.

System Voltage is a term used to identify whether the reference is being made to ***primary or secondary*** distribution systems. Residential, commercial, and small industrial loads are normally served with secondary voltages under 600 Volts. Manufacturers have standardized on providing insulated wire with a maximum 600 Vac rating for "secondary" services. For example, household wires, such as extension cords, used for 120 Vac have a 600 Vac insulation rating. Other than changing plugs and sockets on either end of the cord, one could use this wire for higher secondary voltages such as 240 Vac.

The 34.5-kV system voltage is used differently among electric companies. Some companies use 34.5-kV distribution voltages for customer service transformers to provide secondary voltage while other companies use 34.5-kV lines between distribution substations as a "subtransmission" voltage.

Voltage Class refers to equipment manufacturers system rating. For example, a manufacturer might specify their breakers to be of the 15-kV voltage class. Meaning, voltages below 15 kV will work fine (e.g., 13.2–13.8 kV.)

Nominal Voltage refers to the utility's actual operating voltage. For example, several power companies have standardized 12.47 kV while others use 24.9 kV as their nominal voltage. Some companies use 13.2, 13.8, 14.4, 20 kV, and others.

The ***Voltage Category*** for distribution is usually ***medium voltage***. Although, utilities often place high-voltage (HV) warning signs on power poles and other associated electrical equipment as a safety precaution.

Distribution Feeders

Distribution lines or feeders, like that shown in Figure 5-2, are normally connected ***radially*** out of the substation. Radially means that only one end of the

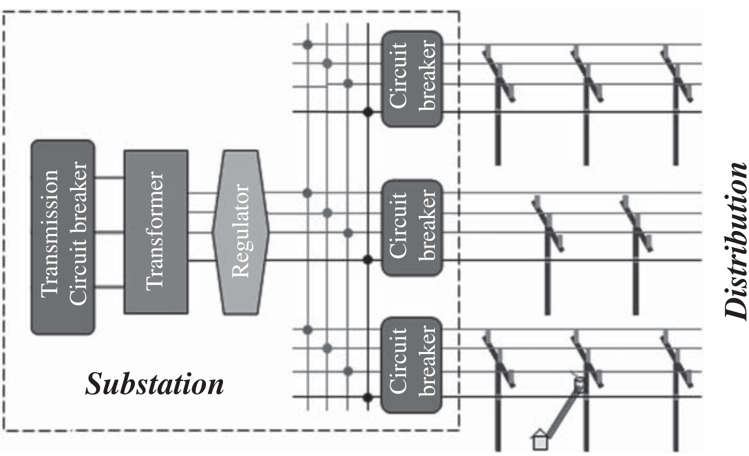


Figure 5-2 Distribution feeders.

distribution power line is connected to a power source. Therefore, if the source end of the line becomes de-energized, the entire feeder is de-energized and all consumers connected to that feeder are out of service.

The transmission side of the substation normally has multiple transmission lines feeding into the substation. In those cases, the loss of a single transmission line should not de-energize the substation and all radial distribution feeders should still have a source of power to serve all consumers. The operative word is "should." Some distribution substations are radially fed by a single transmission line and have a single power transformer serving multiple feeders. Loss of the redial transmission line or single power transformer can interrupt service to all consumers.

Distribution feeders have several disconnect switches located throughout the line. Line switches are configured "***normally closed***" or "***normally open.***" Power from the substation flows up to the normally open switches. These disconnect switches allow for load transfer among feeders, isolation of line sections for maintenance, and provide visual openings for safety purposes while working on lines or equipment. Although the distribution system has several feeders with open/closed disconnect switches, the feeders are still operated radially. The state of these normally open and closed switches is changed (manually or remotely) for fault isolation, load transfer, or sectionalization as needed. For example, to transfer load from one feeder to another, the normally open switch between the two feeders is changed to closed, thus creating a parallel situation between the two feeders until another normally closed switch is opened, thus restoring radial operation. The main reasons for operating the distribution system radially are simplified protection schemes and the safety of operating personnel.

WYE vs. Delta Feeders and Connections

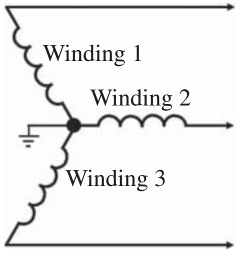
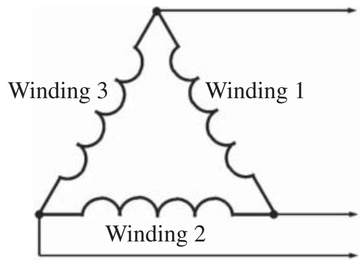


Figure 5-3 Wye connection.

Distribution feeders also use wye and delta configurations, like three-phase generators and transformers discussed earlier. This section compares the two distribution feeder construction alternatives, wye (Figure 5-3) and delta (Figure 5-4). Most three-phase distribution feeders and customer service transformer connections use the wye configuration because of the advantages over disadvantages. Although delta distribution systems exist throughout the United States, much of the delta distribution has been converted to wye.

Figure 5-4 Delta connection.



The common ***wye*** and ***delta configurations*** are shown below:

The wye connected system has one wire from each coil connected together to form the ***neutral***. This neutral is normally ***grounded*** (i.e., connected to earth) via ground rods, multigrounded primary neutral, or the substation ground grid. A feeder's continually grounded neutral is also called a "***multigrounded neutral***" or "***MGN***." MGN provide a low-resistance connection to earth. Grounding gives earth an electrical reference voltage, essentially zero Volts.

The earth surface soil is considered conductive (hence, current flows through soils). However, depending on soil type (rich fertile soil vs. granite rock) and soil condition (wet vs. dry), earth can be a very good conductor or a very poor conductor. Good neutral grounding improves such things as safety, voltage stability, and protection system simplicity.

There are several applications that use wye or delta configurations. Starting with distribution substations; the concept of wye or delta applies to the low-voltage (LV) side of the substation's main power transmission/distribution transformer. Typically, the distribution side of substation power transformers is connected grounded wye, with the neutral connected to the station ground grid. Next is the distribution feeder itself being wye or delta. Most are wye, indicating a four-wire power line having line-to-line (L-L) and line-to-neutral (L-N) voltages. Next, each three-phase consumer transformer references HV and LV sides as either wye or delta.

There are multiple ways to connect three-phase equipment; however, the preferred method is to have four-wire wye equipment connected to four-wire wye–wye distribution transformers on a four-wire wye primary. This arrangement provides a common neutral grounding system throughout that offers safe and reliable service with minimal power quality issues.

Transmission and subtransmission lines are built three phase, without the neutral. The reason for not adding the neutral conductor to transmission and subtransmission lines is current flowing through the neutral conductor is zero when the current magnitudes in all three phases are the same. Thus, neutral current is zero on balanced transmission and subtransmission lines. One of the distribution engineer's responsibilities is to ensure balanced load is present on all three phases, as it appears at the substation for transmission to be balanced. Transmission side of substation transformers are connected either delta or ***source grounded wye***. "Source grounded wye" means the transformer is four-wire wye, but the neutral is connected only to the substation ***ground grid*** and not added to the transmission line.

Regarding distribution lines, most feeders use the four-wire wye configuration to serve three-phase and single-phase load. Single-phase load (i.e., line–neutral connections) produces neutral currents along the feeder. Hopefully, the neutral current balances out at the substation. It is the distribution engineer's responsibility to balance single-phase load as much as possible to have minimum neutral current flowing at the substation. When all distribution feeder three-phase currents are balanced, neutral current is zero, or essentially zero.

Distribution feeders use four-wire wye, delta, or four-wire source grounded wye configurations. Three-wire source-grounded wye and delta distribution lines are more common in California, upstate New York, and to a lesser degree in some mid-western states such as Illinois, Ohio, and Indiana.

While California and New York were establishing ac distribution systems in the early years, the Rural Electrification Act of 1936, executive order 7037 signed by President Roosevelt, provided federal loans for the installation of electrical distribution systems to serve isolated rural areas of the United States. The Rural Electrification Administration's Engineering Division in Washington, DC, provided guidelines for building three-phase, grounded wye systems (then called "star" distribution systems). These guidelines were followed by 45 states.[1] Thus, most distribution systems were built three-phase, four-wire, star (i.e., wye) with exceptions primarily being California and New York.

From the perspective of distribution systems, the following advantages and disadvantages apply:

Advantages: Grounded Wye

- **Common Ground:**
  The power company's primary distribution neutral is directly connected to the consumer's service transformer neutral, which is connected to the customer's service entrance equipment ground. Stray earth current is minimized because a common ground is present regardless of soil type or condition.
- **Better Voltage Stability:**
  Common grounds improve voltage stability because the reference point is consistent. A common ground also improves other power quality issues.
- **Lower Operating Voltage:**
  Consumer equipment is connected "line to neutral (L-N)" instead of the higher voltage "line to line (L-L)." Since equipment is connected to a lower voltage, bushings, air-gap spacing, and insulation cost are reduced.

1 Rural Electrification Administration, 1936.

- **Use of Single Bushing Transformers:**
  Since one side of the service transformer winding is connected to the grounded neutral that connection does not need a bushing. Instead, single bushing transformers are used by having an internal connection to the grounded transformer metal tank, thus saving money.
- **Easier to Detect Line-to-Ground Faults:**
  Should a phase conductor fall to ground or a tree branch contacts a phase conductor, etc., the resulting short circuit fault current flows back to the substation through both the neutral and the earth return path. Ground fault detection is accomplished by simply using a neutral current transformer (CT) on the substation transformer's neutral to detect imbalanced neutral current for protective relays to trip circuit breakers. (Note that in delta feeder configurations, there is no grounded neutral and therefore harder to detect line to ground faults.)
- **Better Single-phase Protection with Fuses:**
  Fuses on transformers and distribution feeder lateral extensions clear faults more reliably than fuses in delta configurations. Since delta service equipment is connected line to line, a fault could blow one or more fuses. A fault on a delta feeder may fatigue or weaken fuses on the unfaulted phases. It is a common practice for delta systems to replace all three fuses in case one or more were weakened from a single-phase fault.

Disadvantages: Grounded Wye

- **Requires Four Conductors:**
  Four-wire grounded wye feeders are more expensive to build than three-wire delta feeders. Delta systems require only three conductors for three-phase power, thus a cost savings advantage to install delta feeders.

Advantages: Delta

- **Three Conductors vs. Four (i.e., Less Expensive to Construct):**
- **Reduced Fault Current:**
  Available fault current is less on delta than grounded wye systems. This can result in lower arc current and fewer fire ignitions due to reduced relay pickup settings.
- **Power Quality Enhancement:**
  Third order harmonics are eliminated by natural cancellation. In other words, the 60-Hz power sine wave is cleaner by nature. The 120-degree phase shift between phases acts to cancel some unwanted interference voltages.
- **Lightning Performance:**
  One could argue that isolated conductors in a delta configuration from ground reduces the effect lightning strikes have on distribution feeders. However,

lightning arresters in delta systems are still connected to earth through localized ground rods.

Disadvantages: Delta

- **No True Ground Reference:**
  Service voltage may be less stable due to the lack of a neutral conductor. Fuse protection may be less effective, other fuses can experience fatigue or weakening. Lack of common ground can instigate or perpetuate power quality issues.
  Delta secondary transformer banks ground the center tap of one transformer to serve as a neutral. This delta ground is technically not neutral and thus cannot be attached to the primary neutral ground without creating circulating currents. (This is discussed in more detail later in this chapter.)
- **Stray Currents:**
  Distribution transformers can cause undesirable stray currents to flow in the earth when their LV secondary is grounded. A small but measurable voltage is connected to ground causing stray currents to occur. This situation gets worse when a high imbalanced current is present on the delta feeder from single-phase loads. Furthermore, nearby lightning strikes and power faults tend to seek these local ground connections.
- **Unbalanced Currents:**
  Three-phase delta transformer banks attempt to regulate or equalize the primary voltage from backfeed. Delta secondary connections on the service transformer attempts to regulate or equalize the primary voltage. This can result in additional stray currents or add unbalanced currents in the feeder.
- **Ground Fault Detection:**
  Phase to ground fault detection and location is more complicated in delta primaries due to the lack of a neutral conductor. Oftentimes the fault needs to expand into a two-phase fault to detect that a problem exists. Substation grounding banks are often used to detect unbalanced current in delta feeders. Grounding banks consist of a four-wire, wye, transformer bank located in the substation to provide a neutral connection to the substation ground grid. A CT is connected to the grounding bank's neutral to measure unbalanced current flowing in the delta feeder. A large neutral current in the grounding bank neutral implies a L-G fault exists on the delta feeder.
  Comparing all the advantages and disadvantages, multigrounded neutral, or four-wire wye distribution feeders have noteworthy advantages over delta feeders. Converting delta to wye requires cost for adding a conductor, insulators, etc. Conversion can be an intentional slow process, done over time as load growth occurs.

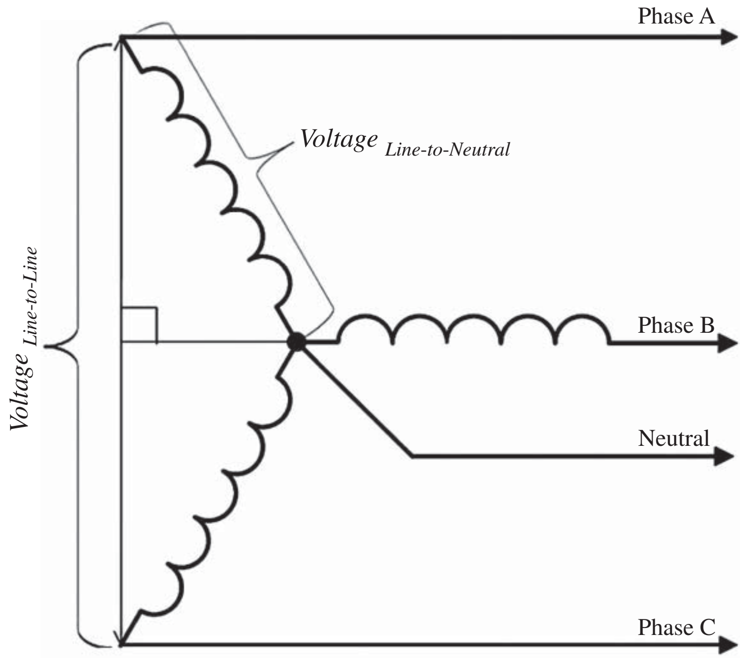


Figure 5-5 Three-phase, four-wire voltages.

Derivation of Line-to-Ground vs. Line-to-Neutral Voltages

(*Optional Supplementary Reading*)

Grounded wye systems have two voltages available for use ($Voltage_{Line\text{-}to\text{-}Line}$ and $Voltage_{Line\text{-}to\text{-}Neutral}$), see Figure 5-5. These two voltages are related mathematically by the $\sqrt{3}$.

$$Voltage_{Line\text{-}to\text{-}Line} = \sqrt{3}\, X\; Voltage_{Line\text{-}to\text{-}Neutral}$$

Or,

$$Voltage_{Line\text{-}to\text{-}Neutral} = \frac{Voltage_{Line\text{-}to\text{-}Line}}{\sqrt{3}}$$

Equipment can be connected either "line to line" (L-L) or "line to neutral" (L-N), depending the equipment rating. The L-N voltage is less than L-L voltage by the $\sqrt{3}$.

The neutral side of the L-N voltage is normally connected to earth by means of grounding; such as substation ground grids, pole ground rods, pole butt wraps, or pole butt plates. The lower voltage L-N connection is the normally used connection point for consumer service transformers. The intent for the distribution engineer is to balance single-phase load on all three phases to minimize neutral current.

For example, 12.47 kV (L-L) distribution systems have 7.2 kV (L-N) voltage. (Hence, 12.47 kV divided by $\sqrt{3}$ equals 7.2 kV.)

The term "line" can be interchanged with the term "phase." It is correct to say either "line to line" or "phase to phase." It is also correct to say, "line to neutral" or "phase to neutral."

WYE

Overhead Primaries

Wye-connected primary distribution feeders consist of three phases and a neutral, as shown in Figures 5-6 and 5-7. The National Electrical Safety Code (NESC) requires a minimum of four grounds per mile to be considered a ***multigrounded neutral*** (MGN).

Figure 5-6 Wye distribution.

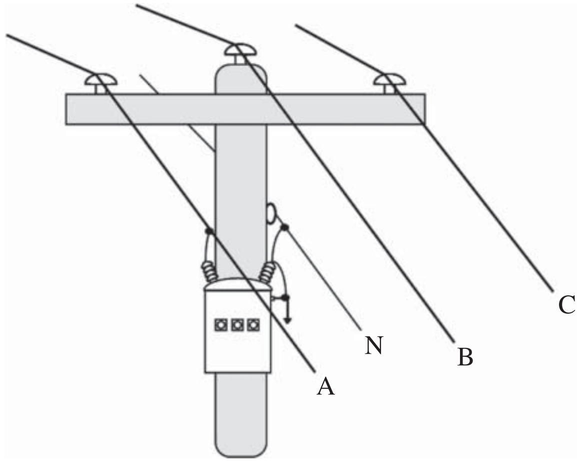


Figure 5-7 Wye three-phase feeder.

One can identify a wye primary configuration by the way single-phase transformers are connected. One transformer HV bushing is connected to a phase conductor while the other HV bushing is connected to the MGN. Examining how the wires are connected to transformer bushings helps determine if the transformer is connected line to neutral or line to line.

(Note that single-phase transformers, having two HV bushings, can be connected either line to line or line to neutral depending on system voltage. This is a common occurrence where a delta distribution feeder is staged for conversion to a grounded wye feeder. The old line-to-line transformers are now connected line to neutral. Therefore, the line-to-line voltage was increased by $\sqrt{3}$. This raised the feeder line-to-line voltage, which in turn reduced system losses, allows more load to be added to the feeder, etc.)

Lateral single-phase feeders branching off wye primaries consist of one-phase conductor and a neutral conductor as shown in Figure 5-8. At the branch off point, the neutral is grounded to the lateral consistent with the company's neutral grounding practice. Figure 5-9 shows a transformer connected to a single-phase lateral.

Delta Overhead Primaries

Delta primary distribution feeders use three conductors (one for each phase) and no neutral (see Figures 5-10 and 5-11). Single-phase transformers used on delta systems must have two HV bushings because each bushing must connect to different phases. Since delta primaries do not have primary neutrals, transformer tank grounds and lightning arrester grounds must be connected to earth via a ground rod at the base of the pole, with a ground wire along the

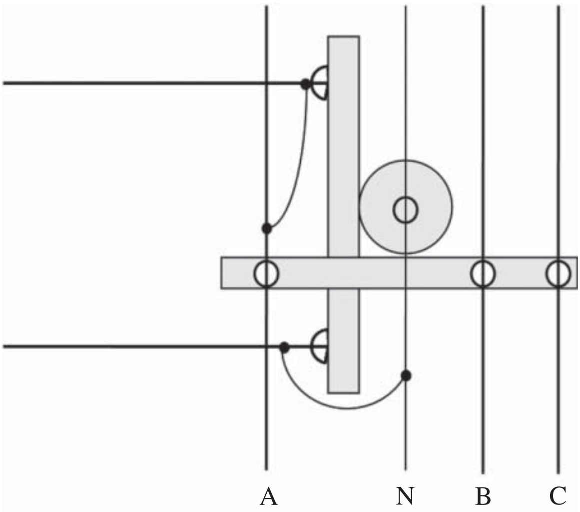


Figure 5-8 Wye one-phase lateral.

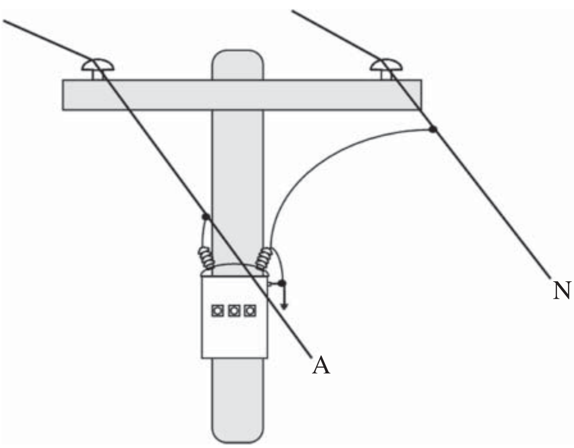


Figure 5-9 One-phase lateral.

side of the pole. Delta primaries and fused laterals require single-phase transformers to be connected phase to phase. Figures 5-11–5-13 show delta primary distribution lines. (Note that delta single-phase lateral extensions require two phases.)

Single-phase delta laterals consist of two-phase conductors, having no neutral.

Figure 5-10 Delta distribution.

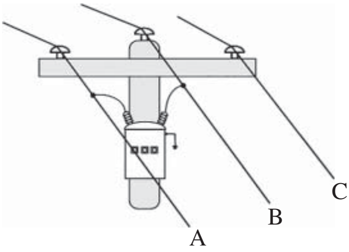


Figure 5-11 Delta three-phase feeder.

Transformer Connections

(*Optional Supplementary Reading*)

This section discusses how ***common transformer configurations*** are made; phase to neutral (i.e., line to ground) for single-phase connections and wye–wye

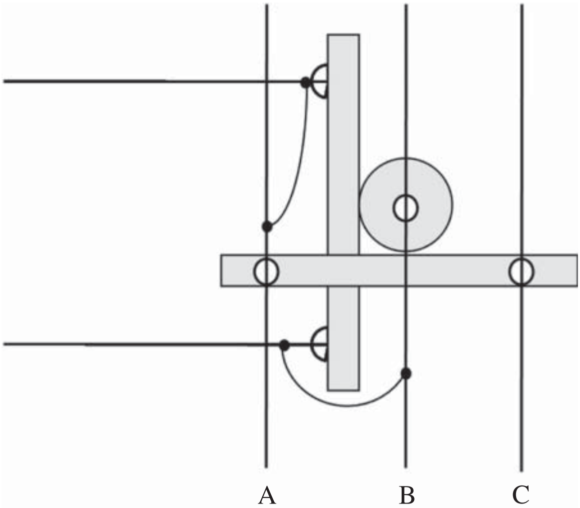


Figure 5-12 Delta one-phase lateral.

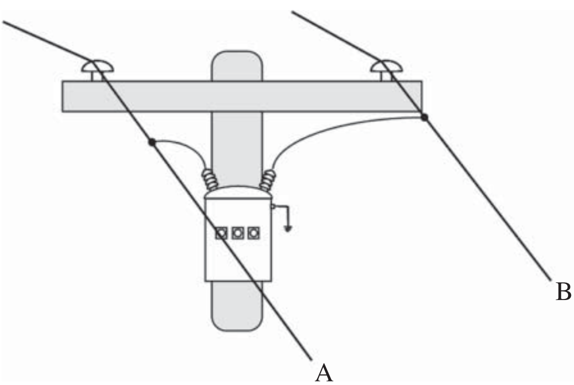


Figure 5-13 Delta one-phase lateral.

for three-phase transformer bank connections. Figures 5-14–5-16 show a common one-phase transformer installation.

Distribution Transformers: Single Phase

Since the standard residential service voltage is 120/240 Vac, distribution transformer turns ratios vary depending on the utility's primary voltage. Service wires, with 120/240 Vac are connected between the distribution service transformer secondary bushings and the consumer's service entrance equipment.

Figure 5-14 Transformer connections.

Transformer Secondary Connections: Residential

To produce two 120 Vac and one 240 Vac service (i.e., 120/240 Vac service) to ***residential consumers***, the distribution transformer has two secondary windings.

Figure 5-15 shows how two 120 Vac and one 240 Vac secondary service is provided from a single-distribution transformer. Figure 5-16 shows the transformer connections. This is the most common connection configuration for residential consumers. This single-phase transformer has two 120 Vac low-side voltage windings connected in series with a neutral connection in the middle. This transformer supplies 120/240 Vac single-phase service to residential customers. Note that the two secondary windings in series (A-B-C-D).

Note the bushing nomenclature. H1 and H2 markings identify the HV side connections (i.e., bushings). X1, X2, and X3 identify the LV side connections (i.e., bushings). This is common nomenclature practice for all voltage classes including the very HV transformers.

For example, suppose the distribution feeder voltage were 12.5-kV line to line which has a line-to-neutral voltage of 7.2 kV (hence, divide line-to-line voltage by the square root of three). Using transformers with 60:1 turns ratios on each of the

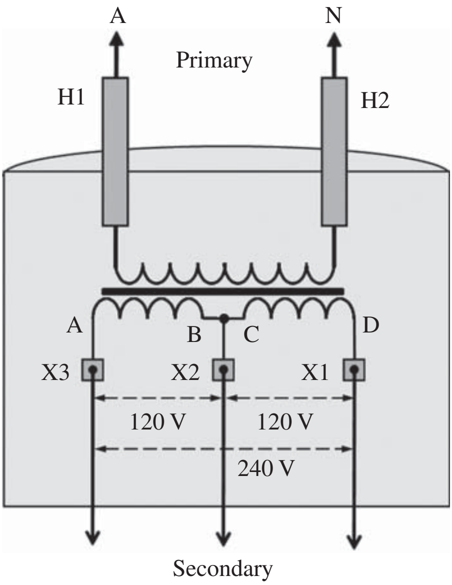


Figure 5-15 Standard two-bushing transformer.

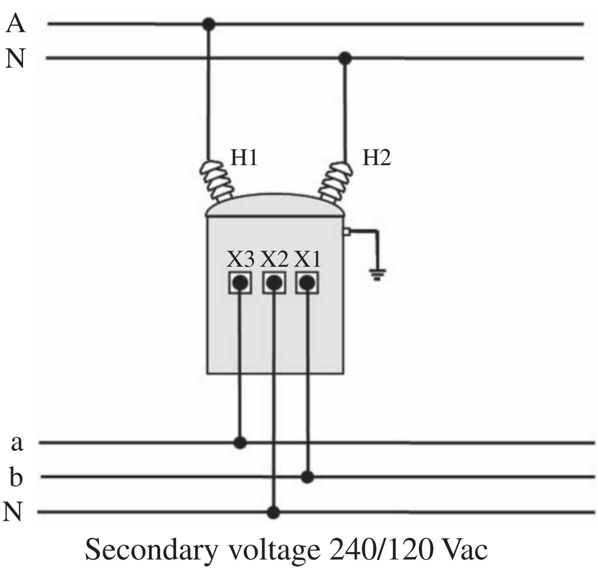
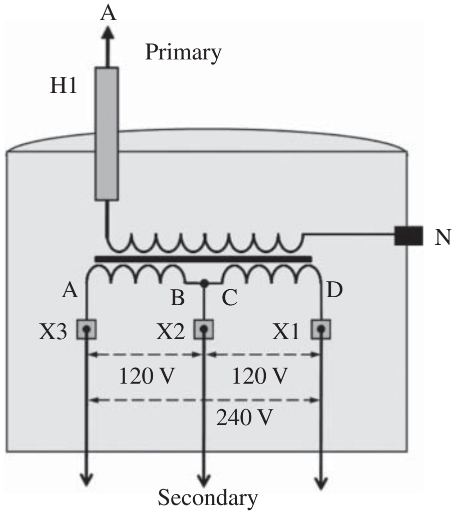


Figure 5-16 Two-bushing transformer connections.

Figure 5-17 Standard one-bushing transformer.



two secondary windings, the secondary voltage becomes 120 Volts (7200 V divided by 60). The two secondary windings added together produce 240 Volts.

Single-Phase One-Bushing Transformer

Figure 5-17 shows also a single-phase transformer; however, one high side bushing has been eliminated. Since one side of the primary winding is connected to the grounded neutral (see Figure 5-18), and since the tank is also grounded allows the HV winding to be connected to the tank internally. This is referred to as a ***single bushing transformer***. The transformer tank has a terminal lug for the neutral/ground connection.

Distribution Transformers: Three-Phase

Three single-phase transformers are commonly banked together to produce three-phase service to ***commercial and light industrial consumers***. The commercial and light industrial consumers are normally served with 208/120 Vac three-phase service. The larger commercial and industrial consumers are normally served with 480/277 Vac three-phase service. This section discusses how the three-phase service voltages are produced. Figure 5-19 shows a typical three-phase 208/120-Vac transformer bank.

Transformer Internal Connections

Standard single-phase distribution transformers must be modified internally to produce only 120 Vac when used in ***three-phase transformer banks***. Two of the

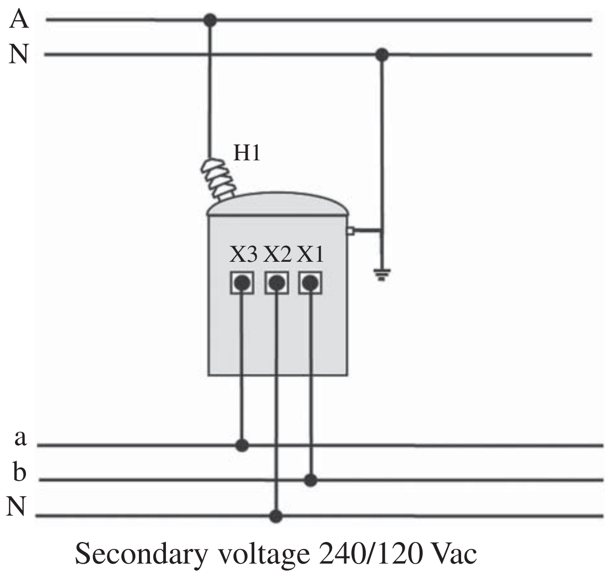


Figure 5-18 One-bushing transformer connections.

Figure 5-19 Three-phase transformer bank.

Figure 5-20 Transformer bank connection #1.

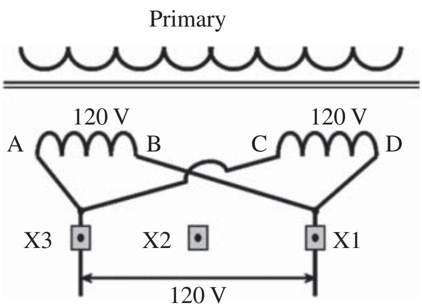
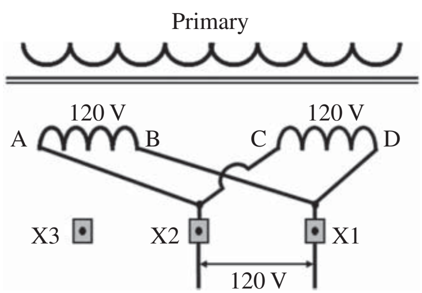


Figure 5-21 Transformer bank connection #2.



possible three ways to internally connect the two secondary windings in parallel to produce only 120 Vac are shown in Figures 5-20 and 5-21. Again, these transformers supply 120 volts only. The reason Figure 5-21 would be preferred by a power company is its similarity to connecting a standard 120/240 transformer, the center secondary bushing is still the neutral. Note how the internal windings are connected (AC-BD). Field personnel refer to this internal connection reconfiguration as "***alley-cat-bad-dog.***"

The Three-Phase Wye–Wye Transformer Bank (208/120 Vac)

The popular three-Phase transformer bank configuration (i.e., wye–wye) is shown in Figure 5-22. The 208 Vac connection comes from having 120-V line-to-neutral times $\sqrt{3}$.

The Three-Phase Wye–Wye Transformer Bank (480/277 Vac)

Industrial consumers that have large motors, several story buildings, several lights, and elevators, require the higher three-phase service 480/277 Vac opposed to the lower 208/120 Vac, three-phase service. The higher voltage system utilizes lower current for the same load. Thus, more facility loads can be added to the service because the voltage is higher. Also, more wire capacity is made available due to reduced current. The standard three-phase transformer configuration

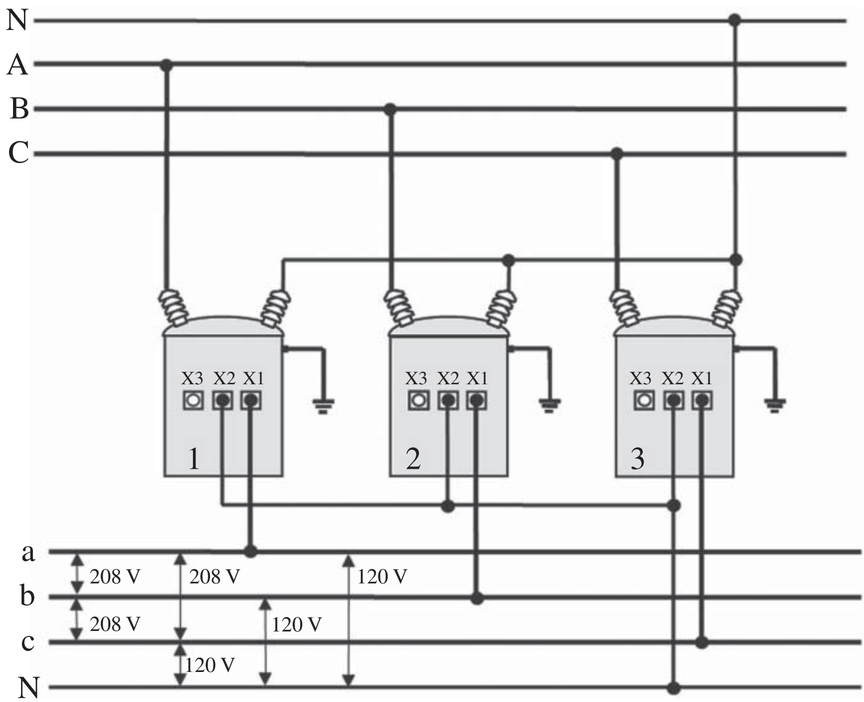


Figure 5-22 208/120 Vac, three-phase wye–wye connection diagram.

for this purpose is the three-phase 480/277 Vac, wye–wye bank, as shown in Figure 5-23.

Dry Pack Transformers

Consumers that take service at 480/277 Vac usually require ***dry-pack*** transformers at their facility to provide 120 Vac service to power miscellaneous receptacles such as in break rooms, cubical outlets, and so on. Dry pack implies the transformer does not contain oil. These dry pack transformers are often found in closets or small rooms with HV warning signs posted on the doors. Figure 5-24 shows an example of a dry pack transformer.

Large motor loads (i.e., elevators) at these larger consumer sites use 480 Vac, three-phase power. Large lighting arrays use 277-Vac line-to-ground single-phase power. While the basic 120 V convenience loads use dry-pack transformers.

Note that 277 Vac line to neutral is a very common industrial voltage for many motors, lighting, etc. Equipment operating at 277 Volts might not be found at your local department store but industrial electrical supply stores are packed full of 277-Volt equipment to be installed at industrial facilities.

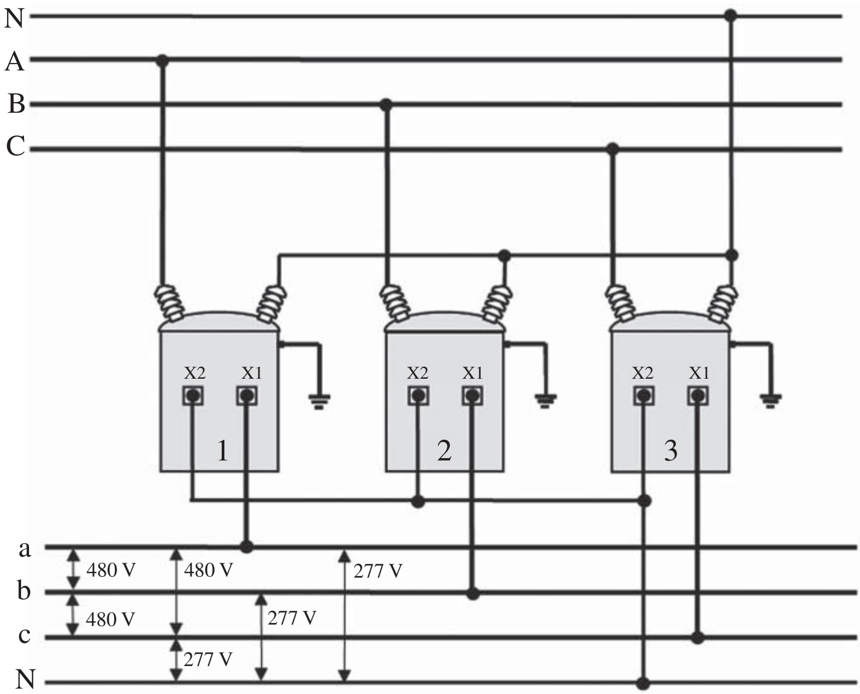


Figure 5-23 480/277 Vac, three-phase connection diagram.

Three-Phase Delta Transformer Banks (240/120 Vac)

Delta–delta and wye–delta transformer banks are less common than wye–wye configurations; however, they are often used. These transformer banks provide 240 V, three-phase service rather than the standard wye connected 208 V, three-phase service. See Figure 5-25. Delta secondary banks provide two 120 V hot legs and one 208 V hot leg, often called the "***stinger,***" "***power leg,***" or "***wild leg.***"

This configuration connects the center tap of transformer #1 to earth ground. This center tap is not neutral with respect to the other two transformers. Only one of three transformer center taps is grounded, which makes the bank unbalanced. With respect to earth as the common ground source, this configuration grounds a small voltage, which can lead to operating issues, such as unwanted stray voltages and currents.

Some of the operating considerations surrounding the use of delta secondary transformer banks are described below:

1) Convenience, standard transformers are utilized
2) Utilities do not have to go inside each transformer and change the A-B-C-D to AC-BD

Figure 5-24 Dry-pack transformer.

3) Connecting the transformer's center tap to ground applies a voltage to ground, thus small stray voltages and currents are likely
4) Unbalanced currents in the bank caused by grounding this small potential can cause primary fuses to blow. The primary neutral is often disconnected from ground to stop fuses from blowing. Disconnecting the primary neutral from ground must be done after the transformer bank is energized because each transformer requires the primary neutral grounded to be energized. Once the bank is energized, the primary neutral can be disconnected from ground. Some utilities install a primary neutral grounding cutout switch for this purpose.
5) Delta secondaries can operate with only two transformers in place and still provide three-phase service. Removing one transformer still provides three-phase service because of the 120° phase shift between phases.
6) One advantage to using 240 V instead of 208 V is electric heaters and other resistive loads designed to run on 240 Vac are less productive when run at 208 Vac. The current amplitude flowing through resistive heating elements depend on the applied voltage; hence, higher voltages cause higher currents to flow. Since electric heat is a function of current squared, heating is more effective at higher voltages. For example, a 240 V clothes dryer could take 10–15 minutes longer to dry clothes when operated at 208 V.

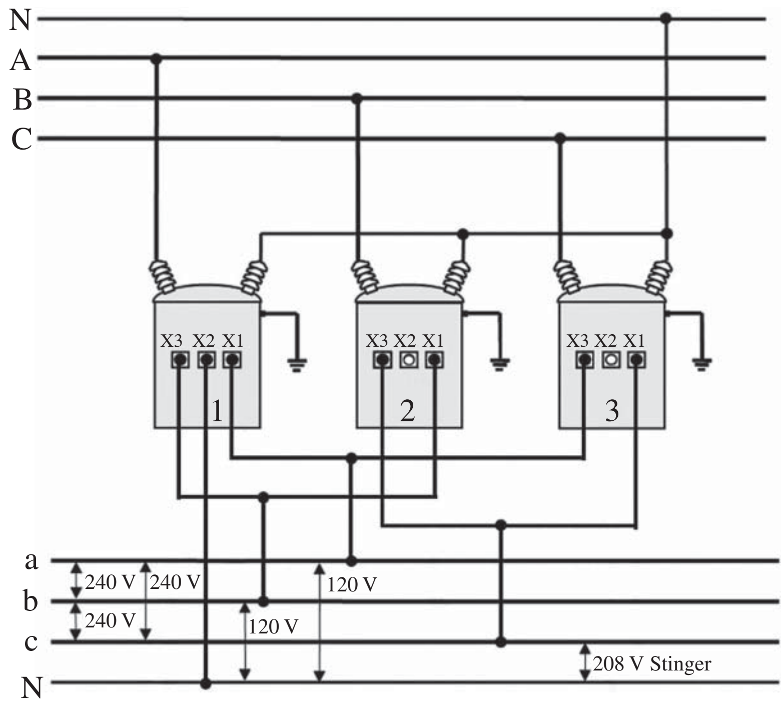


Figure 5-25 Wye–delta transformer bank.

Fuses and Cut-Outs

The purpose of a ***fuse*** is to interrupt power flowing to equipment when excessive current occurs to protect the equipment from damage caused by short circuits and power faults. Fuses like the one shown in Figure 5-26 interrupts the flow of current when the maximum continuous current rating of the fuse is exceeded. The fuse takes a very short period to melt open when the current rating is exceeded. The higher the excessive current, the faster the fuse operates.

Fused cut outs shown in Figures 5-27 and 5-28 are common protection devices used in distribution systems. They are used to protect distribution transformers, underground feeders, capacitor banks, substation service transformers, and other equipment. When blown, the fused cut-out door falls open and provides a visible indication for line workers to see. The hinged door falls open and hangs downward as shown in Figure 5-28. Sometimes the door does not fall open; it remains intact due to ice, corrosion from salt fog, or other mechanical operation

Figure 5-26 Fuse cut-out.

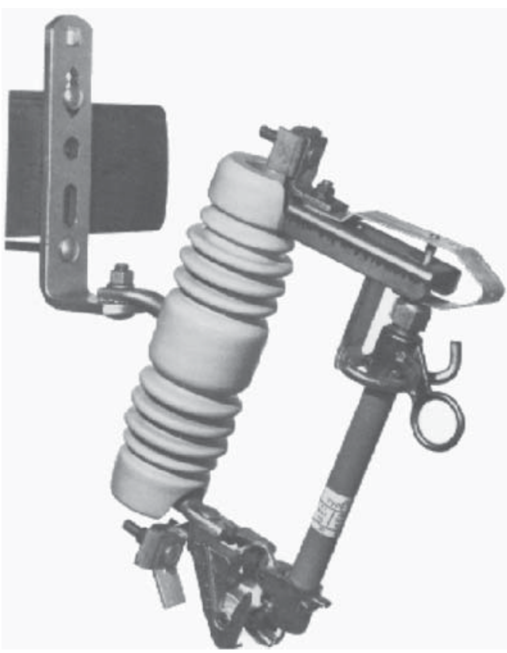


Figure 5-27 Fuse cut-out.

Figure 5-28 Fuse door.

infringements. Line workers on patrol find the outage location quickly by seeing the fallen door and blown fuse from a distance.

Comparing fuses to circuit breakers, circuit breakers can open and close circuits repeatedly while a fuse opens the circuit one time and must be replaced. Fuses are single-phase devices, while circuit breakers are normally gang operated three-phase devices. Breakers can interrupt very high magnitudes of current. Breakers can close into a fault and trip back open. Breakers can be controlled remotely. However, breakers require periodic maintenance.

Special note: these universal type fuses are undergoing significant change by manufacturers to minimize expulsion of hot metal when clearing a fault. Expulsion fuses are known to start fire ignitions. Several new fuse designs are available, such as sealed openings, fully enclosed elements, and electronic clearing mechanisms. For example, Figure 5-29 shows S&C Electric Company's Fault Tamer® Fuse Limiter replacement that offers reduced fire ignition risk.

Figure 5-29 Fault tamer fuse and cut-out. Courtesy of S&C Electric Company.

Riser or Dip Pole

The purpose of a riser or dip pole is to transition from overhead construction to underground construction. Some electric utilities refer to them as ***dip poles*** when the power source is from overhead to underground and ***riser poles*** when the source is underground serving overhead. Either way, they represent an overhead to underground transition. An example of a typical transition pole is shown in Figure 5-30.

Underground Service

Underground construction is usually about 3–5 times more costly than overhead construction. Most people prefer underground construction as opposed to overhead construction for esthetic reasons. Underground systems are not exposed to birds, trees, wind, lightning and should be more reliable. However, underground systems fault due to cable, elbow, splice, dig-ins, and connector failures. When underground systems fault, they can cause significant damage (i.e., cable, elbow, or splice failure). Therefore, underground feeders are usually not automatically re-energized when a fault occurs. Instead, trouble men must first find the problem,

Figure 5-30 Dip pole or riser pole.

isolate the faulted equipment, and restore service to everyone outside of the faulted section.

Primary Distribution Cable

Primary underground cables are one of the most important parts of any underground system. If a fault occurs on an underground cable, the feeder or fused section of the feeder is out of service until a crew can isolate the bad section of cable and perform necessary load transfer switching operations to restore power. Distribution automation (discussed in more detail later) would do this switching activity automatically thus significantly reducing outage time.

Most primary distribution cables like the one shown in Figure 5-31 consist of two conductors (***main center conductor*** and ***concentric neutral conductor***) with layers of insulation and semiconductive wraps. The main center conductor is composed of either copper or aluminum. The outer conductor, or concentric neutral, is usually copper. The outer cover or ***jacket*** is made of polyethylene, polyvinyl chloride (PVC), or thermoplastic material.

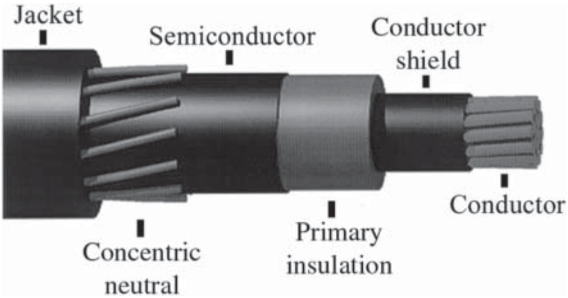


Figure 5-31
Single-conductor primary distribution cable.

The concentric neutral helps trip a circuit breaker or fuse quickly if dug into by a backhoe. Should a backhoe operator penetrate the cable, the blade is first grounded by the concentric neutral before striking the energized center conductor. This allows short circuit current to flow and trip the breaker without harming the equipment operator.

Underground cables have a significant amount of natural electrical capacitance. When cables are de-energized, cables can store a dangerous voltage charge. Special safety awareness procedures are required when working with de-energized underground cables because a voltage charge could be present.

Load Break Elbow

Load break elbows are used to connect underground cables to transformers, switches, and other cabinet or pad mount devices. As the name implies, load break elbows are designed to connect and disconnect energized lines to equipment. However, safe working practices require operating personnel to use insulated rubber protection and fiberglass hot-stick tools to ensure safe working conditions exist when installing or removing elbows. Operators normally de-energize the equipment before connecting or removing these load break devices. Figure 5-32 shows a line worker wearing rubber gloves removing an underground cable elbow using a fiberglass insulated tool.

Figures 5-33 and 5-34 show typical load break elbow connectors.

Splices

Underground splices are used to connect cable ends together. They are normally used for extending cables or for emergency repairs. It is preferable not to use splices. Splices, like anything else, add an element of exposure to risk or failure.

Figures 5-35 and 5-36 show typical splices used in underground distribution systems. Note that all underground connections, especially elbows and splices

Figure 5-32 Load break connections.

Figure 5-33 Load break elbow.

require special installation procedures to assure high quality workmanship for long-lasting reliable performance. Underground equipment is susceptible to water and rodent damage; therefore, extreme care must be taken when performing cable splicing.

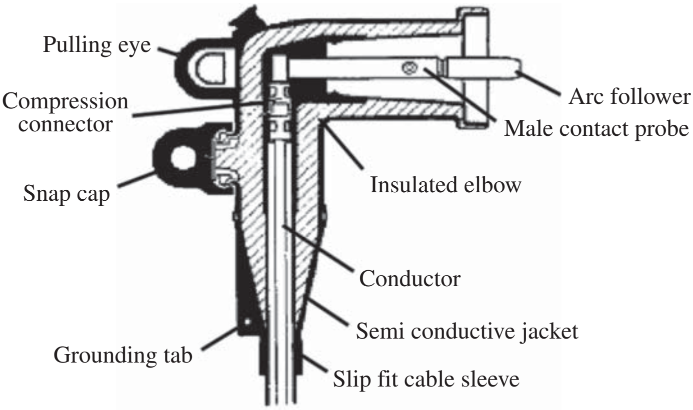


Figure 5-34 Load break elbow components.

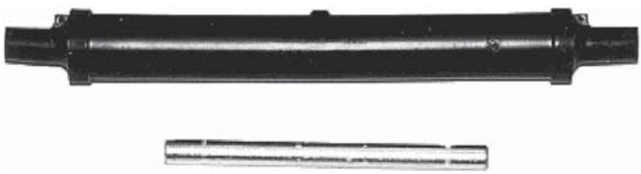


Figure 5-35 Underground long compression splice with cover.

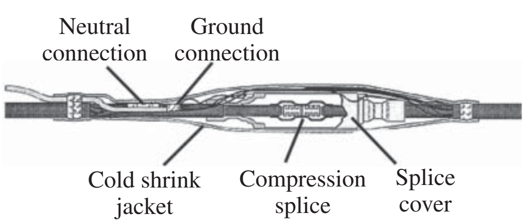


Figure 5-36 3M primary underground splice.

Underground Single-Phase Connection

Figure 5-37 shows a 7.2 kV–120/240 Vac, 25-kVA ***single-phase padmount transformer***. Two HV bushings are present on the left and three LV connectors are present on the right. The two HV bushings allow ***daisy chaining*** transformers in series to serve multiple residences in a loop arrangement.

Figure 5-37 Loop transformer.

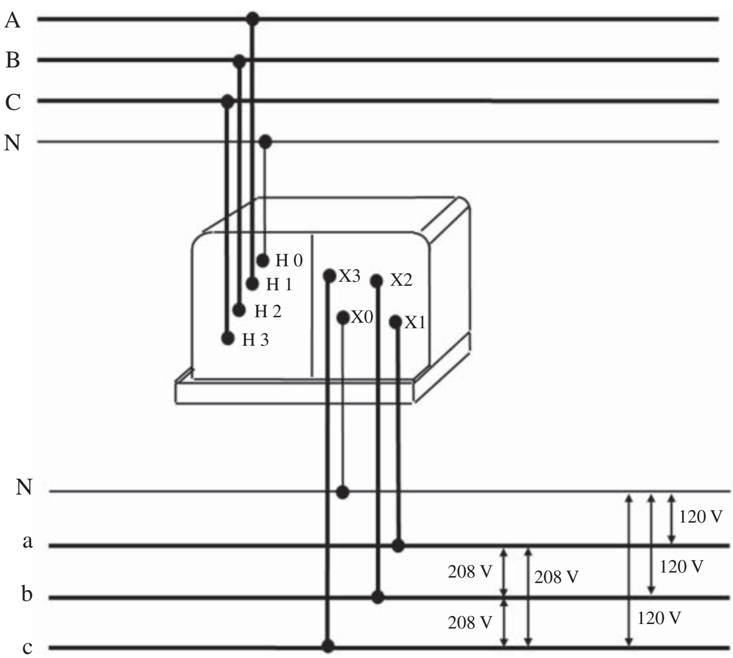


Figure 5-38 Underground wye–wye connection diagram.

Underground Wye–Wye Three-Phase Connections

Figure 5-38 shows how an underground ***three-phase padmount transformer*** is connected to a four-wire wye primary and a four-wire wye secondary. This is very similar to the overhead wye–wye configuration discussed earlier.

This connection supplies 208/120 Vac, three-phase service to the consumer.

Single-Phase Open-Loop Underground System

A typical ***single-phase underground distribution system*** serving a small subdivision is shown in Figure 5-39. This scheme provides reliable loop operation to several consumers. Notice the several normally closed and the one normally open switches operating in a radial configuration. This loop design uses "***daisy-chained***" padmount transformers with incorporated switches to provide the capability of load transfer and equipment isolation during troubleshooting and maintenance activities. Configurations like this allow a faulted section of

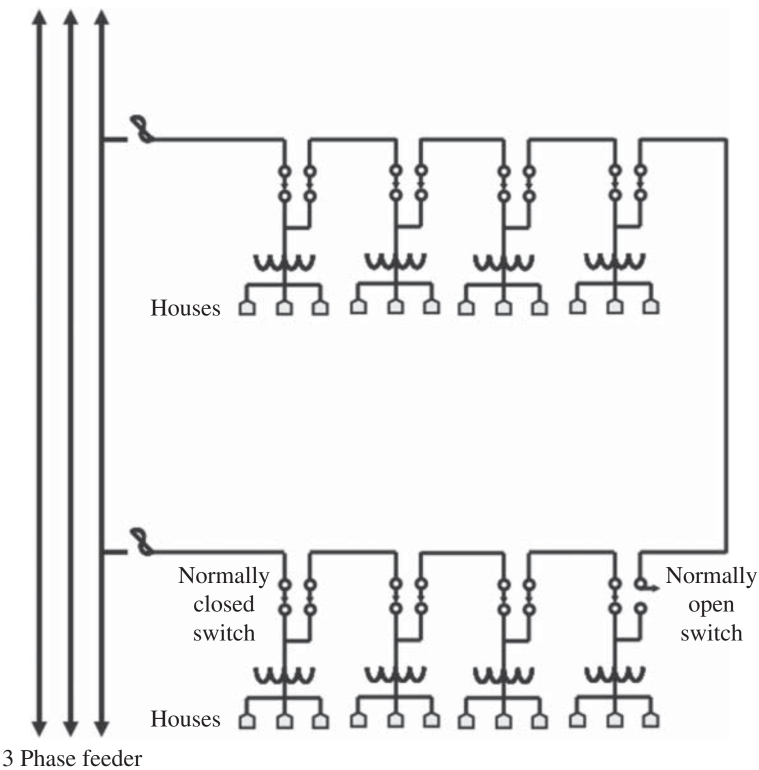


Figure 5-39 Distribution primary loop.

cable to be isolated quickly and service restored while the cable is being repaired or replaced.

Secondary Service Wire

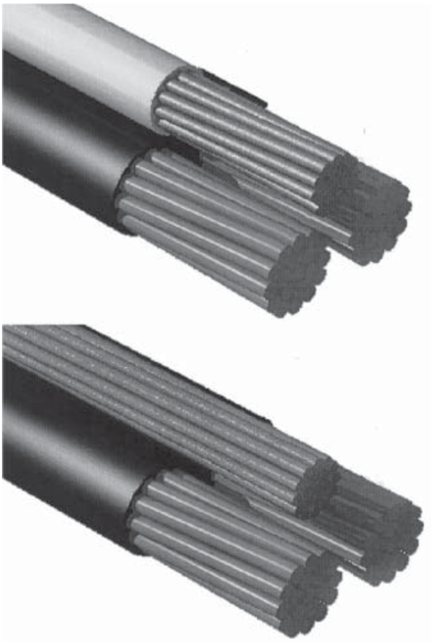
The electric utility is responsible for the service wires between the secondary side of the distribution service transformer and the consumers' service entrance equipment.

Examples of secondary service wires are shown in Figure 5-40. Most secondary distribution wires consist of two insulated conductors and a neutral. Overhead service wires normally use a bare neutral conductor while underground service wires are all insulated.

The conductor's insulation is either polyethylene or rubber coated and rated 600 Vac. The conductors are aluminum or copper. The neutral is usually the same size as the hot conductor.

Examples of overhead and underground ***Triplex*** cables, used for residential 120/240 V service, are shown in Figure 5-40. (Note, ***Quadraplex*** cables are used for three-phase services.) To reduce conductor sag between the service pole and service entrance equipment, conductors are twisted together with the neutral. For single-phase service, such as street lighting, one insulated conductor is twisted together with an uninsulated neutral and referred to as ***duplex*** cable.

Figure 5-40 Secondary cable.



6

Consumption

Chapter Objectives

After completing this chapter, the reader will be able to:

☑ *Explain the different categories of energy consumption (residential, commercial, and industrial) and their load characteristics.*
☑ *Explain how power factor and system efficiency are related.*
☑ *Discuss metering, demand side management, and smart consumption.*
☑ *Explain how residential panels, lighting, receptacles, GFCI circuit breakers, and 240-Vac circuits are wired.*
☑ *Explain the common problems associated with starting large motors and how various types of soft start equipment help reduce flicker.*
☑ *Describe the various types of power quality issues and resolutions.*
☑ *Describe how industrial service entrance equipment, emergency generators, and uninterruptible power supplies (UPSs) work.*

Electrical Energy Consumption

Consumption is electrical energy used by various loads on the power system. Consumption also includes the energy used to transport and deliver energy to consumers. For example, the losses due to heating conductors in power lines, transformers, etc. are considered part of consumption.

Electricity is consumed and measured several different ways depending on whether the load is residential, commercial, or industrial and whether the load is resistive, inductive, capacitive, or a combination. Electric utilities consume electricity during the production, transport, and delivery stages to the end consumers. Electrical energy produced must equal electrical energy consumed.

Electric Power System Basics for the Nonelectrical Professional, Third Edition. Steven W. Blume.

This chapter discusses the consumption side of electric power systems, primarily the customers. This chapter also discusses how system efficiency is measured and supported.

In ***residential*** electric consumption, larger users of electrical energy are items such as air-conditioning units, refrigerators, stoves, space heating, electric water heaters, clothes dryers, and to a lesser degree lighting, radios, TVs, and personal computers. Typically, all other home appliances and office equipment use less energy and account for a small percentage of total residential consumption. Residential consumption has steadily grown over the years and appears this trend is continuing. Residential ***energy consumption*** is measured in kilowatt-hours (kWh).

Commercial electric consumption is also steadily growing. Commercial loads include mercantile, office operations, warehousing and storage, education, public assembly, lodging, health care, food sales, and services. Commercial consumption includes larger scale lighting, heating, air-conditioning, kitchen apparatus, and motor loads such as elevators and large clothes handling equipment. Typically, special metering is used to ***record peak demand*** (in kilowatts) along with energy consumption in kWh.

Industrial electric consumption appears to be steady. Industrial loads involve large motors, heavy duty machinery, high volume air conditioning (HVAC) systems, etc. where special metering equipment is used to measure ***power factor (PF), demand, and energy***. Normally, industrial consumption necessitates the use current transformers (CTs) and potential transformers (PTs) to scale down the electrical quantities for use with standard metering equipment.

Primary metering is used to measure consumption for very large electrical energy consumers (i.e., military bases, oil refineries, mining industry, and large casinos). These large consumers normally have their own substations and primary distribution facilities.

Consumption Characteristics

The combination of the three load types (i.e., resistors, inductors, and capacitors) working together in power systems influences system losses, voltage stability, revenue, and reliability. This section explains how these load types interact and how their interaction can improve or impede the overall operational performance and efficiency of electrical power systems.

Basic AC Circuits

The three basic ac circuit types are resistive, inductive, and capacitive are shown in Figure 6-1.

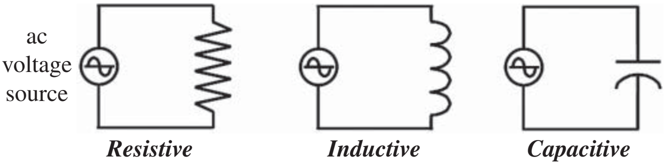


Figure 6-1 Types of circuits.

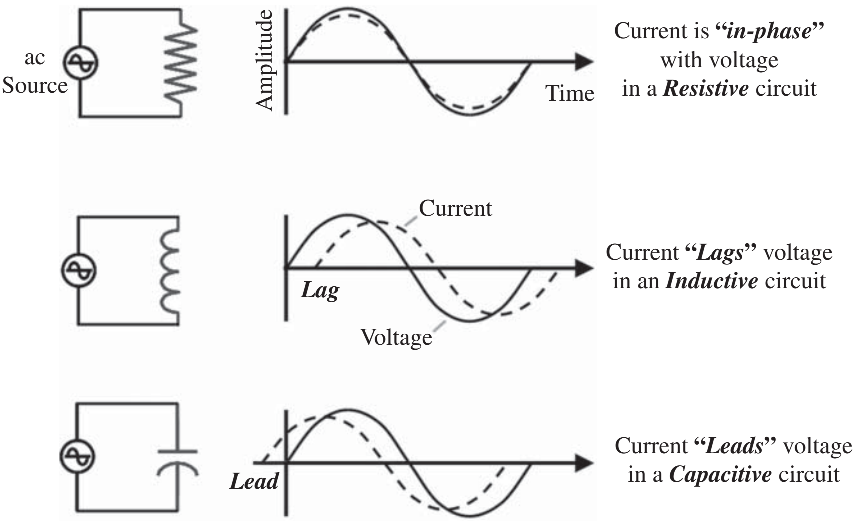


Figure 6-2 Voltage and current relationships.

Depending on the load type connected to an ac voltage source, a time or **phase angle** difference between applied voltage and resulting current occurs. The phase angle is usually measured in degrees (lead or lag) of the 360 degrees power cycle.

Phase Angle Comparisons between Load Types

The phase angle between the applied voltage and resulting current is different for each basic load type. Figure 6-2 shows the three load-type phase angles.

Combining Load Types

When both inductive loads and capacitor loads are connected together, their phase angles combine. Figure 6-3 shows this concept. ***Part (A)*** shows a lagging inductive phase angle added to a leading capacitive phase angle, when combined becomes equal to the phase angle of resistive loads. The phase angle does not have to cancel entirely; the net result can be either inductive lagging or capacitive leading.

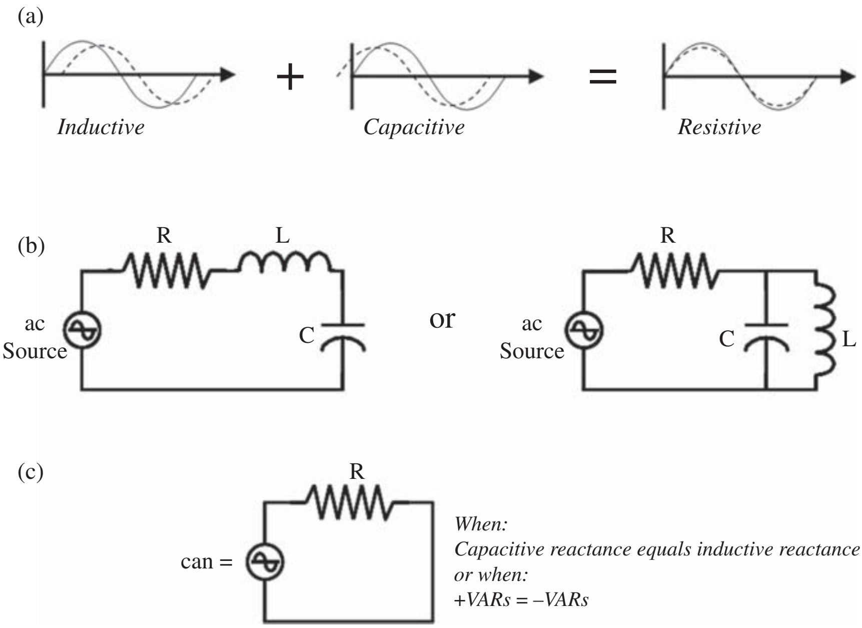


Figure 6-3 Equivalent circuits.

Part (B) shows two ways capacitors and inductors can be connected together to make their phase angles combine. ***Part (C)*** shows the equivalent resistive circuit when combining these two electrical components at full cancellation.

Power System Efficiency

The ***efficiency*** of a power system is maximized when the total combined load is purely resistive. When total load on the system approaches pure resistive, total generation is minimized as well as current flow and system losses in power lines and equipment. Therefore, total power (active plus reactive) becomes active or "real" power only (i.e., watts only). This condition is hard to achieve in real time; however, the operational goal is to minimize generation and system losses, while providing good voltage and frequency support to consumers.

When system efficiency is maximized (i.e., minimum power required to serve all loads properly), three significant benefits are realized.

1) Power losses are minimized
2) Heat radiated from equipment and power lines are reduced, thus reducing stress on the power system.

3) Capacity is made available in transmission lines, distribution lines, transformers, and substation equipment. If current flow is less, then equipment has more capacity available to serve additional load.

When the system is not running close to resistive where possible, current is not minimized, and inductive or capacitive reactive power becomes involved. One way to measure the power system efficiency is to determine ***PF***.

Power Factor

The efficiency of a power system can be viewed as: how much total power (i.e., "active or real" power plus "reactive" power) is needed to get work done. ***PF*** is a term used for efficiency and its calculation is based on the ratio between real power and total power, as shown below:

$$Power\,Factor = \frac{Real\ \ Power}{Total\ \ Power} \times 100\%$$

Typically, PFs above 95% are considered "good" (i.e., high PF) and PFs below 90% are considered "poor" (i.e., low). Some motors, for example, operate in the low 80–85% PF range and the addition of capacitors help improve overall efficiency.

For example, suppose you were trying to cross a river from point "A" to point "B" as shown in Figure 6-4. The shortest path requiring the least amount of energy would be to swim a straight line, as shown on the left image. However, suppose water is flowing downward, causing you to swim a little upstream toward point "C" to arrive at point "B." The extra energy exerted from "C" to "B" would be considered wasteful. In electrical circuits, this wasteful opposing energy is called unnecessary "reactive energy," which contributes to overall system losses.

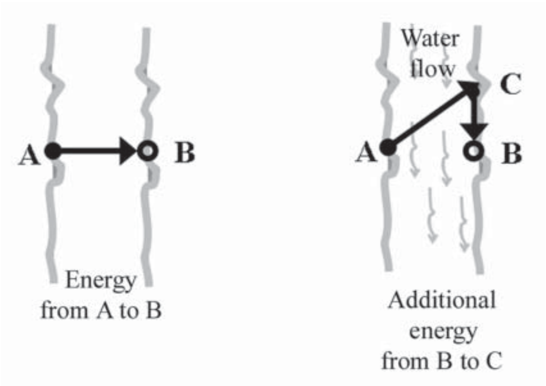


Figure 6-4 Power factor.

Keep in mind that reactive power is needed for motors and other inductive loads to produce their magnetic fields. Instead of using faraway generators to provide reactive power support, adding capacitors locally to the motor's electrical connection terminals fulfills the need for the motor's reactive power. Furthermore, having capacitors at the motor itself, instead of faraway generators reduces losses in the transmission and distribution stages of power delivery.

(*Optional Supplementary Reading*)

Refer to Appendix B for a graphical analysis of electrical PF.

Supply and Demand in Real Time

Let us put the power system into perspective; first comes voltage (the potential energy source), then load is switched on to cause current to flow. Energy is then consumed during the period the load is starting up and performing work. Meanwhile, system losses are occurring, thus requiring supply to increase for balance between generation (supply) and consumption (demand). Throughout this process, electric utilities try to maintain good voltage and frequency. The consumers draw power and energy from the system. Consumers and system losses dictate total demand. In real-time, power producers must supply this total demand through generation, transmission, and distribution systems.

Electric power systems operate in real time. As load increases, frequency decreases and generation must be added to supply the increased demand, maintain frequency, and provide good voltage. Also, as load increases, line treatment (i.e., switched capacitors) are switched on to provide good voltage support. Otherwise, voltage could lower to unacceptable levels (sag), frequency could drop (causing some motors to slow down), consumer lights could dim, and motors could overheat. Consumer equipment is designed for a given voltage and frequency. On the other hand, as load on the system decreases, frequency increases, and generation must be reduced or frequency will increase. Furthermore, switched capacitors must be taken offline to reduce voltage and not over correct the system's reactive power requirements (i.e., a potential net leading situation).

From a generator operator's perspective, to increase system frequency means the prime mover spinning the generator's shaft must increase (hence, more steam to the turbine). To increase generator output voltage, the generator rotor's magnetic field must increase by increasing the exciter's output voltage, causing more current to flow in the rotor's magnetic field winding. System voltage can also be increased by switching on shunt capacitors or switching off shunt reactors. System operators are continuously balancing these system elements as demand changes up and down in real time.

Demand Side Management

Since demand determines the amount of generation needed, one way to minimize generation is to reduce demand, especially during peak periods. Demand side management (DSM) programs are encouraged or implemented to help manage load growth, especially during peak demand periods. DSM programs are designed to help consumers reduce energy cost by reducing demand. DSM also helps delay construction of new generation, transmission, and distribution facilities. DSM programs used for residential and business consumers involve reducing demand by conducting energy audits, controlling consumer equipment (i.e., air conditions and heating) or by providing economic incentives [i.e., time of use (TOU) rates].

Another way demand is reduced is through electric load product improvement. For example, LED lighting significantly reduces electrical energy consumption while providing equivalent illumination. Incandescent lighting was traditionally measured in watts (i.e., a 100-watt light bulb). Today, consumers use energy efficient LED lighting, which eliminated the wasteful nonvisual portions of the light spectrum. LED lighting also reduces light bulb heat because unseen infrared energy is not produced. The change was significant enough for LED lighting fixtures to be specified in ***lumens***, rather than watts. The more lumens, the brighter the light. For example, a 100-watt incandescent light bulb produces approximately 1,600 lumens of light from a 120-Vac source while drawing about 0.8 amperes. Similar lumens of light can be produced by a LED bulb, which requires only 17.5 watts of electrical power and draws only 0.15 amperes of current at 120 Vac; an 81% reduction in energy. Other load product improvements having significant energy reduction characteristics include variable speed drive motors used for swimming pool pumps, modern household appliances with improved insulation, home automation control systems, and several other energy cost cutting products.

The kinds of demand side energy reduction incentives provided by utilities depend on consumer type, as described below:

Residential

Residential and small business DSM programs include the following:

- Lighting (i.e., high-efficiency lighting, such as LEDs)
- High-efficiency washing machines, clothes dryers, and refrigerators (rebates)
- Home-energy audits (to identify usage patterns that can be improved)
- Insulation upgrades
- Appliance management (or smart controls for TOU rates)
- Equipment control to only operate during off-peak periods (i.e., water heaters, pool pumps, and irrigation pumps)

Commercial

Commercial consumers might see DSM programs that are geared more toward overall operations efficiency, for example:

- Efficient building design; remodeling or renovation activities using more energy efficient products and technologies, including efficient lighting, heating, air-conditioning, motor upgrades, variable speed drives, and other more efficient electrical equipment.
- Replacement incentives to remove older lower efficiency equipment
- Real-time energy consumption monitoring programs to encourage better operational methods within a business or organization, such as PF correction capacitors, controllable HVAC systems, and co-generation use of steam for hot water and heating.

Industrial

The DSM programs for industrial consumers focus on energy initiatives, for example:

- Use of local renewable energy resources such as solar PV and energy storage (batteries) to self-generate facility needed electricity.
- Design and implement strategic efficient load patterns by incorporating real-time energy rate information and conservation.
- Energy consumption surveys, studies, or engineering support to provide recommendations for load curtailment, or co-generation schemes using standby emergency generators during periods of peak demand.

There are other demand side incentives available to help reduce electrical energy consumption such as exterior or interior shading, awnings, wall glazing, heat reflectors, automatic control devices, and home or building energy management systems.

There is a concerted effort in the electrical industry to focus on ways to make electric energy consumption more efficient, less demanding, and less dependent on fossil fuel resources. Consumption control through “DSM” programs is one of the best ways to postpone new generation projects, maintain or lower electric utility costs, and conserve energy.

Data Centers

Another aspect of growing demand on the grid system is powering data centers. Data centers have a long-term, increasing load that is classified as flat (or base load) because of their high average ***load factor***. Data centers have an almost constant load throughout the year with small amplitude variations. Data center loads are often referred to as "***critical***" power or "***IT load***." Power consumed at data centers is primarily for IT equipment, such as computers, data storage, servers, routers, and switches. Power for lighting or cooling the data center is typically not included in the term "critical" power. Data centers require emergency backup power systems, which include automatic start generators, uninterruptible power supplies (UPSs), and load management tools to ensure continuous operation without interruption.

Data centers use a significant amount of energy to maintain their servers, consuming about 2–4 kW per square foot, or 100 kWh/day per square foot. The scale is about ten times the power consumption of a typical American home. The largest data centers, having tens of thousands of devices, require over 100 MW of power, which is enough to power approximately 80,000 households.

Data center operators will often plan for a 90% load factor, although utility professionals frequently report the actual number is more typically around 80–85%. Meaning, roughly 90% of full load is continuous, where variations are considered relatively small. ***Energy management control systems*** (EMCSs) are used to regulate site infrastructure loads, such as cooling, lighting, and power delivery systems.

Metering

Electric metering is the process for direct measurement of energy consumption. The electric quantities being measured depend on consumer type and level of consumption. Residential consumers are metered for ***energy*** only in kWh consumed. Small-commercial and light-industrial consumers might have a ***demand*** meter as part of their metering package. Large industrial consumers might have energy (kWh), demand (peak kW), and PF metering (%PF). The largest consumers might receive power at distribution primary, subtransmission or transmission voltage levels where ***primary metering*** is required.

This metering section discusses the key elements included in basic metering packages. These key elements are automatically measured in most smart metering devices, however, not all elements are enabled or used. For example, a smart meter used for residential services can measure demand, but demand is not included in billing. On the other hand, utility control centers might ping residential smart meters to obtain real-time voltage level information to help troubleshoot service problems. Utilities might aggregate load on given transformers to run loading studies. Furthermore, outage management software uses smart meter information to pinpoint the likely service interruption device, such as fuse, recloser, station breaker, and so on.

Residential Metering

The most common type of electric meter is the kWh meter, like those shown in Figures 6-5 and 6-6. These meters measure electrical energy. Energy is the product of power (watts) times time (hours). Total power, which includes "VARs," is not measured in residential load. The units measured are ***watt-hours***. For scaling purposes, kWh is used as the standard unit for measuring residential electrical energy.

The older dial type kWh meters (Figure 6-5) measure actual energy flow in the three conductor service wires connected to the utility's distribution transformer. The current flowing in both hot legs plus the voltage across the two hot legs provide the necessary information needed to record residential energy consumption. Residential load connected to 240 Vac is included in the measurement because its current also flows through the two hot leg service conductors.

Regarding the older style meter (Figure 6-5), dials turn in ratios of 10:1. In other words, the dial on the right makes ten increments before the next dial on its left moves one increment, and so on. The difference between dial readings is the energy consumed for that billing cycle. The electronic or solid-state meters

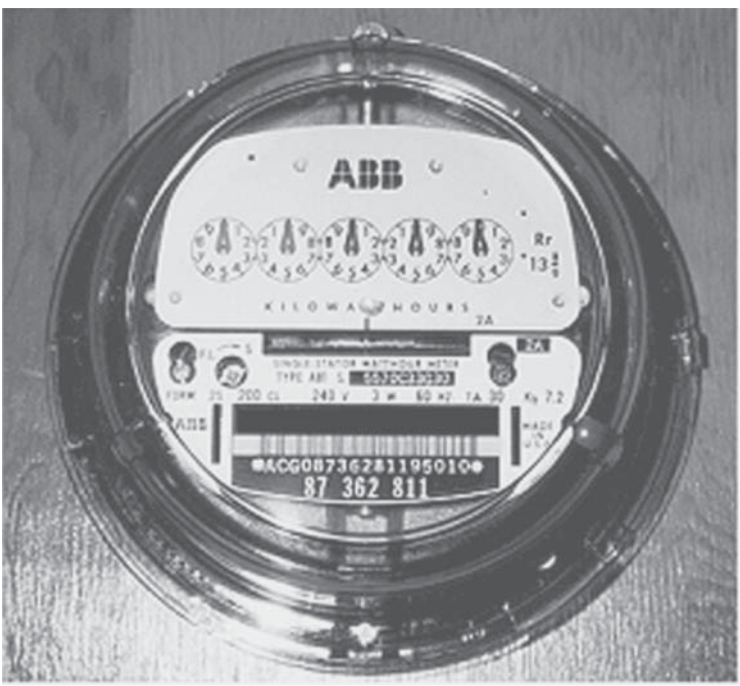


Figure 6-5 Older electro-mechanical kWh meter.

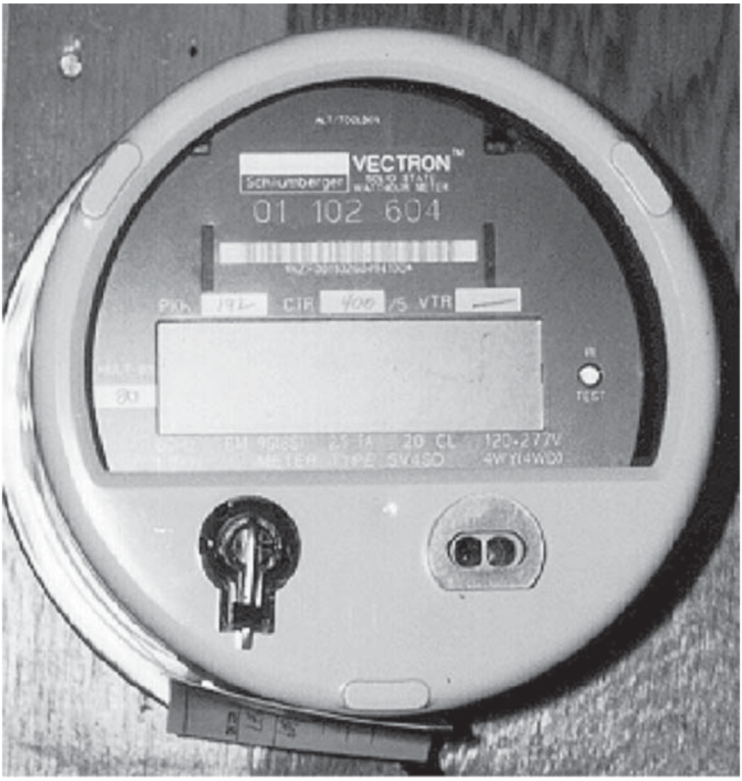


Figure 6-6 Electronic meter.

(as shown in Figure 6-6) record several additional consumption data such as TOU, peak demand, voltage, and in most cases can remotely communicate this information to the utility or other locations through telephone lines, radio signals, power lines, or small handheld recording units.

Demand Metering

Small commercial and light industrial loads might have ***demand*** meters incorporated in their electrical metering equipment. The customer is charged for the highest sustained 15-minute sliding peak usage within a billing cycle. This type of metering is called "demand" metering. Older style clock-type energy meters have a ***sweep demand arm***, which shows the maximum 15-minute demand for that billing cycle. Figure 6-7 shows the demand needle and scale. Figure 6-8 shows an older electromechanical clock type demand and energy meter. Meter readers must manually reset the demand meter's sweep arm after

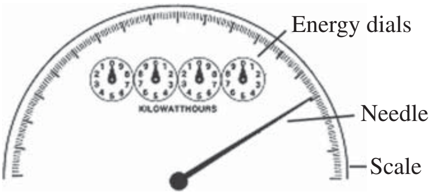


Figure 6-7 Demand needle and scale.

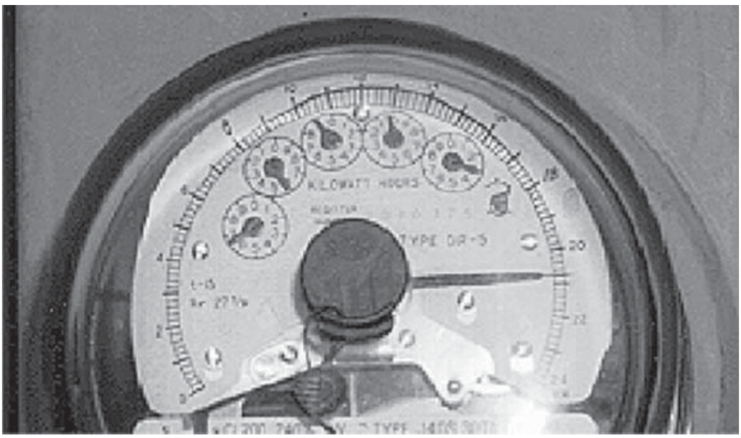


Figure 6-8 Demand meter.

each billing cycle. Electronic solid-state demand meters record this information. ***Advanced metering infrastructure*** (AMI) uses electronic meters (smart meters) with communications capability to automatically transfer this information to the electric utility without the need of meter readers.

Time of Use Metering

A variation of demand metering is TOU metering. While demand meters measure the 15-minute rolling peak demand for each billing cycle, TOU meters record energy and demand consumption during different periods of the day. TOU metering allows utilities to charge different rates for different periods of the day. For example, during the part of the day when energy consumption is highest, having maximum generation online, or peak periods, TOU rates are higher than off-peak times rates. During the part of the day when energy consumption is lowest, or off peak, TOU rates are much cheaper. These variable rates provide incentives to discourage consumption during peak hours and encourage consumption during off peak hours. Smart meters are sometimes called “microprocessor” meters with communications capabilities.

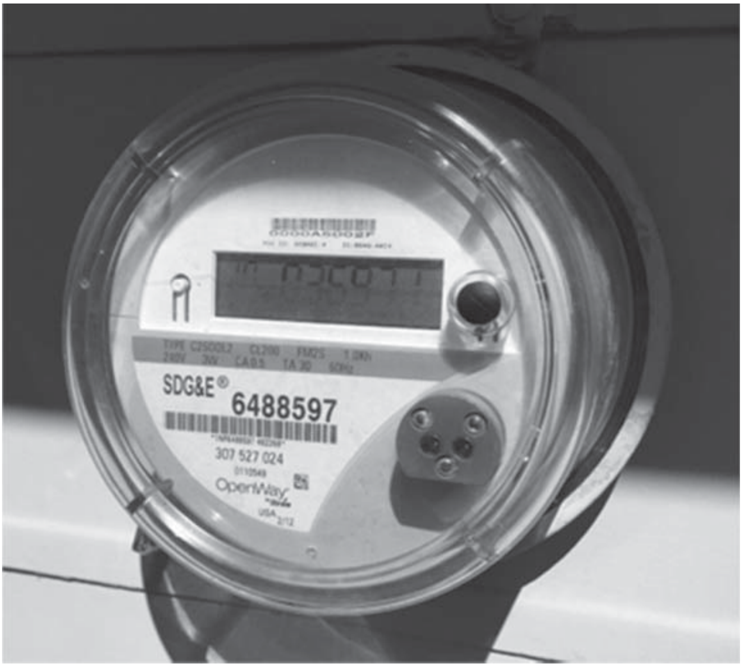


Figure 6-9 Residential smart meter.

Smart Consumption

Smart meters, like the one shown in Figure 6-9, use two-way communications to help the power utility understand residential consumer's load characteristics, remote control service turn on/off, measure consumption based on TOU, and in some cases, utilities offer incentives to interconnect with the consumer's ***home area networks*** (HANs) for DSM.

Home automation is available for the consumer to control consumption by setting up program schedules or manually controlling loads, such as room temperature thermostats, sprinkler systems, lighting, and smart appliances. Incentives help reduce the power bill and contribute toward reducing overall power grid consumption.

Smart appliances enable consumers the ability to optimize energy consumption. For example, smart thermostats in residential dwellings enable users to control their heating and air conditioning equipment by either schedules or remotely controlled from bed or while driving. The user can adjust climate as needed. Kitchen automation enables users to remotely control, among other items, refrigerators, dishwashers, and stoves. Through mobile apps and appliance wireless Internet connectivity, these smart appliances provide timely process control with progress updates. Users can preheat, start, pause, stop, and adjust temperature settings, and cook time, all from their smartphone. Smart dishwashers send alerts when a cycle is finished, when detergent replenishment is needed, and can automatically reorder consumables. Display screens on refrigerator doors enable users to monitor status of all home smart devices, display calendar appointments, shopping lists, and do this through voice commands. The more users control their load efficiently through smart devices; the more grid energy is conserved, and everyone benefits. Furthermore, enabled utilities control high-consumption smart devices, such as central heating, water heaters, air conditioning, swimming pool pump motors, and broadcast ***energy emergency alerts*** when declared.

Figure 6-10 shows how HANs connect several ac and dc smart devices to create the ultimate residential electric power utilization system. This system incorporates the electric utility with home generation (i.e., rooftop solar), controllable load automation, electric vehicles, and much more. The future poses exciting new ways to reduce energy consumption through smart load and source enabled devices. Note that several of these devices are available in dc by shopping at recreational vehicle stores. Furthermore, resistive load (i.e., kitchen stoves, toasters, and heaters) can work from dc sources since the ac power supplied is rms.

Reactive Meters

Watt-hour meters are neither designed nor intended to measure reactive power. However, by shifting the phase angle of the load CT, a second watt-hour meter can be connected to this phase-shifted load to measure reactive energy consumption. The phase is usually shifted with a capacitor–resistor network in single-phase systems and with phase-shifting transformers in three-phase systems. The phase-shifting device helps measure the circuit's reactive power in ***kilo-VAR-hours*** (***kVAR***) or in units of 1,000 VAR-hours. When connected this way, the second kVAR-hour meter is called a ***reactive power meter***. The electric utility can calculate the average PF based on kWh and kVARh information. Some utilities employ direct reading PF meters where peak PF information is provided.

Primary Metering

Some customers have very large loads for their operation and require service at primary distribution voltage. Special primary voltage metering packages are required for voltages above 600 V. Metering personnel install what is known as ***primary metering*** equipment when it is not practical to do the metering at secondary voltage levels. Primary metering equipment includes high accuracy PTs (i.e., metering class PTs) and high-accuracy CTs (i.e., metering class CTs). Special structures, equipment cabinets, or equipment racks are required with this type of metering installation.

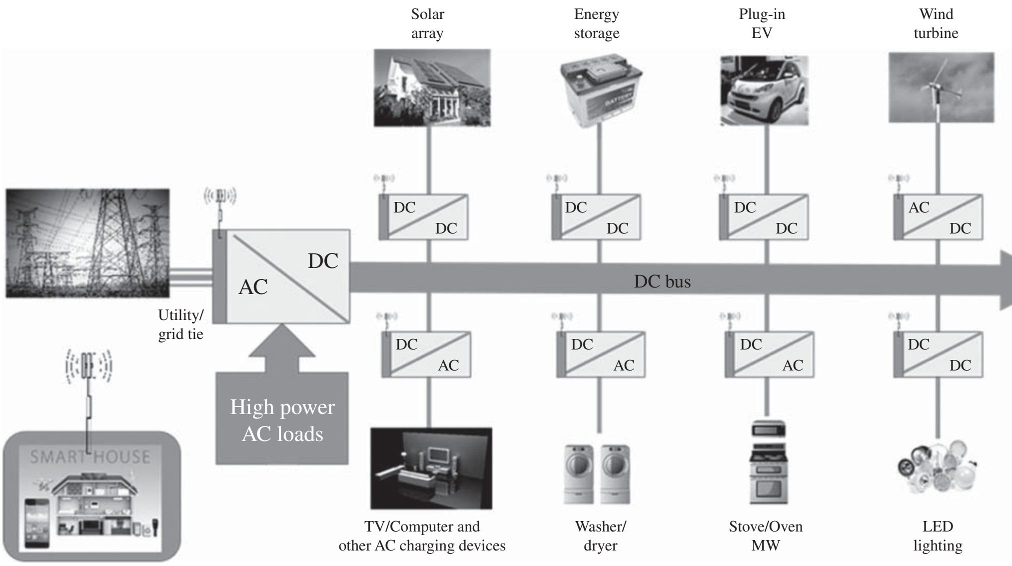


Figure 6-10 Home area network.

Figure 6-11 Underground primary metering.

There are many possible ways to build primary metering equipment housings depending on the type of application. For example, primary metering equipment might apply to underground (Figure 6-11), overhead (Figure 6-12), substation (control room), or industrial installations.

Performance-Based Rates

Regulated distribution utilities are faced with performance-based rates. That is, Public Service Commissions or other regulatory agencies set performance criteria relating to customer service reliability and the utility's reliability performance is taken into consideration when rate increases are requested. If the utility meets or exceeds set performance criteria, it is usually allowed to collect a "bonus" on the base rate. On the other hand, if the utility fails to meet the established performance criteria, utilities might be penalized with a lower rate of return. Performance-based incentives behoove utilities to improve their reliability performance.

Figure 6-12 Overhead primary metering.

Some of the performance-based rate indices include:

SAIFI, *which stands for system average interruption frequency index.*
SAMII*, which stands for system average momentary interruption index.*
SAIDI*, which stands for system average interruption duration index.*

These and other measurements focus on reliable service to the consumer. These indexes were originally manually derived based on daily outage reports and are now supplied by system control center computers.

Service Entrance Equipment

The electric utility connects their distribution transformer service wires to the consumer's service entrance equipment. The National Electric Code (NEC) has very specific rules, regulations, and requirements on how service entrance equipment must be designed, installed, connected, and inspected. This section discusses the basic equipment designs, demand side connections, and special load characteristics considerations used for residential, commercial, and industrial consumers.

Residential Service Entrance Equipment

Actual service entrance equipment can vary from manufacturer to manufacturer; however, the basic designs and concepts are standard. Residential service equipment provides a standard and practical means of connecting the electric utility's 120/240-Vac single-phase service, having two hot legs and one neutral wire, to residential loads throughout the premises.

The standard ***distribution service panel*** is designed to encourage balancing of the two 120-V hot legs with connected loads. These designs make it convenient to connect 240-V loads to the panel by using one combination circuit breaker. Since each consecutive circuit breaker space in the panel connects to the opposite hot leg, any two adjacent breaker spaces conveniently provide a 240-Vac source. Therefore, a 240-Vac connection is done by connecting two adjacent 120-V breakers and installing a plastic or metal ***bridge clip*** across the two individual 120-V breakers. The bridge clip trips both breakers simultaneously when a problem occurs on either hot leg.

Figure 6-13 Basic panel.

Figure 6-14 Meter cover removed.

A typical 120/240-Vac panel is shown in Figure 6-13, note the meter socket. Figure 6-14 shows the same residential panel with the outside cover removed, exposing the meter socket and breaker spaces. Figure 6-15 shows the panel with the breaker space cover removed. This panel is ready for wiring.

The left panel shows the location for the kWh meter. The center panel shows the meter socket connections. The right panel shows the individual breaker position spaces (without the breakers). Note that the center of the lower portion has the metal tabs alternating left and right. This allows vertically adjacent circuit breakers to connect to opposing hot legs for 240-V service.

Service Entrance Panel

The drawing in Figure 6-16 shows how the two hot legs and neutral are connected inside a typical breaker panel. The primary neutral is connected to the ***neutral bus bar***. The service panel's ***grounding bus bar*** is connected to the house's grounding electrode system. A recent change to the NEC allows the use of concrete-encased

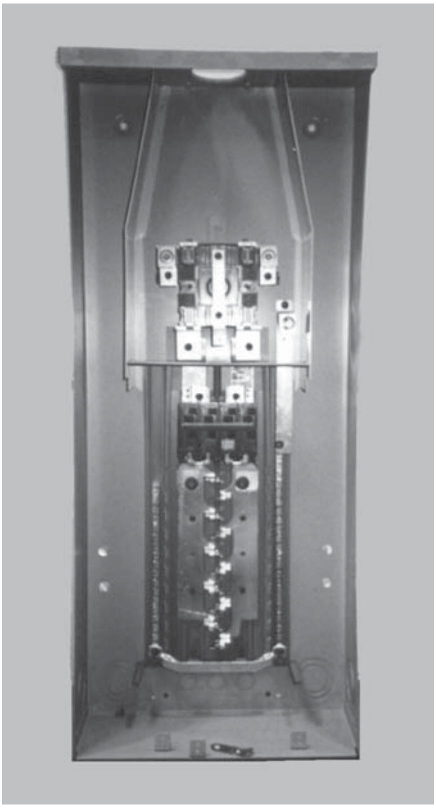


Figure 6-15 Breaker cover removed.

electrodes (also known as ***Ufer-grounds*** after its developer Herbert G Ufer), often found in the foundation of a structure, as part of the grounding electrode system. This common ground connection between the utility's service transformer and end user improves voltage stability, protection equipment effectiveness, and safety.

The two hot legs of the service entrance conductors are first connected to the ***main breaker***. The load side of the main breaker connects to the opposing 120-V breaker buses. Again, this arrangement of opposite bus bars encourages load balance. Load balance minimizes, and in some cases, eliminates current flowing through the neutral. Note that the two breakers providing 240-V service have a plastic clip across their levers, so if one breaker trips both hot legs trip.

Light Switch

Figure 6-17 shows how a standard light switch circuit is configured. The NEC color code standard is stated on the drawing.

Note how the wires can be extended to connect additional lights to a single breaker. The green ground wire (sometimes a bare copper wire) is used to

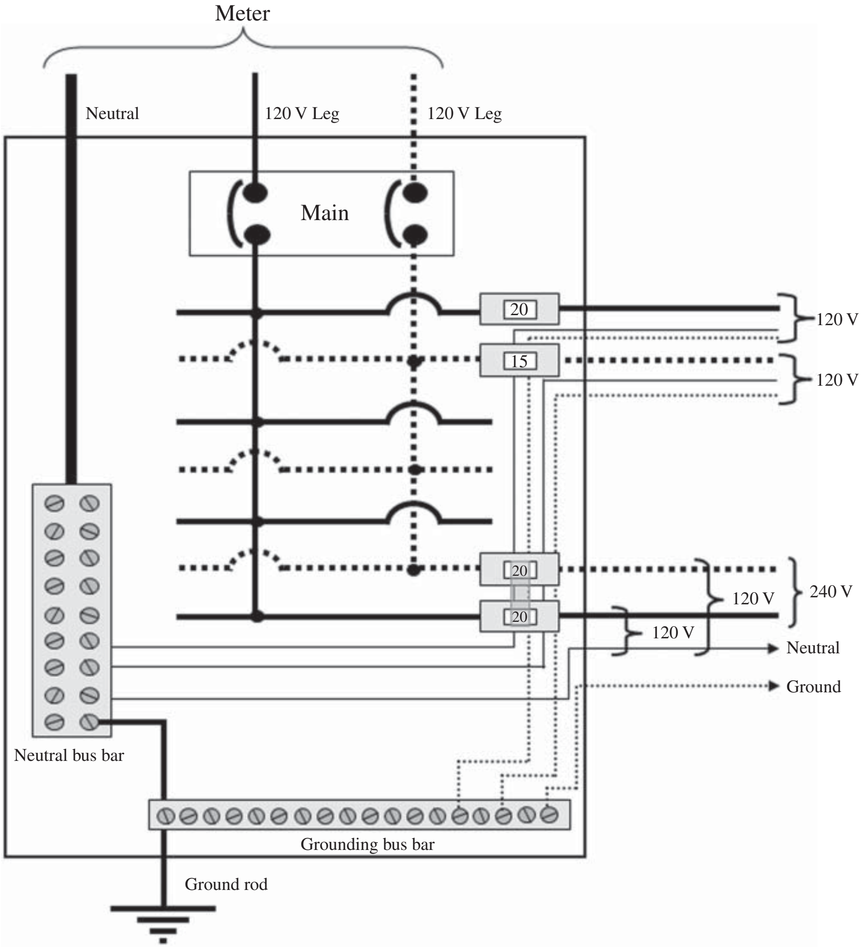


Figure 6-16 Electrical panel – residential.

connect the light fixture metal to ground. Also note how the green ground wire and the white neutral wire eventually connect to the same grounding electrode at the service panel (see Figure 6-16). The reason for connecting the neutral and ground wires together at the service panel is to provide an appliance ground connection that will trip the breaker should a hot wire fray and contact the metal appliance. The frayed hot wire shorts to the grounded metal appliance and trips the panel breaker, thus removing a potentially dangerous situation.

Receptacle

Figure 6-18 shows the basic connections of a standard three-conductor receptacle.

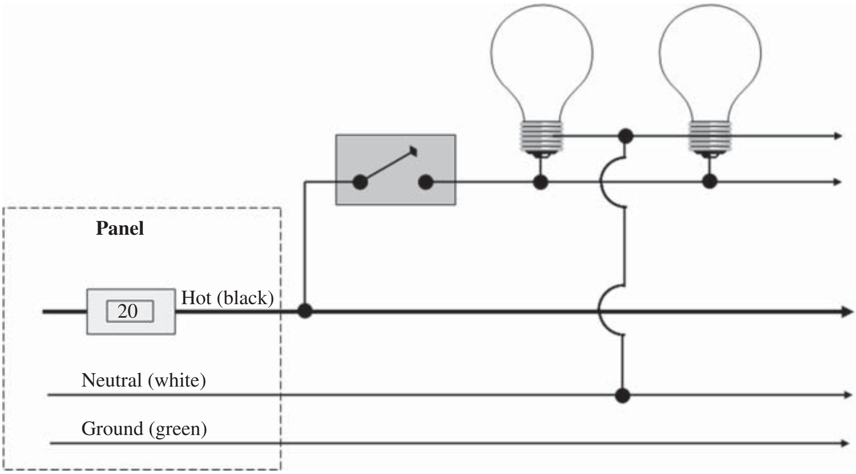


Figure 6-17 Light circuit.

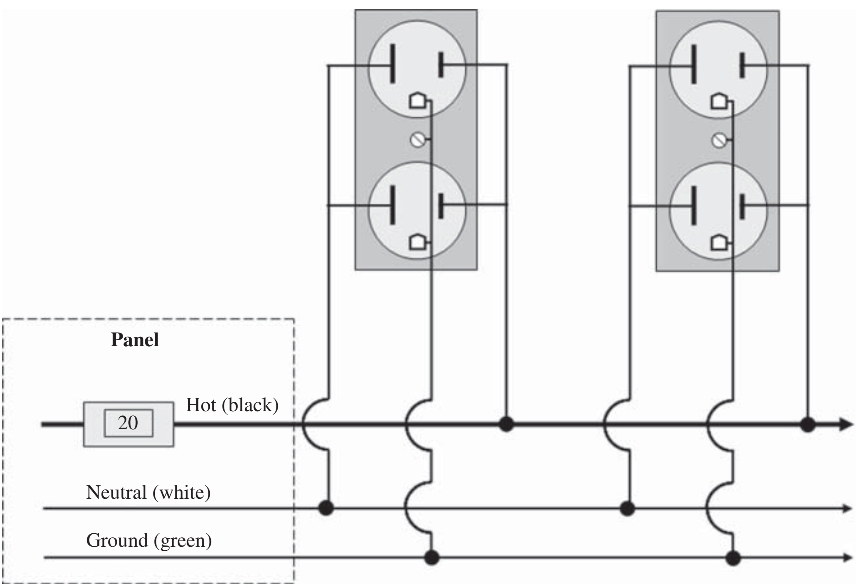


Figure 6-18 Receptacle circuit.

The hot wire is connected to the "short slot" in the receptacle and the neutral wire is connected to the "long slot." That too is an NEC requirement. The grounding wire is connected to the round holes in the receptacle, which in turn is connected to the screw hole that holds down the cover plate and the bracket that mounts the receptacle to the junction box. Therefore, the cover plate screw is a direct connection to ground. *This screw connection is very important for safely grounding devices that use adapters for connecting older style plugs.*

Ground Fault Circuit Interrupter Receptacles

Figure 6-19 shows the basic connections standard for a ***ground fault circuit interrupter*** (GFCI) receptacle.

The purpose of the GFCI is to interrupt current flow to the load should the amount of current flowing out on the hot leg (black) does not match the current returning on the neutral (white). The GFCI breaker will trip should the difference in current be in the order of 5 milliamps (0.005 amps). Five milliamps are below the average human lock-on current, therefore the person can let go of the shocking equipment without harm.

The GFCI is an essential safety device. The NEC requires GFCI protection in all bathrooms, kitchens (receptacles within 3 feet of the sink), outdoor, and garage receptacles. Most GFCI receptacles offer an extra set of screws marked "***load connections***" to connect additional receptacles to be protected by the same GFCI.

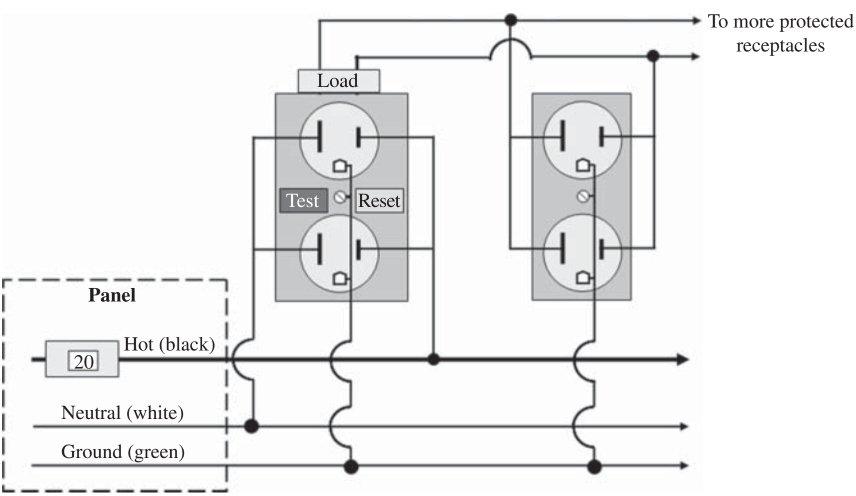


Figure 6-19 GFCI circuit.

The National Electric Code revision in 2017 requires all "bedroom" circuits in a residential installation be served from an ***arc-fault circuit interrupter*** (AFCI) type circuit breaker located in the service panel. This requirement came about due to concern over the number of fires caused by electric blankets and other thermostat-controlled devices. High-activity thermostats (internally switching power on/off frequently) allow extended arcing and sparking to take place. In other words, some thermostats arced too often when deciding whether heating elements should be on or off, thus leading to fires. The AFCI detects what is referred to as ***electrical noise*** generated by arcing and sparking. This noise is used to trip open the circuit breaker. (Note that to avoid arguments, it is normally assumed that if a room has a closet, or capable of having a closet, it should be considered a bedroom for code compliance purposes and outlets are required to be protected by an AFCI breaker.) The NEC also requires AFCI breakers on basically all residential 15- and 20-ampere branch circuits supplying outlets in kitchens, family rooms, dining rooms, living rooms, and recreation rooms.

240 Volt Loads

Figure 6-20 shows the basic connection wiring standard for 240-Volt loads (i.e., clothes dryers, stoves, and water heaters):

Note that the two 120-V breakers are bridged together with a plastic cap. In many cases, a single-molded case is used to house the 240-V breaker mechanism.

The neutral (white) wire is brought to the 240-V appliance and used for its 120-V load such as lights, clocks, and timers. The ground wire (green) is connected to the

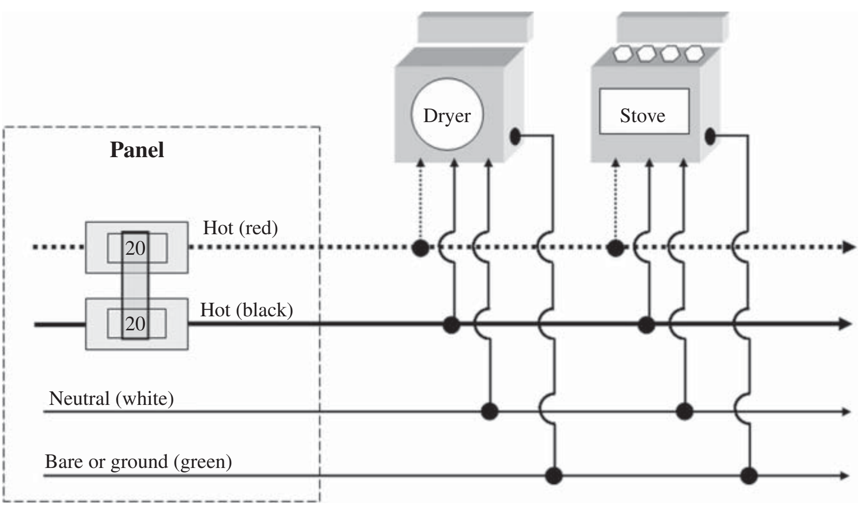


Figure 6-20 240- volt circuit.

Figure 6-21 Industrial panel.

metal appliance. The green ground wire will cause the 240-V panel breaker to trip should either hot wire fray and contact the metal appliance.

Commercial and Industrial Service Entrance Equipment

Commercial and industrial service entrance equipment, like that shown in Figure 6-21, consists of metering equipment (including CTs), a main circuit breaker, disconnect switch, several feeder breakers and sometimes PF correction capacitors, emergency generator with transfer switch, and an UPS system. Some large industrial operations have very large motors requiring ***soft start*** (sometimes called "***reduced voltage start***") equipment to reduce the high inrush current to motors when starting. Soft motor starting helps reduce lighting ***flicker*** as well.

Power Factor Correction

Low PF loads such as motors, transformers, and some electronic nonlinear loads require reactive energy or "VARs" from the utility to operate properly. Excessive reactive demand should be reduced with the installation of capacitors. Capacitors help cancel out the motor's reactive power demand and provide voltage support, reduce losses, can lower power bills, and improve overall energy utilization efficiency.

PF is the ratio of real power (i.e., watts) to the total power (i.e., watts plus VARs). The reactive portion of total power can be reduced or eliminated with the application of capacitors. The surcharge that some utilities charge for low PF is then eliminated.

To correct low PFs, the customer installs capacitors on their side of the meter. When the utility installs the capacitors on their distribution system instead of the customer, the consumer still pays the utility's poor PF fees because reactive power still flows through their meter. When the consumer installs the capacitors, on consumer side of the meter, they no longer pay the extra utility fees.

Electric motors require magnetic fields to spin their shafts to perform mechanical work. The current passing through the motors' wires produces the magnet fields necessary to make the shaft spin. The energy consumed by the motor to create the magnetic fields is "reactive" energy (i.e., VARs). This reactive energy, by itself, does not provide useful work. The "real" component of total power (i.e., watts) provides the useful work done by the spinning shaft. Installing capacitors at the motor's terminals counteracts the motor's need for reactive power and thereby reduces, minimizes or eliminates the reactive component of the energy source. Thus, a properly installed large motor consumes essentially real power only. Lighting flickers or the dimming of lights while a motor is starting up and coming up to speed is thereby reduced or removed entirely. In essence, the installation of motor capacitors supplies the motor's reactive requirements instead of it coming from remote or faraway generators.

Over-Correcting Power Factor

An excessive amount of added capacitance can also increase the total current flowing in the wires. To minimize the total amount of ac current flowing through wires, reactive power must be minimized. Like inductive load causing total current to increase above minimum, overcompensated capacitive load can also increase total current flow in the wires. When the consumer over corrects, extra reactive power flows back through the metering equipment toward the utility. This reactive power is consumed by adjacent consumers, thus reducing the utility's need to install system capacitors. In some cases, consumers receive credit on their utility bill for overcompensating PF.

Location of Power Factor Correction Capacitors

The closer the PF correction capacitors are installed to the load itself, the more beneficial the results are for the consumer. As far as the meter is concerned, the capacitors can be located anywhere on the demand side of the meter. When capacitors are located at the load connection terminals, current flow in the consumer's electrical system is reduced. The utility is typically only interested in the customer's PF at the meter. The customer benefits by putting the capacitors as close to the load as possible to minimize losses in the building wiring system and improve terminal voltage so that the equipment can run more efficiently.

Motor Starting Techniques

(*Optional Supplementary Reading*)

When large motors are started, noticeable ***voltage dips*** or ***flicker*** can occur on the consumer's wiring system that can also affect neighboring loads and the utility's system. Depending on the voltage sensitivity of other connected loads, these voltage dips might not be noticeable. However, they can also be annoying or harmful to equipment. For example, light bulbs can dim and be annoying to office personnel, voltage dips can cause other motors to slow down, overheat, and possibly fail. Reduced motor starting equipment is often used to minimize voltage dips and flicker.

The iron core and copper wires in large motors need to become magnetized to run at full speed. The in-rush current that occurs when large motors start can be in the order of 7–11 times the full load current of the motor. When large motors start, they often cause low-voltage conditions (dips or flicker). Utilities adopt guidelines or policies to control voltage dip when starting large motors. The utility requirement is typically around 3–5% voltage drop on the customer interface. Reduced motor starting equipment is commonly used to meet this utility requirement.

There are several methods for reducing voltage dip and flicker when starting large motors. Reduced voltage motor starting equipment (often called ***soft starting***) include series resistors, shunt capacitors, auto-transformers, special winding connections, and other control schemes connected to the motor circuitry, all aimed at reducing in-rush current when the motor starts.

The three most common means for providing soft start or reduced voltage start on large motors include the following:

1) **Resistors** are temporarily placed in series with the motor starter circuit breaker contacts or ***contactor*** to reduce current flow to the motor initially when started, then the resistors are bypassed to enable full running voltage. This approach reduces inrush current to less than five times full-load current. Once the motor reaches full speed, the resistors are bypassed, leaving solid conductors to provide full-power requirements.
2) **Wye–delta** connection change-over of the motor windings is another effective way to reduce inrush current. The motor windings are first connected in a wye configuration, where applied voltage is only line to ground, then the motor windings are reconnected in a delta configuration for full voltage and output power.
3) **Auto-transformers** are used to apply a reduced voltage to the motor terminals when started and then switched to full voltage after the motor reaches full speed. This scheme can be used with motors that do not have external access to internal windings.

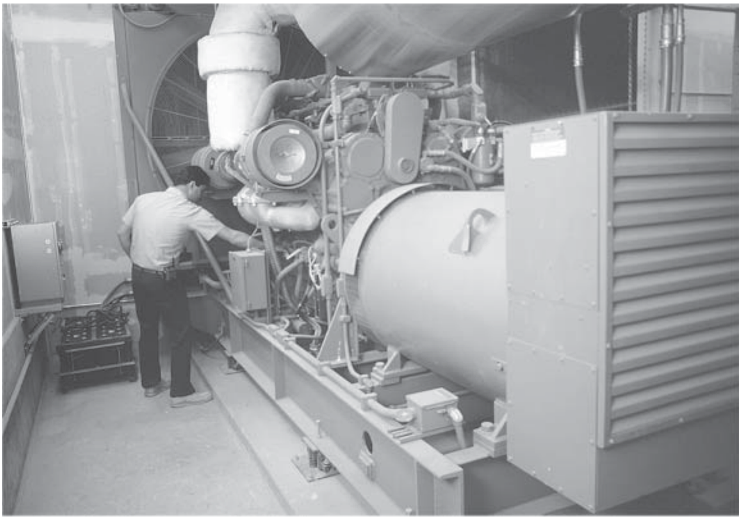


Figure 6-22 Emergency generator.

Emergency Stand-by Generators

Emergency power transfer systems are commonly used on essential loads to provide local emergency power upon loss of utility power. Upon loss of utility power, the generator, like that shown in Figure 6-22 is immediately started, allowed to come up to full speed, and warm up before the transfer switch connects the critical load. PTs are used in the transfer switch to sense when utility power is on and off. Short time delays, approximately 15 seconds, are used to stabilize the generator before load is applied.

Utilities often use emergency generators as on-line peaking units. These peaking generators have special protective relaying equipment needed to synchronize to the utility power grid system. Synchronization requires a proper match among frequency, voltage, phase angle, and rotation before the emergency generator is connected to the utility power grid system.

UPS Systems

UPS systems are commonly found in critical load facilities such as police stations, hospitals, and data centers. where 100% reliable power is required. Figure 6-23 shows a block diagram of a typical emergency generator system with a UPS. Note that utility power feeds all load, including the main, emergency, and UPS panels. Upon the loss of utility power, the generator immediately starts. Once the generator is up to speed and able to carry load (approximately 15 seconds), the transfer switch operates and connects the generator to the emergency and UPS load

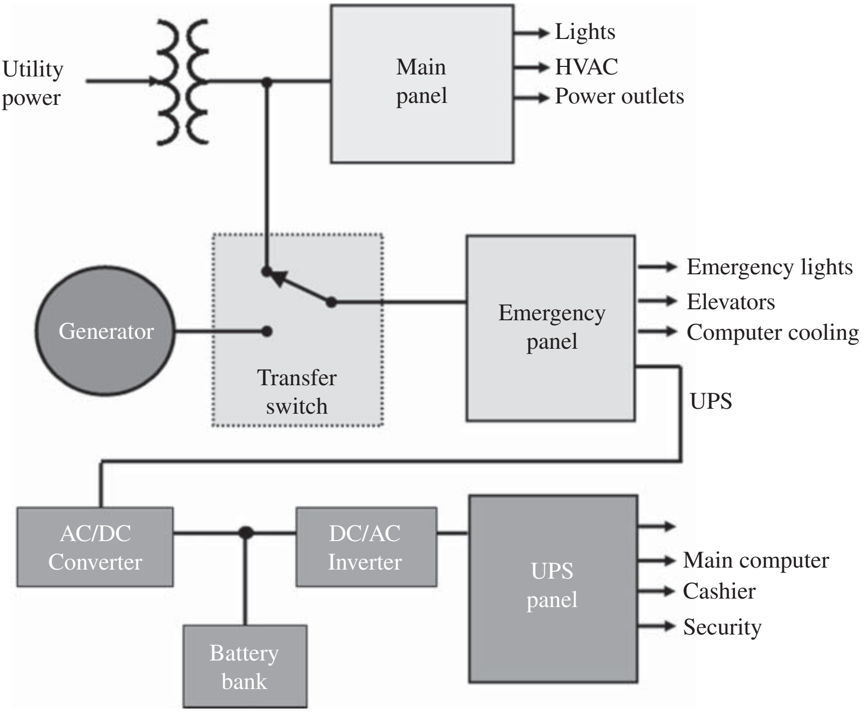


Figure 6-23 UPS system.

panels. The UPS loads never experience an outage because those loads are served by batteries during the source transfer process. UPS batteries are charged by utility power or by the generator after the transfer occurs. UPS batteries have ac/dc converters for charging and dc/ac inverters to provide continuous ac power to the UPS load.

When utility power is restored, the main panel loads are automatically restored. However, all emergency loads must be turned off while the transfer switch reconnects utility power to the emergency panel. Then all emergency loads are restored with utility power. If the transfer switch includes synchronization provisions, interrupting the emergency load panels is not necessary. When utility power is lost and restored, critical UPS load remains powered by the batteries. The batteries revert back to utility power for charging.

Power Quality

Power quality is the term used to describe fitness of the electric power service to serve electrical load and the load's ability to function properly. Some loads are not sensitive to power quality issues while others are very sensitive to power quality issues. Incandescent light bulbs, for example, are not affected by minor power quality issues, such as voltage spikes and harmonics. Some electrical equipment may malfunction if a minimum level of power quality is not provided. Some electrical equipment might fail prematurely or not operate at all if power quality is not provided. Very sensitive equipment can be found in hospitals and manufacturing plants.

This section provides a high-level overview of the meaning of power quality and other service-related issues. There are basically seven types of power quality types described by IEEE standard 1159, as listed below and shown in Figure 6-24:

1) Transients
   a) Impulsive (surges)
   b) Oscillatory
2) Interruptions
   a) Instantaneous (0.5–30 cycles)
   b) Momentary (30 cycles–2 seconds)
   c) Temporary (2 seconds to 2 minutes)
   d) Sustained (greater than 2 minutes)
3) Sag/Undervoltage
4) Swell/Overvoltage
5) Waveform distortion
   a) DC offset
   b) Harmonics
   c) Induced harmonics
   d) Notching (periodic interference disturbances)
   e) Noise
6) Voltage fluctuations
7) Frequency variations

Most high-tech equipment runs on low-voltage dc sources. These dc power supplies convert ordinary 120-Volt service voltage into low-voltage dc. These dc power supplies have specific ac power quality requirements. Most dc power supplies tolerate 120 Volts $\pm$ 10%. Depending on the duration of the power quality waveform issue, some high-tech equipment may withstand wider variations. When sensitive equipment fails or does not operate properly, a power quality problem might exist. The source of the problem can be the power company, the consumer, or an adjacent consumer. These parties need to share information in the problem resolution process.

Some adverse effects from power quality issues are overheating motors, premature equipment damage, data communication errors, analog interference, false

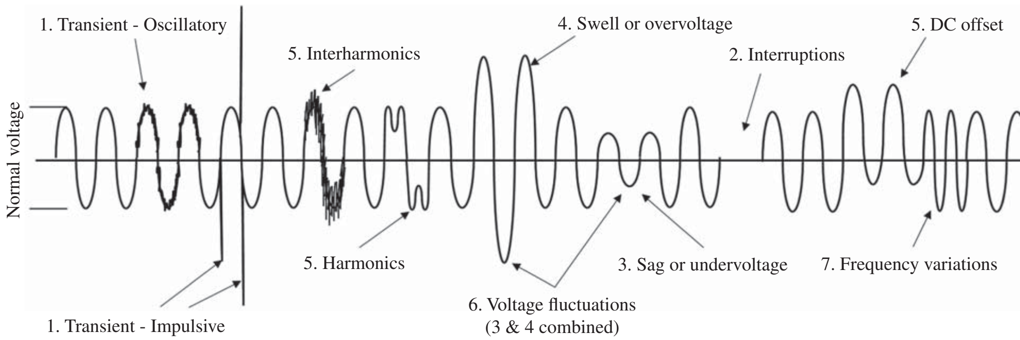


Figure 6-24 Power quality waveforms.

switching operations, and other annoyances depending on the equipment and issues.

The equipment used to resolve power quality issues are UPSs, waveform filters, surge suppressors, better grounding, shielding, and other means depending on the type of problem encountered.

7

System Protection

Chapter Objectives

After completing this chapter, the reader will be able to:

☑ *Explain how transmission and distribution lines, substation equipment, and generators are protected*
☑ *Discuss what is meant by zones of protection*
☑ *Explain the concept of inverse current versus time with respect to clearing faults*
☑ *Explain how to effectively use one-line diagrams*
☑ *Describe the steps needed to synchronize a generator onto the power grid*

Two Types of Protection

There are two types of "protection" referred to in electric power systems. The first is ***system protection*** having to do with protective relays, fault currents, effective grounding, circuit breakers, and fuses. The second is ***personal protection*** having to do with rubber gloves, insulating blankets, grounding jumpers, switching platforms, and tagging. This chapter discusses "system protection." ("Personal Protection" is discussed later in Chapter 11, Safety.)

The protection of high-voltage power system equipment is accomplished through protective relaying equipment that senses abnormal conditions and initiates trip signals to open circuit breakers, operate motorized air disconnect switches, and so on. Some interrupting equipment have self-contained protection devices, such as "electronic reclosers." The objective of system protection is to remove faulted equipment from the energized power system as fast as possible before the situation advances to damage other equipment or becomes harmful to the public or employees. It is important to understand that system protection is for the protection of equipment – *it is not intended for the protection of people*.

Electric Power System Basics for the Nonelectrical Professional, Third Edition. Steven W. Blume.

System protection protects equipment from damage due to power faults and/or lightning strikes. System protection uses solid state and/or electromechanical protective relays to monitor the power system's electrical parameters and trip circuit breakers under abnormal conditions or undesirable situations. Also, protective relays initiate alarms to system control operators notifying them of changes that have occurred in the system. The control operators can then react to these incoming alarms to help secure the system.

Effective grounding is another means to protect or minimize damage to equipment. Effective grounding can minimize damage to equipment and safeguard personnel by making protective relays react faster.

The explanation of system protection will start by describing the different types of faults and protective relays, and then proceed to explaining how distribution lines, transmission lines, substation equipment, and generators are protected by relays.

Before we dive into protective relays, let us review the various types of faults these relays are trying to sense. The common fault types are described below:

- **Line-Ground (L-G) or Phase-Ground (P-G)** is the most common fault type. L-G faults refer to events such as trees contacting one or more phases, phase conductors falling to ground, lightning strikes, and winding failure in a transformer. Regarding underground equipment, L-G faults are typically cable, splice, or elbow failures.
- **Line-Line (L-L) or Phase-Phase (P-P)** is a less common fault type involving two phases. This condition occurs when wind causes two-phase conductors to slap together, ice unloading, car-pole accidents, etc., thus creating a short circuit condition among phases resulting in tripping the source circuit breaker. A variation to L-L faults is the line-line-ground fault.
- **Three-Phase (3-Phase)** is another less common fault type. This condition occurs when all three phases come in contact with each other, causing the circuit breaker to trip. Three-phase faults can occur with airplane accidents, equipment failures, storms, etc. The term "***bolted fault***" is often used by engineering personnel to describe a worst case solidly connected three-phase fault situation. The term is used to determine the total available fault current at a particular location.
- **Open-Conductor:** When a three-phase line or equipment experiences a conductor failure in the open condition while the other two conductors remain intact, unbalanced currents flow in the system. When unbalanced currents flow in the system, they must be sensed and the condition removed quickly by tripping circuit breakers. Large motors, for example, can be damaged when one of the three phases become de-energized; this is known as "**single phasing.**"
- **Others:** There are several other undesirable conditions that can occur on power systems requiring the tripping of circuit breakers. Faults are usually referred to

as equipment failures or power line issues. However, known undesirable conditions on the power grid itself can start protection intervention. For example, three-phase faults in adjacent utilities might cause a power swing condition that is best handled by leaving substation breakers closed to let the power swing self-attenuate by propagating in the interconnected grid.

Most protective relays monitor conditions within the substation (i.e., major equipment and bus) and its connecting transmission and distribution lines. ***Remedial action schemes*** (RASs), sometimes referred to as "***special protection schemes*** (SPSs) or ***system integrity protection schemes*** (SIPSs) are used to oversee conditions involving the entire interconnection, grid, or bulk electric system (BES). These RAS protection schemes use fast computers connected to remote CTs, PTs, and other sensors throughout various substations, power plants, etc. to monitor grid conditions that could lead to a major disturbance.

System Protection Equipment and Concepts

System protection, often called ***protective relaying***, includes microprocessors and/or older electromechanical devices, primarily located in substations, to monitor power system voltages and currents throughout the yard. Yard CTs and PTs are connected to relays located in the control building for input information. Circuit breakers are tripped by relays when abnormal conditions are detected.

Modern microprocessor protective relays convert analog voltage and current information into digital format to find power, impedance, distance to faults, and several other key performance factors needed to monitor and assess system conditions in real time. When abnormal conditions occur, relays initiate control signals, such as breaker trip commands, to stop the undesirable condition. System control operators are then alarmed of changed breaker status, such as "breaker 1274 now open" or "breaker 1274 now closed." Protective relays, telecommunications equipment, and all other critical equipment in substations are battery powered with backup. Therefore, the entire system protection, telecommunications, system control center, and other key system components are fully functional should ac power become out of service.

Protective Relays

A protective relay is a device used to monitor system conditions (i.e., amps, volts, watts, and VARs) using CTs and PTs and reacts to abnormal conditions based on engineered settings. The relay compares real-time actual quantities against preset programmable threshold values and sends dc electrical control signals to trip circuit breakers or operate other devices to clear abnormal conditions. When system problems are detected and breakers tripped, alarms are sent to the system control operators. As a result, energy source equipment is de-energized, and depending on whether networked transmission or radial distribution is involved, consumers are taken offline with minimal equipment damage. The operation of protective relays is the stabilizing force against unwanted destabilizing forces that occur in electric power systems when unanticipated power faults or lightning strikes occur.

Protective relays are manufactured as two types: ***solid state*** and the older ***electromechanical***. The older electromechanical relays, which are very mechanical in nature, are comprised of coils of wire, magnets, spinning disks, and moving electrical contacts. The newer solid-state relays, often referred to as "***microprocessor***" type relays are fully electronic and have no moving parts. Solid state relays carry out many functions in one box. These solid-state relays have revolutionized protection with their untapped capability being stretched over to substation automation, digital network integration, and smart grid functionality; not to mention the tremendous saving in substation control building space. Most utilities have replaced their electromechanical relays with microprocessor-based solid-state relays.

The basic differences are listed below:

Solid State

- **Advantages:** Multiple functionality, small space requirements, easy to set up and test, self-testing, remote access capability, software updateable, and they provide fault history and location information. See Figure 7-1.
- **Disadvantages:** External power is required, software can be complex, and many functional eggs all in one basket.

Electromechanical Relays

- **Advantages:** Usually self-powered, simple, and single function design. See Figure 7-2.
- **Disadvantages:** Normally one relay per phase, difficult to set up, and requires periodic adjustment and testing.

Inverse Current–Time Concept

In general, protective relays are designed to follow the ***inverse time–current*** curve as shown in Figure 7-3. In other words, *the time to trip a circuit breaker shortens as the amount of fault current increases*. A relay sensing a near end fault (located near the substation) initiates a trip to the circuit breaker faster than a fault located down the line. Distant faults draw less available fault current due to additional power line wire resistance. Each circuit breaker requires a fixed amount of time to open the circuit once it receives a trip signal. This fixed time is based on the

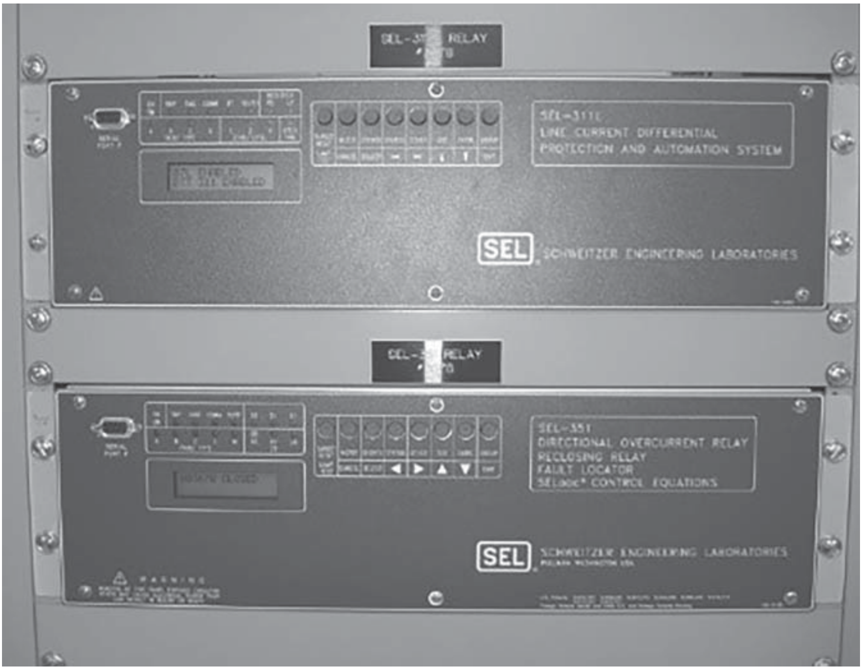


Figure 7-1 Solid-state relays.

breaker's internal mechanical mechanism. Some breakers have an internal trip time less than two cycles after receiving a trip signal from the relay while older breakers might take up to nine cycles to trip. The energy flowing into the fault is greatly reduced with fast clearing.

The time to initiate a trip signal to the breaker is shown along the vertical-axis and the amount of current flowing in the protected line is shown along the horizontal-axis. As actual real-time current stays below the "***minimum pickup"*** setting, the time to trip (vertical axis) is ***never*** and the relay does not operate. When line current exceeds the minimum pickup setting, it means a fault is present on the line, and a breaker trip signal is initiated by the relay. The trip signal is intentionally delayed for lower fault currents, this allows time for downstream devices, such as fuses, to clear the fault first. This breaker-fuse coordination minimizes the number of customers out of service.

When line current exceeds the ***instantaneous*** overcurrent setting, the time to trip becomes ***as fast as possible*** and the relay initiates a trip command without any intentional time delay. Between these two set points, the relay engineer adjusts the shape and slope of the curve to meet ***system protection coordination*** objectives.

Figure 7-2 Electromechanical relays.

"***Relay coordination***" is the term used to create a situation where the most ***downstream*** device from the source clears the fault first, thus minimizing the number of customers out of service. Whenever possible, ***upstream*** devices act as ***back-up clearing*** devices. A carefully thought-out protection scheme requires proper coordination among all clearing devices in the transmission and distribution systems. Relay engineers must understand and take into consideration all idiosyncrasies associated with equipment and the variable system conditions that could come into play. There are many key factors to consider in a well-coordinated study: environmental considerations, equipment limitations, unique coordination circumstances, available fault current levels, and emergency situations. Also, relays must take into considerations operations personnel transferring load during emergencies and maintenance procedures, which could affect trip settings.

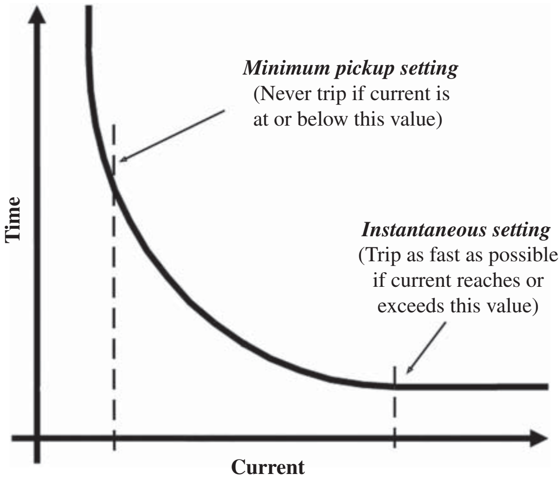


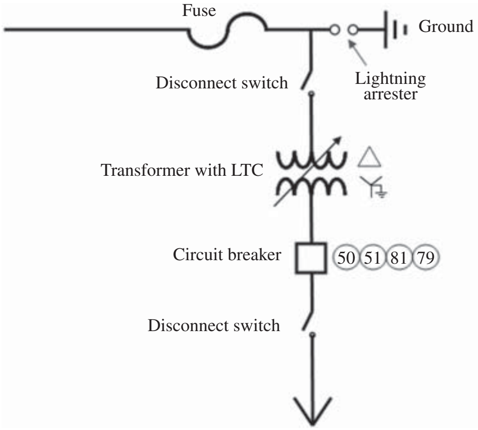
Figure 7-3 Time vs. current curve.

One-Line Diagrams

A "***one-line diagram***" (also referred to as the "***single-line diagram***") is a simplified drawing of a portion of the system that shows the electrical placement of major equipment and protection devices. One-line diagrams are simplified "***three-line diagrams"*** with drawing redundancy removed. Extra information is added to the one-line diagram to give the engineer, systems operator, or field personnel the full picture of the electrical equipment and protection schemes involved. One-line diagrams are very useful for planning preventative maintenance activities, rerouting power after a fault, preparing switching orders to change system configuration, and to view the relationships between smaller troubled sections of the power system to the overall system.

There are many uses for one-line diagrams. Electric utility personnel use one-line diagrams to perform their work activities daily. The most common uses are listed below:

- **Line Crews** use one-line diagrams to know what protection devices are present on the power line being worked, to identify disconnect switch locations for load transfer opportunities, and to see the association to other nearby lines or equipment that are part of the system.
- **System Operators** use one-line diagrams to identify the electrical placement of breakers, air switches, transformers, regulators, etc. in substations that may indicate alarms and/or need corrective action. System operators use one-line diagrams to figure out how to switch the system to isolate failed equipment, and to restore power.



50	Instantaneous overcurrent relay
51	AC time overcurrent relay
79	AC reclosing relay
81	Frequency relay

Figure 7-4 One-line diagram.

- **Electrical Engineers** use one-line diagrams to plan for desired system behavior and to determine infrastructure changes to improve reliability and performance.
- **Consumers** use one-line diagrams to document their electrical system and determine needed upgrades.

An example of a one-line diagram for a simple distribution substation is shown in Figure 7-4. Note the protective relay numbers in circles. These numbers represent relay functions and are identified in the adjacent table. A complete list of relay number identifications and functions is available in IEEE Standard C37.2,[1] Standard for Electrical Power System Device Function Numbers. (We will discuss these relay types next.)

Distribution Protection

Distribution lines (i.e., feeders) are normally fed radially out of substations, meaning distribution feeders have only one utility source. Traditional distribution line protection schemes used on radially fed lines involve overcurrent protection devices with automatic reclosing, and in many cases under frequency load shed relays. This approach to distribution protection is very common; however, variations exist.

Note that although the discussion below describes individual relay types, microprocessor relays are package oriented (i.e., distribution line protection) and will contain all of them. It is helpful to break down the different relay types knowing they now come in packages.

1 IEEE Standard C37.2, Standard for Electrical Power System Device Function Numbers.

Overcurrent and Reclosing Relays

Each distribution feeder has a set of overcurrent relays: one for each phase and one for ground for a total of four (4) overcurrent sensing relays. Each relay has an instantaneous and a time delayed capability. The instantaneous and time delay capabilities are interconnected with the reclosing relay. This substation breaker relay package must coordinate with downstream reclosers and fuses.

Overcurrent relays are connected directly to the current transformers (CTs) found on circuit breaker bushings. This enables monitoring of actual current magnitudes flowing through the breaker in real time. Normally there are four CTs used for each feeder breaker (one for each phase and one for the grounded neutral). These relays are looking for overcurrent conditions (i.e., faults) caused by either phase to ground, phase to phase, two phases to ground, or three phases together. The protection engineer analyzes the available fault current magnitudes for each possible fault condition and recommends relay settings that are later programmed into the relays and tested. These relay settings are periodically reevaluated for load growth, new open/closed feeder switch configurations, and new construction projects to ensure proper feeder protection.

Typical Distribution Feeder Relay Operation

Suppose a lightning strike hits a distribution feeder's "B" phase near the substation and causes a B-Phase to ground fault. The lightning arrester activates and causes a high current line-to-ground fault. The ground overcurrent relay senses the sudden increase in ground current above its programmed threshold setting and instantly sends a trip signal to the feeder's breaker. The breaker de-energizes the feeder and all consumers on that feeder are now out of power. The overcurrent relay simultaneously sends a signal to the reclosing relay to initiate a timer. After the reclosing relay's preset time delay expires (e.g., 5 seconds), the reclosing relay initiates a close signal to the same breaker, thus re-energizing the feeder. This first-time delay, or interval, is typically 5 seconds long. If the fault is temporary, as in lightning, the breaker holds closed, and all consumers remain in service after a brief 5-second outage.

A comment about the above scenario: the instantaneous trip setting (sometimes referred to as the ***fast trip*** setting) on the substation breaker is faster than the time it takes to melt a downstream fuse. When a lightning strike hits a distribution line, the normal sequence of events would be to have all consumers trip offline by the upstream device, and about 5 seconds later, all consumers are back in service without having any distribution fuses melt.

Now suppose a permanent fault occurs on a fused lateral connected to the main feeder. For example, a tree falls onto the line, downstream of a fuse. The substation feeder breaker trips on instantaneous or fast trip and recloses about 5 seconds later. However, this time the tree is still in the line (i.e., a permanent fault) and the current fault again flows after the substation breaker re-energizes the line. In most distribution protection schemes, the fast trip is disabled (i.e., taken out of service) after the first trip and the time delayed overcurrent relay takes over, allowing time for the downstream fuse to melt and clear the fault. Consumers upstream of the blown or open fuse remain in service while consumers downstream of the fuse remain out of power. All consumers on that feeder experienced a voltage sag during the time the fuse was melting and then those consumers upstream of the blow fuse are back to full voltage after the fuse melts. The customers downstream of the blow fuse remain out of power until a utility line worker finds the blown fuse (e.g., door open or hanging), clears the tree, replaces the fuse, and closes the fuse cut-out with a new fuse, thus restoring service to the remaining consumers.

In cases where the permanent tree fault is on the main feeder, not on a fused lateral, the substation breaker will go through its trip and close sequence until ***lock-out***. The substation breaker will trip due to its instantaneous relay. After the first-time delay of about 5 seconds, the reclose relay sends a close command to the substation breaker to re-energize the feeder. If the tree is still in the main line after reclosing (i.e., a permanent fault), the breaker will trip again by the time delayed overcurrent relay. After the second preset time delay expires (about 15 seconds), the reclose relay sends a second close command to the breaker to reenergize the feeder. If the fault current flows again, the time delay overcurrent relay trips the feeder for the third time. All consumers are out of power again. Now after the third preset time delay (this time maybe 25 seconds), the line is automatically reclosed for the third time. If the fault is still present, the overcurrent time delayed relay trips the breaker for the fourth time and ***locks-out***. The reclosing relay no longer sends a close signal to the breaker and all consumers remain out of power until the line workers clear the tree, reset the relays, and close the breaker manually or remotely via a system control center operator. (Note that there is a programmable relay reset timer that places the breaker relay sequence back to the beginning if the reclosing action was successful in restoring power.)

Lock-out is a term used to describe no more automatic attempts to restore power. The fault is permanent, and someone must patrol the line or inspect the equipment before service can be restored. Therefore, after a lock-out, a line worker is sent to ***patrol the line*** to determine the cause, repair the problem, and start the restoration process.

As stated earlier, there are variations to this traditional distribution protection scheme; however, what was described above (i.e., one-fast and three time-delayed trips to lockout) is very common throughout the industry.

Caution: a distribution line can become reenergized several times automatically. Thus, a similar scenario could occur in car-pole accidents where a power line conductor comes in contact with the car. The conductor could and probably will re-energize multiple times before the upstream breaker “locks-out.” Also, system control operators could test a locked-out line remotely, without knowing it is a car-pole accident, if they have good reason, such as bad weather. As a safety precaution ***always stay clear of fallen power lines because of automatic reclosing!***

Underfrequency Relays

To help prevent a cascading outage, underfrequency load shed relays are used to arrest frequency decline. ***Underfrequency relays*** (also called “***load shed***” relays) are used on certain distribution feeders to shed load by tripping substation circuit breakers, as frequency declines. This is an attempt to automatically balance load with generation during a frequency declining situation (i.e., loss of generation). System frequency drops when there is more load than generation (i.e., load-generation imbalance). Similarly, system frequency increases when there is more generation than load (i.e., loss of load situation). When generation trips or an important import tie line trips, and system frequency is dropping, load shed relays start to trip distribution feeder breakers as a ***remedial action.*** This automatic load shedding scheme trips up to 30% of total load, in steps, as an attempt to prevent the system from cascading into a wide area outage.

The typical underfrequency load shed scheme in the United States (i.e., 60 Hz) have relay settings based on the following guidelines:

At 59.3 Hz, shed a minimum of 10% of load.
At 59.0 Hz, shed a minimum of 10% of load.
At 58.7 Hz, shed a minimum of 10% of load.
At 58.5 Hz or lower, the system behaves based on its multitude of protective relay devices. System action could include grid islanding, a domino effect into a major power outage, or a complete blackout.
Some systems start diesel engine generators and/or combustion turbines automatically upon underfrequency detection. This action helps shorten the time frame to restore generation-load balance.

Transmission Protection

Transmission protection is much different than distribution protection, simply because transmission is usually networked, not simply a radially fed system. Transmission systems typically have multiple lines to a substation.

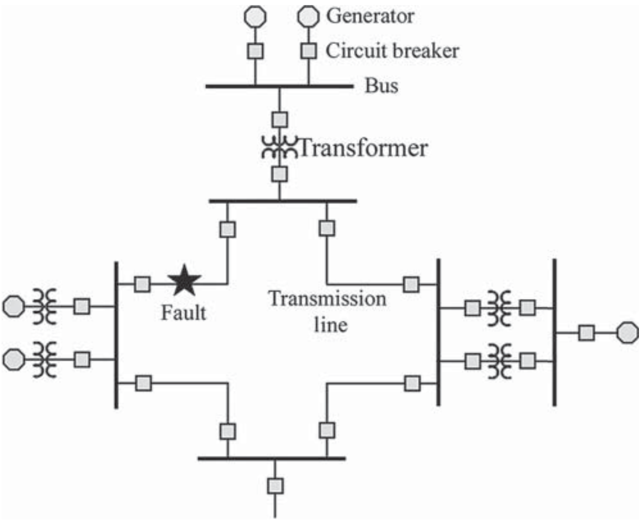


Figure 7-5 Transmission fault.

Therefore, transmission lines have special protective relaying schemes to identify which transmission line faulted and to trip corresponding breakers. To complicate matters, some transmission lines have generation at the other end that contributes to the fault current while other lines are merely transporting generation to other substations. Furthermore, some transmission lines serve load at their far end. To accommodate a network type transmission system, the concept of ***zone relaying*** (sometimes called ***distance or impedance relaying***) is used.

The direction of fault current flow verifies that a particular breaker(s) needs to trip. For example, the excessive current must leave the substation towards the fault. Both fault current magnitude and direction are required for transmission breakers to trip.

As another example, notice the location of the fault on the transmission one-line diagram shown in Figure 7-5. Notice the multiple transmission lines, generators, transformers and buses for this power system. A fault on one of the transmission lines requires breakers on both ends of that line to trip. Zone relaying, with directional capability, identifies the faulted line and trips the appropriate breakers. Also, zone relaying provides back up tripping protection should the primary protection scheme fail.

Zone or Distance Relays

Let us discuss zone protection. Figure 7-6 shows the concept of zone relaying.

In this scheme, each breaker has three protection zones looking down the line but only breaker "A" zones are shown. In other words, breaker "A" has

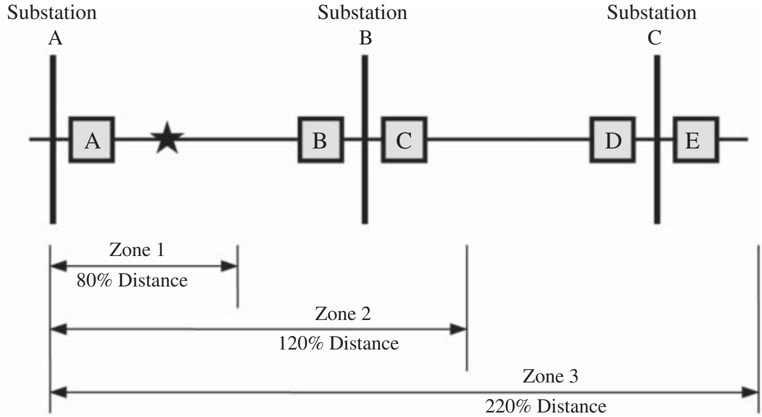


Figure 7-6 Zone protection.

three zones looking toward the right (as shown) and breaker "B" has three zones looking left (not shown), breaker "C" has three zones looking right (not shown), and so on. Typical zone relaying works as follows:

Zone 1 Relays

The zone 1 relay is programed to recognize faults located 80% to 90% of the line section and trip instantaneously (i.e., 1–3 cycles or 17–51 milliseconds).

In this example, the fault is in zone 1 of breaker "A" and therefore breaker "A" trips instantaneously. Instantaneous (or high speed) implies that the relay is set for instantaneous and fault clearing depends only on the time it takes the breaker to open its contacts to interrupt the current.

Zone 2 Relays

The zone 2 relay is programed to recognize faults located one-line section plus about half of the next line section (approximately 120% to 150%). Zone 2 tripping is time delayed to coordinate with zone 1 relays.

In this example, the fault is in zone 2 of breaker "B," thus breaker "B" would trip after a short-time delay. However, in zone protection schemes, the zone 1 breaker sends a communications signal to the opposite end of the line telling the zone 2 relay of breaker "B" this is our fault, remove your time delay and trip immediately. These communications schemes use optical fiber, microwave, power line carrier, or copper communications systems. In this case, breaker "A" would send a transfer trip signal to substation B, telling breaker "B" to bypass its zone 2 time delay setting and trip immediately. This provides high-speed line clearing at both ends, even though there is a built-in time delay in zone 2 relays.

Note that if the fault were in the middle of the line, zone 1 protection overlaps and both ends trip high speed without the need for communications signal.

Zone 3 Relays

Zone 3 relays are set to reach past the protected line section, past the next line section, and plus an added half of the next line section. With proper time delay settings, zone 3 relays provide a backup protection scheme. The trip is time delayed more than zone 2 to coordinate with zone 2 and zone 1 protection. Zone 3 provides full backup. In some cases, zone 4 relays are used (i.e., some nuclear power plants).

In the example above, zone 3 back-up protection would not be involved. When a zone 2 breaker does not trip the line in its allotted time, then the zone 3 relay trips the line as backup.

(Note that the various telecommunications systems used in electric power systems for system protection schemes are discussed in Chapter 9.)

Substation Protection

Substation protection is generally provided by ***differential relays***. Differential relays are used to protect major transformers and bus sections from faults. Substation differential relays are very similar in concept to GFCI breakers discussed earlier in residential wiring (Chapter 6). In the case of the GFCI receptacle breaker, the current leaving the hot leg (black wire) must equal or be within 5 milliamps of the current returning in the neutral (white wire) or the GFCI breaker trips. Similarly, differential relays used in substation transformers and buswork monitor the current entering vs. exiting the protection zone. These concepts and others are discussed below as they apply to substation transformers and bus protection schemes.

Differential Relays

Differential relays are generally used to protect buses, transformers, and generators. Differential relays operate on the principle that the current going into the protected device must equal to the current leaving the protected device (neglecting losses, etc.) or a differential condition is present. Should a differential condition be detected, then all circuit breakers capable of feeding current into the device, from either side, are tripped.

Transformer Differential Relays

Current transformers (CTs) on both the high side and low side of a transformer are connected to a ***transformer differential relay***. ***Matching CTs*** are used to compensate for the transformer windings turns ratio. Should a differential condition be detected between the current entering the transformer and exiting the transformer after adjusting for small differences due to losses and magnetization currents, the relay trips the source breaker(s) (both sides), and the transformer is de-energized immediately. There are no automatic reclosing relays on transformers, or bus, differential protection.

Bus Differential Protection Schemes

Bus differential relays are used to protect the buswork in substations. The current entering the bus (usually exiting the power transformer) must equal the current leaving the bus (usually the summation of current from all transmission or distribution lines). Line-to-ground faults in the bus will upset the current balance in the differential relay and cause the relay to initiate trip signals to all source breakers.

Over and Undervoltage Relays

Another application of system protective relays is the monitoring of high- and low-bus voltage. For example, ***overvoltage relays*** are sometimes used to switch off substation capacitor banks. While ***undervoltage relays*** are sometimes used to switch on substation capacitor banks. Over and undervoltage relays are also used to trip line or generator breakers when abnormal conditions occur.

Generator Protection

The chances of failure of rotating machines are small due to improved design, technology, and materials. However, failures can occur, and the consequences can be catastrophic. It is very important that proper generation protection is provided. This section summarizes the techniques used to protect very expensive large generators.

When a generator trips off-line for any reason, it is extremely important to determine exactly what caused the generator to trip. This condition should not happen again. Some of the undesirable operating conditions for a generator to experience and the protective schemes used to protect the generator are listed below:

Winding Short Circuit

Differential relays normally provide adequate protection to guard against shorted windings in the generator stator. The current entering the winding must equal the current leaving the winding or a winding to ground fault may be present, and the generator breaker is tripped.

Unbalanced Fault Current

The very strong magnetic forces that are imposed on a generator during a fault, especially an ***unbalanced fault*** (e.g., line to ground fault as opposed to a three-phase fault), cannot be sustained for a long period of time. This condition quickly causes rotor overheating and serious damage. To protect against this condition, a reverse rotation overcurrent relay is used. Reverse rotation currents (i.e., ***negative sequence current***) relays look for currents that want to reverse the direction of the rotor. ***Positive sequence currents***, for comparison's sake, rotate the rotor in the correct direction.

Frequency Excursion

A generator's frequency can be affected by over and underloading conditions and by system disturbances. Frequency excursions can cause overexcitation problems and can cause turbine blade damage. Excessive underfrequency excursion conditions can also affect auxiliary equipment, such as station service transformers that power ancillary equipment at the power plant. Underfrequency relays and volts per hertz relays are often used to protect against excessive frequency excursions.

Loss of Excitation

When loss of generator excitation occurs, reactive power flows from the system into the generator. Complete loss of excitation can cause the generator to lose synchronism. Therefore, loss of excitation relays (i.e., undervoltage relay) are used to trip generators.

Field Ground Protection

Field ground protection is needed to protect the generator against a possible short circuit in the rotor's field winding (i.e., a fault between the rotor winding and stator). A fault in the rotor's field winding could cause severe ***current imbalance and generator vibration,*** thus possibly damaging the generator's rotor shaft.

Motoring

This condition is attributed to insufficient mechanical energy placed onto the shaft by the prime mover. When this occurs, power flows from the system into the generator, turning the generator into a motor. Motoring a generator can cause overheating of the turbine blades and other problems. Protection against generators acting in a ***motoring condition*** usually results in tripping the generator.

Steam Safety Valve Tripping

As mentioned earlier in Chapter 2, Generation; steam safety valves are quickly opened whenever the generator is tripped. When a generator trip occurs, two things happen; the circuit breakers feeding power into the grid system trip, and the steam safety valves are open. Opening the steam safety valves releases the turbine's high-temperature and high-pressure steam into the atmosphere. Steam valve tripping removes the forces used to spin the turbine and thus, the turbine eventually comes to a stop. Normally, the generator-turbine rotor is kept spinning slowly to keep this very heavy shaft straight and not wabble next time it is placed into operation.

Generator Synchronization

The purpose of a synchronizing relay and circuit breaker is to safely connect two transmission systems together or to place a spinning generator on-line to a running system. Figure 7-7 shows a generator synchronizing breaker used to place a generator online. There are *four* conditions that must be met before the synchronizing breaker can be closed with minimal transient activity. Failure to meet these four conditions can result in a catastrophic failure of the generator. ***Permissive relay contacts*** are used in circuits like this to prevent (i.e., block) circuit breaker closing until all necessary preconditions are met. An analogy to

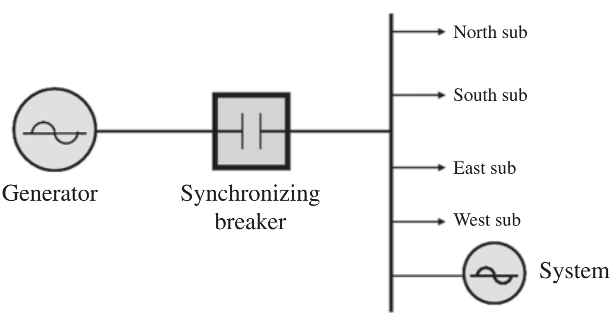


Figure 7-7 Generator synchronization.

"permissive relays" is requiring your foot to be pressing against the brake pedal in your car before the engine will start.

The four conditions that must be met prior to closing a breaker to synchronize a generator to a running system are summarized below:

1) **Frequency**
   The generator must have the same frequency as the system before the circuit breaker can be closed. Not matching frequency on both sides of the breaker before closing could cause the generator to instantly speed up or slow down, causing physical damage or excessive power transients.
2) **Voltage**
   The voltage must be close to the same magnitude on both sides of the breaker. Widely differing voltages (i.e., greater than 10%) could result in excessive voltage transients when the breaker is closed.
3) **Phase Angle**
   The relative phase angle between the generator's frequency and system frequency must be equal to, or very close to, a predetermined setting (typically within 14°). For example, there can be 60-Hz frequency on both sides of the breaker, but one can be 180° out of phase from the other. This is not acceptable. Closing the breaker with 180° phase difference between systems would be catastrophic, like causing a head-on collision. Permissive relay contacts prevent breaker closing when the phase angle between the two systems is greater than typically 14°. (Note that it is only necessary to match one phase on both sides of the breaker, provided it is the same phase.)
4) **Rotation**
   Rotation is normally established during equipment installation. Rotation has to do with matching system phases A, B, and C with generator phases A, B, and C. Once rotation has been established, this situation should never change.

Synchronizing Procedure

Synchronizing relays and/or synchroscopes such as the one shown in Figure 7-8 help match the generator to the system for a graceful connection. Synchroscopes display the relative speed of the generator with respect to the system. A needle rotating clockwise indicates the generator is spinning slightly faster than the system. The normal procedure for closing the breaker is to have the generator spin slightly faster than the system or at least accelerate in the positive direction when the breaker is closed. Once the breaker is closed, the needle stops moving and it is time to open the steam throttle valves to push power into the system.

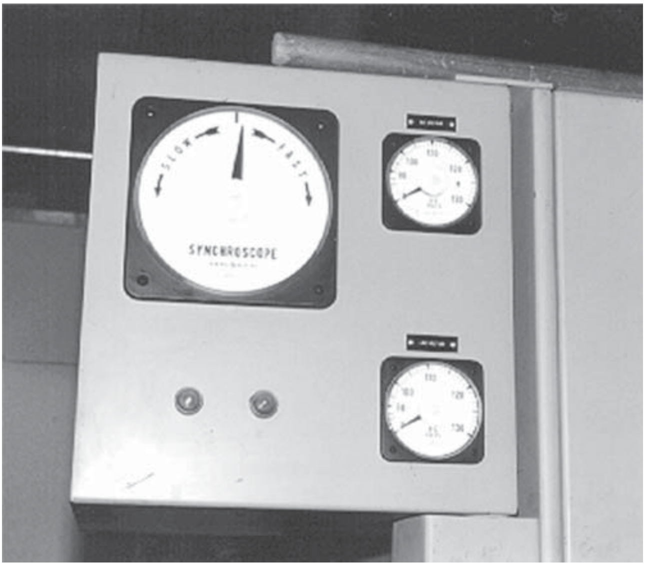


Figure 7-8 Synchroscope.

Overall Transmission Protection

The drawing in Figure 7-9 shows the many transmission zones of protection found in a typical interconnected electric power system. All ***zones overlap*** to provide a full complement of protection against line, bus, generator, and transformer faults. Overlap is achieved using CTs on opposite sides of the equipment being protected. For example, note the transformer differential protection zone. CTs are used on the opposite side of the protecting breakers. This arrangement serves two purposes: first, zone overlap is provided and second, if a breaker does not open quickly and current continues to flow through the failed breaker, then ***breaker failure*** protection is initiated. Breaker failure relays trip all breakers feeding current to the failed breaker when a predetermined fault clearing time is exceeded. A breaker failure trip can result in clearing several very critical breakers in a substation.

Substation Automation

The advent of Ethernet communications connectivity and smart intelligent devices, including smart protective relays is rapidly changing how substation protection is configured, constructed, maintained, and operated. New equipment being used in substations include digital interface instrument transformers

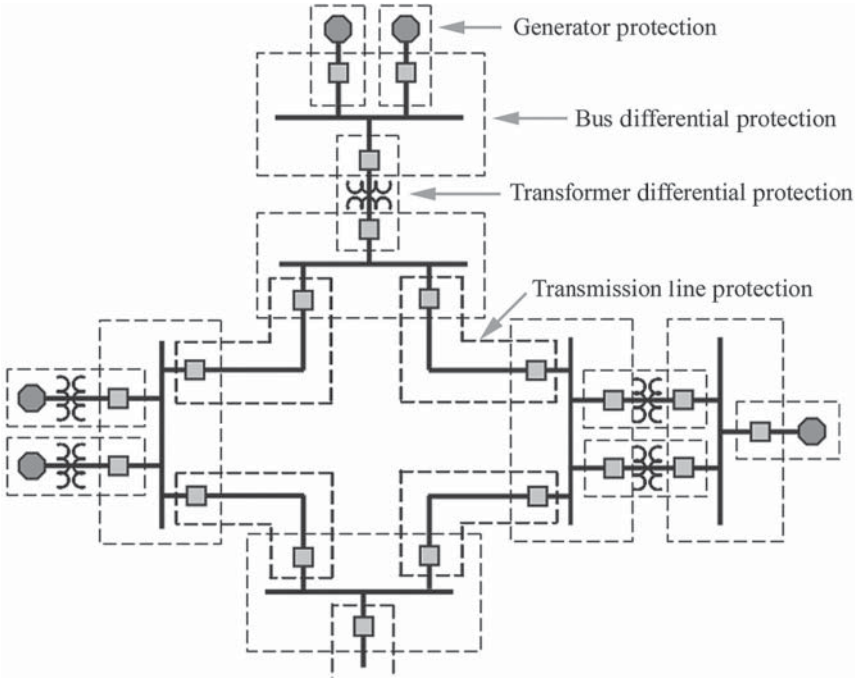


Figure 7-9 Transmission protection.

(CTs and PTs), digital interface protective relays, and optical fiber linked equipment. New intelligent circuit breakers provide this capability or existing analog equipment can be modified with "***merging units***." Merging units (see Figure 7-10) provide an electronic interface between the older traditional analog equipment and the new digital interface equipment. These merging units help transition older substations with new technology devices. The new equipment improves reliability, connectivity, device programming flexibility, and enterprise information utilization and management.

Smart substations or digital substation automation helps provide special protection and transfer schemes, such as automatically transferring load from a faulted bus to a healthy bus while avoiding overload tripping due to ***adaptive relaying***. Intelligent supply sectionalizing schemes help avoid generator trips by using smart devices to identify a faulted section of supply, isolate that section, and restore supply to unfaulted sections. New equipment condition monitoring devices watch the number of breaker operations, accumulated fault clearing statistics, etc. to determine when maintenance is needed. Effective, just-in-time maintenance programs are made possible with new information tracking schemes provided by modern substation automation devices.

Figure 7-10 Merging unit. Curtesy of Visimax.

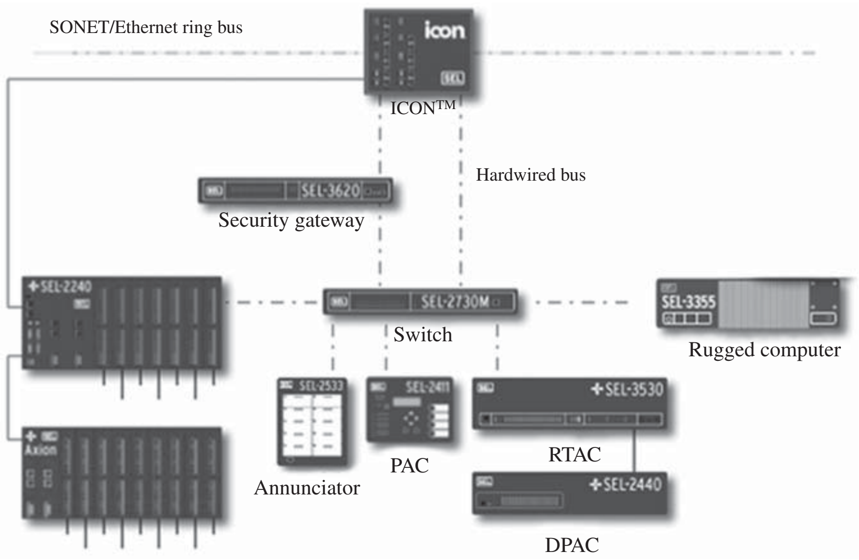


Figure 7-11 Digital substation. Courtesy of SELinc.com.

Substation automation and digital connectivity is underway. Figure 7-11 shows the typical arrangement using digitally interfaced equipment in substations with modern LAN Ethernet connectivity over high-speed category rated copper wire, optical fiber, and sometimes wireless communications technologies.

The next generation of digital protective relaying is digital interfaces using optical CTs, PTs, and circuit breakers.

Wildfire Ignition Risk Reduction

New protective relay technologies are being developed and installed in electric power systems located in high-risk and high-consequence wildfire threat areas. These new technologies quickly detect and isolate faults, thus helping to prevent sparks that can ignite wildfires. Some of the key technologies in use today or emerging perfection before widespread utilization include:

1) **Disabling Automatic Reclosing:** An immediate improvement to traditional relay protection schemes to help reduce ignitions is to disable automatic reclosing during fire seasons. This modification removes time delayed tripping and subsequent attempts to blow downstream fuses. This modification increases the number of outages and outage duration customers experience. This modification changes the balance between service reliability and wildfire safety risk.
2) **Fast Trip Settings:** Utilities are implementing "fast trip" settings in high-wildfire threat areas, where power lines are de-energized almost immediately upon detection of an abnormal event, like a grounded foreign object contacting the line. This method increases relay pickup sensitivity and reduces detection duration time required to ensure a fault is occurring. Again, this setting change can reduce service reliability while improving wildfire safety risk.
3) **Arc Sense Technology:** This advanced technology detects electrical arcing and high-impedance faults, which are often hard to spot but can lead to equipment failures or fires. By identifying these abnormalities early, the system can trip circuit breakers before electrical contact is made with dry vegetation or soil surfaces.
4) **Broken Conductor Detection:** Certain advanced technology relays can detect broken conductors on transmission and distribution lines. This function allows for the line to be de-energized before the conductor hits the ground, thus reducing the risk of sparks that could ignite a wildfire.
5) **Rapid Earth Fault Current Limiter (REFCL):** This technology helps limit the amount of current that can flow during a fault, thus preventing arcs that could trigger a fire in high-risk areas.
6) **Travelling-Wave-Based Fault Location:** This system uses high-speed sensing to precisely locate faults on transmission lines. Faults create traveling electromagnetic waves and quick wave recognition by end of line sensors is used to trip substation breakers. Knowing the exact fault location helps line patrol crews find and repair the infraction.

These existing and emerging technologies are part of a grid modernization effort aimed at increasing the reliability and safety of power systems in high-wildfire threat areas.

8

Interconnected Power Systems

Chapter Objectives

After completing this chapter, the reader will be able to:

☑ *Explain why interconnected power systems are better than isolated control areas*
☑ *Describe the major power grids in North America*
☑ *Describe regulatory oversight encompassing the electric power industry*
☑ *Explain the key operating parameters to keep power grids stable*
☑ *Explain power grid reliability and stability*
☑ *Explain the purpose for frequency, voltage, and angular control*
☑ *Discuss system demand and generator loading*
☑ *Explain the purposes of "Spinning Reserve" and "Reactive Supply"*
☑ *Describe what happens during a cascading system disturbance*
☑ *Discuss what system control operators do to prevent major disturbances*

Interconnected Power Systems

Interconnected power systems (i.e., ***power grids***) offer several important advantages over the alternative of independent power islands. Large power grids are built to take advantage of electrical ***inertia*** to maximize system stability, reliability, and security. Inertia is the tendency of objects in motion to stay in motion and objects at rest to stay at rest, unless a force causes its speed or direction to change. This physical law applies to spinning rotor generators. The interconnected power grid is seen as a strong system able to plow through contingency triggers to avoid widespread outages. The larger and stronger the grid system, the more likely the system will survive contingencies (i.e., disturbances). The term "***security***" refers to the capability of a power system to maintain reliability and operate within acceptable limits even in the face of unexpected disturbances, disruptions, and loss of

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key generation or major substation equipment. Also, in today's regulatory atmosphere, large, interconnected power grids continue to offer new opportunities in sales/marketing, alternative revenue streams, and resource sharing.

Electric power systems became interconnected power grids a long time ago. Interconnected systems stabilize the grid, which in turn improve reliability and security. It also helps reduce the overall cost of providing reserves. Interconnected systems help maintain frequency, avoid voltage collapse, and reduce the chance of undesirable load shed situations.

Utilities having interconnected power systems benefit from information exchange and equipment sharing opportunities. Information benefits include joint planning studies, cooperation during emergencies (i.e., storm damage), coordinated power exchange, and reserves sharing. Equipment sharing opportunities provides access to long lead item major equipment items during emergencies. Thus, system reliability and accelerated restoration opportunities exist among utilities participating in an interconnected power grid system.

The North American Power Grids

The ***North American Electric Reliability Corporation*** (NERC) is responsible for ensuring that the bulk electric power system in North America is reliable, adequate, and secure. NERC was originally formed in 1968 (following the 1965 major blackout of over 30 million people affected in northeastern USA and southeastern Canada) and has operated successfully as a self-regulatory organization, relying on reciprocity and the mutual self-interest of all those involved in the production, transmission, and distribution of electricity in North America. On January 1, 2007, following the second major blackout of 2003 (over 50 million people affected in northeastern USA and Canada), NERC acquired the duties of overseeing operating standards compliance with enforcement powers given by the Federal Energy Regulatory Commission (FERC). NERC and Canadian authorities now oversee the bulk electric power grids.

The massive, interconnected power grid system in the USA and Canada is broken down into four separate grids: the Western grid, the Eastern grid, Texas, and Quebec.

Figure 8-1 shows the power grid interconnections structure in North America.

The three U.S. grids are composed of regions and/or utilities having interconnected transmission lines and control centers. They share similarities such as 60-Hz frequency and system transmission voltages; nonetheless, they have specific individual requirements such as ownership, topography, and fuel resources. All generation units in each grid are synchronized together, sharing load, and providing reliable generation and load balance within their very large power grid areas.

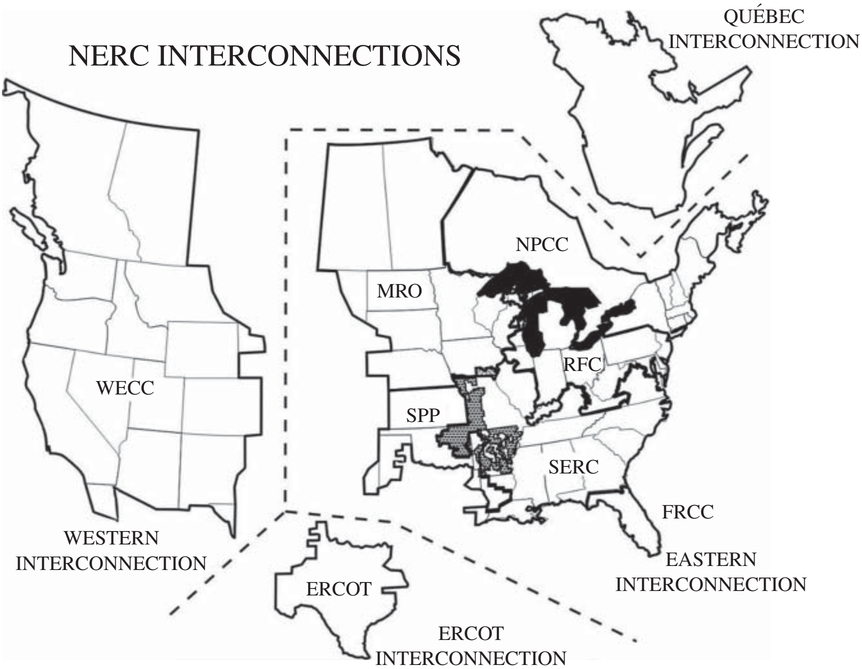


Figure 8-1 Power grid interconnections.

Regulatory Environment

The regulatory environment in the electric power industry continues to change, causing some uncertainty in the way companies are structured. Many electric companies have positioned themselves as being generation, transmission, or distribution companies to align with the regulatory framework.

Due to the governmental deregulation of the electric power industry and to avoid potential conflicts, employees in wholesale power contracts departments (i.e., marketing) must remain physically separated and not communicate with employees dealing with the actual electrical generation and transmission systems (i.e., operations) because of the unfair advantages or disadvantages in an open market environment. Some view having knowledge of a company's strengths, weaknesses, future construction projects, and major equipment maintenance schedules is unfair. Similar rules exist for the separation of transmission and distribution employees where necessary. Whereas transmission is governed federally by NERC, distribution is governed by independent state agencies.

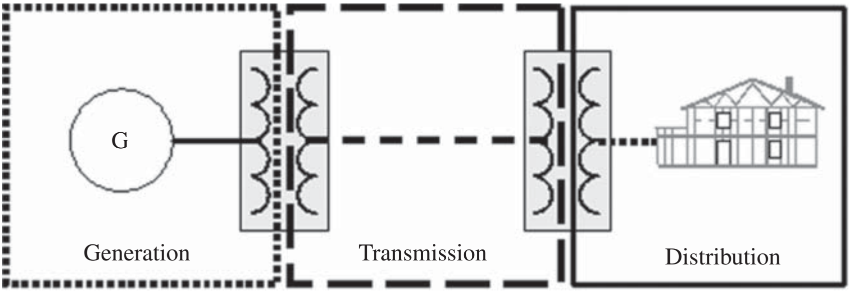


Figure 8-2 Regulatory divisions.

Figure 8-2 illustrates where the actual divisions occur in the deregulated model. Note the division is between the windings of transformers. However, actual equipment ownership arrangements are defined on a case-by-case basis.

Independent System Operators (ISOs) and Regional Transmission Operators (RTOs)

The ***Federal Energy Regulatory Commission*** (FERC) requires that power entities form joint transmission operations areas known as ***regional transmission operators*** (RTOs) or ***independent system operators*** (ISOs). These groups are charged with the requirements that all parties work together, have equal access to information, and provide a marketplace for energy exchange.

In the United States, an ISO is a federally regulated regional organization which coordinates, controls, and monitors the operation of the electrical power system of a particular service area. The RTOs such as the Pennsylvania – New Jersey – Maryland Interconnection (PJM) have a similar function and responsibility but operate within more than one U.S. state.

The ISO or RTO act as a marketplace in wholesale power since the late 1990s. Most ISOs and RTOs are set up as nonprofit corporations using a governance model developed by FERC in April 1996. Also, FERC Order 888/889 requires ***Open Access*** of the grid to all electricity suppliers and mandates the requirement for an ***Open Access Same-Time Information System*** (***OASIS***) to coordinate transmission suppliers and their customers.

The Canadian equivalent to the ISO and RTO is the ***Independent Electricity System Operator*** (IESO).

There are currently five ISOs operating in North America:

- Alberta Electric System Operator (AESO)
- California ISO (CAISO)

- Electric Reliability Council of Texas (ERCOT), also a Regional Reliability Council (see below)
- Independent Electricity System Operator (IESO), operates the Ontario Hydro system
- New York ISO (NYISO)

There are currently four RTOs operating in North America:

- Midcontinent Independent System Operator (MISO)
- ISO New England (ISONE), an RTO despite the ISO in its name
- Pennsylvania-New Jersey-Maryland Interconnection (PJM)
- Southwest Power Pool (SPP)

Regional Entities

The North American Electric Reliability Corporation (NERC), whose mission is to improve the reliability and security of the bulk power system in North America works with six regional entities. The regional members come from all segments of the electric industry: investor-owned utilities; federal power agencies; rural electric cooperatives; state, municipal and provincial utilities; independent power producers; power marketers; and end-use customers. These regional entities account for virtually all the electricity supplied in the United States, Canada, and a portion of Baja California Norte, Mexico.

- Midwest Reliability Organization (MRO)
- Northeast Power Coordinating Council (NPCC)
- Reliability First (RF)
- SERC Reliability Corporation (SERC)
- Texas Reliability Entity (TRE)
- Western Electricity Coordinating Council (WECC)

The Balancing Authority

NERC rules require all generation, transmission, and demand operating entities in an interconnection be included in the metered boundaries of a ***balancing authority (BA)***. There are more than 100 BAs in the United States.[1] The BA ensures that power system demand and supply are always balanced, which maintains safe and reliable operation of the power system.

Before deregulation, a BA was almost synonymous with a utility company. The utility-controlled transmission, generation, and distribution operations and responsible for the balance of all generation and load within their control area.

1 NERC Balancing and Frequency Control Technical Document.

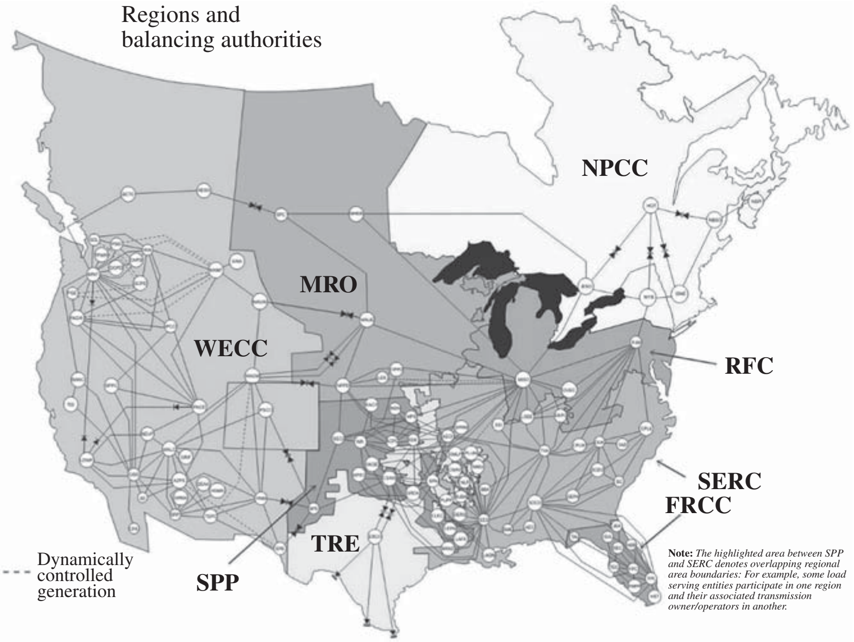


Figure 8-3 NERC regions and balancing authorities.

All generation, transmission, and load for that utility were inside the utility's control area, in essence a BA. However, with today's deregulation, BAs are not necessarily individual utility control areas but approved NERC areas that may control generation in multiple utilities.

The BA is responsible for maintaining online generation reserves if a generator trips off-line within their control area. Also, the BA must be capable of controlling generation through the ***automatic generation control*** (*AGC*) system. The BA is also responsible for communicating electronically all data required to calculate the ***area control error*** (*ACE*), the difference between scheduled and actual tie line flow.

Figure 8-3 shows the NERC Regions and Balancing Authorities.

Interchange Scheduling

Figure 8-4 shows a simple power grid made up of four BAs: A, B, C, and D. These BAs are interconnected by ***tie lines.*** The net power flow across all BAs in this simple grid must add up to zero. The BA's net interchange flow is the net some of its tie line flows. The power flowing on these tie lines are accurately metered

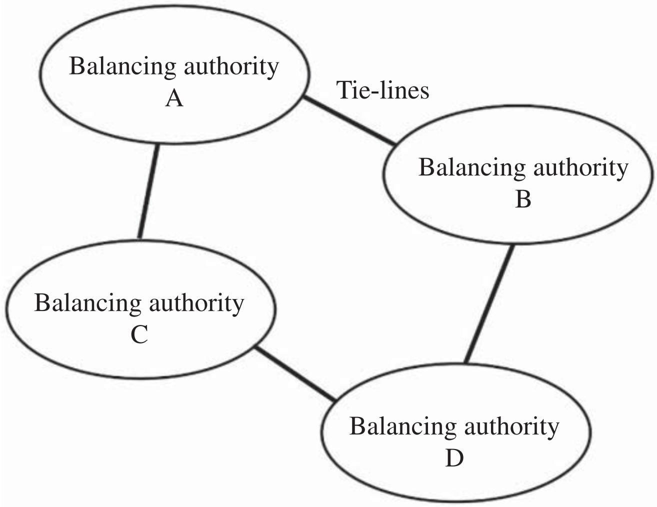


Figure 8-4 Interconnected systems.

and scheduled with agreements on pricing. Pricing agreements include provisions for special circumstances such as emergencies, planned outages, and ***inadvertent power flow***. The error between scheduled and actual tie line flow (i.e., inadvertent) is properly accounted for and settled between all parties involved on a continuous basis.

For example, suppose these BAs have the following net interchange flows scheduled for the current hour:

BA-A = −300 MW
BA-B = +200 MW
BA-C = +250 MW
BA-D = −150 MW

Note that the scheduled net interchange summation for this grid equals zero.

Area Control Error

The mathematical equation ACE is used to determine the instantaneous difference between a BA's net actual interchange flow and its scheduled interchange flow, considering the effects of frequency and metering error. ACE, measured in MWs, gets real-time input data from tie line metering points. ACE carefully monitors and reports the net sum of all tie line flows in the BA area.

ACE is a very useful equation. Carefully monitoring and adjusting tie line flow using ACE helps keep the interconnected system stable. If ACE is greater than zero for example, the entity is over-generating and outputting more power over their tie lines than scheduled. Whereas, if ACE is below zero, the entity is under-generating and importing power. One interesting aspect about the ACE equation is ACE stays approximately the same value (i.e., zero) if a large generator trips outside the BA area (yet inside the grid) and ACE goes negative only if a generator trips inside the BA area. Therefore, entities know immediately when generation trips inside their control area because the ACE value suddenly goes negative. When ACE goes negative, the BA must respond to this generation deficiency utilizing its generation reserves. The BA has a designated time limit (i.e., 10 minutes) to bring ACE back to its pre-disturbance value or be in violation of NERC reliability standards. This concept keeps other BAs from adding generation in response to a drop in grid frequency due to a loss of generation outside their BA area.

ACE Equation

(*Optional Supplementary Reading*)

ACE is a mathematical equation made up of three terms interchange flow, frequency, and metering error, as shown below:

$$ACE = (NI_{Actual} - NI_{Scheduled}) - 10\beta(F_{Actual} - F_{Scheduled}) - IME$$

$NI_{Actual} = Net\ Interchange_{Actual}$
$NI_{Scheduled} = Net\ Interchange_{Scheduled}$
$F_{Actual} = Frequency_{Actual}$
$F_{Scheduled} = Frequency_{Scheduled}$
$IME =$ Interchange metering error
$\beta =$ Bias; a constant value based on past major disturbances

This equation helps BAs track scheduled vs. actual interchange power flow. For example, suppose the interchange metering error is zero and frequency is 60 Hz, then the ACE equation reduces to the difference between scheduled and actual interchange flow.

Frequency ***Bias*** (β) is a number derived from past major disturbances and used to estimate how much grid frequency declines for a loss of generation. For example, a loss of 2,000 MWs drops the grid frequency 0.1 Hz. Bias is used to convert the frequency term in the ACE equation into a power flow effect caused by a change in frequency.

BAs use all or part of the ACE equation to operate their control area depending on the situation. Normally, both tie line flow and frequency are carefully monitored and controlled (ignoring metering accuracy). In this situation, the BA is operating under what is called ***tie line bias***. Tie line bias allows the BA to maintain its interchange schedule and respond to interconnection frequency errors caused by generation–load unbalance. The term ***flat tie line control*** is used when only tie line flows are closely monitored and controlled. The term ***flat frequency control*** is used when only frequency is closely monitored and controlled. These last two conditions are used when the grid is broken up into islands following a major disturbance or when restoring an island from "black start."

Normally, ACE is controlled by the AGC part of the ***energy management system*** (EMS). The EMS uses AGC to ramp up/down generators to match changing demand. (Note that EMS computer software tools are discussed in more detail later in Chapter 9, System Control Centers and Telecommunications.)

Time Correction

Interconnected power grids change frequency slightly when accumulative clock time does not match accumulative grid frequency when using 60 cycles per second. ***Time error*** is the difference between the number of cycles created based on clock time and the number of cycles generated by the grid at 60 cycles per second (in reference to the National Institute of Standards and Technology). Time error is caused by accumulative frequency error (over or under generation trying to meet changing demand). Therefore, bulk interconnection frequency is adjusted faster or slower for a specific period to correct time error. Ultimately, the number of cycles created by the grid matches the number of cycles that should have been produced over the same period of real time. For example, if the grid over generated the number of cycles for a given period, grid frequency is reduced by 0.02 Hz (or 59.98 Hz) until corrected. If the grid under generated the number of cycles for a given period, grid frequency is increased 0.02 Hz (or 60.02 Hz) until corrected.

In other words, there are 60 cycles in a second, 3,600 cycles in a minute, and 5,184,000 cycles in a day. Grid frequency is increased or decreased (±0.02 Hz) when the actual number of cycles generated does not match the exact same number of cycles in real time.

Time error correction is an important concept, usually met daily. This concept is needed for older ac powered electric clocks, phonographs (older record players), and so on. Modern electric clocks and audio/visual players no longer depend on power frequency accuracy, thus the need for time error correction is being questioned.

Interconnected System Operations

Now that we have covered the major building blocks of a power system (i.e., generation, transmission, substations, distribution, consumption, protection, and the elements of power grid organization), the next discussion explains the fundamental concepts, constraints, and operating conditions that make an interconnected power system stable, reliable, and secure.

Inertia of the Power Grid

Inertia is one of the main reasons that large interconnected systems are built. Inertia is the tendency of an object at rest to remain at rest or of an object in motion to remain in motion. The larger the object, the more inertia it has. For example, a rotating body such as a heavy generator shaft will try to continue its rotation, even during a major system disturbance. The more spinning generators connected in the power grid interconnection the more inertia the grid has available to resist change. Power systems boost stability and reliability by increasing inertia. Solar PV is an example of a generation type that does not contribute to grid inertia because it has no spinning mass. Inverter-based resources (IBRs) in general do not contribute to spinning inertia. The power industry is changing how IBRs operate when connected to the grid system to improve their support towards grid stability. (More on this topic later in Chapter 10, The Transitioning Digital Power Grid.)

Inertia comes into play when faults occur. The sudden increase in load (i.e., fault current) causes generators to slow down, and high inertia helps reduce the downward frequency swing. Otherwise, voltage and frequency collapse further and faster causing a greater disturbance. Inertia helps reduce ***cascading outages*** (sometimes called ***the domino effect***) when generators and transmission lines trip sequentially due to changing line and equipment loading.

One helpful way for an interconnected power grid system to increase electrical inertia is to add, not subtract, rotating machines. Note that the word “machine” is used instead of “generator” because both motors and generators contribute to electrical inertia. Motor shafts want to keep spinning during a power outage; thus they generate power back into the grid.

Power system stabilizers (PSSs) are installed on generators’ governors to help stabilize frequency during fault conditions. Generator governors are used to control the amount of steam applied to their turbines for frequency control. When a major system disturbance occurs and frequency swings, PSS changes normal governor response to oppose frequency swings. In other words, during a system disturbance where frequency becomes unstable, PSS increase steam to the turbine when frequency declines and decreases steam to the turbine when frequency increases, thus helping to stabilize system frequency.

Figure 8-5 illustrates the concept of inertia and frequency stability in a steady-state interconnected power system.

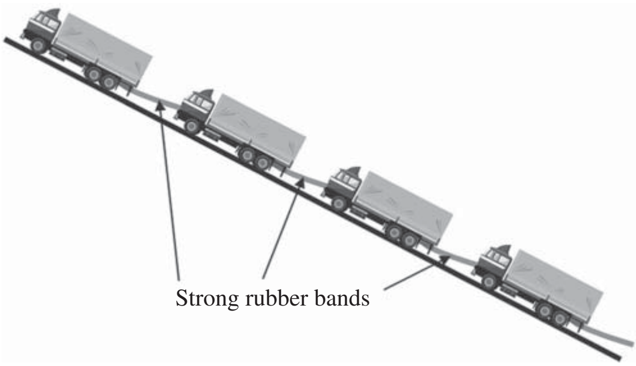


Figure 8-5 Steady state.

Suppose the trucks shown in Figure 8-5 are carrying load and traveling together at 60 miles per hour (hence trucks being analogous to generators and rubber bands being analogous to transmission lines). The trucks are helping each other carry load up the hill. As the hill incline increases (i.e., load and system losses increase), the trucks must increase their horsepower (i.e., throttles) to maintain speed at 60 mph. If the incline becomes too great for these trucks to maintain 60 mph, then additional trucks must be added or load removed. As the incline decreases (i.e., less load and losses), the trucks must decrease their throttles to maintain speed. If significant load is removed, some trucks would not be needed and are taken offline while maintaining 60 mph.

In a large-scale integrated power grid, very similar concepts and actions occur. The grid generators are working together to share the load and maintain frequency. They all slow down when load is added, and they all speed up when load is removed. The transmission lines are also part of system stability. Overloaded transmission lines can go into voltage collapse. Thus, all generator units and transmission lines work together, producing a highly reliable electric power system that balances generation with load at a constant frequency and with good stable voltage.

Balanced Generation Conditions

Power out of the generator is a function of rotor angle. Figure 8-6 shows the generator's rotor angle. Zero power out occurs when the rotor angle is zero degrees and maximum power out occurs when the rotor angle is 90 degrees. When two same size generators are connected to one bus as shown in Figure 8-6, they both produce the same amount of power, and their rotor angles are equal. This represents a balanced generation situation.

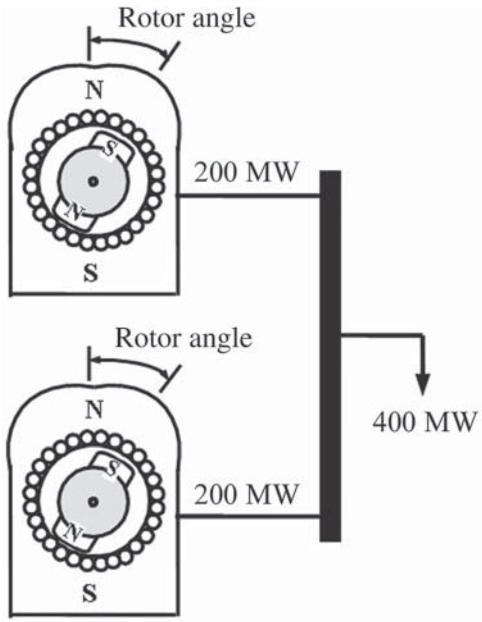


Figure 8-6 Balanced generation.

Unbalanced Generation Conditions

When two generators of the same size are connected to one bus and their rotor angles are not equal as shown in Figure 8-7, the output power of one generator is different than the other. This represents an unbalanced generation situation.

Increasing exciter current increases the rotor's magnetic field and produces a higher output voltage. Increasing the steam to the turbine (prime mover) increases the real output power of the generator and tries to increase grid frequency. Thus, increasing both the exciter current and steam to the turbine increases rotor angle, power output, and system voltage.

When two generating units are connected to the same bus and one unit is larger than the other, yet they both output the same amount of power, the larger unit will have a smaller rotor angle than the smaller unit. Since maximum power out occurs at a rotor angle of 90 degrees, the larger unit's rotor angle is less for the same amount of generator output power.

System Stability

Stability is the term used to describe how a power grid handles a system disturbance. A stable system will recover without the loss of generation or load.

Figure 8-7 Unbalanced generation.

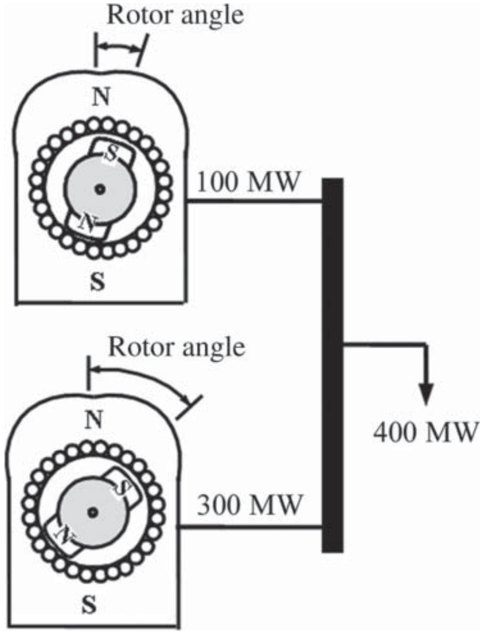
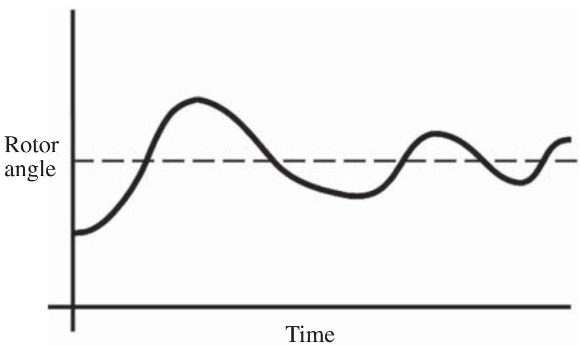


Figure 8-8 System stable.



An unstable system could trip generator units, shed load, and hopefully settle down into islands without experiencing a large-scale blackout.

System stability is directly related to generator loading. The generator's rotor angle changes when loading on the generator changes. As shown in Figure 8-8, a stable system undergoing a system fault will have its generator rotor angle swing and converge back to a stable steady state condition. As long as the rotor angle converges back to a stable state, the system will eventually become stable. This is obviously a desired situation after a disturbance.

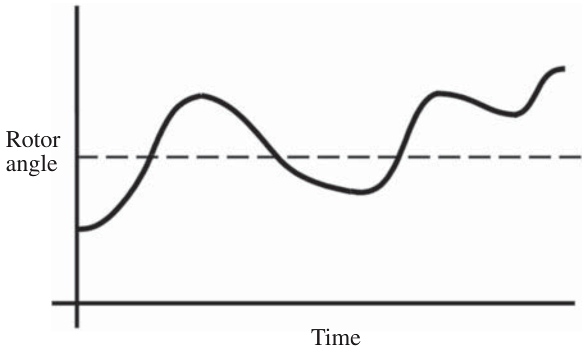


Figure 8-9 System instability.

System Instability

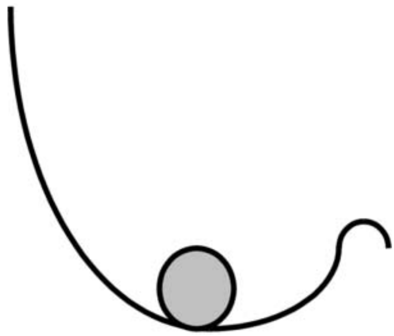
Since generator rotor angles change when load conditions change, sudden large changes in generator loading can cause great rotor angle swings, thus creating a condition of ***system instability***. As shown in Figure 8-9, these great rotor angle swings can cause the generator to become unstable and trip offline. Loss of generation stability causes underfrequency and overfrequency conditions on the system. When generation–load balance is not achieved quickly, loss of generation and load occurs. Loss of load can cause more generators to trip (over frequency) and loss of generation can cause more load to trip (i.e., the domino effect). The system will eventually become unstable unless corrective action is taken quickly to reestablish balance between generation and load to stop frequency swing. Therefore, extreme load-generation variations can cause a system to become unstable, having major power and frequency swings, resulting in a widespread outage, islanding, or full system blackout.

Conditional Stability

Each generator in the grid operates in a condition called ***conditionally stable***. For example, in Figure 8-10, conditionally stable means that the ball, if pushed up the wall to the left, will roll back down to the bottom, then roll to the right, and settle back to the bottom. But if the ball is pushed up the left wall too far and let go, the ball will roll off the right edge, resulting in a generator trip.

This analogy describes what happens to grid generators when their rotor angles exceed their stability limit. There is a conditional stability limit as to whether the unit will regain stability during a disturbance. Stability studies are performed to identify conditions where disturbances could result in unstable operations. System operators adhere to these operating constraints as determined by engineering and planning studies. Otherwise, the system could become unstable,

Figure 8-10 Conditional stability.



resulting in a major disturbance consisting of cascading outages and possibly a wide area blackout.

The engineering and planning departments constantly analyzing load additions, possible single, double, triple contingency outages, impacts of new construction, and other significant planned or unplanned changes to the system to determine whether new operating constraints and guardrail parameters are required. These conditionally stable operating parameters can change during peak and nonpeak conditions, equipment maintenance outages, emergency situations, etc.

Unit Regulation and Frequency Response

A stable system is one where the frequency remains almost constant at the designed value of 60 Hz (ignoring time error correction frequency variances). The required generation-load balance necessary to achieve a stable 60-Hz operation is accomplished through unit regulation and having a quick frequency response.

All generating units in the grid collectively control system frequency. Generators that are placed online as "***load following units***" provide the necessary ramp up or down action necessary to achieve frequency stability. Electric utilities operate in a "***load following***" mode of operation. That is, consumers turn loads on and off at will, without notifying the utility. As a result, utilities adjust net generation to accommodate load changes. Utilities must plan and predict future load changes. Therefore, hour-ahead, day-ahead, week-ahead, yearly, and then generation and load resource planning prepares for future requirements.

System Demand and Generator Loading

System demand is the net load on the system within a control area (i.e., BA area) that must be served by available generation and tie line resources. Some

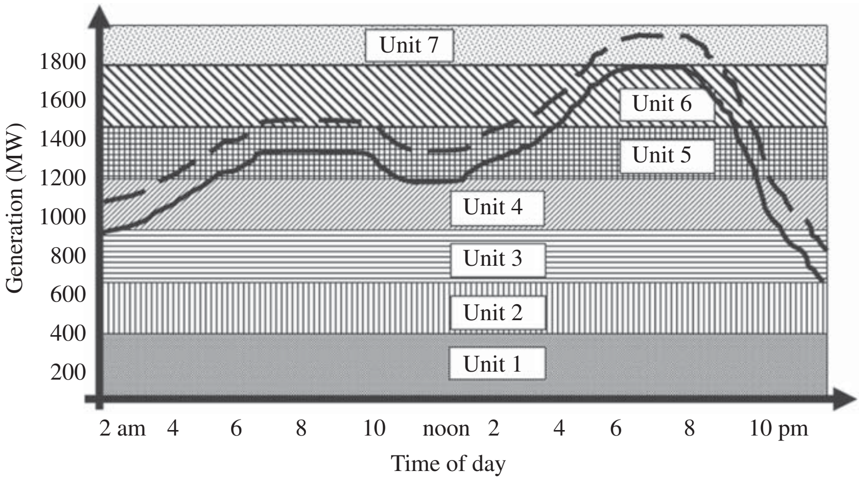


Figure 8-11 Generator loading.

generators are designed to run as ***base load units,*** capable of running 24/7s while others are designed to run as ***load peaking units***. Load peaking units generally cost more to operate than base load units but offer other features such as fast startup and quick ramp rates. Another generation type is ***load following units***. Load following units are used as a more expensive base load unit that can operate 24/7s, and with relatively low incremental cost for up/down output power. Other generator types, such as hydro and wind are used whenever available.

A typical 24-hour generation–demand curve for a small BA area is shown in Figure 8-11.

This demand is supplied by baseload, load-following, and peaking generation units. Generator units 1, 2, and 3 are considered base load units (least expensive to operate and designed to operate 24/7s). Generator units 4 and 5 are considered load following units (used to maintain ACE and tie line bias). Generator units 6 and 7 are considered peaking units (usually the most expensive to operate, can start quickly, and help balance generation-load).

Spinning Reserves

The purpose of ***spinning reserves*** is to help restore control area stability when a disturbance event occurs within the BA area. Maintaining adequate spinning reserves is a requirement set forth by NERC. Spinning reserve is generation capacity that can be placed online quickly or capacity already available due to underutilized generators.

Large fossil fuel fired generators normally take several hours to restart following a disturbance compared to sometimes days to restart a nuclear power plant. Spinning reserves must be able to go online almost immediately without operator intervention should an online generator or import transmission tie line trip.

There are two types of spinning reserves; those necessary to meet changing load conditions and those that must respond quickly in the event of a system disturbance. Online generation units used to meet changing load requirements are the "load-following" units. Online generation units that have capacity available for use during a disturbance can be designated as spinning reserve units. Spinning reserve units are used to respond quickly to help arrest and restore system frequency. Offline, "***fast starting***" generation units can be used to meet the spinning reserve requirement provided the BA can restore ACE within the specified time constraint (normally 10 minutes).

Supplemental reserves are units that are online, spinning but not serving load. Other spinning reserve resources are peaking generators, combustion turbine generators, and interruptible load.

On one hand, spinning reserve is designed to add generation quickly when generation is lost as an attempt to restore system frequency and generation-load balance following a disturbance. On the other hand, underfrequency load shed relay schemes trip load breakers as an attempt to restore system frequency. Load shedding protection is considered a safety net; if frequency continues to decline (e.g., generation balance lingers), distribution load is trip.

Capacity for Sale

Since the generation owner has the option to ***export energy*** to other areas, there is an opportunity to ***sell excess generation capacity (energy)*** on the spot market or through long term sales agreements. The ability to make these sales is dependent on loading and available generation. For example, the northwest area of the United States usually has an abundance of hydroelectric generation for sale. Excess capacity, that is above the utility's load requirement, could be sold on the open market.

Referring to the previous diagram (Figure 8-11), generator units 4 and 5 operate less than full capacity as load following units. From a generation marketing perspective, units 5, 6, and 7 have excess capacity and are available for energy sales through the tie lines. These high-cost units for one utility might appear as low-cost units to other utilities in need of generation, especially during peak conditions or when generation units are offline for maintenance.

Reactive Reserves and Voltage Control

Reactive power is consumed by inductive loads. Furthermore, as transmission lines load up, their consumption of reactive power increases. Therefore, as load increases, the demand for reactive power, both load and lines, increases. Supply of this reactive power comes from generation units, switchable capacitor banks, transmission line charging, static VAR concentrators, and tie line contract agreements. These reactive power resources must be readily available to system operators to maintain good voltage throughout the system. In reverse, when system load decreases, reactive support also decrease, or high voltage will exist in the system.

System voltage is controlled using reactive supply resources. Therefore, NERC requires a minimum reactive reserve availability to ensure good voltage support during system disturbances. When system voltage is low, operators bring online reactive resources, and when system voltage is high, operators curtail reactive resources. Each utility or BA knows when their systems are likely to have high or low voltage and plan for reactive resources and reserves accordingly.

Generator Dispatch

Generator dispatch is a primary function of day-to-day operations. System-wide generating plants include ***customer owned***, ***independent power producers (IPPs)*** (merchant plants), and utility owned. Each generator has unique performance characteristics and associated cost. Optimizing generation dispatch takes into consideration unit characteristics, operating cost, incremental cost, cost of system losses, voltage support, system reliability, and several other factors needed to insure proper power flow, voltage support, contingency survival, and reserves. Generation operators must plan ahead hourly, daily, monthly, yearly, and long term to ensure capacity is available always.

Required Total Generation is determined by load forecasts plus many other driving factors that would or could affect operations (i.e., weather, equipment maintenance, and other foreseeable and unforeseeable factors). The ideal total generation dispatch plan might be to optimize cost, optimize reliability, minimize risk, or a mixture of these critical factors. The resource plan must effectively and reliably meet system demand with disturbance stability provisions in place.

The process of deciding which units to use to meet a daily or weekly requirement is extremely complex. There are many variables that must be considered. To help solve this problem, many utilities use a program called ***unit commitment*** to help schedule their generation mixture. The diagram shown in Figure 8-12 illustrates some of the factors that go into deciding what units should be used or committed to meet a load forecast.

Load Forecasting

Accurate and complete load forecasting is a valuable tool in day-to-day power grid operations, future projections for generation, infrastructure requirements, outage

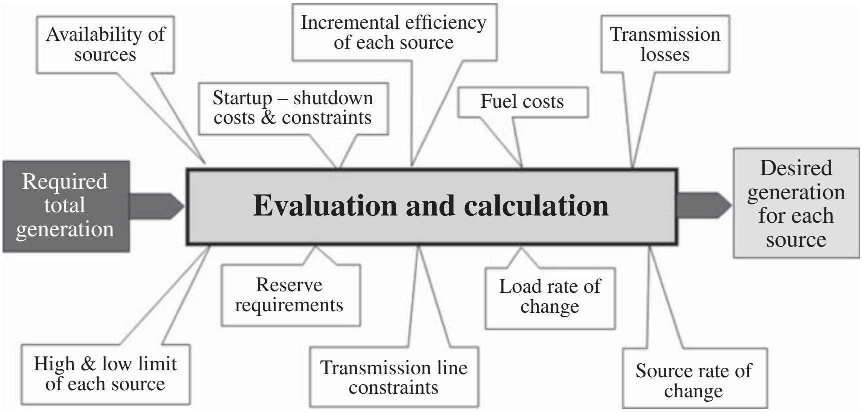


Figure 8-12 Generator dispatch factors.

and contingency planning to name a few. Load forecasts are used to decide when to build additional generation, transmission, and distribution facilities. Load forecasts are used in demand side management systems as well; for example, to curtail load during energy emergencies. They are also used for budget planning, revenue forecasting, and operational needs assessments.

Utilities share load forecasts for bulk grid reliability studies, joint venture projects, and to help BAs provide and plan for dependable generation–load balance.

Reliable Grid Operations

Let us first review the terminology behind planned and unplanned outages, equipment failures, faults, and other events that, if not properly controlled, could lead to operating personnel safety incidents, cascading outages, and possible system wide blackouts. For example, high-voltage substation equipment, such as transformers, circuit breakers, and regulators, require periodic maintenance. "***Scheduled***" or "***planned***" outages are required to isolate such equipment in a manner that provides a safe maintenance environment while ensuring a reliable power grid. The equipment isolation process is accomplished by carefully executing "***switching***" operations. Switching is the term used by operations personnel to systematically operate high-voltage substation and field disconnect switches to establish isolation. Once equipment is properly isolated, ground jumper cables are attached between the equipment's high-voltage bushings and the substation ground grid. Ground jumpers ensure maintenance personnel are safe to work on equipment that could become accidentally energized. In essence, ground jumpers are high-capacity cables with fault current rated clamps on each end to short-out or bypass equipment that is isolated for maintenance. (Grounding is discussed in more detail later in Chapter 11, Safety.)

Aside from scheduled maintenance, substation equipment can fail unexpectedly. The term "***unplanned***" or "***emergency***" outages can unexpectedly cause dangerous high short circuit current (or fault current) to flow. When fault current flows, protective relays sense the undesirable condition and send control signals to trip associated circuit breakers. Faults are cleared by protection devices such as circuit breakers, reclosers, and fuses, and can cause customer outages.

Outages, or the loss of electrical service, are generally either planned for maintenance activities or unplanned circuit breakers trips due to power faults on equipment or lines. Outages are normally associated with areas without power or the number of customers without power.

During "***normal***" operations, substation equipment, transmission lines, or distribution feeders that need to be taken out of service for any reason not associated with unexpected protective relay trips, are considered planned or scheduled outages. In this case, electrical service is typically rerouted (through switching) so that consumers are unaffected by the scheduled maintenance activities. There can be several lines or substation equipment out of service at any given time, as long as the interconnected power system and customer service remains intact and reliable.

In comparison, "***emergency***" operations occur when unexpected equipment failures or line outages occur. In the more extreme events, equipment outages lead to other equipment being overloaded, thus causing expanded outages (i.e., "domino effect"). Sometimes outages significantly affect the balance between generation and load, where cascading outages occur and possible blackouts.

System "***blackouts***" require emergency restoration procedures. Restoration starts with a power plant that has blackstart capability. "***Blackstart***" capable power plants can activate standby generators sufficiently to start up the isolated power plant on its own. Hydro-power plants are often used for blackstart since they only require the opening of water flow gates to start generation. Once the blackstart power plant is running and able to pick up load, transmission lines are energized to critical distribution substations. Load is then added in small increments by sequentially energizing distribution feeders. As more and more load is added, generation is increased. As the grid is being restored, power plants start up by utilizing incoming energized transmission lines for station power. As more and more generation is added (frequency is allowed to increase to approximately 63 Hz), then more load is added (frequency decreases to approximately 60 Hz). Then more generation is added (bringing frequency up to approximately 63 Hz) and more load is added. This process continues until the grid is restored and balancing area reinstate AGC and begin monitoring ACE.

A utility has a predetermined plan for blackstart with an intended goal. For example, the goal might be to establish a transmission path to a nuclear power plant across the system. This written and practiced (simulated) blackstart procedure selects the best transmission path between the blackstart generator and the nuclear power plant. This planned sequence of events is referred to as the "***cranking***" path.

Eventually, all individual power grid islands are restored. Then the entire interconnection is restored by synchronizing the islands. As islands are restored, customers are restored.

Let us now discuss factors that contribute to grid reliability for both normal and emergency operating conditions.

Normal Operations

Normal operation occurs when all loads are served with stable frequency, good voltage, proper transmission line flows, ample reserve margins, and experiencing minimal impact from equipment and line faults. In today's environment, "normal operations" means operating several generation units and transmission lines at or near full capacity, difficulty trying to schedule equipment outages for maintenance, and responding to daily events (i.e., planned outages, switching equipment, and lines out for maintenance, and coordinating new construction projects).

Disturbance Situational Awareness

System control center operators are on alert to take corrective action should an abnormal event occur suddenly. Operator situational awareness is key to circumvent possible line overloads, low transmission voltage conditions, or frequency deviations.

While normal operations are ongoing, an event can suddenly take place causing audio and visual alarms, observing automatic changes in system parameters, control room chatter increases, and suddenly you find yourself in the onset of a major disturbance. The initial system response to a developing disturbance is automatic; however, manual intervention comes into play as soon as the operators assess the situation and start implementing additional corrective actions. Let us explore what happens during a major disturbance to the grid system.

Frequency Deviation

Generators are limited to a narrow operating frequency range or bandwidth for continuous operation; typically, 60 ± 0.5 Hz. ***Frequency deviation*** outside these tight parameters will cause generators to trip. Since transmission systems are interconnected to various generation sources (i.e., tie lines), excessive frequency deviation may also trip transmission lines to protect these sources of supply.

System frequency deviation must be carefully monitored and corrected immediately to protect against generator trips and system disturbances. Control center operators and in particular generator operators are continuously monitoring the following common causes of frequency deviation:

Sudden Supply/Demand Imbalance Loss of supply (generation) reduces frequency. Loss of load increases frequency. Either way, frequency deviation is not tolerable and system operators and generator operators must be ready to take immediate action upon witnessing a sudden frequency deviation.

When a unit or power plant trips and load–generation balance is upset, the restoration process begins with spinning inertia. Spinning inertia helps to slow down the change in frequency, thus buying time for additional interaction. Then generator governors try to arrest system frequency by increasing steam to their turbines. Units with power system stabilizers also attempt to correct rotor angle swing by adjusting governor response in opposition to the changing frequency. Note that generator governors have a set deadband (i.e., no action taken) of ±0.036 Hz to allow for minor system frequency swings. After deadband, generator governors mechanically intervene to "***arrest frequency***." This is an automatic means to stabilize (arrest) frequency using generator governors. When successful, governors arrest (stabilize) frequency to a value just below 60 Hz. If frequency does not stabilize, more units trip offline, thus worsening the situation.

Meanwhile, the BA having the generation outage (based on the ACE equation) assesses the situation and starts to bring on spinning reserves to restore grid frequency and correct ACE.

When generator rotor angles and system frequency do not stabilize quickly, cascading outages are likely (i.e., domino effect) to occur, resulting in grid separation (islanding). The separated islands enter their own generation-load balance situation using flat frequency control. If the island were exporting power before the disturbance, frequency would become high, and generation must be reduced to obtain balance. If the island was importing power before the disturbance, frequency would become low, and load shedding and/or increased generation must occur to obtain balance.

Islands are ready to synchronize with each other once balance is achieved. When islands do not achieve balance, their disturbance could grow and result in a blackout situation, thus requiring blackstart and restoration procedures. Eventually, all islands are functioning, and the entire interconnection is restored by synchronizing the islands.

Short Circuits or Line Faults Faults on major transmission lines are usually cleared by protective relays opening circuit breakers at both ends. Line outages cause power to flow differently throughout the grid. Power flow changes due to line outages can suddenly add load to other lines, generators, and transformers, which could also become overloaded. Overloaded transmission lines could experience voltage collapse and trip. System operators must take further action or chance other breakers to clear overloaded lines or equipment. Time is of the essence when it comes to being in the middle of a major unexpected system disturbance.

Cascading Failures

Cascading failures situation may be created by a system disturbance. A system blackout can result in the loss of transmission and/or generation in a cascading sequence. For example, the August 2003 outage that affected most of the Northeastern United States was due to cascading outages. The scenario began by having some transmission and generating facilities in the Northeast out of service for maintenance. Then, one of the in-service transmission lines tripped because it sagged into a tree under heavy load conditions. At the time of the trip, major cities in Ohio were in a "heavy" import condition, meaning much of their energy was being supplied by the transmission interconnection system. Once the first line tripped, the power flow changed, and sections of the remaining interconnected transmission system started to overload. One by one, several major transmission lines and generators tripped offline.

As the transmission lines began to disconnect, the system experienced sections having excess load and generation shortages. This created a frequency deviation situation, and the remaining on-line generation began to slow down due to the overload condition. The utilities involved did not have adequate generation reserves online at the time to meet the sudden change in demand, therefore generator units began tripping. As generation trips, the problem continued to worsen.

The interconnected system, at the time of the initial failure, had some time and opportunity to ***island*** (i.e., separate from the grid). This time frame was probably less than a minute. In that short time frame, if the utility did not "disconnect" from the grid (thus become an island) and was not able to meet internal load with reserves or through an operational underfrequency load shedding scheme, the utility remained on the grid while the cascading failures continued.

Eventually, the entire grid was left with no supply. Only those systems that disconnected (i.e., island) were able to survive, at least partially. As a result of this major disturbance, the following has been implemented:

Transmission Line Ratings NERC and reliability coordinators study and dictate when facilities can be taken out of service. Also, they are making sure there is always adequate transmission capacity, with import limits, to maintain system integrity.

Control Operator Training NERC established guidelines, requirements, and a certification process to ensure operators are qualified, and have continuing education and training to keep pace with system requirements.

Voltage Deviation

System voltage can deviate from normal to cause operational problems. Voltage constraints are not as restrictive as frequency constraints. Voltage can be regulated or controlled by generation and connected equipment such as regulators, capacitors, and reactors. Usually, load is less sensitive to voltage fluctuations than frequency. The control center operators are looking for system issues that could cause voltage to deviate substantially, thus avoiding:

Uncontrolled Brown Out An uncontrolled ***brown out*** is a condition where excessively low voltage is present on the electric grid. This condition can persist for long periods of time and result in equipment failure (i.e., overheating motors or other constant power devices). Some loads, such as lighting and resistive heating, might show flicker or heat reduction from low-voltage conditions but not become damaged.

Voltage Surge ***Voltage surges*** result when services are restored, and high/low-voltage transients occur during switching operations. Voltage surges are usually transient or short term in nature. This type of voltage deviation may damage consumer equipment (i.e., computers) and possibly lead to other equipment failures.

Normally, utilities are required to maintain voltage within tolerances set by industry standards or regulatory authorities. Manufacturers are expected to design consumer equipment such that it can safely operate within these normal power company service tolerances. System operators are responsible for preventing deviations that exceed specified tolerances. System operators are expected to ensure voltage stability through constant monitoring and adjusting system equipment in real time.

Emergency Operations

Emergency operations exist when the power system is experiencing outages, faults, load shed, adverse weather conditions, or voltage and/or frequency instability. These problems or conditions require the immediate attention of all operating personnel.

To avoid emergency operations, planning and general operating criteria established by regulatory agencies and individual utility companies are used to ensure the system remains stable under a variety of normal and abnormal conditions. The operation of any electric power system during abnormal or emergency conditions requires specially trained, skilled, and certified operators. Often the operator's experience and familiarity with the system capabilities can mean the difference between a small area disturbance and a total system shutdown. This section deals with the various conditions and typical operating guidelines imposed on operators under emergency conditions.

Loss of Generation

Equipment failure, load imbalance, or another malfunction can cause a generator to trip offline. This loss of generation will result in more load than supply until the situation can be resolved. Since the power grid system operates in real time, its reaction to differences in generation and load balance results in a change in frequency. The response must be immediate, requiring corrective reactions within a very short time frame. To compensate for loss of generation, the following planning criteria are in place:

Spinning Reserve ***Spinning Reserve*** as discussed earlier provides additional generation to be placed online quickly, ready to accept load. The typical requirement for spinning reserve is "5–10% of load being served or loss of single largest contingency." If, for example, the generator that trips is the largest unit on line, the utility must have access to spinning reserves that will compensate for the loss of that unit and restore ACE to predisturbance levels within NERC's required time allotment (currently 10 minutes).

Transmission Reserves ***Transmission reserves*** can provide instantaneous response to loss of generation or transmission line. Operators carefully monitor transmission line loading conditions in the event of an outage to make sure available capacity and transmission reserves are available.

Emergency Generation There are some systems where emergency generation can be started at short notice and placed online (i.e., 10 minutes or less). The interim period may be handled by a combination of spinning and transmission reserves. Fast starting emergency generation, such as peaking units, are started for availability. These emergency units are usually located in substations and are fueled by diesel or another fuel source that can be easily replenished.

Controlled Brown Outs If the mismatch between generation and load is not too great, it may be possible to compensate by reducing distribution voltages. This condition is called a ***controlled brown out***. When this condition occurs, the lighting dims slightly (sometimes not noticeable). The reduced voltage situation results in less power being consumed by resistive loads (such as electric heaters, incandescent lights, and other resistive residential or business loads). Lightly loaded motors continue to operate at normal speed, however, they could become overheated due to the increase in current from the voltage reduction. Heavily loaded motors slow down or trip.

Rolling Outages If there is a lack of spinning reserve and transmission capability, and if the utility cannot bring supply up to meet demand quickly, load shedding is the only option available to ensure the system remains stable at 60 Hz. Switching off load to keep balance, then restoring the load and switching off other load to maintain balance is referred to as a ***rolling blackout***. Operators trip and close substation distribution breakers to maintain balance while having limited generation available. However, this approach is usually a last resort as it does result in lost revenue and lowers customer satisfaction ratings.

A utility that is highly dependent on their own generation is susceptible to constraining conditions for the loss of a unit. A utility that has most of its energy provided by purchases from other utilities over transmission tie-lines usually experiences less chance of losing their own generating units. However, they are more dependent on system disturbances and uncontrollable events that are outside their system.

The reliability criterion established by NERC requires that the utility or controlling party adjust system parameters within 10 minutes after a loss of generation to prepare for the next worst-case contingency. Ten minutes is not much time because another event (such as another relay trip operation) could occur in the meantime.

Loss of Transmission Sources

Losing a major transmission line due to weather or malfunction is much the same as loss of generation. Since the transmission system delivers energy in both import and export mode, loss of a transmission line may result in different scenarios.

Export Mode The loss of a major transmission line when the control area is in export mode results in too much generation for the local load being served. Without correction, the system could experience severe overvoltage and/or overfrequency conditions. Over generation that is causing high voltage and frequency is rectified by reducing local generation.

Import Mode The loss of a transmission line for a control area in the import mode results in an excess of load compared to supply. This scenario is identical to the loss of generation where system frequency and voltage decrease. Automatic load shedding schemes try to balance load with available generation. Outages are still possible. As internal generation comes online, load is restored.

Due to increased restrictions on generation, many utilities are dependent on transmission sources to meet growing energy demands. Often, the loss of a transmission line is more serious than the loss of a generator.

9

System Control Centers and Telecommunications

Chapter Objectives

After completing this chapter, the reader will be able to:

☑ *Explain the functions and equipment in Electric System Control Centers*
☑ *Describe how Supervisory Control and Data Acquisition (SCADA) enables remote control of substation equipment*
☑ *Explain the functions of Energy Management Systems (EMSs)*
☑ *Describe EMS software tools used by system operators*
☑ *Explain how synchrophasors and Wide Area Monitoring Systems help assess system reliability and security*
☑ *Describe the types of telecommunications systems used by power companies*
☑ *Discuss how advances in digital substation equipment and automation impact efficiencies in system control centers, equipment wiring, and functionality capabilities*

Electric System Control Centers

Electric system control centers (ESCCs) like the one shown in Figure 9-1 operate 24 hours a day, 7 days per week, 365 days per year, not-stop making sure the electric power system within their control area is operating properly. This control center is the California Independent System Operator (CAISO). The California ISO manages the flow of electricity across high-voltage, long-distance power lines, operates a competitive wholesale energy market, and oversees transmission planning. Notice their large display showing current time, ACE, frequency, and demand.

Similar looking control centers are used by power entities to monitor their control area looking for signs of possible problems and taking immediate action to avoid major system disturbances should a warning sign occur. Operators are

Electric Power System Basics for the Nonelectrical Professional, Third Edition. Steven W. Blume.

Figure 9-1 Electric system control center. With permission of the California ISO.

tasked with the responsibility to maintain system connectivity, reliability, stability, and continuous service. They are also responsible for coordinating field crew work activities and clearances to make sure crews are safely reported on high-voltage lines and equipment. System control center operators have noteworthy responsibilities.

Under normal conditions, control operators monitor the system and are prepared to respond immediately to incoming alarms from equipment out in the field. Under emergency conditions, control operators respond cautiously to incoming alarms, requests from field personnel, and inter-agency communications alerts. They realize the complexity of controlling a major system and the possible consequences should they make an error in judgment. They are highly trained in situation awareness and ready to take immediate action.

System control operators have many software tools at their disposal. These tools help operators analyze possible "*what if*" scenarios if something were to happen, based on real-time loads and line flows. Operators have direct communication lines to people in the field and other strategic locations.

The main tool of the ESCC operator is the ***supervisory control and data acquisition*** (SCADA) system. This system allows control operators to monitor equipment conditions, control equipment as necessary, dispatch generation, and obtain printable reports of all parameters about the power system. The SCADA system is made up of a centrally located ***master computer*** and several

remote terminal units (RTUs) located throughout the system. An equipment failure or breakdown in the telecommunications equipment supporting SCADA can cause control operators to make incorrect system adjustments. For example, a communication channel failure between the master computer and a RTU would result in no display updates about the status of a substation equipment operation. The operator would not know if breakers were actually open or closed. The lack of up-to-date information is detrimental to the reliable operation of the system, especially during disturbances when critical decisions are made.

Telecommunications equipment is used to communicate information electronically between the ESCC and the several RTUs. When problems occur in telecommunications or control center equipment, system operators must occupy ***backup control centers*** or send personnel to critical substations to resume monitoring and control functions. Control centers and backup control centers normally have emergency generators and uninterruptible power supply (UPS) systems to make sure computers, lights, communications equipment, and other critical electric dependent loads are powered without interruption.

This chapter discusses the equipment used in ESCCs, substations, and telecommunications.

Supervisory Control and Data Acquisition (SCADA)

The basic operation of virtually every electric utility in the United States relies upon SCADA systems. Up until the late 1940s, many utilities had personnel stationed at substations to perform equipment monitoring, switching, and control activities. In some cases, these were residents who remained on call 24 hours a day. With the advent of SCADA systems, it was no longer necessary for utilities to maintain manned operation of substations. Today, utilities access system information in near real time to control the power system. The SCADA master computer scans or polls each RTU to obtain updated information in a short time delayed operation (typically, 2–4 seconds for full system scan).

The basic function of SCADA is to monitor key electrical parameters throughout the control area, be notified when equipment changes state, operate equipment whenever necessary, obtain essential data to formulate reports, and to determine necessary actions needed to maintain system integrity. At the control center, the basic functions are to display information, generate alarms if anything abnormal occurs, store information, and remotely control the operation of substation or line field equipment when necessary. Remote monitoring and control of field equipment is essential to ensure normal operations and to properly respond to changes needed to regain normal operation. Also, other equipment not found in substations might have remote control capability through SCADA, such as transmission line motor operated switches, emergency load transfer switches, demand side load management automation, and other communications equipped control and monitoring devices.

SCADA systems have the capability of providing graphical representation of generation stations, transmission lines, substations, and distribution feeders. Depending on control area responsibilities, ESCC operators have full control of their systems and responsibilities. They might have monitoring-only capability of adjacent utility control areas.

SCADA alerts control operators that a change of state has occurred. SCADA gives operators full control to change the state back to normal after the initiating problem has been corrected out in the field. If an operator closes an open breaker via SCADA, for example, then SCADA will in turn alarm the dispatcher that the breaker status has changed to now closed. The closed indication is driven by relay contacts in the actual breaker itself. This indication feedback technique is inherent in the SCADA system. This allows operators to verify actions taken.

SCADA systems normally update information about every 2–4 seconds, the amount of time needed by the main computer to exchange information to each RTU sequentially. In reality, a lot can happen between scans and data updates. During normal operations, this time delay is tolerable. However, during disturbances or emergency situations, this time is long.

In terms of smart transmission technology, ***wide area monitoring systems (WAMSs)*** are being implemented, which are much faster than SCADA. WAMS use phasor measuring units (PMUs), also called ***synchrophasors***, with very fast computers and telecommunications systems. (WAMS are discussed in more detail later in this chapter.)

Figure 9-2 outlines the equipment that makes up a SCADA system, including the control center, RTUs, and telecommunications equipment. Notice the map board, the main computer, and the various communications systems that connect RTUs to the main or centralized computer. Several control centers like to use map boards for overview and manual backup. The communications systems are typically comprised of optical fiber, microwave, radio, copper cables, and power line carrier (PLC).

Data Acquisition Functions

The ***data acquisition*** portion of SCADA gives operators the ability to remotely monitor analog electrical quantities such as real/reactive power, voltage, and current with updates every 2–4 seconds. Also, operators are alerted to problems as they occur through alarm and indication points. For example, tripped breakers, security breaches, fire alarms, and enunciator panel alarms, send signals to the control center where a visual and/or audible alarm attracts the attention of the

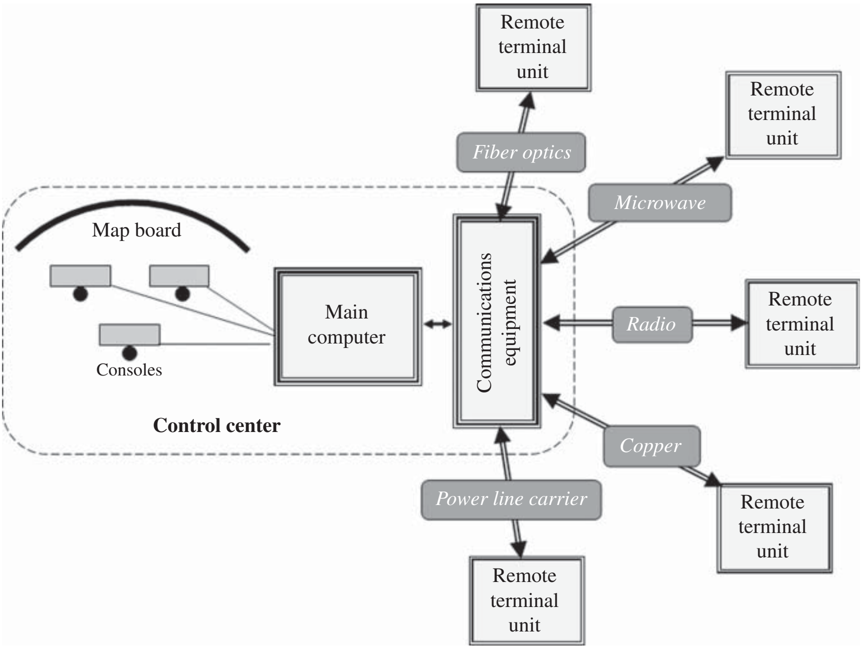


Figure 9-2 SCADA system.

system operator. The operator then uses SCADA control functions to operate equipment or inform other departments that equipment requires attention (such as low oil level alarm on a transformer).

Some examples of analog data acquisition information include:

- Bus volts
- Transformer watts
- Transmission line watts
- Feeder amps
- System VARs
- Regulator position

Examples of alarm and indication information include:

- Breaker 1274 now open
- Motor operator switch 577 now closed
- Station service power now off
- Major alarm panel activated
- Entry/security alarm activated
- Control building door now open

Also, SCADA enables the communication of accumulation data such as the following:

- Generator unit 1 MW-hours
- Generator unit 1 MVAR-hours

Control Functions

The ***control*** portion of SCADA allows operators to remotely control/operate equipment at a particular substation such as:

- Close breaker 1274
- Open motor operator switch 577
- Start emergency generator
- Disable autoreclosing

SCADA is an essential tool in modern power system operations. Once SCADA is established, several software tools become available to significantly help operators run their portion of power grid system. These software tools make up the energy management system (EMS).

Energy Management Systems

EMS**s** became a major extension from SCADA with the arrival of advanced computer programs and applications. Sophisticated computer programs were developed to monitor system conditions in almost real time and initiate automatic programmed control responses to assist the operation of actual equipment. An example of an automatic power grid function that is controlled by many EMS systems is generation. ***Automatic generation control*** (AGC) is a comprehensive EMS tool in use today. Smart computer programs are used to ramp up and down generators in response to changes in demand based on best economics and system reliability factors.

Other very important EMS computer software tools were developed to improve the reliable operation of large, interconnected power grids. These software tools help reduce power production costs, improve real-time analysis of current operating conditions, provide information to avoid wrong decision making by operators, improve system reliability, security, and much more. The umbrella term used to describe all these important system operation software tools is known as the ***energy management system*** or EMS.

It should be noted that EMS primarily applies to transmission control centers and distribution management systems (DMSs) applies to distribution control centers.

The significant EMS software programs in use today are described below:

State Estimator

The ***state estimator*** models the power grid system, considers current conditions such as line outages for maintenance, and so on. Operators see all line and substation equipment ratings and power flow levels, voltage levels, and equipment status. The information is presented in a way that helps operators see the status of the entire system at a glance; usually in terms of capacity utilization percentages with color coding indicating normal warning, or overloaded conditions. The state estimator calculates bus voltages and power flows where sensor information (from CTs and PTs) is not available. The state estimator uses all available sensor measurements, known facts about the system (equipment outages), and other relevant information (i.e., weather) to calculate the best possible estimate of the true status (or "state") of the power system. The state estimator is used to calculate new power flow conditions, such as voltages, currents, and line flows when lines or equipment is taken out of service from crew requests. These software tools help operators predict "what if" scenarios, before and after the remote controlled action takes place.

Contingency Analysis

The reliability software programs in the EMS perform "what if" or ***contingency analysis*** scenarios to determine worst case problems that might result if each major line or transformer were taken out of service for any reason. The output ranks potential contingencies according to severity and probability of occurrence and lists recommended actions should such events occur.

Furthermore, if a line is to be taken out of service for any reason, the contingency analysis program determines the next worst case contingency scenario so that operators can adjust system loading, generation dispatch, voltage control, etc. to best handle the next contingency. Operating system levels as if the worst-case contingency scenario occurred is known as "***N-1.***" N-1 is the operating level system operators are expected to follow according to NERC reliability standards.

Transmission Stability Analysis

Transmission stability analysis (TSA) reliability software runs a series of outage scenarios based on real-time conditions looking for transmission line overloads and other system short falls that can push the system close to its stability limits. The software is looking for increasing voltage violations, increasing VAR requirements, interchange transactions, and reports problems to the system operator or ESCC engineer.

The software also looks for voltage stability issues to avoid low voltage and voltage collapse problems.

Dynamic Security Assessment

To help system operators identify other potential problems, the ***dynamic security assessment program*** reports system equipment that is reaching rating threshold conditions in real time. For example, bus voltage approaching over-limit, lines approaching over-loading, etc. are reported to the operator. Software takes into consideration thermal constraints and emergency ratings. This software helps operators identify potential problems before they happen and helps provide safe operating margins during emergency conditions.

Emergency Load Shedding

The EMS is capable of shedding load in an emergency. Like underfrequency load shed relays, the EMS can trip load fed from distribution circuit breakers if the frequency declines. The operator can identify areas to drop load fast and effectively via the SCADA system. System operators can use the software to coordinate rolling blackouts.

Power Flow Analysis

Static information about the system's lines, transformers, etc. is entered into the computer programs regularly. For example, conductor resistance of a new transmission line that is scheduled to go into service is entered into the EMS database. The EMS then calculates the new ***power flow*** conditions with the new line included. The software can report detailed system information during daily, weekly, monthly, and yearly peak conditions. This power flow data is very useful to planning engineers who determine future power system infrastructure additions.

Generation Planning, Scheduling, and Control

The EMS is an effective place to plan generation needs. This planning software incorporates load forecast information, generation schedules, interchange or tie line exchange schedules, unit maintenance schedules, and unit outage situations to determine the best overall generation dispatch plan. Furthermore, based on all these schedules, the AGC part of the EMS controls the dispatch of generation. System operations, area control error (ACE), and frequency are then monitored according to this schedule, thus assuring system reliability and compliance.

Economic Dispatch

The ***economic dispatch*** software allocates available generation resources to achieve optimal area economy. It takes into consideration generator incremental loading costs on an individual generator basis, transmission line losses, and factors in reliability constraints. The EMS helps determine ***optimal power flow*** based on actual generator data, contingency constraints, and real-time loading.

Reactive Power Scheduling

The EMS has the capability to schedule (usually up to 24 hours ahead) the controllable reactive resources, required by NERC, for optimum power flow based on economics, reliability, and security.

Dynamic Reserves Analysis

The EMS can periodically calculate reserve requirements of the system. For example, spinning, 10 minute, 30 minute predictions are presented for a close look at generation requirements and available resources. The program takes into consideration operating circumstances (i.e., largest unit online and timeframe requirements to make changes) to generate reports and alert operators and engineers when necessary.

Load Profiling and Forecasts

EMS software can produce load forecast reports. For example, the EMS can determine load forecasts for the next 2–4 hours on a continuous running basis or the next 5 or 7 day forecast on an hourly basis. These forecasts take into consideration weather information, history trends, time of day, and several other variables that could affect system loading.

Demand Side Management

As discussed earlier in Chapter 6, Consumption; demand side management (DSM) is used to reduce load during on-peak conditions. The control signal used to shed interruptible load comes from the EMS. The EMS's DSM program decides when to initiate the broadcast signal that results in effective load reduction.

The conditions for selective signal broadcasting is programmed into the EMS decision logic.

Energy Accounting

Since all records of sales, purchases, meter readings, and billings are centralized in the EMS database, energy accounting reports are generated for management and regulatory authorities.

Operator Training Simulator

The EMS has the capability to have a functioning operator training console. This training console emulates a real console and can be put into real operation at any time. The ***training simulator*** gives power system operators real experience controlling the system by using current system data, terminology, labeling, and electrical quantities on a real-time basis. However, the actual control points are deactivated to the trainee.

Wide Area Monitoring Systems (WAMS)

As mentioned earlier in this chapter, ensuring system reliability and security is dependent on maintaining good voltage and stable frequency as demand changes. Transmission system operators and EMS computer programs focus on making sure good voltage is provided throughout the interconnection (grid) to avoid equipment overload and voltage collapse issues that can lead to major disturbances. Transmission system operators ensure voltage stays within $\pm$ 10%. Generation system operators ensure frequency stays stable at 60 Hz by continuously balancing generation to variable demand. Generator operators have the added duty to balance demand as undispatchable distributed generation continues to grow on the distribution system. Furthermore, renewable energy resources, such as wind and solar, offer variable generation resources. Now generator operators must balance variable generation with variable demand, a growing challenge for grid stability. The need for an effective wide area monitoring tool that oversees interconnection health continues to grow.

To better assist planning engineers ensure system reliability and security are at forefront, a relatively new panoramic view of interconnection health is underway, called the WAMS. WAMSs help interconnection transmission planning engineers model the system to identify potential grid disturbance issues much faster and in greater detail when compared to the traditional SCADA and EMS. WAMS measure grid conditions 30 times per second, roughly 100 times faster than

SCADA. In other words, WAMS take 100 samples for each SCADA scan of the system. As early as 2009, the U.S. Department of Energy's (DOE) Smart Grid initiative helped grant funds for research this effort. Today there are over 2,500 locations across the U.S. Bulk Electric System providing big data samples for WAMS.[1]

WAMS use ***phasor measurement units*** (PMUs) to measure voltage, current, and frequency attributes. PMU data is enhanced by adding precise time information from GPS satellite clocks to become known as "***Synchrophasors.***" Synchrophasors provide massive, detailed information about the system in essentially real time. PMU data is sent to ***phasor data concentrators*** (PDCs), and on to ***super-PDCs*** where the massive data is analyzed and reported. This WAMS provides detailed time synchronized electrical measurements throughout the grid for analysis and to identify vulnerable stress points that can lead to a major disturbance.

PMU sensors are installed in key substations throughout the interconnection and used to report voltage (or current) phase angle information that is time tagged by the global positioning system (GPS). The PDC assembles PMU messages into high-speed data streams and then sends this information to super-PDC locations for further aggregation. The combined PMU data from across the interconnection is modeled and analyzed by power system engineers to identify potential reliability concerns ahead of time.

The eventual goal of WAMS is to eventually inform operating personnel to adjust conditions, possibly requiring significant preemptive action, to avoid a predicted major system disturbance if not corrected. Currently, WAMS help transmission operating engineers identify potential operating scenarios but are not actually informing grid operators in real time to take immediate action. WAMS are evolving.

In essence, WAMS use strategically located PMUs installed in substations across the interconnection to provide essential real-time information about the accumulative power angles across the interconnection. A ***power angle*** is the difference between substation voltage angles located at both ends of a transmission line. The power angle across a transmission line increases as the power flow on that line increases. Maximum power flow across a transmission line occurs when its power angle is 90° and zero power flows when its power angle is 0°. Power angles can be positive or negative depending on the direction of power flow. Furthermore, the accumulative effect of these transmission line power angles across an interconnection creates what is referred to as interconnection "***stress***" or "***twist.***" During high-load flow conditions, interconnection twist can result in reliability concerns, especially when a critical transmission line,

1 U.S. Department of Energy, Office of Electricity.

generator, or major substation equipment trips offline. When a transmission line trips, power flow shifts among the other interconnected transmission lines, resulting in the possibility of overloading other lines and causing one or more of these other lines to enter voltage collapse, which would dramatically impede system stability. WAMS's charts and tables are used to display accumulative power angles across the interconnection, in multiple directions to monitor system stress. Planning engineers study these accumulative power angles from past major disturbances to determine the maximum safe twist parameters to use for the real-time system.

Let us discuss how substation bus voltage angles and transmission line power angles determine interconnection stress or twist using synchrophasors.

Suppose a suspiciously large power angle occurs in a path of multiple transmission lines across the interconnection, now actions can be taken early to reduce that twist or system stress down to acceptable levels; thus, avoiding a major disturbance. The intent is to have massive, detailed data collected and analyzed in essentially real time by using very fast computers coupled to very fast communications systems. WAMS use an extremely large amount of data that must be processed is real time to be effective.

When a large twist occurs in the interconnection, control centers could have options available to mitigate the situation, such as adjust generation output allocation to reduce accumulative power angles across transmission lines. This can be accomplished by increasing generation on one side of the grid and reducing generation on another side of the grid, thus reducing power flow across critical lines in the interconnection. The redispatch might not be economical nor help marketing; however, transmission reliability is of the highest priority.

In its present form, WAMSs are used to help engineers analyze past disturbances and strengthen the system against future disturbances. WAMS technology is expected to be integrated into grid control systems at some point in the future.

Synchrophasors and Power Angles

(*Optional Supplementary Reading*)

The power angle of a transmission line is the angle difference between the sending end substation bus voltage angle and the receiving end substation bus voltage angle. It is also the angle between voltage and current and depends on factors such as load, conditions on the network, and line impedance. The real power at the receiving end of the transmission line is proportional to the mathematical sine of the angle difference, as shown in the formula below:

$$Power_{Trans\ Line} = \left[\frac{(Voltage_{Sub\ A})(Voltage_{Sub\ B})}{Transmission\ Line\ Impedance}\right] \sin(Angle_{Sub\ B} - Angle_{Sub\ A})$$

When the power angle increases to 90°, maximum power flows on the transmission line. When the power angle decreases to 0°, zero power flows across the transmission line. WAMS track the transmission line power angles across the interconnection providing a measurement of system stress or twist. This information provides a means to measure encroachment of a predetermined stability limit determined by system planning engineers using models with data from previous system disturbances.

Substation voltage angles used in the power angle equation are determined using PMUs. A PMU is a standalone device or protective relay output signal that is time stamped with an electronic input from a GPS receiver. The resulting time stamped measurement is called a ***synchrophasor***. Thus, synchrophasors are used to measure the magnitudes and phase angles of substation buses throughout the interconnection. Typically, a common bus, such as Atlanta, GA, is used as the reference point. Based on this reference point, substation voltage angles with time information can be measured across the interconnection in multiple directions.

Synchrophasors provide continuous time stamped voltage and/or current waveform information to a data center for storage and access for analysis. Figure 9-3 shows an example of how synchrophasor voltage angle information is tracked across an interconnection. Note that the ***reference bus*** "B," where the sine wave crosses the zero axis and the voltage phase angle is said to be "zero" degrees. In other words, reference is made to the zero crossing of the sine wave at substation bus "B" (e.g., Atlanta). Now note that how all the other substations have either leading or lagging voltage angles with respect to the reference substation. In this example, the total power angle, or ***Twist***, from bus "A" to bus "D" is 230°. This angle can exceed 360° and much more for heavily loaded lines across a large interconnection.

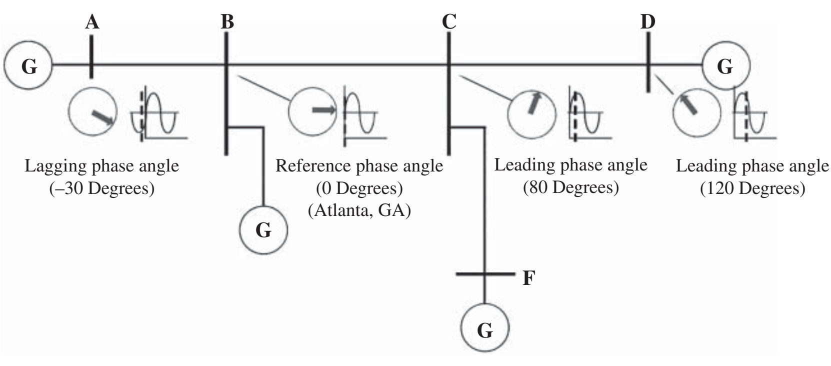


Figure 9-3 Synchrophasors in WAMS.

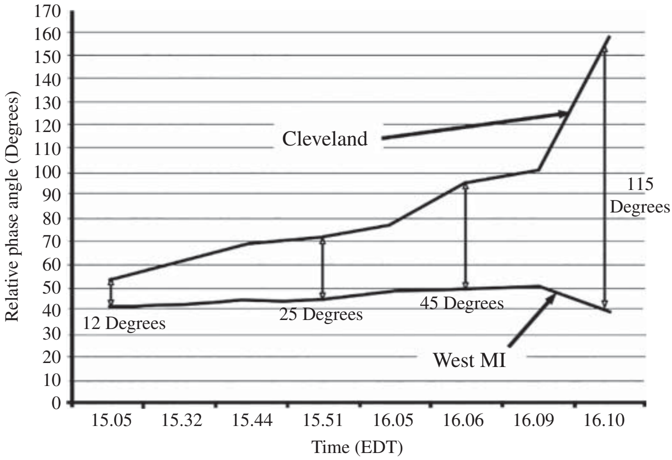


Figure 9-4 Eastern grid power angles.

Synchrophasors capture this information (roughly 30 samples per second) and the data center aggregates this data from multiple PMUs across the interconnection to assess system reliability and security in essentially real time.

For another example, Figure 9-4 shows the relative power angles between Cleaveland and West Michigan during the August 14, 2003 blackout in the eastern grid interconnection. Notice the power angle differences between Cleveland and West Michigan increase over time. Also notice the angle acceleration during the later part of this disturbance. This condition caused power flow to increase, stress on the system to increase, and pushed the interconnection closer to instability.

Most interconnections today have synchrophasors in service with data collection producing reports. Eventually, this valuable reliability assessment tool will serve system control centers in real time. This tool provides another dimension toward system reliability awareness. SCADA does not provide this level of visibility.

Telecommunications

Telecommunications systems play a vital role in the reliable operation of large interconnected power systems. Advanced high-speed data networks are used for SCADA, system protection, remote metering, corporate data, and voice communications. Equipment like that shown in Figure 9-5 is used to provide communications services for customer call centers, service center dispatch operations, system control center, corporate communications, secure private lines, direct interagency voice and data circuits, digital data circuits, and many other

Figure 9-5 Communications equipment.

communications services. Video networks are used for security surveillance, video conferencing, and enhanced training programs. These electronic communications networks are normally designed, built, and maintained by the electric utility.

These data, voice, and video networks are generally made up of six distinct communications system types, as follows:

- Optical fiber
- Microwave
- Power line carrier
- Radio
- Leased telephone circuits
- Satellite

The fundamentals of each of these communications systems are discussed next.

Optical Fiber

Optical fiber communication systems continue to be installed on electrical power systems all over the world. Private utility owned optical fiber systems are used to host several services, primarily electric operations system protection, corporate communications, and customer service. Optical fiber networks provide the primary backbone service for most utilities due to its inherent broadband capabilities. Additionally, unused optical fibers within a cable are often leased to third parties as a means for additional revenue to the electric company.

An optical fiber cable can have as few as 12 optical fiber strands or as many as 7,000 plus optical fiber strands in one cable, depending on need and cable type. The photo in Figure 9-6 shows coiled overhead ***optical ground wire*** (***OPGW***) terminating in a substation. The OPGW is connected (spliced) to a nonconductive ***all dielectric self-supporting*** (ADSS) optical fiber cable going into the control building.

The photo in Figure 9-7 shows a piece of OPGW. Lightning does not damage optical fibers because optical fiber is made of non-conductive glass. Note that the

Figure 9-6 Substation optical fiber cables.

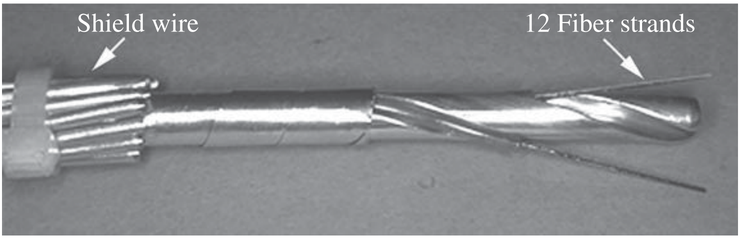


Figure 9-7 OPGW.

two buffer tubes of 12 optical fiber strands each that are contained in the center core of this OPGW shield wire cable.

An optical fiber strand itself is made of a very small glass core (approximately 8 micrometers in diameter), a glass cladding around the core (approximately 125 micrometers in diameter), and a color-coding acrylic coating around the cladding (approximately 250 micrometers in diameter). The acrylic coating adds identification and protection. Twelve of these optical fiber strands are placed inside a buffer tube. A jacket surrounds several colored groups of colored buffer tubes to make up an optical fiber cable. Some cables have aluminum shields, steel armor rods, fiberglass strength members, and/or protection layers depending on application.

Light pulses are transmitted into the glass core aperture angle at one end of the optical fiber strand and exits the opposite end of the optical fiber strand core. The light pulses reflect off the surface interface between the 8-μm core and 125-μm cladding based on the principle of ***reflection of light***. Reflection of light is the same principle that makes one see mountain reflections in calm lakes or bounce rocks over the surface of calm water. The light pulses exit the optical fiber core slightly wider than when entering the optical fiber strand. The longer the optical fiber strand, the wider the output pulse, due to the internal reflection path length. There is a practical limit to the optical fiber cable length and pulse rate due to output pulses overlapping for accurate on/off light pulse detection. Typically, an optical fiber cable length is limited to about 70 miles (112 km) with 10-Gbps data rate without repeaters, when using a single-color pulse stream.

Figure 9-8 shows how pulses enter and exit an optical fiber strand. The light must enter the core within the ***aperture angle*** to enable the reflection of light to occur between the core and cladding surface interface. Note that sharp bends in optical fibers will not let reflection of light occur and data errors result.

Electronic on/off digital communications signals are converted into on/off light pulses using fast responding laser diodes. The laser diode is pointed toward the

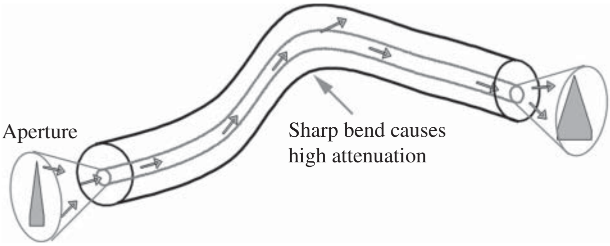


Figure 9-8 Optical fiber principles.

optical fiber's aperture core. At the receive end, a very sensitive fast responding photo detector transforms the optical pulses back into electronic pulses for the communications equipment to process. Traditional optical fiber systems operate as electronic to optical and optical to electronic modems. Modern high-speed optical fiber switches use optical signals without conversion to electronic voltages and currents. Optical switches with optical cables provide extremely fast digital communications. Furthermore, ***wave division multiplexing*** (WDM) uses hundreds of different wavelengths of optical pulse streams simultaneously to significantly increase digital communications.

Optical fiber cables can be wrapped around existing static wires very easily. Many existing transmission lines incorporate ***optical fiber wrap*** technology, mainly on the shield wires as shown in Figure 9-9.

A typical substation control building optical fiber cable terminations cabinet is shown in Figure 9-10. Each strand has an optical fiber connector. Thick jackets are used around each optical fiber strand for added protection.

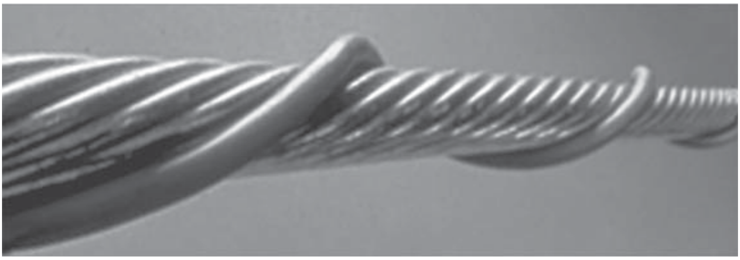


Figure 9-9 Optical fiber wrap.

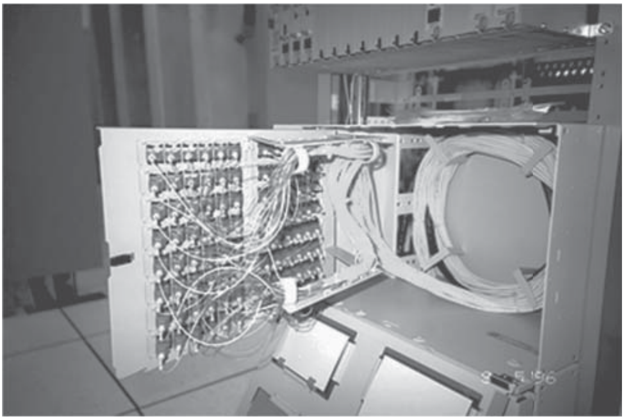


Figure 9-10 Optical fiber termination.

Figure 9-11 MW communications.

Microwave Radio

Microwave radio (MW) communications systems like those shown in Figure 9-11 use special ***parabolic shaped reflector antennas*** (called ***dishes***) to reflect radio energy coming out of the waveguide ***feedhorn*** into a beam pointing toward the MW receive antenna. These super-high-frequency (SHF) ***line of sight radio waves*** travel through air at near the speed of light. The receiving antenna at the opposite end of the radio path reflects the energy into another feedhorn where the waveguide transports the radio energy to the communications receiver. The nature of microwave energy enables the use of narrow rectangular waveguides to transport the SHF radio energy between the radio equipment and dish antennas. These point-to-point microwave communications systems can span distances of up to about 70 miles (110 km) without repeaters and can communicate analog or digital data, voice and video signals. Digital MW data rates can exceed 10 Gbps under optimal conditions. (Note that MW digital data signals are relatively slow compared to WDM optical fiber communications.)

The drawing in Figure 9-12 shows how SHF radio signals bounce off the reflected dish antenna and into waveguide feed horns located at the parabolic reflector's focal points. The radio energy then travels through the waveguide into the radio equipment. The microwave radios (at both ends) have receivers

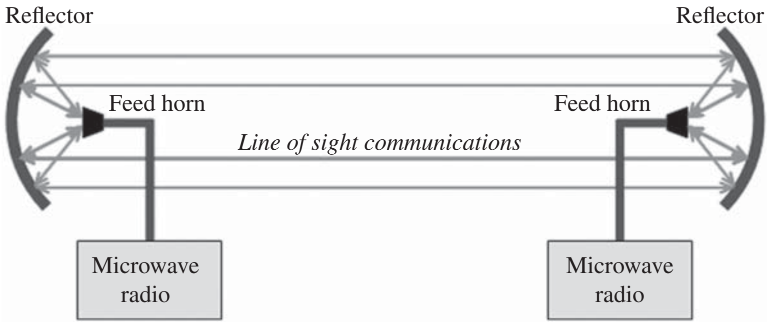


Figure 9-12 Microwave systems.

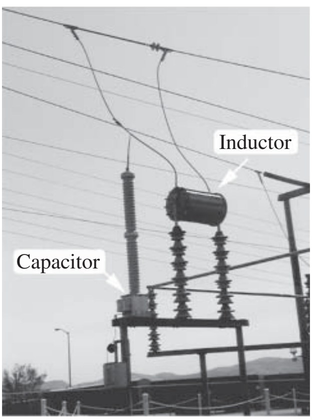


Figure 9-13 Power line carrier.

and transmitters operating at slightly different frequencies to enable two-way simulcast transmission.

Power Line Carrier

PLC systems operate by superimposing a high-frequency radio signal (i.e., 150–300 kHz) onto an existing low-frequency power line (60 Hz). PLC systems are point to point (i.e., substation to substation). They offer very slow data rates compared to optical fiber or microwave systems. PLC systems like that shown in Figure 9-13 have been in operation for several decades and continue to be used due to their unique security, reliability, and cyber-attack avoidance benefits. The communication path is typically the center phase of the three-phase transmission line.

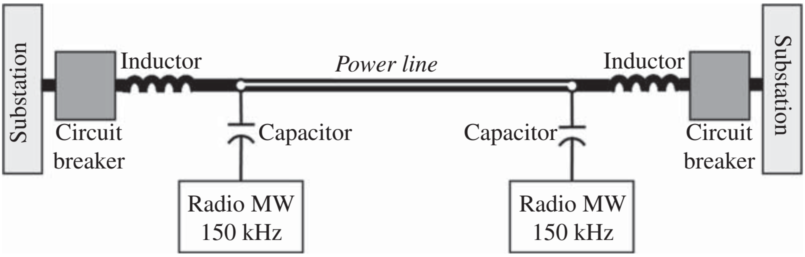


Figure 9-14 PLC system.

Referring to Figure 9-14, the theory of operation uses the principle that high-frequency radio signals pass easily through capacitors yet are blocked or severely attenuated by inductors or coils. Whereas low-frequency signals are just the opposite; they pass through inductors easily yet are blocked by capacitors. Figure 9-14 shows how the equipment is located on a power line between substations.

Inductors are sometimes called ***line traps*** or ***wave traps*** and the capacitors are called ***coupling capacitors***. Notice how radio communications occur between the coils in front of circuit breakers. Therefore, a line fault that trips the circuit breakers still enables communications (unless the line is cut).

There are a few drawbacks to older PLC technology, such as transformers severely attenuate the radio signals, snow and rain weather conditions can cause high noise levels, and noise causes data errors. Therefore, PLC has significant bandwidth limitations when used for the Internet or other high-speed communications services.

Radio Communications

Multiple address systems (MASs) are point to multipoint (P-MP) networks that are usually configured in a "star" architecture. They communicate to multiple fixed remote radio stations, one at a time. In each area, one "master" station communicates with multiple RTUs, usually in the 450-, 900-, or 1400-MHz radio frequency spectrum (referred to as the "UHF" or ultra-high-frequency band). MAS systems can be designed for either licensed or unlicensed use, which is usually decided based on the criticality of the equipment to be controlled or monitored.

Point to point (P-P) and P-MP radio communications systems are used by electric utilities for many reasons. P-MP systems are commonly used to provide SCADA data communications services between system control centers and RTUs, usually when optical fibers or microwave radio is too costly. P-MP radio systems are also used as base station systems to communicate with field crews.

Portable P-P radio systems are used for voice communications but are quickly being replaced with cellular phone technology systems.

The common form of communications used for distribution automation, SCADA and distribution feeder communications is licensed or unlicensed UHF wireless communications.

Copper Communications

Electric utilities might use ***twisted pair copper*** communications systems between substations for SCADA and protective relaying applications. Utilities tend to avoid leased copper services for important circuits simply because repair issues are controlled by a third party.

There are basically two ownership scenarios involved in copper communications systems; the utility can own the copper cables, or the copper circuits are leased from a third party such as the local telephone company. Leased circuits are used when there are low priority applications such as voice, remote metering, and interruptible load control. Whereas leased circuits are not normally used for high reliability data circuits such as SCADA or system protection. Electric utilities prefer using privately owned in-house copper cable circuits for critical data communications since they have full control over emergency maintenance situations.

Satellite Communications

Satellite communications are used in electric power systems for limited applications that can tolerate the inherent 2–3 second latency delay times. For example, meter reading and remote information monitoring work well with satellite communications. High-speed protective relaying applications do not bode well with satellite communications because the inherent time delay is intolerable. Also, satellite voice communications have pauses which can degrade quality of service.

Utility Communications Systems

Most electric utilities use a mixture of all the above-described communications systems. The communications channels used by utilities can be provided by the utility itself or be leased through third party communications service providers. Typically, utilities own their communications systems to have better control over repair response and preventative maintenance since this function is very critical, especially when used for protective relays, system control centers, and special/secure corporate voice and data applications.

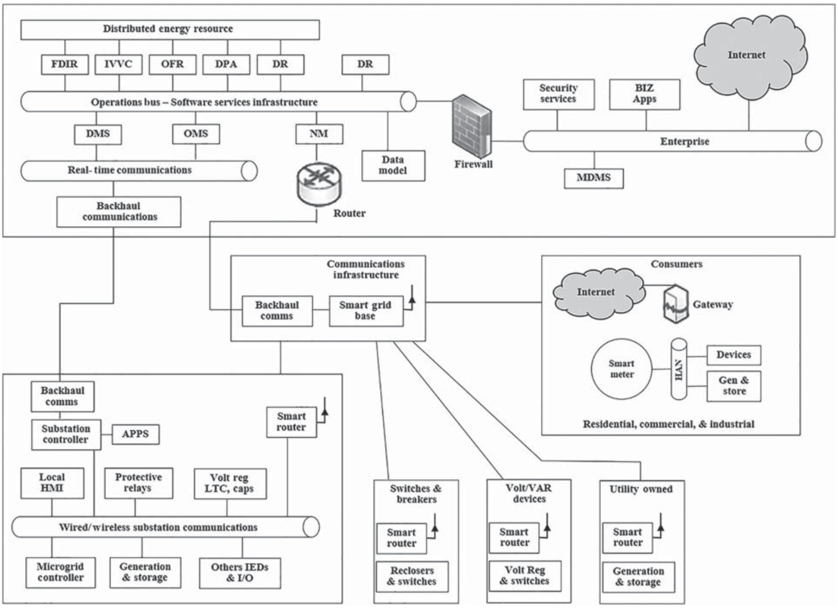


Figure 9-15 Distribution management. Courtesy of John McDonald and Mini Thomas.

Communication equipment used in the electric power grid system must be able to provide service to several applications, such as SCADA, protective relaying, corporate communications, distribution automation, customer information services, and more. The components used in modern power utility communications systems include digital interfaces for intelligent electronic devices (IEDs), PLCs, WAMS, plus protective relaying, sequence of events recorders, GPS time synchronization, PMUs, state monitoring servers, and analog-digital converters (merging units). The growing demand and need for a dependable utility owned telecommunications infrastructure and interfaces is growing daily.

Figure 9-15 shows the sophistication of a modern power utility communications system. The integration and connectivity of a utility's digital grid operations equipment including SCADA, protective relays, and now wide area networks show the growing need for elaborate, reliable, dependable, and cybersecure utility telecommunications systems.

10

The Transitioning Digital Power Grid

Chapter Objectives

After completing this chapter, the reader will be able to:

☑ *Explain the meaning of "Grid Resiliency"*
☑ *Discuss the many factors linking a transition into a digital power grid*
☑ *Explain how "Duck Curve" issues are affecting grid transition*
☑ *Describe "Inverter Based-Resources" (IBRs) and how they affect grid performance*
☑ *Discuss what NERC and IEEE are doing to improve IBR performance*
☑ *Describe the transitioning distribution system*
☑ *Explain how microgrids improve system stability and resilience*
☑ *Discuss the impact electric vehicles have on power grids*
☑ *Discuss how a "Digital Twin" can be used to improve cybersecurity*
☑ *Describe the "Digital Grid of the Future"*

Grid Resiliency

The ***resiliency*** of an electric power system refers to the system's ability to anticipate, withstand, and recover from disruptions, whether they are caused by natural disasters, cyberattacks, equipment failures, or other unforeseen events. Resiliency is a measurement of the predisturbance state. The disturbance would not occur to a completely resilient system. Resiliency ensures that power systems can continue to provide reliable service, minimize outage durations, and improve their ability to handle future disruptions. The elements of resilience include redundancy, diversity, flexibility, and a robust cybersecurity response and recovery. Combined, resiliency is resistance to undesired events and fast recovery should an uncontrollable event occur.

Electric Power System Basics for the Nonelectrical Professional, Third Edition. Steven W. Blume.

Digitalization brings unique opportunities to boost resiliency of a power system. A resilient power grid refers to the grid's condition and preparedness before any disruption occurs. The infrastructure must be robust, critical components having backups, and with ongoing inspections and preventative maintenance programs in place. A resilient grid employs real-time monitoring systems and predictive analytics to forecast potential problems. Critical systems are isolated from less essential ones to prevent a cyberattack from spreading and to reduce the risk of a large-scale or widespread outage. There must be a skilled workforce with comprehensive contingency plans in place. A resilient grid diversifies its energy sources, incorporating renewable energy (solar, wind, and hydro) along with traditional fossil fuels sources to reduce its dependency on a single source of power. Microgrids and decentralized power sources enable essential services, such as hospitals, to remain operational. Risk mapping, assessment reviews, and scenario testing help grid operators respond correctly under different types of disturbances. Regulatory compliance and public collaboration help ensure a coordinated effort occurs when building a resilient infrastructure. Lastly, demand response programs and consumer education help to reduce burden on the power grid. All these factors are being fulfilled through digital technology products and services.

The overall goal is to have proactive management and resilience-building measures in place to minimize potential damage, support operations under grid stress, and ensure rapid recovery when disturbances inevitably occur.

With all that said, this chapter discusses emerging technologies, infrastructure enhancements, and management software used to build a resilient, intelligent, and flexible grid as we step forward into the digital realm of electric power systems.

The Intelligent Grid

Electric power grid modernization, from generation to consumption, is undergoing substantial and continuous transformation. The bulk electric power system (BES) is evolving to become more digital, automated, responsive, adaptive, and informative, all while preserving reliability and security. The traditional power grid has transitioned into an "***intelligent grid,***" thus becoming a world-class leader in innovation, application, and risk management.

The term "intelligent grid" refers to the integration of smart devices and advanced technologies into the grid infrastructure. These technologies enhance automated control, provide flexibility to pioneer new challenges, enable information sharing, and offer new market incentives. These intelligent grid features are being embedded into our power grid system to strengthen performance and to secure a sustainable future.

We have seen dramatic changes in substation automation (i.e., microprocessor adaptive relays, intelligent devices for auto transfer schemes, digital sensors, merging units, LAN Ethernet communications, and more), in transmission automation (i.e., time tagged phasor measurement units, wide area monitoring networks, and more), in distribution automation (i.e., advanced metering infrastructure, automatic fault isolation, sectionalization, selective restoration, and more), and in consumption pattern changes (i.e., demand side management, home automation, improved appliance efficiency, and private energy resources).

The foundation or technical standard for this digital grid transformation is the International Electrotechnical Commission (IEC) Standard 61850[1] "Communications Networks and Systems for Power Utility Automation," which started development back in the mid-1990s. This standard focuses on the design of electrical substation automation systems to ensure interoperability among intelligent electronic devices (IEDs) used in substations and to improve the communications within electrical grid systems. This standard gained recognition by utilities, manufacturers, and end users. IEC 61850 continues to evolve, driven by advancements in technology, increasing demand for renewable energy integration, and the need for more secure and flexible grid automation systems. It has become a crucial part of the modernization of electrical grid systems and plays a significant role in the development of intelligent grid infrastructures worldwide.

The "smart grid" has become the "intelligent grid," where advanced systems use digitalization to expand monitoring, hasten control, and circumvent progressive cybersecurity threats. We will now discuss developments in transmission reliability and distribution operation strategies toward eventual grid resiliency and flexibility.

Transitioning Grid Reliability

The major trends affecting grid reliability include deep-rooted inverter-based resources (IBRs), extensive growth in battery energy storage systems (BESSs), wide use of distributed energy resources (DERs), self-sustainable microgrids, distribution automation, changes in system protection strategies, adaptation to electric transportation, and efforts to enhance Cybersecurity against physical and nonphysical terrorist attacks.

These trends and continuous efforts to advance grid reliability are best shown by recognizing their impact in what is referred to as the "***duck curve***" (see Figure 10-1). The duck curve shows how the California Independent System

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1 IEC TR 61850-7-5:2021, Communication networks and systems for power utility automation, current standard at the time of this book revision.

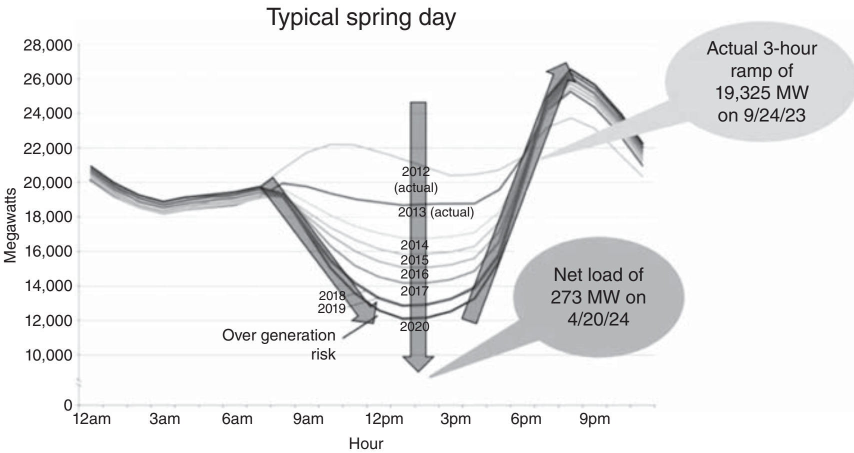

Figure 10-1 Duck curve.

Operator's (CAISO) control area daytime net load is declining each year, primarily due to the abundance of offsetting solar power systems. The graph shows how demand remaining after subtracting variable renewable generation is declining sharply during sunlight hours' year after year. Net daytime load went from over 20 GWs in 2012 to a negative number in 2023[2]. This example demonstrates what can happen elsewhere with an abundance of customer owned solar systems used to offset consumption.

The key takeaway points to understand in this graphic, which are topics discussed in this book, include:

- Growth in residential rooftop solar systems cancelling demand
- Growth in utility-scale energy sources (wind, solar, and battery storage plants)
- Extensive growth in DER generation on distribution feeders, requiring bi-directional flow (opposed to traditional single source radial feeders)
- The high dependency on IBRs
- Minimum demand now occurs during daylight hours
- Peak demand occurs in the evening, with minor peaks occurring in mornings
- Extreme generation ramp-up rates are now needed during late afternoons when the sun is setting
- Net demand has become a negative number in 2023[3]
- Existing fossil-fueled generation plants or other energy resources are needed in late afternoon to meet extreme ramp rate requirements

2 U.S. Energy Information Administration (eia), Today in Energy report June 21, 2023
3 U.S. Energy Information Administration (eia), Today in Energy report June 21, 2023

- Significant battery storage output appears most beneficial during early evening hours
- Battery charging is desirable during daytime or late-night hours
- Transmission lines are used to transport large scale solar and wind generation sources to distant load serving areas

As the power grid transitions from fossil-fueled generation to renewable energy, with a high concentration of DER and other IBR resources, reliability reliance changes from traditional spinning inertia to making IBRs respond better to power faults, transient conditions, system disturbances, or other impeding circumstances.

We will now discuss the issues planning engineers and system operators face as the power grid transitions to a more digital environment.

Battery Energy Storage Systems

A key purpose for ***BESS*** is to support generation during extreme ramp up periods, such as sunsetting. (Note that without daylight sun, high demand becomes present, requiring nonsolar energy supply resources.) Depending on the time of year, as the sun sets, demand is no longer supported by solar production and load balance must be provided by other means of generation. For example, the CAISO duck curve in Figure 10-1 shows the actual 3-hour ramp-up rate was 19.325 GW on September 24, 2023. The current battery storage capacity in California is 13.4 GW[4].

An example of a Lithium-Ion battery storage plant is PG&E's Moss Landing facility shown in Figure 10-2. The Moss Landing 400 MW/1600 MWh battery is intended to output 400 MWs for 4 hours. The 4-hours storage can help cover the peak ramp-up period between 5 pm and 9 pm or until nighttime generation resources take over. These inverter-based battery storage systems reduce the needed ramp rate generation requirement.

DER Transformation

On the generation side, a transformation from the traditional fossil-fueled electric power grid to renewable and carbon-free energy sources is being driven by regulatory mandates to reduce greenhouse gas emissions. This shift involves the integration of a growing number of DERs across transmission, distribution, and customer sites. The increase in locally operated and controlled small-scale generation units (i.e., DERs) and other IBRs, such as battery storage facilities, adds complexity to system operations and protection.

4 California Governor's office, www.gov.ca.gov/2024/10/15/california-exceeds-another-clean-energy-milestone, October 15, 2024

Figure 10-2 Moss landing battery. With permission of Pacific Gas and Electric Company (PG&E).

Managing bulk transmission generation–demand balance with the influx of distribution level DERs poses new challenges in generation dispatch and controlling energy flows. Normally, generation dispatch is governed at the federal level by NERC through reliability standards where area control error (ACE) and other constraints are carefully watched. DERs placed at the distribution system level fall outside NERC control, thus load balance becomes more complex. Furthermore, DERs at the distribution level push power in a bidirectional manner. Substation regulators and feeder protection schemes must accommodate bidirectional power flow. Despite these growing complexities, consumers, regulators, and government agencies continue to demand improved service reliability, grid resiliency, and the safety of utility workers and the public.

High Dependency on IBRs

IBRs have emerged as a pivotal component in modern day power systems revolutionizing generation, transmission, and consumption. The effects a high dependency on IBRs has on system reliability and operations will now be discussed.

As mentioned earlier, traditional power systems rely on rotating machines, such as turbines, to provide physical inertia to help stabilize frequency during disturbances. However, conventional IBRs lack this inherent inertia, which can reduce overall system stability. To support grid stability with large-scale use of IBRs, daytime solar, wind generation, battery storage systems, and other IBRs are now required to remain online (not trip), at least through the initial phase of a disturbance. One synthetic solution to enhance system stability in a grid dominated by IBRs is to mandate voltage and frequency ride-through capabilities. Without this requirement, system stability could be weakened.

The power industry is adapting to the growth in IBRs by changing performance expectation standards. For example, IEEE Std 1547-2018[5], Standard for Interconnection and Interoperability of DERs with Associated Electric Power System Interfaces, was developed to address IBRs. NERC's updated Reliability Standard PRC-024-3[6], Frequency and Voltage Protection Settings for Generating Resources, also addresses the new performance expectations. The major change has to do with voltage and frequency excursions ride through requirements. IEEE 1547 sets up new operating parameters and NERC Reliability Standard PRC-024-3 ensures IBR generators remain connected during defined frequency and voltage excursions. The intent of these important industry changes is to help IBR generation emulate spinning inertia generation.

IEEE 1547 breaks down IBR generation interfaces into three categories.

(I) Abnormal operating performance Category I is based on essential bulk power system (BPS) stability/reliability needs and *reasonably attainable by all DER technologies* that are in common usage today.
(II) Abnormal operating performance Category II covers all BPS stability/reliability needs and is coordinated *with existing reliability standards to avoid tripping for a wider range of disturbances* of concern to BPS stability.
(III) Abnormal operating performance Category III is based on both BPS stability/reliability and *distribution system reliability/power quality needs* and is coordinated *with existing interconnection requirements for very high DER penetration*.

At the transmission interconnection level, NERC applications are primarily based on IEEE Category III. Category III offers the highest disturbance ride-through capabilities, intended to address integration issues such as power quality and system overloads caused by DER tripping where there is a very high concentration of DERs. This category also provides increased bulk power system security by further reducing the potential loss of DER during bulk system events. Whereas distribution systems are primarily based on IEEE Category II to remain compatible with existing DERs; however, Category III accounts for bidirectional power flow, which could be a significant factor.

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5 IEEE Std 1547-2018, Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power System Interfaces
6 NERC Reliability Standard PRC-024-3, Frequency and Voltage Protection Settings for Generating Resources

Voltage Ride Through

(Optional Supplementary Reading)

Let us break down what is meant by voltage and frequency ride through requirements.

IEEE Std 1547-2018 "Standard for Interconnection and Interoperability of DER and associated Electric Power System Interfaces"; Voltage Ride Through Category III, is shown in Figure 10-3. The horizontal axis displays ***time*** and the vertical axis displays ***voltage***. Notice at the far right of the horizontal timeline, the continuous operating capability or steady-state voltage requirement is ±10%. (Transmission operators try to hold transmission voltage to within these limits.) Now notice the IEEE voltage tolerance requirement for short duration voltage excursions is much greater. The graphic shows that an IBR must not disconnect or cease operations during the initial phase of the disturbance, less than 1 second. The IBR must remain online for up to 15 seconds if the disturbance voltage drop reduces to only 50%. The graph shows overvoltage transients have a lower tolerance than under-voltage transients, that is due to arcing or insulation breakdown characteristics of equipment. The emphasis is to have IBRs ride through short-duration low-voltage excursions.

NERC Reliability Standard PRC-024-3 Voltage Ride Through requirements are shown in Figure 10-4. Notice the long term or continuous voltage ride through

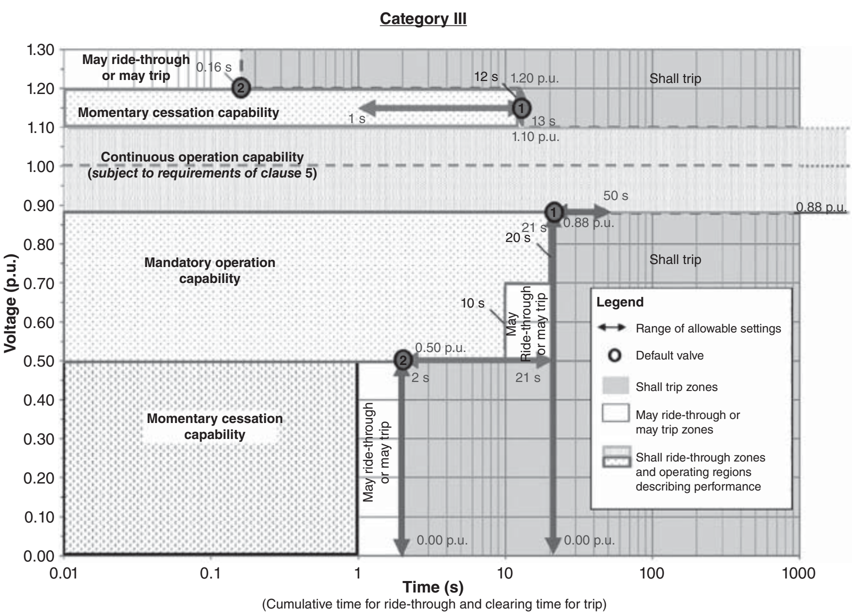

Figure 10-3 IEEE voltage ride through.

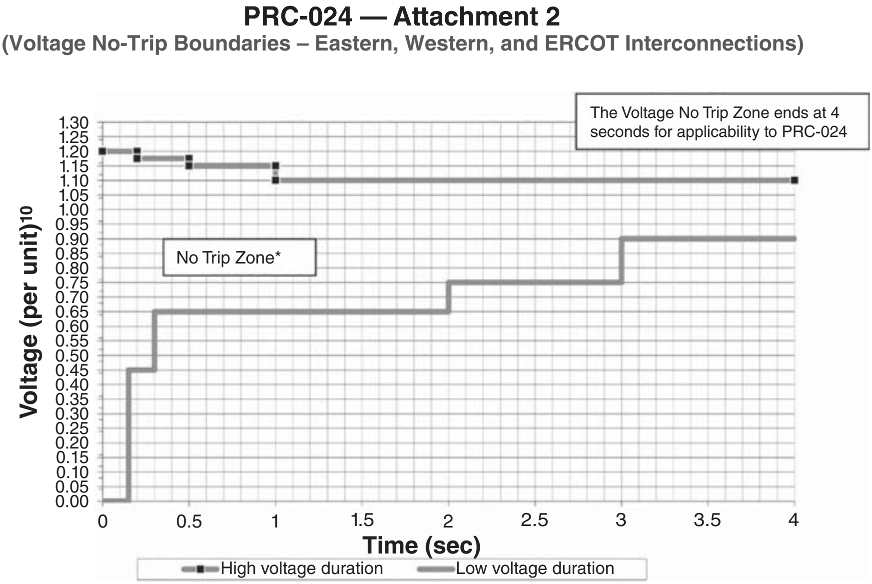

Figure 10-4 NERC voltage ride through.

requirement of ±10% (same as IEEE). Short duration disturbances require IBRs to stay connected to 100% loss of voltage when under 0.15 seconds, 45% voltage when under 0.3 seconds, 65% voltage when under 2 seconds, and 75% voltage when under 3 seconds. A disturbance can last much longer than that shown; however, compliant IBRs must ride through the initial stages of a disturbance. Should the voltage excursions exceed those voltage ranges during those durations, then IBRs are allowed to trip offline.

Frequency Ride Through

(Optional Supplementary Reading)

Now let us examine the ***frequency ride through*** requirement. IEEE Std 1547–2018 for frequency ride through (all Categories) is shown in Figure 10-5. Notice at the far right of timeline, the continuous operation capability or steady-state requirement is 60 ± 1.2 Hz. This frequency range allows for time error correction (60 ± 0.02 Hz) and typical generator manufacturer's continuous operating parameters. IBR generation must be able to ride through up to 61.8 Hz or as low as 57.0 Hz if the frequency excursion is under 250 seconds. IBR ride through is optional for frequencies above 61.8 Hz and below 57.0 Hz.

NERC Reliability Standard PRC-024-3 for Frequency Ride Through is shown in Figure 10-6. Notice the long term or continuous frequency ride through requirement of 60 ± 0.5 Hz. The IBR must stay connected for frequency excursions up to

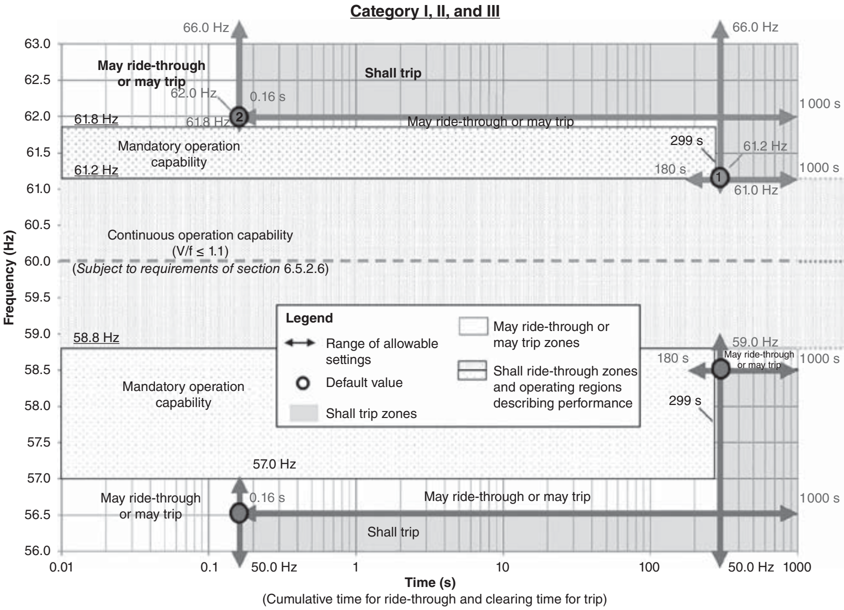

Figure 10-5 IEEE frequency ride through.

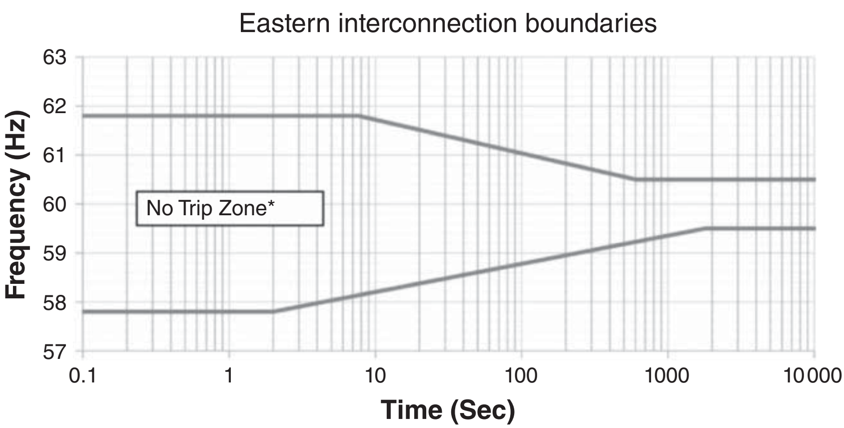

Figure 10-6 NERC frequency ride through.

61.8 Hz, for up to 8 seconds, and stay connected for frequency excursions down to 57.8 Hz, for under 2 seconds.

Traditionally, IBRs would cease output or trip during minor disturbances. Now, the revised IEEE and NERC rules intend to have IBRs ride through the initial critical stages of disturbances to help stabilize the grid.

The Transitioning Distribution System

Conventional distribution systems operate with limited automation. Their key attributes include radial configuration, low visibility of system conditions, centralized control centers with SCADA, and advanced distribution management systems (ADMSs) when available. These conventional systems have a semiautomatic approach to outage reporting and restoration, provide much needed asset management and mapping, provide an interactive customer service interface, and use a stepped-up telecommunications network. However, the distribution system situation is changing rapidly with the onslaught of distribution energy resources (DERs), resilient microgrids, the increased need for strengthening cybersecurity, bi-directional power flow, electric transportation, and energy marketing.

With these grid modernization changes seizing the distribution system, more sophistication is needed. Where ADMSs have led the frontier this far, distributed energy resource management systems (DERMSs) are coming into play, offering a higher level of software platforms and services to accommodate growth in DERs. ADMS is a comprehensive software platform that helps electric utilities manage and optimize their traditional distribution networks by integrating various tools and functionalities to improve reliability, efficiency, and safety of power distribution. ADMS broadly oversees the distribution network grid operations and provides real-time monitoring, voltage regulation, load management, fault detection, and restoration. Whereas DERMS specifically manage DERs like solar panels, wind turbines, battery storage, electric vehicles (EVs), and microgrids. DERMS help ensure their integration into the grid without compromising stability.

Whereas ADMS offers a comprehensive suite of software tools for outage management, grid optimization, load balancing, and automation of traditional grid functions, DERMS focuses on the coordination, control, and optimization of distributed resources, balancing their output and managing their interaction with the grid. DERMS offer more specific capabilities for forecasting DER output, coordinating with utility-scale generation, and managing energy storage, load flexibility, and grid balancing in a decentralized energy environment.

In the transitioning distribution world, ADMS supports grid modernization but focuses more on traditional utility operations and infrastructure management. Whereas DERMS play a critical role in modernizing the grid by enabling the integration of renewable energy sources and decentralized resources. In summary, ADMS is a broader system for managing the entire distribution grid and DERMS is a more specialized system focused on managing and refining DER integration within the grid. The two systems work hand-in-hand, and both are required in the transitioning distribution system.

The impact of high concentration of IBRs, plus battery storage, EVs, and microgrids is triggering utilities to implement DERMS.

Comparing Traditional to Modernized Distribution Systems

The modernized intelligent distribution system includes microprocessor-powered protection schemes, two-way power flow infrastructure, information coordination with smart microgrid networks, organized integration of wide-ranging DERs, and interactive software programs.

To achieve a well-orchestrated and robust integrated distribution system, enhanced coordination is needed among distribution system planning, engineering, operations, and customer service groups. Here are a few examples of why these groups must work together to realize the goals of the transitioning distribution system. For instance, effective deployment of distribution automation solutions such as fault location, isolation, and service restoration (FLISR) requires input from several of these groups. Another change is FERC introduced Order 2222 in September 2020, which allows tariff changes to enable *aggregated* DERs to take part in wholesale energy markets. Meaning, behind the meter (BTM) DERs such as small-scale energy resources like rooftop solar panels, home battery storage installations, EVs, charging equipment, and energy-efficient appliances are allowed to participate in broader energy markets. Another example of why these groups must work together is relay protection strategies and settings. DERs can back feed distribution substation feeders where protective relays and voltage regulators must cope with reverse power flow and automatic circuit switching. Still another consideration to ensure a robust integrated distribution system is utilities must have or gear up for BTM visibility to control loads during peak hours (i.e., HVAC, water heaters, vehicle battery charging, and energy producing schemes).

Utilities have improved distribution reliability by adding more remote-controlled electronic switches, motor operated air disconnect switches, capacitor voltage control devices, and ***programmable logic controllers*** (PLCs) for decentralized switching. These plant additions help to enhance automated service restoration. The benefits seen thus far from these distribution system enhancements are faster fault detection, automatic failed equipment isolation, automatic fault area sectionalizing, and automatic service restoration to unfaulted sections, thus improving service reliability. These automated functions are part of the new digital grid era.

Key Components and Features of ADMS

Utility distribution systems that provide ADMS hardware and software enhance the management and operation of distribution grids through a combination of real-time data, analytics, and control capabilities. ADMS includes several key components and features, such as:

- **SCADA (Supervisory Control and Data Acquisition)** allows almost real-time monitoring and control of critical grid components like substation transformer loading and circuit breaker control, thus enabling operators to detect anomalies and manage operations remotely.
- **Outage Management System (OMS)** helps detect and manage power outages, utilizing analytics (i.e., smart meter information) to predict fault isolation locations and offer solutions for quicker service restoration.
- **Distribution Management System (DMS)** automates and optimizes the distribution network, including tasks like voltage regulation, load balance, and managing a limited number of DERs.
- **Energy Management and Optimization** ensures effective peak load management, asset optimization, and demand response through data integration from smart meters and sensors, providing improved forecasting and energy resource management.
- **Fault Location, Isolation, and Service Restoration (FLISR)** facilitates quick fault detection and service restoration, reducing downtime and minimizing the impact on customers during outages.
- **Volt/VAR Optimization (VVO)** refines voltage and reactive power balance to improve power delivery efficiency, reduce energy losses, and enhance grid performance.
- **Advanced Analytics and Data Management** leverages algorithms, machine learning, and big data to predict load patterns, manage constraints, and optimize grid operations in real-time.
- **Customer Information Systems (CISs)** enables remote services like connecting/disconnecting residential power, demand-side management control, and EV integration.
- **Geographical Information Systems (GISs)** support asset management and grid mapping, essential for efficient grid planning and field operations.
- **Off-Line Operations Planning** includes load flow analysis, optimal feeder reconfiguration, capacitor placement, and voltage profile optimization for better distribution planning.

Together, these components make ADMS a comprehensive tool for modernizing traditional distribution systems by enhancing the efficiency, reliability, and grid resilience, especially in the context of integrating renewable energy sources and improving customer service.

Key Components and Functions of DERMs

DERMSs are essential for modernizing the grid to accommodate the growing shift towards dependency on renewable energy sources, decentralization of control, energy marketing, and the proliferation of DERs. It enhances grid flexibility, sustainability, and economic efficiency. DERMS include several key components and features, such as:

- **DER Integration** is accomplished by providing a framework enabling effective communication and control between the utility and distributed resources.
- **Grid Stability and Balance** is enhanced by coordinating supply and demand of electricity across a network of distributed assets. DERMS help manage fluctuations from renewable energy sources and prevent imbalances by using other resources like battery storage or demand-side adjustments.
- **Real-time Monitoring and Control of DERs** is provided to operators through real-time visibility of the grid, such as adjusting energy output, managing voltage, and responding to grid conditions or faults.
- **Optimization of DERs Economic Value** through demand forecasts, renewable energy production predictions, and scheduling dispatch of various resources to minimize cost and ensure efficient energy usage.
- **Decentralized Energy Markets** is supported by helping participants with energy trading, selling excess energy back to the grid, or other grid services.
- **Other Grid Services and Demand Response** can be provided such as consumers adjusting their energy usage during peak times in response to price signals or grid needs. DERMS help utilities manage peak demand more efficiently.
- **Software Platform Providers offer** DER aggregation and optimization, grid edge control and analytics, load balancing and peak demand management, automatic grid response, regulatory compliance, and microgrid management.

In summary, DERMS are essential for modernizing the grid to accommodate the growing shift towards renewable energy, decentralization, and the proliferation of DERs. DERMS enhance grid flexibility, sustainability, economic efficiency, energy marketing, and regulatory compliance.

Resilient Microgrids

A ***microgrid*** is a small electric service island that can connect and disconnect from the main distribution grid gracefully and is able to operate in both grid-controlled or island mode. The key drivers seeking microgrid integration include enhanced reliability for the utility, commercial, industrial, critical load, and military consumers. The benefits of having microgrids are increased reliability, improved resiliency, energy cost reduction, increased revenue, energy security, increased use of renewable energy resources, and the reduction of carbon emission. The microgrid real-time controller supports the reliability of the microgrid system.

Resilient microgrids are localized, self-sufficient energy systems that can operate independently or in conjunction with the main utility grid. They are designed to enhance reliability and resiliency of electric supply, particularly during extreme events such as natural disasters, cyberattacks, or grid failures. A resilient microgrid typically integrates renewable energy sources, energy storage systems, and smart control technologies to provide continuous power to its critical infrastructure, with or without the utility.

Microgrids interface with distribution feeders at the ***point of common coupling*** (PCC). Their advanced control systems allow for smooth transitions between grid-connected and islanded operations during normal conditions or emergencies. During normal conditions, microgrids can operate in conjunction with the main power grid, thus drawing power when needed or export excess energy into the grid as a DER. This allows microgrids to participate in energy markets and optimize costs. During main power grid emergency situations, microgrids can operate in their islanding mode (off-grid). Resilient microgrids switch to island mode, thus relying on their internal resources to maintain continuous power supply. In this mode, microgrids operate independently to primarily serve critical loads such as hospitals, emergency public services, and water treatment facilities.

Microgrids can black start independently without external power, prioritize essential loads during critical periods, and can help stabilize the main power grid by providing ancillary services such as frequency regulation and peak shaving when connected.

Microgrids and ***net metering*** can work together to further enhance energy efficiency and grid resilience. Microgrids generate and store local energy, often from renewable sources, while net metering allows excess energy to be exported to the main power grid in exchange for credit. This reduces electricity costs and supports renewable energy use. Together, they enable energy independence, optimize power usage, and improve grid stability, especially during outages, by providing backup energy services and monetizing surplus power.

One of the first microgrids to operate in the above manner is Alcatraz Island, see Figure 10-7. In 2012, Alcatraz Island transitioned from diesel generators to pioneering a microgrid system in the United States. The microgrid integrates over 1,300 solar panels with an advanced battery storage system. The Alcatraz microgrid can reduce reliance on fossil fuels and cut greenhouse gas emissions by 700,000 pounds annually. This microgrid system can balance energy supply and demand, enable autonomous operation, and be resilient during main power grid disruptions.

This project was successful in demonstrating the viability of renewable energy and microgrids in remote locations, thus serving as a model for future sustainable energy systems.

Figure 10-7 Alcatraz Island. Dima Brinza/Shutterstock.

Electric Vehicles

Home and EVs batteries can comfortably power the typical residential home while sustaining energy independence with a modest rooftop solar system. For example, a typical residential consumer's energy usage ranges from 600 kWh to 1,200 kWh per month (or 20–40 kWh per day) depending on which state, house size, usage, etc. Some of today's EVs are equipped with batteries having 85–100-kWh capacity. Therefore, a fully charged EV battery can power a home for 2–4 days. A typical home battery system of 15–40 kWh could power the home for 1–2 days. A rooftop solar system consisting of 20 300 W panels, and with 5 hours of solar production, produces 30 kWh per day, which can comfortably power the home, charge the home battery, and the EV.

EV adoption is rapidly increasing in the United States, driven by consumer demand, supportive public policy, and industry commitments to electrification. However, insufficient utility preparedness can lead to infrastructure overload, particularly from Level-2 charging stations (240 Vac), which can double home energy demand. An abundance of Level-1 (120 Vac) and Level-2 charging stations could create secondary demand spikes, unplanned asset failures, and increasing maintenance costs. Understanding customer load profile behavior and charging patterns is crucial for utilities to properly plan infrastructure as the home transitions to a new fuel station. The alignment of mass EV charging with existing peak demand periods, especially during extreme weather or natural disaster events remains a significant concern.

Fast Charging

Most EVs charge overnight, but only for a fraction of that time. On-board chargers utilize ac power from external sources, while off-board dc chargers provide fast, high-power charging. Level-1 (120 Vac) on-board chargers produce up to 2 kWs while Level-2 chargers (240 Vac) produce 5–20 kWs. Managed charging, or smart charging, optimizes charging schedules based on grid conditions, thus helping to flatten grid peak demand while avoiding secondary peaks.

Fast charging stations, like the one shown in Figure 10-8, cater to drivers seeking quick charges. These stations are usually located in convenient spots like parking lots, near highways, or at service areas for easy access during long trips. While a “typical” EV median energy consumption (model year 2024) is 37 kWh/100 miles[7], Tesla Superchargers stations, like the one shown in Figure 10-8, provide high-speed charging, delivering up to 250 kW of charging power, allowing cars to gain hundreds of miles of range in just 15–30 minutes. These supercharges bypass the vehicle’s onboard charger and feed the vehicle’s battery pack directly. Superchargers use rectifiers to convert grid ac power into dc power to directly charge the batteries.

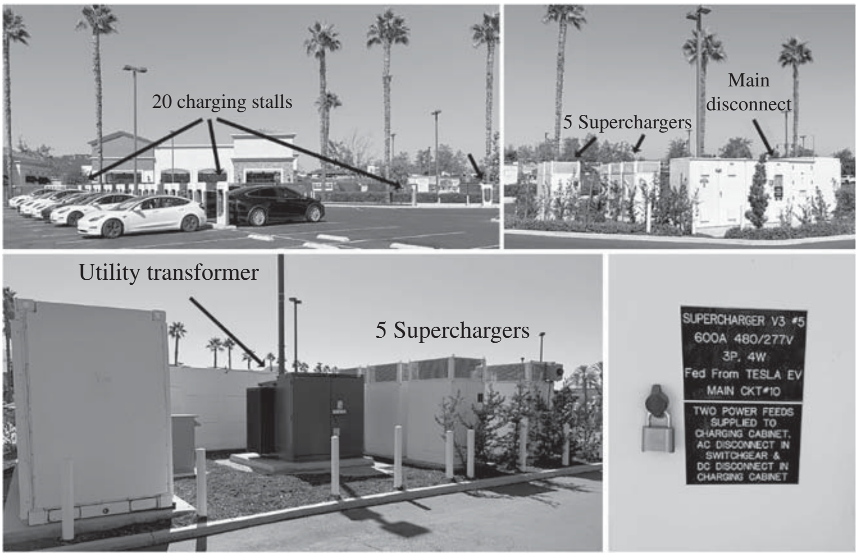

Figure 10-8 Fast charging station.

7 Environmental Protection Agency (EPA), Green Vehicle Guide

The Tesla Supercharging station shown in the photo utilizes a 2,500-kVA padmount transformer, five separate 500-kVA superchargers, 20 charging stalls, and a main disconnect switch. Each supercharger is rated 500 kVA, 480/277 V, 600 amp, and four-wire wye connection. Thus, five superchargers have a total capacity of 2,500 kVA to match the padmount transformer. Each supercharger connects to four charging stalls, thus 250 kVA or 250 kW (at unity power factor) is available for each EV being charged. The charging circuitry is designed to manage charging power, when multiple cars are connected, to avoid overheating or overcharging.

EV Infrastructure and Grid Operations

Utilities must proactively design distribution infrastructure for managed charging strategies, otherwise, substantial infrastructure upgrades will be necessary quickly to accommodate expected large-scale EV load growth.

Managed or smart charging helps reduce peak demand and ensures that charging occurs only when the network is not constrained. Smart charging avoids secondary demand peaks and addresses challenges like those presented in the duck curve by utilizing load gaps and available generation. Additionally, smart charging helps balance or spread distribution feeder loading, shift periods of high demand to periods of low demand, and allow for the effective use of off-peak generation availability. A well-planned EV infrastructure will ultimately contribute to a balanced and efficient energy supply system.

There are two types of managed or smart charging, also referred to as "***dynamic charging***":

1) **Passive Charging:** Involves timers and time-of-use (TOU) rates.
2) **Active Charging:** Utilities control charging to address electric system challenges.

Distribution companies can implement tariffs to incentivize off-peak or passive charging and set up special agreements for active (also called flexible) EV charger installations. Flexible charging offers grid services like load flattening, improved generation-load balance, frequency stability, voltage support, and renewable energy balance. TOU tariffs and demand response programs are designed to encourage charging during desired periods, such as peak solar generation hours. However, passive charging incentives such as timer-based and TOU charging can lead to compounded load and secondary peak demands. Dynamic charging programs position utilities for abundant EV load growth.

Bi-directorial EV Charging as a DER

EVs can serve as a DER through bidirectional charging, although most EVs currently lack this capability. With enough EVs, they can function as energy storage systems, shifting solar generation from daytime to evening. A strategic EV

DER integration strategy aims to capitalize on high-solar production periods while improving system load factor.

EV Environmental Impact

EVs have a lower ***carbon footprint*** compared to internal combustion engine (ICE) vehicles. EVs emit approximately 72.6 gCO_2/mile vs. 258.1 gCO_2/mile. The efficiency of EVs (64.4–86%) significantly surpasses that of ICEs by 14–33%. As renewable energy becomes a more significant part of the power grid, ***emissions*** from EVs decrease.[8]

EV Charging Methods

Future advancements in the use of electric transportation might include wireless charging technologies; both static (while parked) and dynamic (while driving), and battery swapping systems. Dynamic charging is intended to power vehicles while driving and not actually charging batteries. Additionally, heavy transport vehicles could adopt pantograph systems, like trolleybuses, for designated roadways.

The transition to EVs presents both opportunities and challenges for utilities, infrastructure, and the environment. A proactive approach to grid management and charging infrastructure is crucial in supporting this evolving landscape. The goal is to minimize impacts from uncontrolled EV growth on demand and to ensure a sustainable future is provided.

Building the Digital Grid of Tomorrow

The energy industry is undergoing a significant transition from fossil fuel to sustainable energy sources, driven by decarbonization. The key drivers of this energy transition are higher penetration of renewables at the transmission level with IBRs and DERs at the distribution level. The future power grid system is further influenced by how transmission and distribution infrastructure planning and operational controls influence or accommodate expected load growth.

Cybersecurity becomes a paramount concern with all this digitally intelligent infrastructure development. Aside from cyber-attack software upgrades, NERC Critical Infrastructure Protection (CIP) standards, secure operations centers, encryption, passwords, and all the rest, a relatively new approach to cybersecurity is underway, that of the “digital twin (DT).”

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8 International Energy Agency (IEA), *The Role of Renewables in Reducing EV Emissions*.

The Digital Twin and Cybersecurity

The real-time virtual representation or continuously updated detailed computer model of an electric power grid system is called a "DT." A DT can offer real-time insights through simulations by analyzing real-time operations, cyber vulnerabilities, and test responses without impacting the actual grid.

A DT contributes to electric power systems cybersecurity in several ways. It mirrors the physical power system by continuously receiving data from sensors and control systems, thus allowing it to detect anomalies and deviations in operational behavior that may indicate a cyberattack or malfunction. ***Machine learning*** and ***artificial intelligence*** (AI) enhance the DT's ability to identify suspicious activities or potential breaches more quickly than traditional systems.

Simulating various cyberattacks (such as malware, ransomware, or denial-of-service attacks) within the DT environment helps cybersecurity experts analyze their impact on the power system and test their effectiveness as defensive measures. The DT can test and improve the network's resilience before a real cyber attack occurs.

The DT can also run predictive analytics to assess potential vulnerabilities before they are exploited. This predictive approach strengthens grid weak points, such as outdated software, insecure communication protocols, or unprotected access points. Furthermore, it ensures compliance with cybersecurity regulations (e.g., NERC-CIP) by simulating the effects of regulatory changes and providing reports needed to demonstrate compliance.

Lastly, a DT integrates operational technologies (OTs), such as SCADA, with information technology (IT) systems, like data centers. By doing so, DTs enable comprehensive testing and ensure security across all domains.

The integration of a power system DT provides a proactive, real-time, and dynamic approach to safeguarding the critical infrastructure and system operations against cyber threats. DTs improve situational awareness and lead a path to unlimited enhancements. Watch for DT development in the coming years!

Grid Flexibility

After years of low or negative load growth, electricity demand is now expected to rise significantly due to the electrification of transportation, the high demand for large data centers, and spin off load growth due to emerging technologies. To support this expected load growth, renewable energy resources, which seize carbon reduction opportunities are being built. Combined, these changes affect how power is transmitted, distributed, and consumed. A future power grid that can host dramatic change in DER implementation, intelligent edge networks, and infrastructure digitization is essential to provide capacity, enable two-way power transfer, accommodate load growth, provide a complex control management system, etc. must be flexible.

Grid flexibility must become part of infrastructure development to accommodate edge intelligence systems, like microgrids and DERs. with resiliency and reliability. With intelligent microgrids coming online throughout the distribution system, for example, the number of controllable points within the grid (referred to as ***edge intelligence points***) are increasing and becoming more difficult for centralized control to manage operationally and reliably. Real-time logic controllers are needed to accommodate these edge intelligent sources and loads. The paradigm is shifting from centralized control to decentralized distributed intelligence control to meet these challenges. Thus, distribution systems having ADMSs, DERMS, and distribution infrastructure automation, such as fault FLISR, need to accommodate a decentralized control nature.

For the grid to continue working toward improved system reliability, efficiency, and to maximize the use of renewable resources, and so on, a flexible framework must be provided. A flexible grid can accommodate the level of intelligence

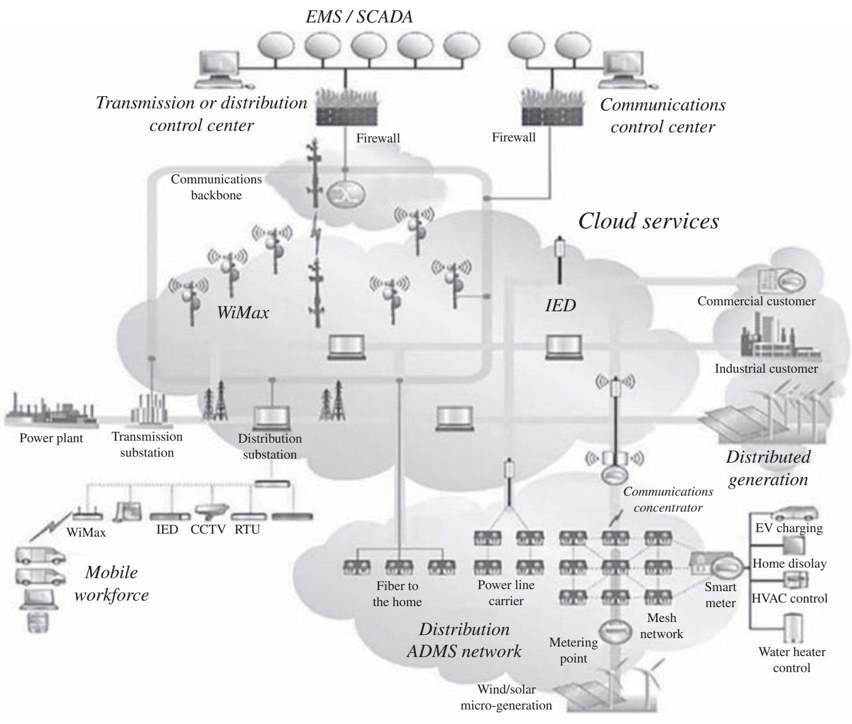


Figure 10-9 Grid flexibility.

occurring across the grid, especially if maximum use of renewable resources is desired. The flexible digital power grid makes use of ***generic object-oriented system event (GOOSE)*** control by incorporating the already established messaging system part of industry standard communications interface standard IEC 61850.

GOOSE provides the means for decentralized control through communicating messages, setpoints, and commands for tripping, regulating, and data gathering to/from microgrids, DERs, and other asset primary controllers across the network. Decentralized control is provided by PLCs, use of digital communications systems (GOOSE), and distribution automation. Although decentralized control is fast, efficient, effective, etc., control center oversight or supervision is still an option.

In summary, grid flexibility ensures the power system can balance supply and demand despite uncertainties. It supports renewable energy integration, optimizes energy use, and enhances the grid's resilience and reliability, meeting the evolving needs of utilities, policies, and consumers. Figure 10-9 shows an example of how modern systems can work together to form a flexible grid.

11

Personal Protection (Safety)

Chapter Objectives

After completing this chapter, the reader will be able to:

☑ *Discuss "Personal Protection Equipment" used for safety in electric power systems*
☑ *Explain human vulnerability to electricity*
☑ *Explain how one can be safe by "Isolation" or "Equipotential"*
☑ *Discuss "Ground Potential Rise" and associated "Touch" and "Step" potentials*
☑ *Discuss how "energized" or "de-energized and grounded" lines provide safe working environments for field workers*
☑ *Explain the meaning, causes, and safety procedures of "Arc Flash"*
☑ *Discuss the "safety hazards" around the home*

Electrical Safety

The main issues regarding ***electrical safety*** are the invisible nature of hazardous situations and the element of surprise. One must anticipate, visualize, and plan for the unexpected and follow all proper safety rules before an accident to gain confidence in working around electricity. Those who have experience in electrical safety respect the surprise nature of electrical hazards and plan for the unexpected. There are several methodologies and personal protective equipment (PPE) available that make working conditions around electrical equipment safe. The common methodologies and safety equipment are explained in this chapter. The theories behind those methodologies are also discussed. Knowledge of fundamental electrical safety principles is very important and effective in recognizing and avoiding possible electrical hazards.

There are two aspects of electrical safety that are discussed in this chapter; ***electric shock*** (i.e., current flow through the body) and ***arc flash*** (i.e., being burned

Electric Power System Basics for the Nonelectrical Professional, Third Edition. Steven W. Blume.

by heat created by an electrical arc when an equipment failure occurs). Protection against electrical shock is discussed first.

Personal Protection

Personal protection refers to the use of proper clothing, insulating rubber goods, or other safety tools that provide ***electrical isolation*** from electrical shock. Another form of personal protection is the application of ***equipotential*** principles, where everything a person comes in contact with is at the same potential. Electrical current cannot flow through a person if equipotential exists. Either way, using insulating personal protection equipment (PPE) or working in a ***zone of equipotential*** (ZOE) are known methods for dependable electrical safety.

Human Vulnerability to Electrical Current

Knowledge of human vulnerability to electrical current is helpful to understand prior to a discussion of safety prevention techniques. The level of current flowing through the body determines the seriousness of the situation. Note that the focus is on current flow through the body opposed to voltage. Yes, a person can touch voltage, create a path for current to flow, and experience a shock, but it is the amount of current flowing through the body that causes concern.

Electric shock hazard testing[1] back in the early 1950s showed that the human body is sensitive to a range of about 1–2 milliamps (0.001–0.002 amps) of current. As little as 16 milliamps (0.016 amps) can cause the loss of muscle control (i.e., "***lock-on***"). As little as 23 milliamps (0.023 amps) can cause difficulty breathing, and 50 milliamps can cause severe burning. These current levels are rather small when compared to normal household electrical load. For example, a 60 watt, 120-V incandescent light bulb draws 500 milliamps (0.5 amps) of current at full brightness.

The residential ***ground fault circuit interrupter*** (GFCI) like those used in bathrooms (discussed earlier) open the circuit breaker when the differential current reaches approximately 5.0 milliamps (0.005 amps). The GFCI opens before dangerous current levels are allowed to flow through the human body. The conclusion is humans are very vulnerable to relatively small electrical currents.

Principles of "Isolation" Safety

A person can be safe from electrical hazards using proper rubber isolation products such as gloves, shoes, blankets, and mats[2]. Proper rubber goods allow a person to

1 "Electric Shock Hazard" by Charles F Dalziel which appeared in the February 1972 issue of IEEE Spectrum.
2 OSHA 29CFR1910 Occupational Safety Standard.

become isolated from ***touch and step potentials*** that would otherwise be harmful. Electric utilities test their rubber goods frequently to ensure that safe working conditions are provided.

Rubber gloves are routinely used when working on energized medium voltage systems (i.e., hot-line maintenance on distribution feeders) and de-energized medium voltage systems just in case it becomes accidentally energized. Rubber gloves by themselves are not rated for energized subtransmission or transmission voltages. Figure 11-1 shows the cotton inner liners, insulated rubber glove, and leather protector glove used in typical live line maintenance on distribution systems or to protect against accidental energization of de-energized lines and equipment.

Figure 11-2 shows high-voltage ***insulated boots***. Figure 11-3 shows high-voltage ***insulated blankets and mats***. Every electric utility has extensive and very detailed safety procedures regarding the proper use of rubber goods and other safety related tools and equipment. Adherence to these strict safety rules and equipment testing procedures ensures that workers are safe. Furthermore, electric

Figure 11-1 Rubber gloves.

Figure 11-2 Insulated boots.

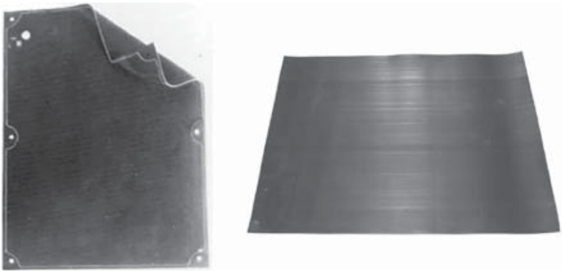


Figure 11-3 Rubber blankets and mats.

utilities spend generous time training workers to work safely, especially when it comes to live line activities.

Principles of "Equipotential" Safety

Substations are built with a large quantity of bare copper conductors and ground rods connected together and buried about 18–26 inches below the surface. Metal fences, major equipment tanks, structural steel, and all other metal objects requiring an electrical ground are all bonded or connected to the buried copper conductors. This elaborate interconnected system of conductive metals forms what is referred to as the station's "***ground grid.***"

This elaborate ground grid provides a safe working environment that is referred to as "***equipotential grounding.***" Normally, a copper conductor is buried outside the fence perimeter (approximately 3 feet from the fence) to extend the ground grid for additional safety to personnel outside the fence. Typically, 2–4 inches of clean gravel is placed on top of the substation soil to serve as additional isolation from current flow and voltage profiles that could exist in the soils during fault conditions. Figure 11-4 shows the ground grid concept.

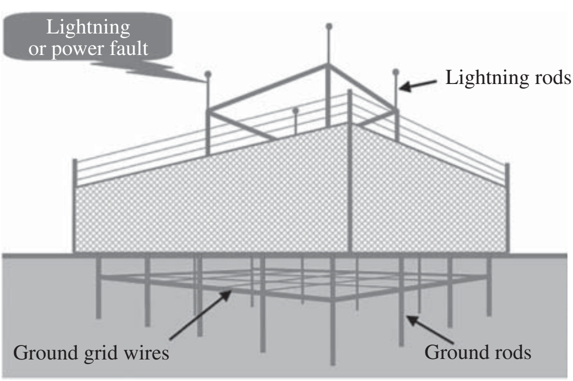


Figure 11-4 Substation ground grid.

There are two main reasons for having an effective grounding system: first, to provide a highly effective, low resistive path for fault current to flow back to their sources to trip circuit breakers (i.e., system protection). Second, effective grounding provides a ZOE for safe working environments. Effective ground grids cause high fault currents to trip circuit breakers faster. The ZOE provided by the ground grid minimizes the risk of someone in the substation experiencing a current flow during a lightning strike or power fault. Theoretically everything a person touches, while in a ZOE is at the same voltage (due to bonding) and therefore no current flows through the person. As an example, suppose you were in an airplane flying 30,000 feet above sea level. Everything inside the airplane seems normal. The same is true in a properly designed substation. When a fault occurs causing a 30,000 volt ***ground potential rise*** (GPR), everything seems normal.

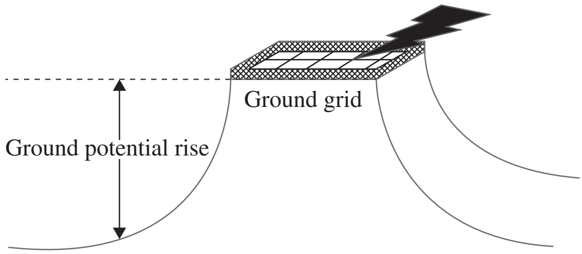
Ground Potential Rise

When a fault occurs on a power system, the portion of current flowing back to the sources' ground grids causes earth soils to experience a surface voltage. This earth soil surface voltage is called GPR. The GPR voltage profile decays exponentially outward from the system grounding locations as shown in Figures 11-5 and 11-6. This GPR condition can cause dangerous ***Touch and Step potentials***.

Touch and Step Potentials

During a lightning strike or power fault event in a substation, the entire substation rises to a high potential and anyone standing on the ground grid during that event should experience no touch or step potential because of equipotential grounding. ***Touch potential*** is the difference between the voltage magnitude of a person (or animal) touching an object and the magnitude of voltage at the person's feet. Touch potential can also be the difference in voltage between two potentials (i.e., hand-to-hand contact). ***Step potential*** is the difference in voltage between a person's (or animal's) feet. Shoes, gloves, and other articles of clothing help insulate a person from touch and step potentials. Approved, tested, and

Figure 11-5 Substation ground potential rise.



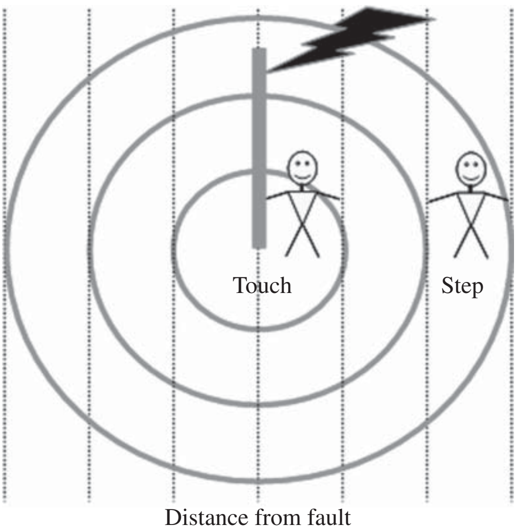


Figure 11-6 Touch and step around structures.

properly used rubber safety products (i.e., PPE) provide isolation from potentially hazardous touch and step potentials.

Working Transmission Safely

Transmission crews work on power lines under energized and de-energized conditions. Either way, all safety precautions are mandatory. Safety precautions fall back to the basic principles of either being fully isolated from electric shock or being in a ZOE. One must plan on the possibility of a de-energized line becoming accidentally energized without notice. Since lines or substation components can become accidentally energized without warning makes it imperative that all safety precautions are implemented prior to the accidental energization.

The following shows examples of the different ways to work on power equipment safely.

Energized Equipment

There are multiple ways to work on energized power lines safely, using insulated bucket trucks, fiberglass nonconductive hot sticks, and bare hand live line maintenance.

Insulated Bucket Trucks Working out of insulated bucket trucks is a means of working on lines that are either energized or de-energized. Depending on the system voltage being worked, rubber gloves, fiberglass hot sticks, or live line bare hand methods can be used safely by working out of ***insulated trucks***. Figure 11-7 shows using an insulated truck.

Figure 11-7 Insulated buckets.

Hot Stick Live Line Maintenance Work can be performed while the lines are energized using hot sticks. Figure 11-8 shows workers using fiberglass ***hot sticks*** to perform maintenance.

"Bare Hand Live-Line" Maintenance Proper bare hand live-line maintenance is where a person is placed in a conductive suit and touches energized transmission voltages, as shown in Figure 11-9. The person must not contact grounded objects. This is like a bird sitting on the wire. The ***conductive suit*** establishes a ZOE and thus eliminates current flow in the suit or human body. Since everything the person touches is at the same potential, no difference in potential exists, thus no current flows through the body. The person is safe from electrical shock. (Picture of author touching live 345 kV.)

De-Energized Equipment and Ground Jumpers

During de-energized conditions, workers apply ***ground jumpers*** to avoid dangerous potentials should the line become accidentally energized.

Figure 11-8 Live maintenance transmission lines.

Grounding equipment serves two purposes:

1) Grounding equipment being worked establishes a safe ZOE like substations. It provides a safe environment against "touch" and "step" potentials.
2) Grounding helps trip circuit breakers faster should the line or substation equipment become accidentally energized.

Figure 11-10 shows various grounding jumpers on a rack in a substation control building. Different clamps are provided depending on the equipment or wires being connected.

Working Distribution Safety

Like transmission line work, distribution line crews work under energized or de-energized conditions. Special safety procedures are mandatory in either situation. Distribution line crews work energized lines using ***rubber isolation equipment*** (PPE, rubber gloves and blankets) for voltages less than 34.5 kV. Figure 11-11 shows live line maintenance activities on a distribution system.

Figure 11-9 Bare hand live line maintenance.

Figure 11-10 Ground jumpers.

Figure 11-11 Live maintenance distribution.

Working distribution lines de-energized requires "ground jumpers" as discussed above.

Switching

Switching is the term used to change the configuration of the electric system or to provide equipment isolation for safe working activities, such as maintenance. Switching is required to open or close disconnect switches, circuit breakers, etc. for planned maintenance, emergency restoration, load transfer, and equipment isolation. Figure 11-12 shows a switching event in an energized substation. Switching requires careful control of all personnel and equipment involved. This control requires radio, phone, or visual communications always. Detailed ***tagging procedures*** are required to prevent others from unknowingly interfering with work activities. Switching can become very time consuming due to the repetitive nature of how switching orders are communicated and verified.

ARC Flash

Electrical ***arc-flash*** hazards are serious risks to worker safety. On the average, every day in the United States five to ten people are sent to special burn units due to arc-flash burns. The National Fire Prevention Association (NFPA) published

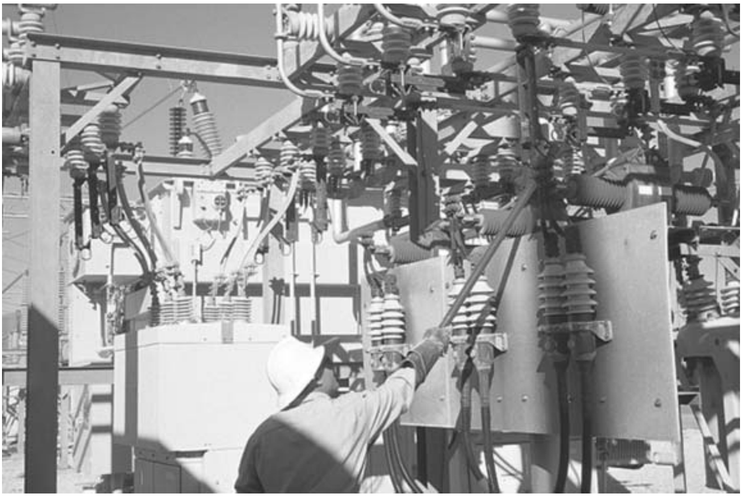


Figure 11-12 Live maintenance substations.

NFPA 70E®, the standard for Electrical Safety in the Workplace®, to document electrical safety requirements regarding arc-flash safety. 70E® defines specific rules for determining the category of electrical hazards and the PPE required for personnel working in defined and marked hazard zones or boundaries. OSHA enforces the NFPA arc-flash requirements under its "general rule" that a safe workplace must be maintained. These regulations force employers to review and modify their electrical systems and work procedures to reduce the arc-flash hazard and to improve worker awareness and safety.

Industry regulations and standards require the electrical equipment owner to do the following:

- Assess whether there are arc-flash hazards
- Calculate the energy released by the arc, if or when present
- Determine the flash protection boundaries
- Provide appropriate PPE for personnel working within the flash protection boundary
- Provide a safety program and training with clear responsibilities
- Provide suitable tools, in addition to PPE for a safe workplace
- Post equipment labels indicating the minimum protective distance, the incident energy level, and required PPE for that location

Employees too have an obligation to arc-flash safety. Employees must follow the requirements of arc-flash labeling by wearing proper PPE and using proper safety tools provided by their employer. Furthermore, they must not work on or near electrical circuits or equipment unless they are a "qualified" worker.

About the Arc

An arc flash is the light and heat produced from an electric arc when supplied with sufficient electrical energy that can cause substantial damage, harm, fire, and/or serious injury. Electrical arcs, when controlled, produce a very bright light and when controlled, can be used in arc lamps (having electrodes), welding, plasma cutting, and other industrial applications.

When an uncontrolled arc occurs at high voltages, arc flashes can produce deafening noises, supersonic concussive forces, superheated shrapnel, temperatures far greater than the sun's surface, and intense high-energy radiation capable of vaporizing nearby materials. Arc-flash temperatures can reach or exceed 35,000°F (19,400°C) at the arc terminals. The result of these violent events can cause destruction of equipment, fire, and injury not only to an electrical worker but also to bystanders. Figure 11-13 shows what happens after an arc-flash event.

Hazard Categories

NFPA 70E® describes ***hazard categories*** that consider human vulnerability factors and the capability of PPE clothing to protect humans exposed to arc-flash incidents. Thermal energy is rated in calories/cm^2 and is the reference used in arc-flash criteria. One calorie/cm^2 can be equal to holding your finger over the tip of a flame of a cigarette lighter for one second. Specifically, one calorie is the amount of heat needed to raise the temperature of one gram of water by 1°C.

Figure 11-13 Arc flash. IEEE Std 1584-2018/IEEE.

Furthermore, a second-degree burn requires approximately 1.2 cal/cm^2 for more than 1 second.

Below are the NFPA categories used in arc-flash rules and regulations. These categories correspond to the required PPE.

- Category 0 – Up to 1.2 cal/cm^2
- Category 1 – 1.2–4 cal/cm^2
- Category 2 – 4.1–8 cal/cm^2
- Category 3 – 8.1–25 cal/cm^2
- Category 4 – 25.1–40 cal/cm^2
- Over 40 cal/cm^2 – Unacceptable Risk

Protective Clothing and Equipment

PPE is the common term used for clothing and equipment to protect electrical workers while performing activities on or near energized equipment. Although similar, PPE for arc flash is different than PPE used for working around high-voltage equipment.

In the case of exposure to arc-flash hazards and depending on the hazard risk category (defined by NFPA), PPE is primarily made up of flame resistant (FR) clothing. FR clothing is the most common and industry accepted PPE to protect the body from burns due to flame. It is not, however, designed to isolate the worker from electrical contact. The beneficial characteristic of FR clothing is it will not continue to burn on its own when a flame source is removed. This protection is achieved by treating the fiber cloth with flame retardant "modacrylic" blended cottons.

Table 11-1 presents the FR PPE required for the various hazard/risk categories.

Table 11-1 Required Flame Retardant Clothing.

Hazard/Risk Category	Eye Protection, Ear Canal Inserts, Long Sleeve Shirt and Pants	Arc Rated Clothing	Face and Head Protection	Flash Suit Hood
0	✓			
1	✓	✓	✓	
2	✓	✓	✓	
3	✓	✓	✓	✓
4	✓	✓	✓	✓

Figure 11-14 Arc-flash clothing.

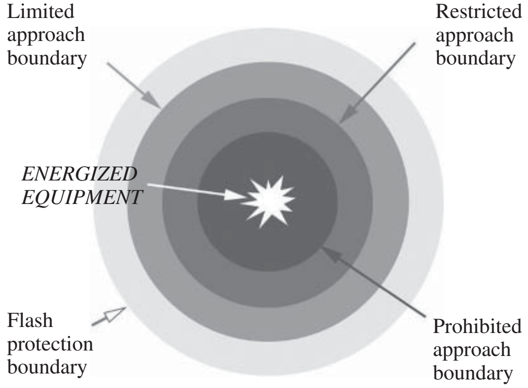
In most applications, clothing and PPE must be either FR rated or arc-flash rated. The electrical worker should never wear materials such as nylon and polyester that can melt and stick to skin. Note that non-FR-rated undergarments may catch fire even when arc rated clothing is worn overtop and survives an arc flash.

Some of this clothing and equipment appears to be bulky, restraining, and cumbersome. Manufacturers try hard to add flexibility, light weightiness, and durability in their FR clothing while meeting the strict arc-flash requirements. Figure 11-14 shows the clothing required for category 4 energy.

The arc rating of FR material is the maximum incident energy resistance demonstrated by a material prior to breaking open (a hole in the material) or to pass through and cause a second or third degree burn with 50% probability.

Arc rating is normally expressed in cal/cm^2 (or small calories of heat energy per square centimeter). The tests for determining arc rating are defined in ASTM F1506 Standard Performance Specification for Flame Resistant Textile Materials for Wearing Apparel for Use by Electrical Workers Exposed to Momentary Electric Arc and Related Thermal Hazards.

Figure 11-15 Arc-flash boundaries.



Approach Boundaries

Based on the hazard categories stated above and the PPE flame retardant capabilities, NFPA 70E® also stipulates four arc-flash approach boundaries that must be known and observed. Figure 11-15 shows these approach boundaries.

Flash Protection Boundary (Outer Boundary) is where a worker is exposed to a curable second degree burn if outside this boundary.

Limited Approach Boundary is the closest area an unqualified person can safely stand. Still requires PPE. A person must be qualified to go any closer.

Restricted Approach Boundary is the closest a qualified person can stand provided they have an approved plan for the work to be performed and it must be absolutely necessary to work in this area.

Prohibited Approach Boundary (Inner Boundary) is considered the same as contacting the energized part. Requires a qualified person with specific training to work on energized conductors, wearing appropriate PPE, and has a documented plan with justification.

As you can see, electrical workers are required to work safely using proper PPE for both electrical contact and arc-flash hazards. All industries have their hazards; the electrical industry has these two hazards (hence, electrical contact and arc flash). A safe working environment is provided when electrical workers are properly trained, use proper safety equipment, and have a proper understanding of all potential hazards before starting their work activities.

Electrical Safety Around the Home

Home safety also involves awareness of touch and step potentials and arc flash. Whether one is exposed to a dangerous touch or step potential in a substation

Figure 11-16 Safety at home.

Figure 11-17 GFCI always be vigilant about electrical safety at home!

or at home, the same circumstances exist, and the same precautions are necessary. As soon as the insulation around energized wires is compromised, dangerous touch and step potentials can exist. Plus, a bright arc-flash event can occur when frayed insulated conductors touch.

For example, worn extension cords can have exposed conductors that can cause 120 Vac touch potential hazards. All worn cords must be replaced. To compound the problem, water, moisture, metal objects, and faulty equipment can increase the possibility of injury from accidental contact. Everyone is vulnerable to electrical current, therefore, always be vigilant about electrical safety at home!

Figures 11-16 and 11-17 show how electrical safety starts at home.

Appendix A

The Derivation of Root Mean Squared

Since the average value of voltage or current in an ac sine wave is zero, the average value of each half of the sine wave is calculated and added together to determine its total effective average value. This total effective average value of an ac sine wave is referred to as root-mean-squared (RMS). RMS (usually shown as rms) has the same heating effect in resistive loads as dc. The process of finding the total effective average value of a sine wave is the method called ***root-mean-squared*** or ***rms.***

The rms value of voltage and current is shown in Figure A-1:

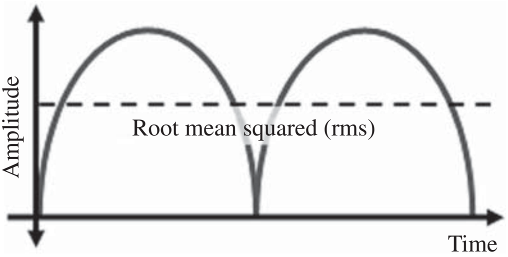


Figure A-1 Root mean squared.

Residential Voltage

The stated 120 Volt ac value of residential voltage is in rms. Furthermore, high-voltage distribution and transmission lines are also stated in rms. Note that multiplying the rms value by the square root of two produces what is known as the ***peak*** value. In the case of residential voltage, the peak value is 165 Vac. Multiplying this peak value by 2 results in the term called the ***peak-to-peak*** value. Peak-to-peak is the total magnitude measured of the sine wave as can be seen on an ***oscilloscope***. (An oscilloscope is a visual voltage measuring device.)

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Residential Voltage:

$$V_{rms} = 120\,\text{Vac}$$
$$V_{Peak} = 165\,\text{Vac}$$
$$V_{Peak-Peak} = 330\,\text{Vac}$$

Appendix B

Graphical Power Factor Analysis

Sometimes it is easier to understand the relationship between real and reactive power graphically. Basically, resistors dissipate energy in the form of heat while performing work functions. The power associated with resistive loads is expressed as ***watts***. The reactive power associated with capacitive and inductive loads are expressed as ***VARs***. Reactive power is ***watt-less*** power and does not contribute to real-work functions. Reactive power (VARs) is required in motors, transformers, and other ac functioning coils to produce magnetic fields. These magnetic fields are needed to make motor shafts spin. The real work done by motors is the load placed on its spinning shaft. The total power supplied to an inductive load such as a motor is watts plus VARs. However, adding these two quantities together requires the algebraic summation process (Pythagorean theorem).

One interesting fact that exists in ac power systems is that inductive VARs are opposite of capacitive VARs and can cancel each other out or leave a net difference. The graphical means of showing the relationship between real and reactive power associated with resistors, inductors, and capacitors are shown in Figure B-1:

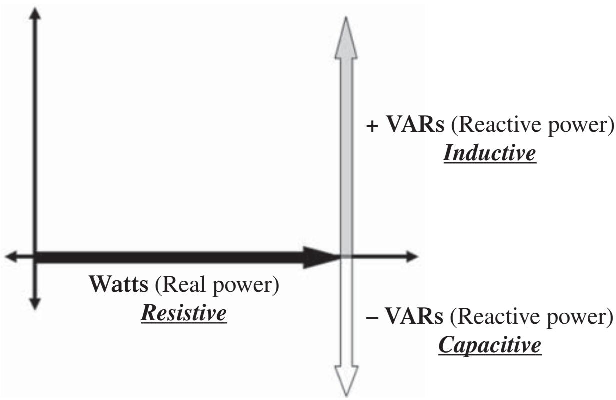

Figure B-1 Electrical power relationships.

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Note how inductive and capacitive VARs oppose each other and can cancel, yet resistive watts remains independent.

Figure B-2 shows the power triangle with capacitive VARs cancelling most of the inductive VARs. The result is net positive VARs or net inductive VARs. Not all inductive VARs were cancelled by capacitive VARs. The circuit remains inductive.

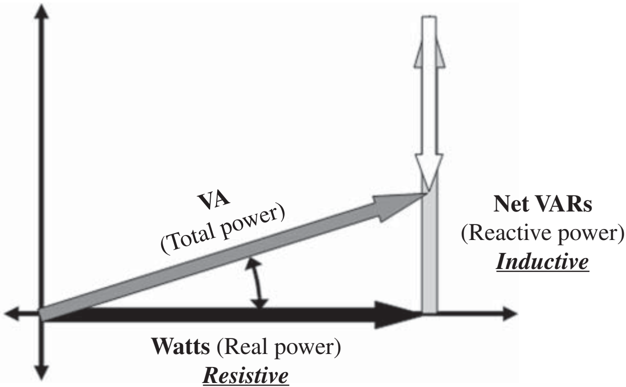

Figure B-2 Power triangle.

The hypotenuse ***VA*** represents ***total*** power; also referred to as ***apparent*** power. Referring to Figure B-3, ***total power*** or ***apparent power*** is peak voltage times peak current. ***Real power*** or ***true power*** is peak voltage times the current at the time of peak voltage. Note that for there to be a power factor angle, the current must lead or lag voltage.

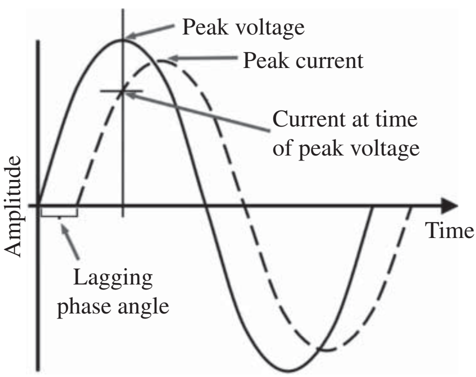

Figure B-3 Power VA.

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IEEE Standard C37.2 "Standard for Electrical Power System Device Function Numbers," 2008.

"NFPA 70E®", National Fire Prevention Association (NFPA), "The standard for Electrical Safety in the Workplace®," 2003.

"Standard Performance Specification for Flame Resistant Textile Materials for Wearing Apparel for Use by Electrical Workers Exposed to Momentary Electric Arc and Related Thermal Hazards," ASTM F1506, 2015.

IEEE Standard 2800-2022 "Standard for Interconnecting and Interoperability of Inverter Based Resources (IBR) Interconnecting with Associated Transmission Electric Power Systems.

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NERC Reliability Standard PRC-024-2 Generator Frequency and Voltage Protective Relay Settings.

Readers interested in more information on the topics presented in the book are encouraged to visit the NERC website: www.NERC.com and review the Electric Power Research Institute's (EPRI's) Power System Dynamics Tutorial.

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