CHAPTER 9

Centralized Electric Power Systems

9.1 Introduction

Those of us lucky enough to live in the industrialized world take for granted the truly remarkable power, literally at our fingertips, that we can access by simply flipping a switch. The lights go on, the air-conditioning keeps us cool, our food stays fresh in the refrigerator, the Internet gives us access to a treasure-house of information, our TVs entertain us. About the only time many of us pay any attention at all to the electric power grid that provides these amazing benefits is when it suddenly goes down and we're left sitting in the dark, in a building that begins to get too hot or too cold, worried about food spoiling in the fridge, and wondering how the next episode in our favorite TV series is going to come out.

The electricity infrastructure providing power to North America includes more than 275,000 miles of high-voltage transmission lines and 1000 gigawatts of generating capacity to serve a customer base of over 300 million people. Although the cost of constructing this infrastructure has been staggering—well over $1 trillion—its value is incalculable. Without it we could not even imagine having a modern economy. Managing that investment is a complex technical challenge that requires real-time control and coordination of tens of thousands of power plants to move electricity across a vast network of transmission lines and distribution networks to meet the exact, constantly varying, power demands of those customers.

Although this book is mostly concerned with alternatives to large, centralized power systems, we need to have some understanding of how these conventional systems work. This chapter explores the history of the utility industry; the physics and engineering that go into the generation, transmission, and distribution of electric power; and some of the regulatory issues involved in the buying and selling of electric power. In the next chapter, the alternative model of a grid based on smaller-scale, decentralized energy systems will be explored.

9.2 Electromagnetism: The Technology behind Electric Power

In the early nineteenth century, scientists such as Hans Christian Oersted, James Clerk Maxwell, and Michael Faraday began to explore the wonders of electromagnetism. Their explanations of how electricity and magnetism interact made possible the development of electrical generators and motors—inventions that have transformed the world.

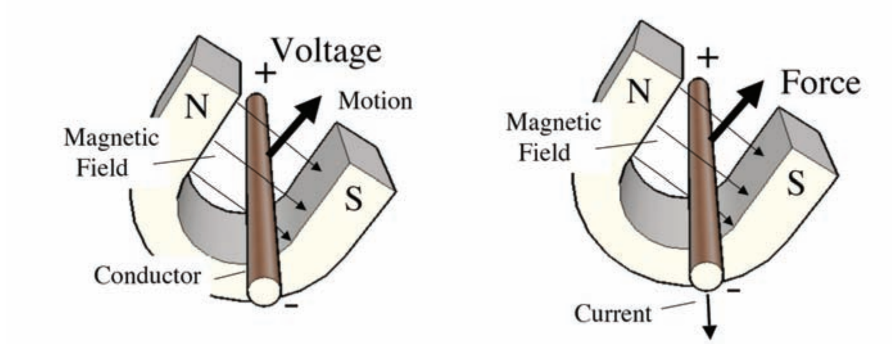
Early experiments demonstrated that a voltage (originally called an *electromotive force*, or *emf*) could be created in an electrical conductor by moving it through a magnetic field as shown in Figure 9.1a. Clever engineering based on that phenomenon led to the development of direct-current dynamos, and later to alternating-current generators. The opposite effect was also observed; that is, if current flows through a wire located in a magnetic field, the wire will experience a force that wants to move the wire as shown in Figure 9.1b. This is the fundamental principle by which electric motors are able to convert electric current into mechanical power.

Notice the inherent symmetry of the two key electromagnetic phenomena. Moving a wire through a magnetic field causes a current to flow, whereas sending current through a wire in a magnetic field creates a force that wants to move the wire. If this suggests to you that a single device could be built that could act as a generator if you applied force to it, or act as a motor if you put current into it, you would be absolutely right. In fact, the electric motors in today's hybrid-electric vehicles do exactly that. In normal operation the electric motor helps power the car, but when the brakes are engaged, the motor acts as a generator, slowing the car by converting the vehicle's kinetic energy into electrical current that recharges the vehicle's battery system.

A key to the development of electromechanical machines, such as motors and generators, was finding a way to create the required magnetic fields. The first *electromagnet* is credited to a British inventor, William Sturgeon, who, in 1825, demonstrated that a magnetic field could be created by sending current through a number of turns of wire wrapped around a horseshoe-shaped piece of iron. With that, the stage was set for the development of generators and motors.

The first practical direct-current (dc) motor/generator, called a dynamo, was developed by a Belgian, Zénobe Gramme. His device, shown in Figure 9.2, consisted of a ring of iron

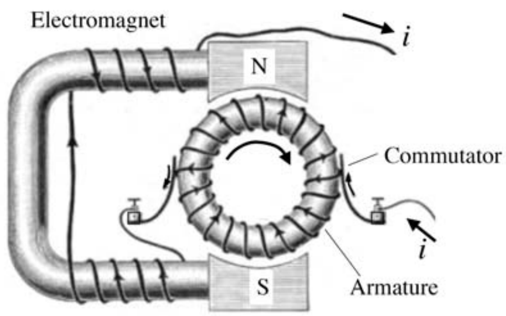
figure 9.1



(a) Motion creates voltage (b) Current creates force

The voltage created when an electrical conductor moves through a magnetic field is the basis for generators (a). The force created when current is passed through a conductor in a magnetic field is the basis for electric motors (b).

figure 9.2



Gramme's "electromotor" could operate as a motor or as a generator.

(the *armature*) wrapped with wire, which was set up to spin within a stationary magnetic field. The magnetic field was based on Sturgeon's electromagnet. The key to Gramme's invention was his method of delivering dc power to and from the armature using contacts (called a *commutator*) that rubbed against the rotating armature windings. Gramme startled the world with his machines at a Vienna Exposition in 1873. Using one dynamo to generate electricity, he was able to power another, operating as a motor, three-quarters of a mile away. The potential to generate power at one location and transmit it through wires to a distant location, where it could do useful work, stimulated imaginations everywhere. An enthusiastic American writer, Henry Adams, even proclaimed the dynamo as "a moral force" comparable to the European cathedrals in a 1900 essay called "The Dynamo and the Virgin."

9.3 Creating the Modern Electric Utility: Edison, Westinghouse, and Insull

Motors and generators quickly found application in factories; however, the first major electric power market developed around the need for illumination. Although many others had worked on the concept of electrically heating a filament to create light, it was Thomas Alva Edison who, in 1879, created the first workable incandescent lamp. Simultaneously he launched the Edison Electric Light Company, which was a full-service illumination company that provided not only the electricity but also the lightbulbs themselves. In 1882, his company began distributing power primarily for lights, but also for electric motors, from his Pearl Street Station in Manhattan. This was to become the first investor-owned utility in the nation.

There was a fatal flaw in Edison's electric utility. Edison's system was based on direct current, which he preferred in part because it provided flicker-free light but also because it enables easier speed control of dc motors. The downside of Edison's dc, however, was that it was generated at low voltage for safety, but at low voltages it is very difficult to move much power from one place to another without incurring unacceptably high losses in the power lines connecting the generators to the loads. Edison's customers, therefore, had to be located within just a mile or two of a generating station, which meant power stations were beginning to be located every few blocks around the city.

9.3.1 The Important Role of Transformers

To understand the difficulty that Edison faced, we need to review briefly some of the electricity concepts introduced in Chapter 4. As presented there, the power delivered by power lines is equal to the voltage of the lines times the current they deliver ($P = vi$). For example, suppose you want to transport 100,000 watts of power on a transmission line. Consider the choice between delivering 100 amps at 1000 volts (100 A × 1000 V = 100,000 W) versus delivering 10 amps at 10,000 volts (10 A × 10,000 V = 100,000 W). Is there any advantage to one over the other?

Recall that power losses in wires are equal to the square of the current times the resistance of the lines (i^2R losses). Suppose the connecting wires in this example have a resistance of 2 ohms, then the i^2R line losses at 100 A and 1000 V would be

$$\textbf{Line losses @ 1000 V} = 100^2 \times 2 = 20{,}000\ \text{W}$$

and the line losses at 10 A and 10,000 V would be

$$\textbf{Line losses @ 10,000 V} = 10^2 \times 2 = 200\ \text{W}$$

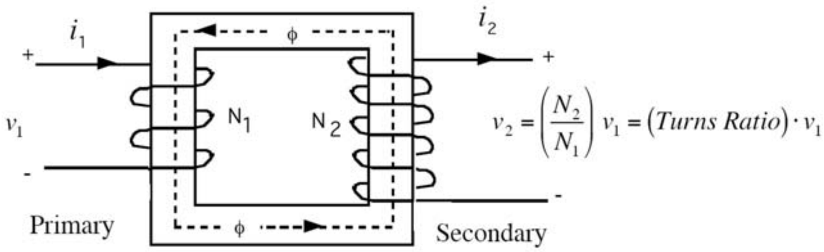
Notice that by increasing the voltage by a factor of 10, the line losses decrease by a factor of 100! At the lower voltage, 20% of the power would be lost in the connecting wires, whereas at the higher voltage line losses would be only 0.2%. Minimizing line losses is why modern transmission lines operate at such high voltages—some as high as 765 kV. Of course, such high voltages must be reduced to much lower levels for safe use in our homes and offices.

In Edison's day, the only way to change voltages conveniently was to take advantage of an 1883 invention called the *transformer*, which, unfortunately for Edison, works only on alternating current (ac). As shown in Figure 9.3, a simple transformer consists of an iron core with two sets of windings. As shown, the primary side of the transformer has N_1 turns of wire carrying current i_1, and the secondary side has N_2 turns carrying i_2. The change in voltage from the primary side to the secondary side is equal to the turns ratio, N_2/N_1.

9.3.2 The Battle between Edison and Westinghouse

Edison's mistake was that he placed his bet on dc power, but dc was unable to take advantage of the reduction in line losses that transformers could provide by increasing the voltage as it goes onto transmission lines and then decreasing it back again to safe levels at the customer's facility. Meanwhile, George Westinghouse recognized the advantages of ac for transmitting

figure 9.3



Transformers are very important in power systems because they can step up voltages to help reduce transmission line losses, and then step them down again for safe use by customers.

power over great distances and so in 1886 he launched a competing company based on ac power, called the Westinghouse Electric Company. Within just a few years, Westinghouse was making significant inroads into Edison's electricity market, and a bizarre feud developed between these two industry giants. Rather than hedge his losses by developing a competing ac technology, Edison stuck with dc and launched a campaign to discredit ac by condemning its high voltages as a safety hazard. To make the point, Edison began demonstrating its lethality by coaxing animals, including dogs, cats, calves, and eventually even a horse, onto a metal plate wired to a 1000-volt ac generator and then electrocuting them in front of the local press (Penrose, 1994).

The advantages of high-voltage transmission, however, were overwhelming and Edison's insistence on dc eventually led to the disintegration of his electric utility enterprise. Through buyouts and mergers, Edison's various electricity interests were incorporated in 1892 into the General Electric company, which shifted its focus from being a utility to manufacturing electrical equipment and end-use devices for utilities and their customers.

One of the first demonstrations of the ability to use ac to deliver power over large distances occurred in 1891 when a 106-mile, 30,000-volt transmission line began to carry 75 kW of power between Lauffen and Frankfurt, Germany. The first transmission line in the United States went into operation in 1890 using 3.3-kV lines to connect a hydroelectric station on the Willamette River in Oregon to the city of Portland, 13 miles away. Meanwhile, the flicker problem for incandescent lamps with ac was resolved by trial and error with various frequencies until it was no longer a noticeable problem. Surprisingly, it wasn't until the 1930s that 60 Hz finally became the standard in the United States. Some countries had by then settled on 50 Hz, and even today, some countries, such as Japan, use both.

9.3.3 Insull Develops the Business Side of Utilities

Another important player in the evolution of electric utilities was Samuel Insull. He is credited with having developed the business side of utilities. It was his realization that the key to making money was to find ways to spread the high fixed costs of facilities over as many customers as possible. One way to do that was to aggressively market the advantages of electric power, especially for use during the daytime to complement what was then the dominant nighttime lighting load. In previous practice, separate generators were used for industrial facilities, street lighting, streetcars, and residential loads, but Insull's idea was to integrate the loads so that he could use the same expensive generation and transmission equipment on a more continuous basis to satisfy them all. Because operating costs were minimal, amortizing high fixed costs over more kilowatt-hour sales results in lower prices, which creates more demand. With controllable transmission line losses and attention to financing, Insull promoted rural electrification, further extending his customer base.

With more customers, more evenly balanced loads, and modest transmission losses, it made sense to build bigger power stations to take advantage of economies of scale, which also contributed to decreasing electricity prices and increasing profits. Large, centralized facilities with long transmission lines required tremendous capital investments. To raise such large sums, Insull introduced the idea of selling utility common stock to the public.

Insull also recognized the inefficiencies associated with multiple power companies competing for the same customers, with each building its own power plants and stringing its own wires up and down the streets. The risk of the monopoly alternative, of course, was that without customer choice, utilities would charge whatever they could get away with. To counter that criticism, he helped establish the concept of regulated monopolies with established franchise territories and prices controlled by *public utility commissions* (PUCs). The era of regulation had begun.

9.4 Electric Power Infrastructure: Generation

The electric power industry in the United States is truly immense, worth more than a trillion dollars with sales that exceed $300 billion each year. About 40% of total U.S. primary energy is used to generate electricity, with about 70% of that coming from the combustion of fossil fuels. All of that combustion is responsible for three-fourths of the country's emissions of sulfur oxides (SO_x), one-third of its carbon dioxide (CO_2) and nitrogen oxides (NO_x), and one-fourth of particulate matter and toxic heavy metals emissions.

How is all that power generated; how does it get from one part of the country to another; and how does it make its way up and down every street in town to get to our homes, businesses, and factories? We'll break these questions into two parts: In this section and the next, we'll look at the power plants themselves. Then, in Section 9.6, we'll examine the grid that transports and distributes power to customers.

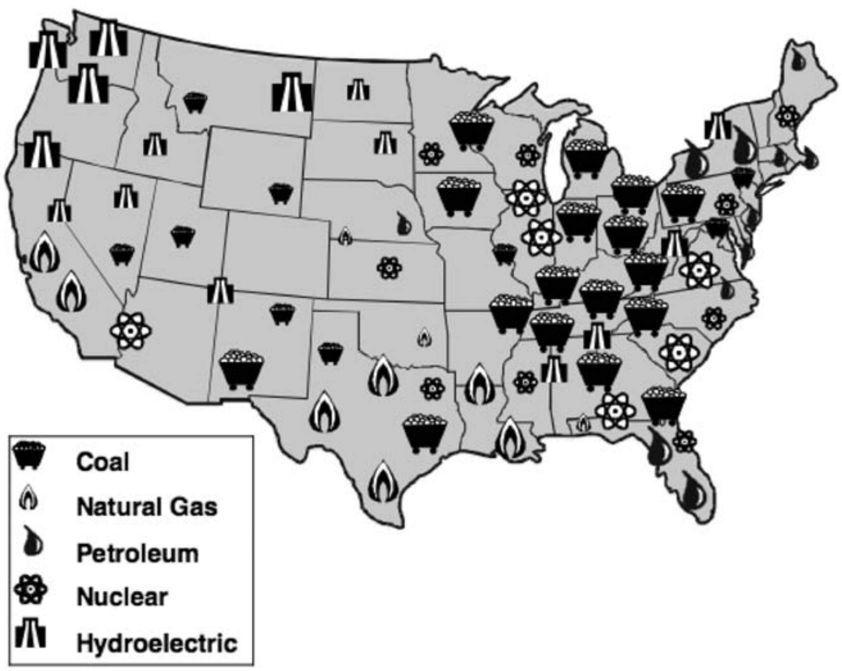
Power plants come in a wide range of sizes, run on a variety of fuels, and utilize a number of different technologies to convert fuels into electricity. Most electricity today is generated in large, central stations with power capacities measured in hundreds or even thousands of megawatts (MW). A single, large nuclear power plant, for example, generates close to 1000 MW (also described as one gigawatt, 1 GW). The total generation capacity of the United States is equivalent to roughly 1000 such power plants. At the other extreme are small-scale, distributed-generation technologies, such as fuel cells and microturbines, with rated capacities of several kilowatts. These will be described in the next chapter of this book.

Coal is the dominant fuel, accounting for 52% of all power plant input energy; nuclear is 21%; natural gas, 15%; and renewables (especially hydro and geothermal), 9%. Notice that petroleum is a very minor fuel in the electricity sector, only about 3%, almost all of which is residual fuel oil—literally the bottom of the barrel—that has little value for anything else.

The distribution of power plants based on fuel type is very uneven as Figure 9.4 suggests. The Pacific Northwest generates most of its power at large hydroelectric facilities owned by the federal government. Coal is predominant in the midwestern and southern states, especially Ohio, West Virginia, Kentucky, and Tennessee. The states of Texas, Louisiana, Oklahoma, and California derive significant fractions from natural gas, whereas what little oil-fired generation there is tends to be in Florida and New York.

Most large power plants, whether they are fueled by coal, natural gas, or even nuclear fission, use heat to boil water, which creates high-temperature, high-pressure steam. The steam expands as it passes through a steam turbine, which in turn powers a generator. These large steam plants tend to be *base-load* plants, which means they operate more or less continuously,

figure 9.4 **Energy Sources for Electricity Generation by Region**



Each large icon represents about 10 GW of capacity; small ones about 5 GW.

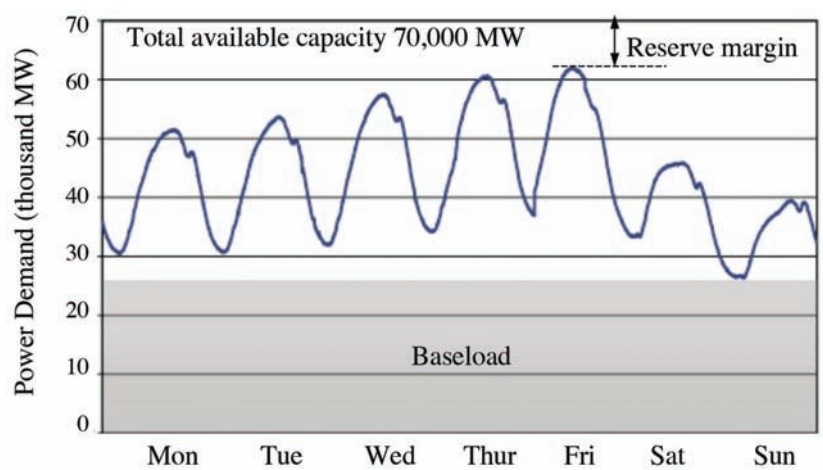
Source: from *The Changing Structure of the Electric Power Industry 2000: An Update* (EIA 2000) twenty-four hours a day, at relatively constant output. Base-load plants tend to be expensive to build, but cheap to operate, so they are economically most efficient when running as much of the time as possible. But, the mix of power demands for houses, commercial buildings, and industrial facilities, which a utility must supply, varies throughout the day. Figure 9.5 shows an example in which demand shows peaks during the day and valleys at night, along with reduced power demands on weekends.

The implications of Figure 9.5 are extremely important. It shows that power companies must have enough generating capacity to meet the highest peak demand (and then some to allow an adequate reserve margin), but many of those power plants will operate only part of the time during the day and be shut down at night. These are called *intermediate-load* and *peaking* power plants (or, just, *peakers*). Given this operating pattern, peakers tend to be plants that are cheap to build, but expensive to operate, which is just the reverse of large, base-load plants.

9.4.1 Conventional Coal-Fired, Steam Power Plants

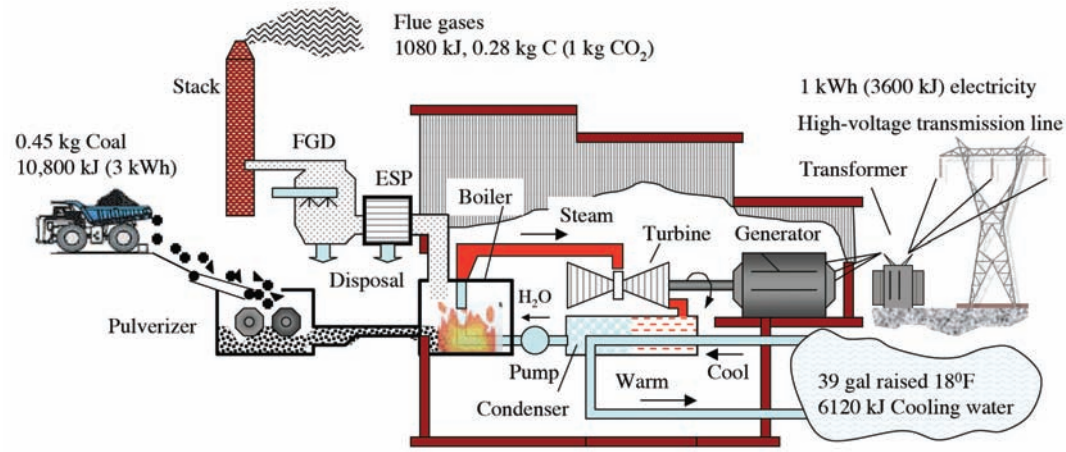
More than half of all of the electrical power generated in the United States is from pulverized-coal, steam power plants similar to the one shown in Figure 9.6. Finely pulverized coal is burned in a boiler, which, as the name implies, boils water to make high-temperature, high-pressure steam. Steam expanding in the blades of the turbine causes the turbine shaft to rotate, which spins the armature of a generator to make electric power. A transformer increases the generator output to the voltage needed for efficient power delivery on the high-voltage transmission lines. Back at the turbine, the expanded steam is condensed back to the liquid state by passing it over a heat exchanger carrying cooling water, usually taken from a local river, lake, or ocean. The condensed steam is returned to the boiler to continue the cycle.

figure 9.5



Power demand in the summer usually peaks in the afternoon. Base-load plants operate at nearly constant power all day long, whereas the output of intermediate and peaking power plants is adjusted to track the daily load pattern.

figure 9.6 **Essential Features in a Conventional Coal-Fired, Steam-Turbine Power Plant**



Numerical values correspond to a 33.3%-efficient plant generating 1 kWh of electricity. Carbon emissions are based on 24 MJ/kg coal with 62% carbon. Emission controls to be explained later include an electrostatic precipitator (ESP) and flue-gas desulfurization (FGD) system.

You might ask, Why bother to cool the steam in the condenser when you're just going to heat it up again to make new steam? That seems like a waste of energy: heating it, cooling it, and heating it back up all over again. There are several ways to think about this. For starters, we need to create a large pressure difference across the turbine to make it spin efficiently, which means we've got to get that spent steam out of the turbine to make room for the incoming steam. You might suggest simply exhausting the steam to the atmosphere, but that would waste a lot of water. Moreover, turbines are easily damaged by impurities in the steam, which means highly purified water has to be used to protect the blades, so we would spend a lot of money on water purification if we use the water only once. We avoid both of those problems by condensing the steam and reusing it. Also, by condensing the steam we create a slight vacuum on the exhaust side of the turbine, which helps create the higher pressure difference across the turbine mentioned above. Finally, in the next chapter we will learn that the maximum possible efficiency of heat engines like this depends on how cold the working fluid becomes in its cycle as well as how hot it gets. So cooling water and condensers are an essential part of the system.

A typical coal plant converts only about one-third the energy in its fuel into the desired output—that is, electricity. About 85% of the remaining two-thirds of the fuel's energy leaves the plant in the form of waste heat in the cooling water. The remainder is lost out the stack. Figure 9.6 includes an energy balance for such a plant along with an estimate of the carbon emissions and cooling water requirements. To generate one kilowatt-hour of electricity, about 1 pound of coal and 39 gallons of cooling water are required and about 1 kg of CO_2 will be emitted into the atmosphere.

The cooling water demands of a large 1000 MW power plant are enormous. Approximately 1 billion gallons of water per day are withdrawn, passed through the condenser, and returned to the source typically 10°C warmer than its initial temperature. When a source of figure 9.7 **Cooling Towers on the John Amos Coal-Fired Power Plant in West Virginia**

Source: U.S. Army Corps of Engineers

cooling water is not conveniently located relative to the plant, large cooling towers are often used, such as the ones shown in Figure 9.7. A portion of the cooling water sprayed into these towers evaporates, transferring heat directly into the atmosphere, leaving the remaining water cool enough to return to the condenser.

Almost two-thirds of the energy put into a conventional power plant ends up in cooling water, but it is at such a low temperature that it is fairly useless. This is one of the principle disadvantages of centralized power generation: there is just not much you can do with a lot of lukewarm water, especially when it is likely to be miles from any potential application. Conversely, it is one of the principle advantages of small-scale, decentralized systems that can generate electricity at the site of the end user who might be able to put that waste heat to work. Such *combined-heat-and-power* systems (CHP) will be explored in the next chapter.

9.4.2 Flue-Gas Emission Controls

Power plants, especially those that burn coal, emit a number of toxic pollutants, including oxides of sulfur (SO_x), oxides of nitrogen (NO_x), and particulate matter (as well as the main culprit responsible for global warming, CO_2). Figure 9.6 shows some of the emission-control devices that can help remove such pollutants from the flue gases. Flue gas from the boiler is

SIDEBAR

SIDEBAR 9.1

Using Fly Ash to Reduce Carbon Emissions from Cement Production

A surprisingly large fraction of global carbon emissions (about 6% to 7%) is attributable to the production of cement. Cement, mixed with water, is the binding agent that holds together sand and gravel aggregate to make concrete. To produce 1 ton of cement requires about 2 tons of limestone and clay or sand along with a lot of heat. In the process, about 1 ton of CO_2 is liberated, partly from the fuel needed to supply that heat and partly from the chemical reactions taking place (calcination):

$$\overbrace{\text{Limestone } (CaCO_3) + \text{Clay or Sand (Si)}}^{\text{2 tons material}} + \overbrace{\text{Heat}}^{\substack{6 \times 10^6 \text{ Btu} \\ 1500^\circ\text{C}}} \rightarrow \overbrace{\text{Cement}}^{\text{1 ton}} + \overbrace{CO_2}^{\text{1 ton}}$$

$$\left.\begin{array}{lccc} \text{Calcination:} & CaCO_3 & \rightarrow & CaO + CO_2 \\ \text{Energy:} & C_xH_y + O_2 & \rightarrow & H_2O + CO_2 \end{array}\right\} \text{Roughly half and half}$$

Fly ash from power plants can replace cement on a one-for-one basis, meaning that for every ton of fly ash used in concrete, a bit more than 1 ton of CO_2 emissions will be saved. The concrete that results, even when well over half of the cement has been replaced with fly ash, has been shown to be stronger and more durable than ordinary concrete. Saving carbon emissions as well as avoiding disposal costs of fly ash is gaining attention, but even so, less than 10% of the 650 million tons generated annually is currently being recycled this way.

often sent to an electrostatic precipitator (ESP), which adds a charge to the particulates in the gas stream so they can be attracted to electrodes that collect this fly ash. Fly ash is normally buried, but it has a much more useful application as a replacement for cement in concrete (see Sidebar 9.1). Next, a flue-gas desulfurization system (FGD, or *scrubber*), sprays a limestone slurry over the flue gases, precipitating the sulfur to form a thick calcium sulfite sludge that must be dewatered and either buried in landfills or reprocessed into useful gypsum.

Not shown in Figure 9.6 are emission controls for nitrogen oxides, NO_x. Nitrogen oxides have two sources. Thermal NO_x is created when high temperatures oxidize the nitrogen, N_2, in air. Fuel NO_x results from nitrogen impurities in fossil fuels. Some NO_x emissions reductions have been based on careful control of the combustion process rather than with external devices such as scrubbers and precipitators. More recently, *selective catalytic reduction* (SCR) technology has proven effective. The SCR in a coal station is similar to the catalytic converters used in cars to control emissions. Before exhaust gases enter the smokestack, they pass through the SCR where anhydrous ammonia reacts with nitrogen oxide and converts it to nitrogen and water.

Flue-gas emission controls are not only very expensive, accounting for upwards of 40% of the capital cost of a new coal plant, but they also drain off about 5% of the power generated by the plant, which lowers overall efficiency.

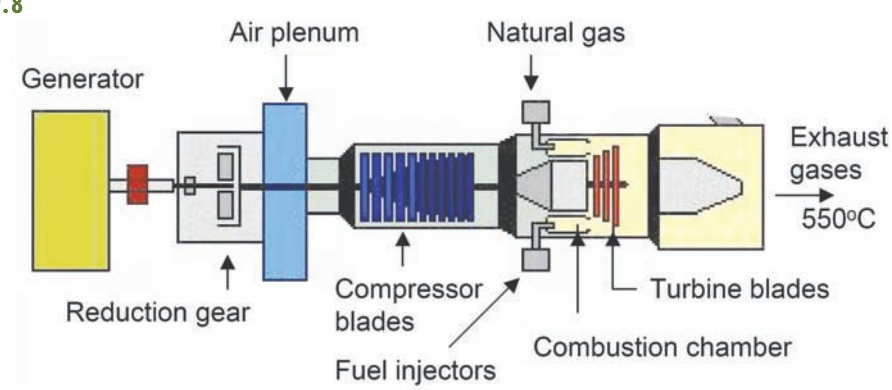
9.4.3 Combustion Gas Turbines

Natural gas as a fuel for power plants has many environmental advantages over the coal-fired power plants just described. It burns cleaner and it is much less carbon intensive. Rather than boiling water to make steam, most gas plants use a turbine similar to that of a jet engine. As shown in Figure 9.8, a simple gas turbine consists of three major components: a compressor, a combustion chamber, and a power turbine. In the compressor, air is drawn in, compressed, and accelerated to several hundreds of miles per hour as it enters the combustion chamber. In the combustion chamber, a steady stream of fuel (usually natural gas) is injected and ignited, creating a high-pressure, high-temperature gas stream that expands through the turbine blades. The expanding hot gases spin the turbine and are then exhausted to the atmosphere. The compressor and turbine share a connecting shaft, so that a portion, typically more than half, of the rotational energy created by the spinning turbine is used to power the compressor. That shaft is also connected to the generator, which produces the desired electrical power output.

Gas turbines have long been used in industrial applications and as such were designed strictly as stationary power systems. These industrial gas turbines tend to be large machines made with heavy, thick materials whose thermal capacitance and moment of inertia reduce their ability to adjust quickly to changing loads. These workhorses tend to have relatively low efficiencies in the 20% to 30% range.

A newer style of gas turbine takes advantage of the billions of dollars of development work that has gone into designing lightweight, compact engines for jet aircraft. The thin, light, super-alloy materials used in these *aeroderivative turbines* enable fast starts and quick acceleration, so they easily adjust to rapid load changes and numerous start-up/shut-down events. Their small size makes it easy to fabricate the complete unit in the factory and ship it to a site, thereby reducing field installation time and cost. Their 30% to 40% efficiency makes them typically more efficient than their industrial counterparts.

figure 9.8 **A Simple-Cycle, Natural-Gas-Fired Gas Turbine**



9.4.4 Combined-Cycle Power Plants

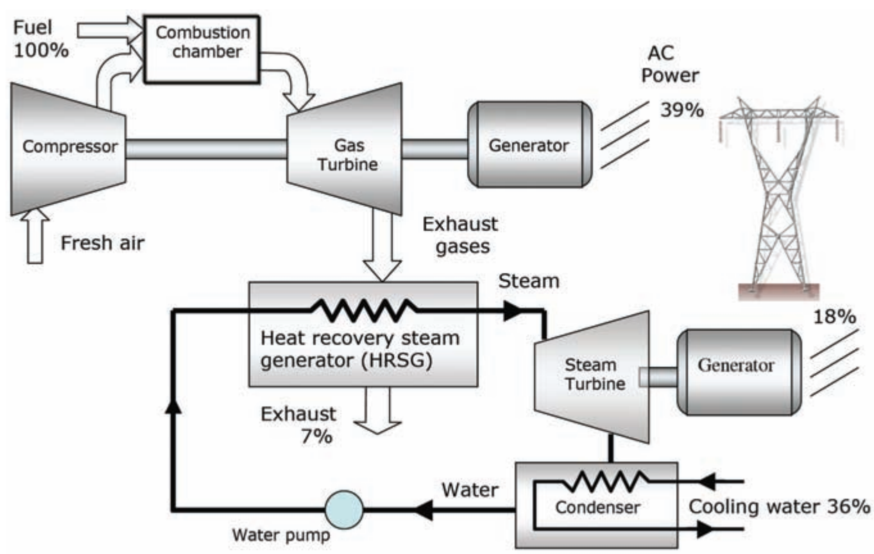
Notice the temperature of the gases exhausted into the atmosphere in the simple-cycle gas turbine shown in Figure 9.8 is over 500°C. Clearly that is a tremendous waste of high-quality heat that could be captured and put to good use. One way to do so is to pass those hot gases through a heat exchanger to boil water and make steam. The heat exchanger is called a heat-recovery-steam-generator (HRSG) and the resulting steam can be put to work in a number of applications, including industrial process heat or water and space heating for buildings. Of course, this combined heat-and-power (CHP) operation is viable only if the gas turbine is located very close to the site where its waste heat can be utilized.

Why not use the steam generated in an HRSG to power a second-stage steam turbine to generate more electricity? That is precisely what is done in a new generation of high-efficiency natural-gas-fired power plants called *combined-cycle* plants. An example of how a gas turbine can be coupled with a steam turbine is shown in Figure 9.9. Working together, such combined-cycle plants have achieved fuel-to-electricity efficiencies approaching 60%.

9.4.5 Integrated Gasification Combined-Cycle (IGCC) Power Plants

With combined-cycle plants achieving such high efficiencies, and with natural gas being an inherently cleaner fuel, the trend in the United States has been away from building new coal-fired power plants. Coal, however, is a much more abundant fuel than natural gas, but in its

figure 9.9



Combined-cycle power plants have achieved efficiencies approaching 60%.

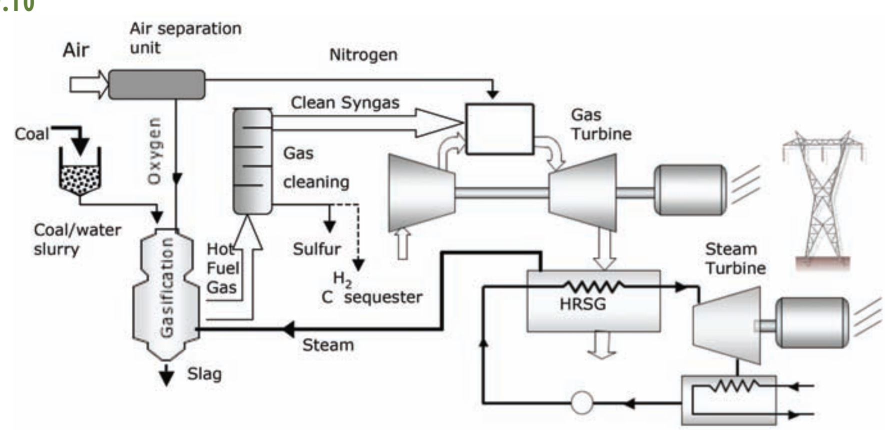
conventional, solid form, it cannot be used in a gas turbine. Erosion and corrosion of turbine blades due to impurities in coal would quickly ruin a gas turbine. However, coal can be processed to convert it into a synthetic gas, which can be burned in what is called an *integrated gasification, combined-cycle* (IGCC) power plant.

Gas derived from coal, called "town gas," was popular in the late 1800s before the discovery of large deposits of natural gas. One hundred years later, coal's air pollution problems prompted the refinement of technologies for coal gasification. Several gasification processes have been developed, primarily in the Great Plains Gasification Plant in Beulah, North Dakota, in the 1970s and later in the 100 MW Cool Water project near Barstow, California, in the 1980s. These early experimental facilities established the technical foundations for future, more commercially viable, IGCC plants.

As shown in Figure 9.10, the essence of an IGCC consists of bringing a coal-water slurry into contact with steam to form a fuel gas consisting mostly of carbon monoxide (CO) and hydrogen (H_2). The fuel gas is cleaned up, removing most of the particulates, mercury, and sulfur, and then burned in the gas turbine. Air used in the combustion process is first separated into nitrogen and oxygen. The nitrogen is used to cool the gas turbine and the oxygen is mixed with the gasified coal, which helps increase combustion efficiency. Despite energy losses in the gasification process, by taking advantage of combined-cycle power generation an IGCC can burn coal with an overall thermal efficiency of around 45%. This is considerably higher efficiency than conventional pulverized coal plants, but still far below the best 60%-efficient combined-cycle natural-gas plants.

IGCC plants are more expensive than pulverized coal plants and they have trouble competing economically with natural-gas-fired combined-cycle plants. As of 2007, there were only four IGCC plants in the world—two in Europe and two in the United States. One of the U.S. plants is located on the Wabash River in Indiana; the other is a newer, state-of-the-art plant near Tampa, Florida. Several others are in the planning stage, including a proposed 1200 MW plant that American Electric Power (AEP) hopes to build somewhere along the Ohio River. Rising and

figure 9.10 **An Integrated Gasification, Combined-Cycle (IGCC) Power Plant**



uncertain future natural gas prices, coupled with the potential to remove carbon in the syngas before it is burned, have reignited interest in IGCC plants. They enjoy significant political support and so are likely to grow in importance in our future electricity mix.

9.4.6 IGCC with Carbon Sequestration

Coal is the most carbon-intense fossil fuel, and it is also the most abundant. If we continue to rely on coal to satisfy most of the world's growing electric power demands, and if we don't control its carbon emissions, our global climate future is indeed precarious.

Table 9.1 presents estimates of the energy content of the world's remaining fossil-fuel resources divided into conventional sources of the type now being exploited, as well as unconventional sources such as oil shale, tar sands, and heavy crude that might be developed in the future. Also shown is an average value of the *carbon intensity* of each fuel (carbon per unit of energy). The product of the resource base times the carbon intensity gives us an estimate of the carbon that would be released if the entire resource were to be consumed. As can be seen, the total carbon content of coal is triple the combined carbon content of oil and gas.

The final column in Table 9.1 converts the carbon emission potential of each fuel into the added CO_2 that would accumulate if half of the carbon emitted remains in the atmosphere (that ratio is called the *airborne fraction*). By these estimates, burning all of the world's coal could triple the CO_2 concentration in the atmosphere from the current 380 ppm to 1144 ppm (380 + 764).

The most promising way to control carbon emissions from coal-fired power plants is based on the IGCC design shown in Figure 9.10. By first converting coal to a syngas in an IGCC plant, it is possible to design the gas-cleaning stage in such a way that the carbon in the fuel gas can be extracted before combustion. By doing so, it may be possible to build "clean coal" power plants that would be able to take advantage of the relative abundance of coal without contributing to global warming. If a carbon sequestration technology could be developed to store that carbon in perpetuity, it may be possible to envision a future with carbon-free, high-efficiency, coal-fired power plants capable of supplying clean electricity for several centuries into the future.

table 9.1 **Fossil-fuel resource estimates, low-heating-value (LHV) carbon intensity, and potential additions to global atmospheric CO_2 if the resource is totally consumed and half of its carbon remains in the atmosphere. Burning all of our coal could triple atmospheric CO_2.**

Fuel	Conventional resources (Exajoules)	Unconventional resources (Exajoules)	Total resource base (Exajoules)	Carbon intensity (Gton C/EJ)	Carbon potential (Gton C)	Add'l CO_2 at 50% AF (ppm CO_2)
Natural gas	9,200	26,900	36,100	0.0150	542	128
Petroleum	8,500	16,100	24,600	0.0200	492	116
Coal	25,200	100,300	125,500	0.0258	3,238	764

Source: based on Nakicenovic, 1996

The key, of course, is finding a way to store all of that carbon, essentially forever. At present there are some carbon sequestration processes underway, but those involve capturing CO_2 and injecting it into oil fields to enhance oil recovery. The injected CO_2 helps push more oil out of the source rock far below the surface. Of course, when that oil is burned, more CO_2 is added back into the atmosphere.

More promising is permanent CO_2 storage in geologic formations such as deep brine aquifers. Such formations consist of highly porous rock, similar to those containing oil and gas, but without the hydrocarbons that produced our fossil fuels. Instead, they are filled with water containing high concentrations of salts dissolved out of the surrounding rocks. When these formations are capped with impermeable rock they might be viable for CO_2 sequestration for the indefinite future.

9.4.7 Nuclear Power

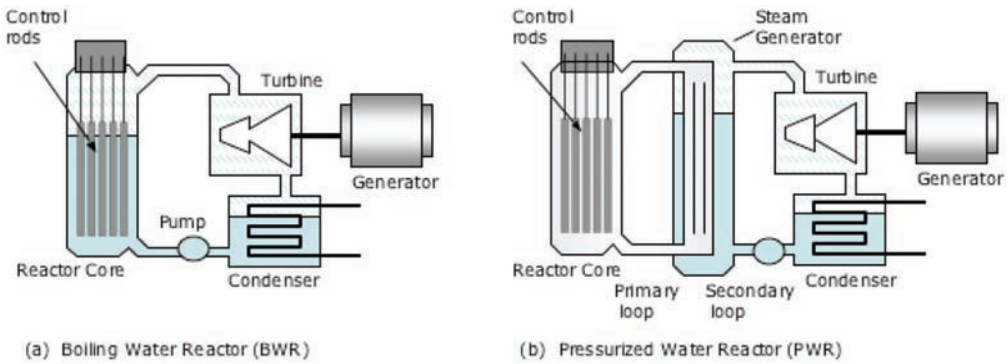
Nuclear power has had a rocky history, leading it from its glory days in the 1970s as a technology thought to be "too cheap to meter," to a technology that in the 1980s some characterized as "too expensive to matter." The truth is probably somewhere in the middle. It does have the advantage of being a carbon-free source of electric power, so it is beginning to enjoy a resurgence of interest. Whether a new generation of cheaper, safer reactors can overcome public misgivings over where to bury radioactive wastes and how to keep plutonium from falling into the wrong hands, remains to be seen.

The essence of nuclear reactor technology is basically the same simple steam cycle described for fossil fueled power plants. The main difference is the heat is created by nuclear reactions (see section 4.7.2 of this book) instead of fossil fuel combustion.

Light water reactors. Water in a reactor core not only acts as the working fluid, it also serves as a *moderator* to slow down neutrons ejected when uranium fissions. In *light water reactors* (LWRs), ordinary water is used as the moderator. Figure 9.11 illustrates the two principle types of LWRs. *Boiling water reactors* (BWRs) make steam by boiling water within the reactor core itself, whereas in *pressurized water reactors* (PWRs) a separate heat exchanger, called a steam generator, is used. PWRs are more complicated, but they can operate at higher temperatures than BWRs and hence are somewhat more efficient. PWRs can be somewhat safer because a fuel leak would not pass any radioactive contaminants into the turbine and condenser. Both types of reactors are used in the United States, but the majority are PWRs.

Heavy water reactors. Reactors commonly used in Canada use heavy water; that is, water in which some of the hydrogen atoms are replaced with deuterium (hydrogen with an added neutron). The deuterium in heavy water is more effective in slowing down neutrons than ordinary hydrogen. The advantage in these Canadian deuterium reactors (commonly called CANDU) is that ordinary uranium as mined, which contains only 0.7% of the fissile isotope U-235, can be used without the enrichment that LWRs require.

figure 9.11 **The Two Types of Light Water Reactors Commonly Used in the United States**



High-temperature, gas-cooled reactors (HTGR). HTGRs use helium as the reactor core coolant rather than water, and, in some designs, it is helium itself that drives the turbine. These reactors operate at considerably higher temperatures than conventional water-moderated reactors, which means their efficiencies can be higher—upwards of 45% rather than the 33% that typifies LWRs.

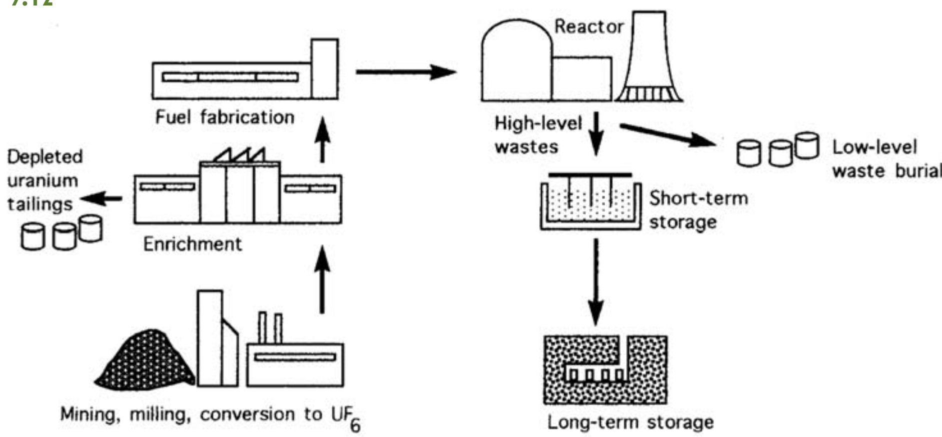
There are two HTGR concepts under development: the Prismatic Fuel Modular Reactor (GT-MHR) based on German technology and the Modular Pebble Bed Reactor (MPBR), which is being developed in South Africa. Both are based on microspheres of fuel, but differ in how they are configured in the reactor. The MPBR incorporates the fuel microspheres in carbon-coated balls ("pebbles") roughly 2 inches in diameter. One reactor will contain close to half a million such balls. A potential advantage of pebble reactors is that they could be refueled continuously by adding new balls and withdrawing spent-fuel balls without having to shut down the reactor.

The nuclear fuel "cycle." The costs and concerns for nuclear fission are not confined to the reactor itself. Figure 9.12 shows current practice from mining and processing of uranium ores, to enrichment that raises the concentration of U-235, to fuel fabrication and shipment to reactors. Highly radioactive spent fuel removed from reactors these days sits on-site in short-term storage facilities while we await a longer-term storage solution such as the underground federal repository planned for Yucca Mountain, Nevada. Eventually, after forty years or so, the reactor reaches the end of its useful lifetime. At that point, it will have to be decommissioned, and its radioactive components will also have to be transported to a secure disposal site.

Reactor wastes contain not only fission fragments formed during the reactions, which tend to have half-lives measured in decades, but also include some radionuclides with very long half-lives. Of major concern is plutonium, which has a half-life of 24,390 years. Only a few percent of the uranium atoms in reactor fuel are the fissile isotope U-235, whereas essentially all of the rest are U-238, which does not fission. Uranium-238 can, however, capture a neutron and be transformed into plutonium as the following reactions suggest:

Eq. 9.1
$$^{238}_{92}\mathrm{U} + \mathrm{n} \rightarrow {}^{239}_{92}\mathrm{U} \xrightarrow{\beta} {}^{239}_{93}\mathrm{Np} \xrightarrow{\beta} {}^{239}_{94}\mathrm{Pu}$$

figure 9.12 A Once-Through Fuel System for Nuclear Reactors



This plutonium, along with several other long-lived radionuclides, makes nuclear wastes dangerously radioactive for tens of thousands of years, which greatly increases the difficulty of providing safe disposal. Removing the plutonium from nuclear wastes before disposal has been proposed as a way to shorten the decay period, but that introduces another problem. Plutonium not only is radioactive and highly toxic, it is also the critical ingredient in the manufacture of nuclear weapons. A single nuclear reactor produces enough plutonium each year to make dozens of small atomic bombs and some have argued that if the plutonium is separated from nuclear wastes the potential of illicit diversions for such weapons would cause an unacceptable risk.

On the other hand, the plutonium is a fissile material, which, if separated from the wastes, can be used as a reactor fuel. Indeed, France, Japan, Russia, and the United Kingdom have reprocessing plants in operation to capture and reuse that plutonium. In the United States, however, Presidents Ford and Carter considered the proliferation risk too high and commercial reprocessing of wastes has ever since not been allowed. Moreover, a recent major study of nuclear power at MIT recommends that reprocessing continue to not be pursued (Sidebar 9.2). Figure 9.13 shows the nuclear fuel cycle including the controversial reprocessing steps.

9.5 Economics of Centralized Power Plants

With such a range of generation technologies to choose from, how should a utility, or society in general, make decisions about which to use? An economic analysis is usually the basis for comparison. Costs of construction, fuel, operations and maintenance (O&M), and financing are crucial factors. Some of these can be straightforward engineering and accounting estimates and others, such as the future cost of fuel and whether there will be a carbon tax and if so, how much and when, require something akin to a crystal ball. Even if these cost estimates can be agreed upon, there are other costs, called *externalities*, that society must bear

SIDEBAR

SIDEBAR 9.2

The Interdisciplinary MIT Study on the Future of Nuclear Power

In July 2003, a distinguished team of researchers from the Massachusetts Institute of Technology and Harvard released one of the most comprehensive, interdisciplinary studies ever conducted on the future of nuclear energy. Their findings and recommendations were heavily influenced by the need for carbon-free sources of power.

They believe there are only four realistic options for reducing CO_2 emissions from electricity generation in the next few decades, and that all four need to be pursued:

1. Increased efficiency in generation and use
2. Expanded use of renewable energy sources such as wind, solar, and geothermal
3. Carbon sequestration, especially from coal-fired power plants
4. Increased use of nuclear power

They identify four unresolved problems that limit today's prospects for nuclear power:

1. *Costs:* Nuclear power has higher overall lifetime costs compared to coal and combined-cycle natural gas, at least in the absence of a carbon tax. To be competitive, capital costs, operations and maintenance costs, construct time, and financing costs all need to be reduced.
2. *Safety:* The Three Mile Island and Chernobyl nuclear accidents, growing concern for the security of nuclear facilities from terrorist attack, and risks associated with transporting nuclear materials have adversely affected public perception.
3. *Proliferation:* Spread of nuclear weapons either by theft when wastes are reprocessed to extract plutonium, or by misuse of nuclear technologies for weapons production by countries developing their own reactor programs.
4. *Waste:* Unresolved challenges in long-term management of radioactive wastes.

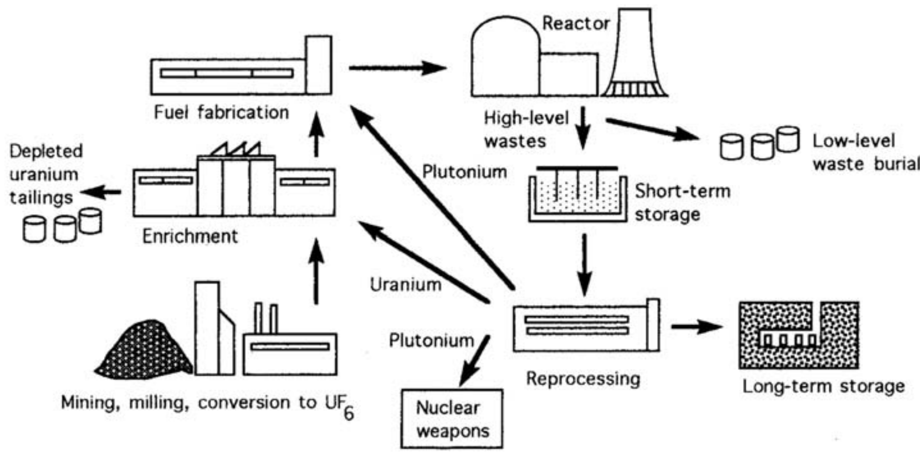
They recommend that priority be given to the deployment of the once-through fuel cycle, rather than the development of the more expensive, greater proliferation risk, closed-fuel-cycle technology involving reprocessing.

that are not usually included in such calculations, such as health care and other costs of the pollution produced. Other complicating factors include the vulnerability we expose ourselves to with large, centralized power plants, transmission lines, pipelines, and other infrastructure that may fail due to natural disasters, such as hurricanes and earthquakes, or less-natural ones, due to terrorism or war.

9.5.1 Cost Per Kilowatt-Hour

In concept, figuring out the cost of electricity from a power plant is simple. Just figure out the annual cost of owning and operating the power plant and divide that by the annual number of kilowatt-hours of electricity generated.

figure 9.13 Nuclear Fuel Cycle with Reprocessing



In its simplest form, the cost of electricity from a power plant can be expressed in terms of *fixed costs* that are incurred whether or not the power plant ever runs, and *variable costs* that depend on how much energy the plant actually generates. Fixed costs include money that has to be spent every year to pay for construction financing, return on debt and equity, insurance, taxes, depreciation, and routine O&M needed whether or not the plant is operated. Variable costs associated with running the plant consist mostly of fuel costs and production-related O&M. When both fixed and variable costs are expressed as $/year amounts, they can be combined to determine the annual cost of owning and operating the power plant.

Fixed costs can be annualized by multiplying the capital cost of the plant by a quantity known as the *fixed charge rate* (FCR):

Eq. 9.2 **Annual fixed costs ($/yr) = Capital cost ($) × FCR (%/yr)**

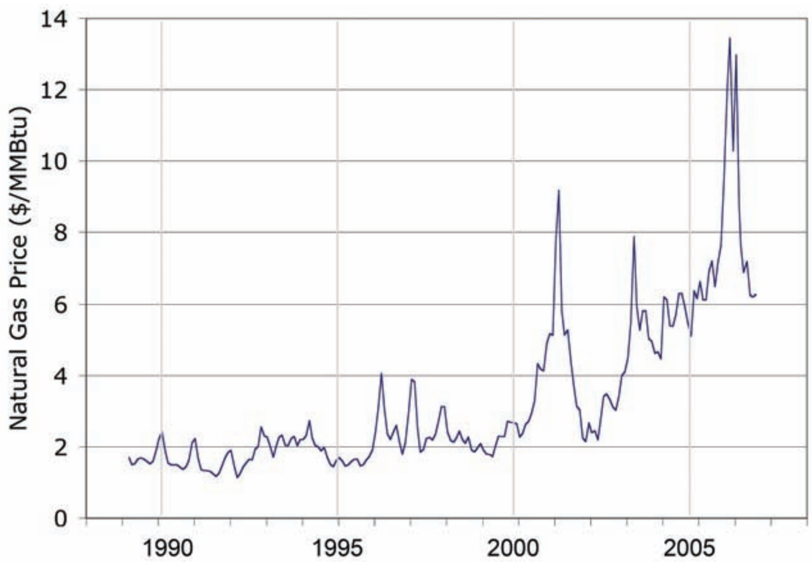
The FCR typically ranges between 11% and 18% per year, depending mostly on the cost of capital, which in turn is a function of current economic conditions, and the perceived risk and O&M for a particular technology.

Variable costs depend on the power plant efficiency, the price of fuel, operations-related O&M, and how much the plant actually runs.

Power plant efficiency in the United States is often described in terms of a *heat rate*, which is the number of Btus needed to generate 1 kWh of electricity; the smaller the heat rate, the higher the efficiency. For example, a new pulverized coal plant may have a heat rate of about 9300 Btu/kWh whereas an advanced combined-cycle natural gas plant heat rate can be down around 6000 Btu/kWh.

Fuel costs in these calculations should be levelized to account for the varying price of fuel over the life of the power plant. This, of course, gets pretty tricky. As an indication of the volatility of fuel prices, consider the twenty-year variation in natural gas prices shown in Figure 9.14.

figure 9.14 Twenty Years of Natural Gas Prices at Henry Hub, Louisiana



The energy delivered by a power plant can be described by its *rated power*, P_R, which is the power it delivers when operating at full capacity, and its *capacity factor* (CF), which is the ratio of the actual energy delivered by a power plant to the energy that would have been delivered if the plant ran continuously at full rated power. Assuming rated power in kW, annual energy in kWh, and 24 hours/day × 365 days/year = 8760 hours in a year, the annual energy delivered by a power plant is given by

Eq. 9.3 $$\textbf{Annual energy (kWh/yr)} = P_R\ \textbf{(kW)} \times \textbf{8760 hr/yr} \times \textbf{CF}$$

Solution Box 9.1 shows how to combine costs and energy production to estimate the average cost of electricity generated.

If we repeat the calculations shown in Solution Box 9.1, while varying the capacity factor and the cost of fuel, we can easily derive the graph shown in Figure 9.15. At 2007 prices for natural gas at around $7/MMBtu, with a high capacity factor, electricity from an NGCC can cost a little less than 6¢/kWh. If the trends shown in Figure 9.14 are any indication, however, a levelized cost of natural gas of more like $10/MMBtu seems likely and the cost of electricity from an NGCC plant rises above 8¢/kWh.

9.5.2 Comparison of Costs for Generation Technologies

Some technologies, such as coal and nuclear plants, tend to be expensive to build and cheap to operate, so they make sense only if they run almost all of the time. Others, such as gas

SOLUTION

SOLUTION BOX 9.1

The Cost of Electricity for a Natural Gas, Combined-Cycle Plant

What is the cost of energy (COE) for a natural gas, combined-cycle (NGCC) power plant using the following cost factors?

Capital cost:	\$500/kW
Fixed charge rate:	14.8%/year
Average heat rate:	7000 Btu/kWh
Levelized fuel/O&M cost:	\$7.00 per million Btu (\$7.00/MMBtu)
Capacity factor:	0.85

Solution:

For simplicity, let's assume the rated power of the plant is just 1 kW:

$$\textbf{Annualized capital cost} = 1\ \text{kW} \times \$500/\text{kW} \times 0.148/\text{yr} = \$72.40/\text{yr}$$

$$\textbf{Annual energy produced} = 1\ \text{kW} \times 8760\ \text{hr/yr} \times 0.85 = 7446\ \text{kWh/yr}$$

$$\textbf{Fuel/O\&M} = 7446\ \text{kWh/yr} \times 7000\ \text{Btu/kWh} \times \$7/10^6\ \text{Btu} = \$364.85/\text{yr}$$

$$\textbf{Total annual costs} = \$72.40 + \$364.85 = \$437.25$$

$$\textbf{Cost of electricity} = \frac{437.25/\text{yr}}{7446\ \text{kWh/yr}} = \$0.059/\text{kWh} = 5.9¢/\text{kWh}$$

(Notice that the final cost of electricity does not depend on having chosen a 1 kW plant.)

turbines, are just the opposite: cheap to build and expensive to operate, so they are better used as peakers (recall Figure 9.5). An economically efficient power system will include a mix of power plant types appropriate to the variation in power demand from day to day and from month to month.

An example of the cost of energy for four types of power plants is shown in Figure 9.16. Costs for simple combustion turbine (CT), a pulverized coal plant (coal), a natural gas combined-cycle (NGCC), and an estimate for the cost of a new nuclear power plant, are compared. As can be seen, for this example CT is the least expensive option as long as it runs fewer than about 1500 hours/year (CF < 0.17), which means it is very appropriate for a peaking power plant that operates only a few hours each day. The coal plant is most cost-effective when it runs at least 3700 hours/year (CF > 0.38), which means it should be a base-load plant operating almost all of the time. The NGCC is least expensive when it runs between 1500 and 3700 hours/year, which means it is most appropriate as an intermediate-load power plant.

figure 9.15 Sensitivity Analysis for the Natural Gas, Combined-Cycle (NGCC) Power Plant of Solution Box 9.1

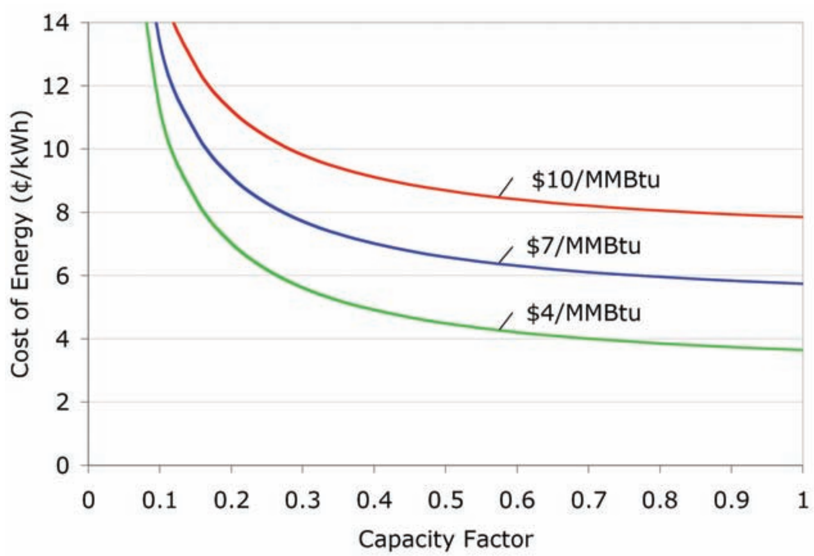
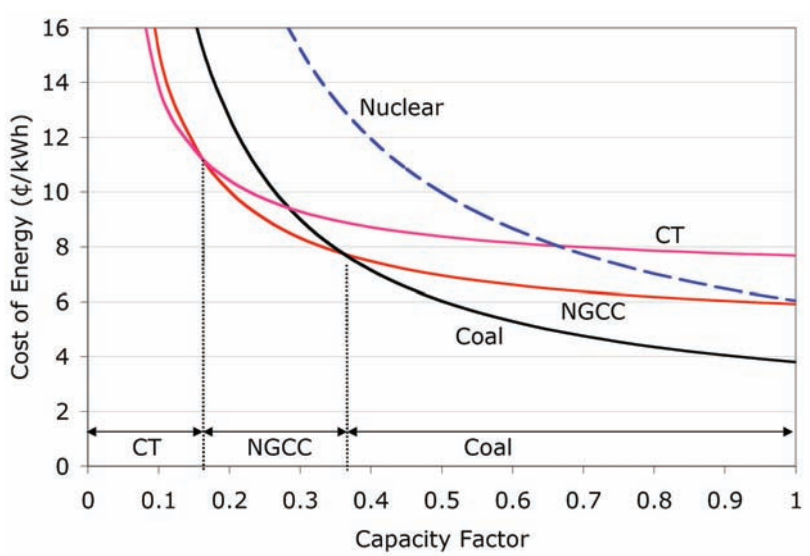


figure 9.16



The least expensive power technology depends on its capacity factor. For this example, CT is the least expensive for CF < 0.17; coal is least for CF > 0.38; in between NGCC is the least expensive option. Assumptions: FCR = 15%, gas @ $7.00/MMBtu; CT $400/kW, 10,000 Btu/kWh; NGCC $600/kW, 7000 Btu/kWh; Coal $1300/kW, 9300 Btu/kWh, $1.70/MMBtu; Nuclear $2300/kW, 10,500 Btu/kWh, $2.00/MMBtu.

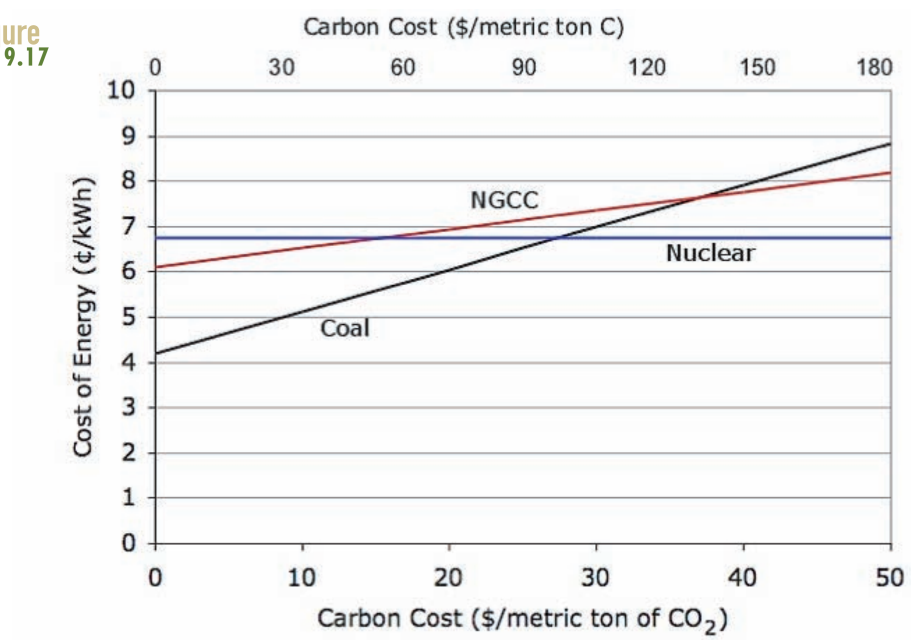
Under the assumptions given in Figure 9.16, nuclear power is not competitive. However, if society institutes a carbon tax that penalizes coal and gas plants, the situation could change. Figure 9.17 shows the implications of adding a cost of carbon emissions to the coal, NGCC, and nuclear plants analyzed in Figure 9.16. With carbon emissions costing more than \$28 per metric ton of CO_2, nuclear power would be the least expensive option; above \$38/ton, coal becomes the most expensive option.

9.6 Electric Power Infrastructure: Transmission and Distribution

Power plants generate electricity and transmission lines and distribution (T&D) systems carry it to customers. Figure 9.18 provides a simple schematic of a complete system consisting of generating stations with transformers to bump up voltages to the high values needed for efficient transmission. High-voltage transmission lines carry bulk power tens or hundreds of miles away to major load centers. Distribution substations drop voltages to levels suitable for local power lines to deliver power to every factory, business, and home that needs it.

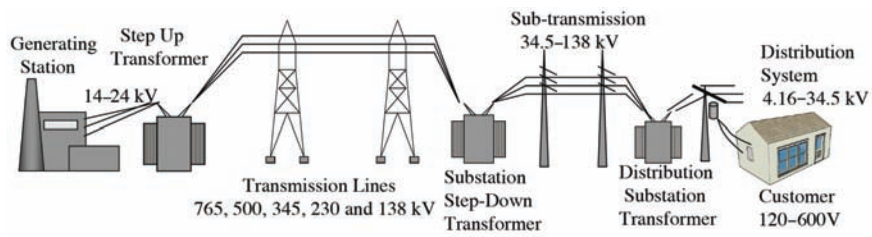
Although the emphasis in this chapter thus far has been on generation of electricity, those costs are often less than half of the total utility bill you are likely to receive for your home. In fact, for the last twenty years or so, utilities have spent more on transmission and distribution than on generation.

figure 9.17



In this analysis, nuclear power would be the least expensive option if carbon were priced above \$28 per metric ton of CO_2. Assumptions are as given in Figure 9.16 with all three plants operating at an 85% capacity factor.

figure 9.18



Generation, transmission, and distribution systems convert fuels to electricity and deliver it tens or hundreds of miles away to utility customers.

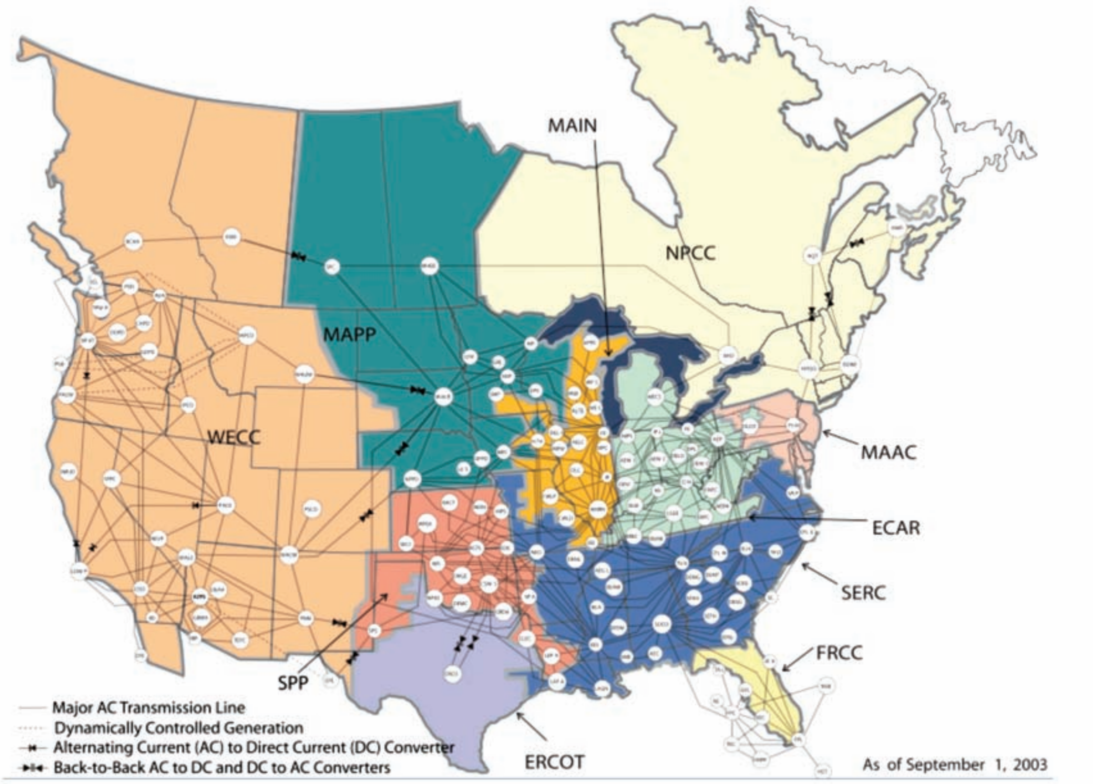
9.6.1 The North American Power Grid

The system in Figure 9.18 suggests a rather linear system with one straight path from sources to loads. In reality, there are multiple paths that electric currents can take to get from generators to end users. Transmission lines are interconnected at switching stations and substations, with lower-voltage, "sub-transmission" lines and distribution feeders extending into every part of the system. The vast array of transmission and distribution lines is called a power "grid." Within a grid, it is impossible to know which path electricity will take as it flows at nearly the speed of light, seeking out the path of least resistance, to get from generator to load.

Figure 9.19 shows a map of the basic structure of the North American power grid including transmission lines and the 140 or so major control-area dispatch centers. Because it is uneconomical to store significant quantities of electricity, at every instant in time the power generated within a dispatch area must equal the power demanded by loads. It is the job of these dispatch centers to constantly juggle the output of their generation facilities to provide just the right amount of power to meet that moment's demand.

Figure 9.19 suggests the North American power grid is one giant interconnected machine, but it actually consists of three separate interconnected grids: the Western Interconnection, the Texas Interconnection, and the Eastern Interconnection (Figure 9.20). Within each of these interconnection zones, everything is synchronized so that voltages, frequencies, phase angles, and currents are locked together into a single enormous ac circuit. Interconnections between the grids are made using the high-voltage dc (HVDC) links shown in Figure 9.19. These links consist of *rectifiers* that convert ac to dc, a connecting HVDC transmission line, and *inverters* that convert dc back to ac. The advantage of a dc link is that problems associated with exactly matching ac frequency, phase, and voltages from one interconnect to another are eliminated in dc. HVDC links can also connect various parts of a single grid, as is the case with the 6000 MW Pacific Intertie between the Pacific Northwest and southern California. Quite often national grids of neighboring countries are linked this way as well.

figure
9.19



The North American power grid, showing major transmission lines, control-area dispatch centers, and the areas covered by regional electricity reliability councils.

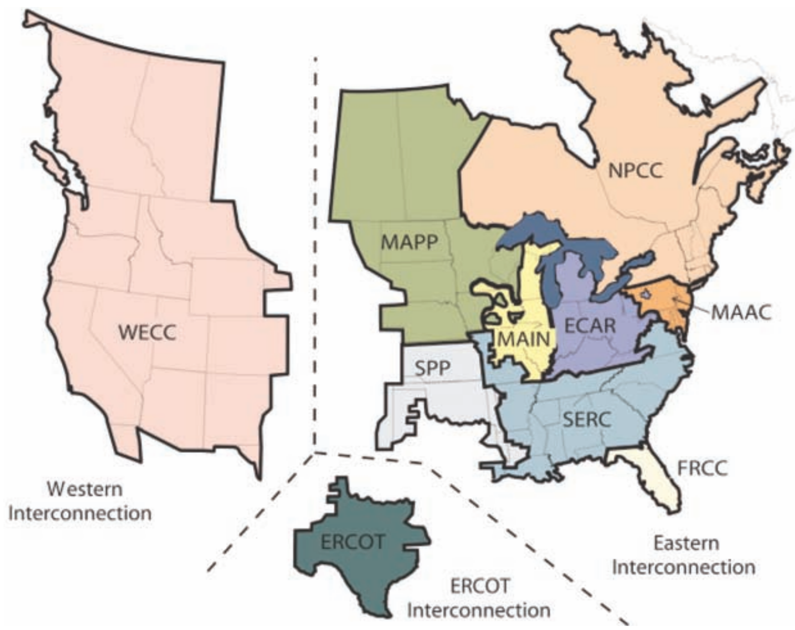
Source: U.S.–Canada Power System Outage Task Force, 2004

9.6.2 Grid Stability

Most blackouts are short term, such as when someone pays more attention to his cell phone than his driving, hits a power pole, and our lights go out for a few minutes. Some are predictable, as in the rolling blackouts that California had to endure during its ill-fated experiment with deregulation in 2000–2001. Some are longer term, as in the great blackout that hit the Midwest and Northeast parts of the United States, as well as Ontario, Canada, in August 2003. That blackout caused 50 million people to be without power, some for as long as four days, and cost the United States roughly $4 billion to $10 billion.

The organization that takes responsibility for overall grid reliability has traditionally been the North American Electric Reliability Council (NERC). NERC is a nonprofit corporation made up of members of the ten regional reliability councils shown in Figure 9.20. The blackout of 2003, coupled with growing concern for terrorism, motivated Congress to pay

figure 9.20



The North American power grid actually consists of three separate grids: The Western Interconnection, the Texas (ERCOT) Interconnection, and the Eastern Interconnection. These are connected to each other using relatively small HVDC links.

more attention to the grid and to include in the Energy Policy Act of 2005 the creation of an *Electricity Reliability Organization* (ERO) that will likely augment or even replace NERC.

During normal operation, the grid responds to slight imbalances in supply and demand by adjusting the voltage and/or frequency of the nominal 60-hertz voltage (it increases the frequency and/or raises the voltage when generation exceeds demand). Small variations are routine; however, large deviations in frequency can cause the rotational speed of generators to fluctuate, leading to vibrations that can damage turbine blades and other equipment. Significant imbalances can lead to automatic shutdowns of portions of the grid, which can affect thousands of people. When parts of the grid shut down, especially when that occurs without warning, power that surges around the outage can potentially overload other parts of the grid causing those sections to go down as well.

Most often, major blackouts occur when the grid is running at near capacity, which for most of the United States occurs during the hottest days of summer when the demand for air-conditioning is at its highest. Perhaps surprisingly, one of the most common triggers for blackouts on those hot days results from insufficient attention having been paid to simple management of tree growth within transmission-line rights-of-way (see Sidebar 9.3). When lines get hot, they expand. When they expand, they sag more and are more likely to short out

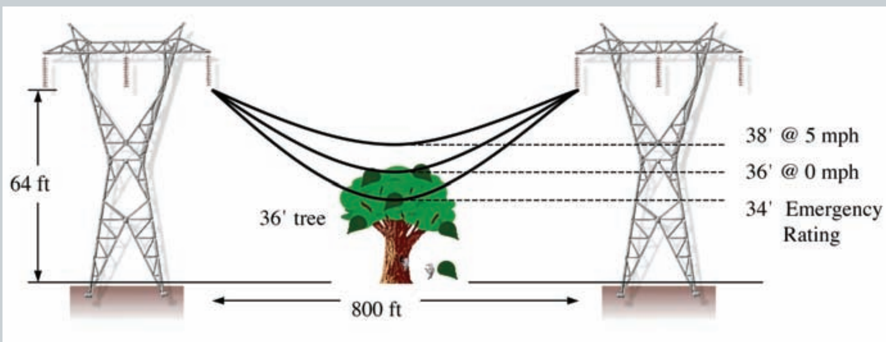
SIDEBAR

SIDEBAR 9.3

Why Do Trees Sometimes Cause Blackouts on Hot Days?

Several major blackouts have been caused by transmission lines shorting out when contacting trees in the right-of-way—especially on hot summer days. Why is that?

1. Peak power demands increase i^2R heating of lines causing them to expand and sag.
2. On hot days, air does not cool the lines as much, increasing the temperature sag.
3. Low wind speeds may not adequately cool the lines, raising line temperature and sag.
4. Vegetation grows during the summer, increasing the chance of line contact.
5. Power outage in one place may increase current in another line, increasing its sag.



in trees. Lines, if allowed to stay stretched, acquire a permanent stretch in them, so there are emergency limits to how much they are allowed to stretch and for how long.

9.7 Evolving Regulation of Electric Power

Samuel Insull shaped what became the modern electric utility by bringing into being the concepts of regulated utilities with monopoly franchises. In exchange for the right to be the only provider of electric power within a designated service territory, utilities accepted the obligation to serve the public by providing reliable service to every customer at rates that were to be determined by public utility commissions (PUCs). The economies of scale that went with increasingly large steam power plants led to an industry based on centralized generation coupled with a complex infrastructure of transmission lines and distribution facilities.

At the end of the twentieth century, however, the benefits of Insull's model began to unravel. Economies of scale had played out and big customers wanted direct access to power that could now be generated by new, smaller turbines at a lower price than grid power. Focus also shifted to the customer's side of the meter when it was realized that it was cheaper and faster to help customers save energy than for utilities to build more power plants. And, finally, growing awareness of the environmental benefits of renewable energy systems led to pressure to find ways to encourage their use.

9.7.1 The Public Utility Holding Company Act of 1935 (PUHCA)

In the early part of the twentieth century, as enormous amounts of money were being made, utility companies began to merge and grow into larger conglomerates. A popular corporate form emerged, called a *utility holding company*. A holding company is a financial shell that exercises management control of one or more companies through ownership of their stock. Holding companies began to purchase each other and by 1929, sixteen holding companies controlled 80% of the U.S. electricity market, with just three of them owning 45% of the total.

With so few entities having so much control, it should have come as no surprise that financial abuses would emerge. Holding companies formed pyramids with other holding companies, each owning stocks in subsequent layers of holding companies. An actual operating utility at the bottom found itself directed by layers of holding companies above it, with each layer demanding its own profits. At one point, these pyramids were sometimes ten layers thick. When the stock market crashed in 1929, the resulting Great Depression drove many holding companies into bankruptcy causing investors to lose fortunes. Insull became somewhat of a scapegoat for the whole financial fiasco associated with holding companies and he fled the country amidst charges of mail fraud, embezzlement, and bankruptcy violations, charges of which he was later cleared.

In response to these abuses, Congress created the *Public Utility Holding Company Act of 1935* (PUHCA) to regulate the gas and electric industries and prevent holding company excesses from reoccurring. Many holding companies were dissolved, their geographic size was limited, and the remaining ones came under control of the newly created Securities and Exchange Commission (SEC).

Although PUHCA has been an effective deterrent to previous holding-company financial abuses, recent changes in utility regulatory structures, with their goal of increasing competition, led many to say it had outlived its usefulness. The main issue was a provision of PUHCA that restricted holding companies to business within a single integrated utility, which is a major deterrent to the modern pressure to allow wholesale wheeling of power from one region in the country to another. As a result, Congress repealed PUHCA in its Energy Policy Act of 2005.

9.7.2 The Public Utility Regulatory Policies Act of 1978 (PURPA)

With the country in shock from the oil crisis of 1973 and with the economies of scale associated with ever larger power plants having pretty much played out, the country was drawn toward energy efficiency; renewable energy systems; and new, small, inexpensive gas turbines.

To encourage these systems, President Carter signed the Public Utility Regulatory Policies Act of 1978 (PURPA).

The two key provisions of PURPA relate to allowing *independent power producers* (IPPs), under certain restricted conditions, to connect their generators to the utility-owned grid. IPPs, for example, were often customers trying to generate some of their own power on-site. Prior to PURPA, utilities could refuse service to such customers, which meant they would have to provide all of their own power, all of the time, including their own redundant, backup power systems. That reality virtually eliminated the possibility of using efficient, economical, on-site power production to offset a portion of a customer's load.

PURPA not only allowed grid interconnection but it also required utilities to purchase electricity from certain *qualifying facilities* (QFs) at a "just and reasonable price." The purchase price of QF electricity was to be based on what it would have cost the utility to generate the power itself or to purchase it on the open market (referred to as the *avoided cost*). This provision stimulated the construction of numerous renewable energy facilities, especially in California, because PURPA guaranteed a market, at a good price, for any electricity generated.

PURPA not only gave birth to the renewable energy industry, it also clearly demonstrated that small, on-site generation could deliver power at considerably lower cost than the retail rates charged by utilities. Competition had begun.

9.7.3 The Energy Policy Act of 1992 (EPAct)

The Energy Policy Act of 1992 (EPAct) created even more competition in the electricity generation market by opening the grid to more than just the QFs identified in PURPA. A new category of access was granted to *exempt wholesale generators* (EWGs), which can be of any size, using any fuel and any generation technology, without the restrictions and ownership constraints that PURPA and PUHCA imposed. EPAct allows EWGs to generate electricity in one location and sell it anywhere else in the country using someone else's transmission system to wheel their power from one location to another. The key restriction of an EWG is that it deals exclusively with the *wholesale wheeling* of power from the generator to a buyer, usually a regulated utility, who is not the final retail customer who uses that power.

9.7.4 FERC's Order 888 (1996)

While the 1992 EPAct allowed independent power producers (IPPs) to gain access to the transmission grid, problems arose during periods when the transmission lines were being used to near capacity. In these and other circumstances, the investor-owned utilities (IOUs) that owned the lines favored their own generators, and IPPs were often denied access. In addition, the regulatory process administered by the Federal Energy Regulatory Commission

(FERC) was initially cumbersome and inefficient. To eliminate such deterrents, FERC issued Order 888 in 1996, which had as a principle goal the elimination of anticompetitive practices in transmission services by requiring IOUs to publish nondiscriminatory tariffs that applied to all generators.

9.7.5 The Emergence of Competitive Markets

Prior to PURPA, the accepted method of regulation was based on monopoly franchises; vertically integrated utilities that owned some or all of their own generation, transmission, and distribution facilities; and consumer protections based on strict control of rates and utility profits. In the final decades of the twentieth century, however, the successful deregulation of other traditional monopolies such as telecommunications, airlines, and the natural gas industry, provided evidence that introducing competition in the electric power industry might also work. Although the disadvantages of multiple systems of wires to transmit and distribute power continue to suggest they be administered as regulated monopolies, there is no inherent reason why there shouldn't be competition between generators who want to put power onto those wires. The whole thrust of PURPA, Order 888, and EPAct 1992 was to begin the opening up of that grid to allow generators to compete for customers, in the hopes of driving down costs and prices.

The emergence of small, less capital-intensive power plants helped independent power producers get into the power generation business. By the early 1990s the cost of electricity generated by IPPs was far less than the average price of power charged by regulated utilities. With EPAct opening the grid, large customers began to imagine how much better off they would be if they could just bypass the regulated utility monopolies and purchase power directly from those small, less expensive units. Large customers, with the wherewithal, threatened to leave the grid entirely and generate their own electricity, whereas others, when allowed, began to take advantage of retail wheeling to purchase power directly from IPPs.

Not only did small power plants become more cost-effective, independent power producers found themselves with a considerable advantage over traditional regulated utilities. Even though utilities and IPPs had equal access to new, less expensive generation, the utilities had huge investments in their existing facilities so the addition of a few low-cost new turbines had almost no impact on their overall average cost of generation.

To help utilities successfully compete with IPPs in the emerging competitive marketplace, FERC included in Order 888 a provision to allow utilities to speed up the recovery of costs on power plants that were no longer cost-effective, also known as *stranded assets*. The argument was based on the idea that when utilities built those expensive power plants, they did so under a regulatory regime that allowed cost recovery of all prudent investments. To be fair, and to help assure utility support for a new competitive market, FERC believed it was appropriate to allow utilities to recover those stranded-asset costs even if that might delay the emergence of a competitive market.

9.7.6 California's Attempt to Restructure

In the 1990s, California's electric rates were among the highest in the nation—especially for its industrial customers—which led to an effort to try to reduce electricity prices by introducing competition among generation sources. In 1996, the California Legislature passed Assembly Bill 1890. AB 1890 had a number of provisions, but the critical ones included the following:

1. To reduce their control of the market, the three major investor-owned utilities (IOUs), Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E), which accounted for three-fourths of California's supply, were required to sell off most of their generation assets. About 40% of California's installed capacity was sold off to a handful of independent power producers including Mirant, Reliant, Williams, Dynergy, and AES. The thought was that new players who purchased these generators would compete to sell their power; thereby, lowering prices.
2. All customers would be given a choice of electricity suppliers. For a period of about four years, large customers who stayed with the IOUs would have their rates frozen at 1996 levels, and small customers would see a 10% reduction. Individual rate payers could choose non-IOU providers if they wanted to, and this "customer choice" was touted as a special advantage of deregulation. Some providers, for example, offered elevated percentages of their power from wind, solar, and other environmentally friendly sources as "green power."
3. Utilities would purchase wholesale power on the market, which, due to competition, was supposed to be comparatively inexpensive. The hope was that with their retail rates frozen at relatively high 1996 levels, and with dropping wholesale prices in the new competitive market, there would be extra profits left over that could be used to pay off those costly stranded assets—mostly nuclear power plants.
4. The competitive process was set up so that each day there would be an auction in which generators would submit bids indicating how much power they were willing to sell the next day and at what price. A new entity, called the California Power Exchange (CalPX) selected enough bids to meet the projected demand. All of those successful bidders were paid the same amount, equal to the highest accepted bid. Any provider who bid too high would not sell power the next day. So if a generator bid $10/MWh (1¢/kWh) and the market clearing price was $40/MWh, that generator would get to sell power at the full $40 level. This was supposed to encourage generators to bid low so they would be assured of the ability to sell power the next day.

On paper, it all sounds pretty good, doesn't it? Competition would cause electricity prices to go down and customers could choose providers based on whatever criteria they liked, including environmental values. As wholesale power prices dropped, utilities with high, fixed retail rates could make enough extra money to pay off old debts and start fresh.

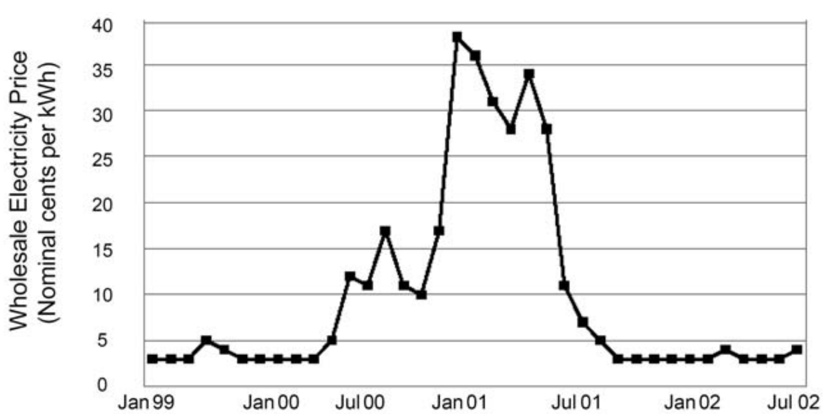
For two years, up until May 2000, the new electricity market seemed to be working with wholesale prices averaging about \$30/Mwh (3¢/kWh). Then, in the summer of 2000, it all began to unravel (Figure 9.21). In August 2000, the wholesale price was five times higher than it had been in the same month in 1999. During a few days in January 2001, when demand is traditionally low and prices normally drop, the wholesale price spiked to the astronomical level of \$1500/Mwh. By the end of 2000, Californians had paid \$33.5 billion for electricity, nearly five times the \$7.5 billion spent in 1999. In just the first month and a half of 2001, they spent as much as they had in all of 1999.

What went wrong? Factors that contributed to the crisis included higher-than-normal natural gas prices, a drought that reduced the availability of imported electricity from the Pacific Northwest, reduced efforts by California utilities to pursue customer energy-efficiency programs in the deregulated environment, and, some argue, insufficient new plant construction. But, when California had to endure rolling blackouts in January 2001, a month when demand is far below the summer peaks and utilities normally have abundant excess capacity, it became clear that none of the above arguments was adequate. Clearly, the IPPs had discovered they could make a lot more money manipulating the market, in part by withholding supplies, than by honestly competing with each other.

The energy crisis finally began to ease by the summer of 2001 after the Federal Energy Regulatory Commission (FERC) finally stepped in and instituted price caps on wholesale power, the governor began to negotiate long-term contracts, and the state's aggressive energy-conservation efforts began to pay off. Those conservation programs, for example, are credited with cutting the June 2001, California energy demand by 14% compared with the previous June.

In March 2003, FERC issued a statement concluding that California's electricity and natural gas prices were driven higher because of widespread manipulation and misconduct by Enron and more than thirty other energy companies during the 2000–2001 energy crisis.

figure 9.21 **California Wholesale Electricity Prices during the Crisis of 2000–2001**



Source: from Bachrach, et al., 2003

In 2004, audiotapes were released that included Enron manipulators joking about stealing money from those dumb grandmothers in California. By 2005, Dynergy, Duke, Mirant, Williams, and Reliant had settled claims with California totaling $2.1 billion—a small fraction of the estimated $71 billion that the crisis is estimated to have cost the state.

Although the momentum of the 1990s toward restructuring was shaken by the California experience, the basic arguments in favor of a more competitive electric power industry remain attractive. Analysis of the failure there has guided the restructuring that continues in a number of other states.

9.8 Summary

This chapter has attempted to describe the history of electric utilities and how they are regulated as well as the main centralized generation facilities that send power over our vast and intricate transmission and distribution system. Techniques were presented to evaluate the economics of different types of power plants and how sensitive those cost numbers are to the assumptions made. The focus has been on the utility's side of the meter; that is, on wholesale markets. This background provides the context for the next chapter in which an alternative model based on small-scale energy systems, often located on the customer's side of the meter, will be presented.