CHAPTER 2

How the Electric System Works

The millions of miles of wire that comprise the electric grid system can be likened to the thousands of miles of capillaries, veins and arteries in the human body. When you exercise a muscle, blood flows to that area of the body. Similarly, when an electrical device is turned on, electricity flows to that "load." Exercise a muscle more strenuously and more blood is drawn to the area, moving in great torrents through several major arteries to dozens of smaller vessels and thousands of even narrower capillaries. The "load" can be traced back to, or as students of electricity say, "seen at," the body's power plant—the heart.

A spidery web of electrical wires crisscrosses the nation. More than 365,000 circuit miles of overhead high-voltage transmission lines carry huge amounts of power to load centers in the United States. More than 4 million miles of distribution lines carry lower voltage electricity to customers.

Massive trunk lines carry vast quantities of high-voltage electricity over hundreds and even thousands of miles. At substations a device called a *transformer* raises (steps up) or lowers (steps down) the voltage. Typically the voltage is raised 1,000 volts (v) for every additional mile electricity is transmitted. Large power plants feed power into bulk transmission lines 10 to 20 miles away at 13.8 kilovolts (kv). A transformer steps up this electricity to voltages of 69 kv to 745 kv, depending on the length of its journey through the wires. The 270-mile transmission line from the Hoover Dam to Los Angeles carries 275 kv. When the high-voltage transmission line reaches a load center, subtransmission transformers step down the voltage to between 69 kv and 138 kv, with the latter voltage being sufficient to send electricity about 110 miles. Some very large industrial customers can make direct use of these high voltages. They may have a single transformer for their own electricity, called a *dedicated transformer*.

Distribution substations are often located in or near towns. From the distribution substation, the electricity flows into feeder lines. Each substation may supply up to 25 feeders. The *feeder primary* is the main

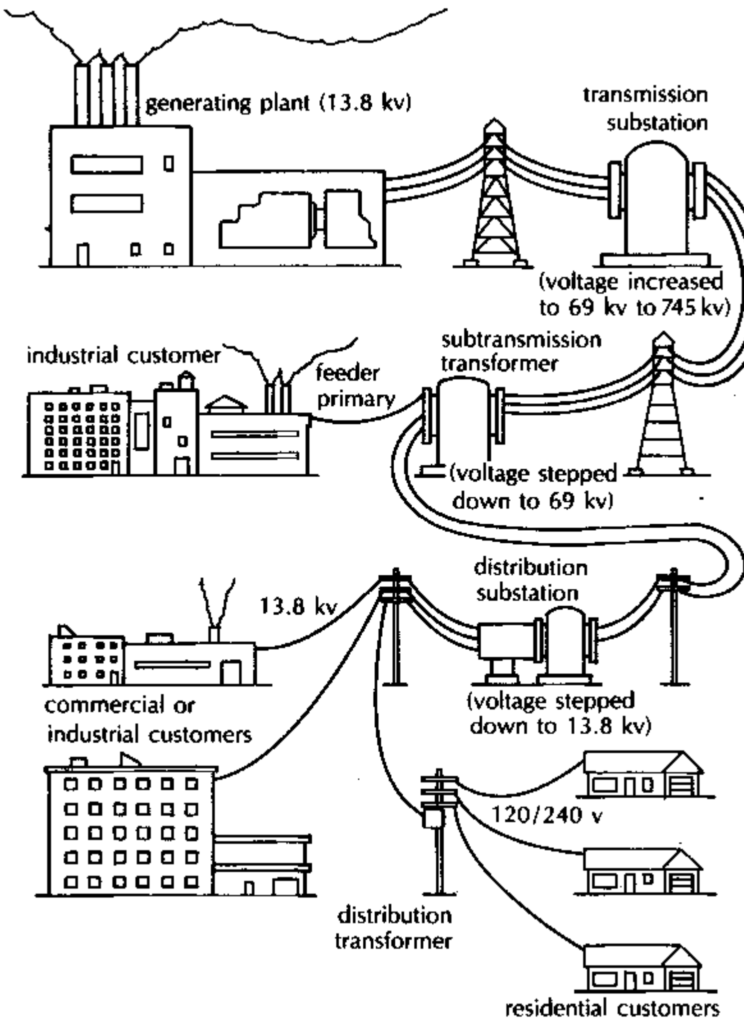

Figure 2–1: The voltage leaving the generating plant is raised (stepped up) by a transformer to very high levels so that electricity can be transported long distances with few line losses. The voltage is lowered (stepped down) by transformers several times to meet the needs of different customers.

line carrying power from the distribution substation. It operates at voltage levels of 2.4 kv to 32 kv. The particular voltage level of a feeder primary depends on the power demand in the feeder's service area. For example, a 15-kv feeder primary will have a peak capacity of 5,000 to 10,000 kilowatts (kw). This size feeder could serve approximately 2,000 homes.

Once again the voltage levels of the feeder primary can serve some industrial customers directly. Electricity sold at higher voltage is cheaper for the utility to deliver, so the customer will be able to buy it at a lower price. Branch lines called *laterals* radiate from the feeder primary. Some commercial customers are connected directly to these branch lines. Voltage must be reduced further through a distribution transformer connected to residences. Each distribution transformer serves one to ten homes. The lines on the customer's side of the distribution transformer are known as the *distribution secondary system*. All houses within the same distribution secondary system are connected in parallel with each other. Thus a short circuit in one person's home will not cut off electricity in another's. But these houses that share a transformer do represent a sort of mini-electrical community. The efforts of one house to move toward electrical self-reliance can, in fact, have an effect on the other houses in the distribution secondary system. As will be discovered, one issue raised by utilities when interconnecting small power producers to the grid system is whether they should continue to share a distribution transformer with other customers or be required to install a transformer solely for their own use.

The distribution secondary in residential areas carries the standard 120/240 v, single-phase power. Single-phase power consists of one signal. In contrast, transmission lines and distribution primary and lateral lines carry three-phase power, which consists of three signals (see figure 2-2). Each signal is out of phase with the other two by 120 degrees. Three-phase power is used by industrial equipment and larger commercial appliances. Motors and other types of machinery cost less and operate more efficiently when supplied by three-phase power. Moreover, it is more economical to transmit three-phase power than single-phase power.

Electricity "leaks" on the way from the power plant to the ultimate user. The leaks are known as *line energy losses,* or just *line losses*. Two factors account for these losses: distance traveled and resistance to electricity flow. Because transmission lines are high voltage, relatively little energy is lost along them.

This is because for a given amount of power (watts) transmitted, the greater the force driving the electricity (volts), the lower the current (amps). The power lost is given by the formula $P = I^2 R$ (where P is power, I is amps and R is resistance). Thus by dropping the current in half, the line losses are reduced by 75 percent.

Proportionately greater line losses occur during lower-voltage distribution because of the higher current. In all, about 9 percent of the electricity is lost getting from the central power plant to the customer. An additional 2 percent is lost in the transformers.

This vast web of electrical service delivery facilities is expensive. The transformers that step up the generator's output to the high voltages necessary for long-distance transmission cost over $2.5 million each. High-voltage power lines cost about $220,000 per mile. Bulk substations that make the first voltage step-downs run as much as $10 million dollars. The smaller lines bringing electricity to individual homes and businesses are less expensive than the big ones, but still cost about $30,000 a mile. The pole-top, or underground, transformers in your neighborhood cost about $1,000, while the cost of bringing electric power that final few feet into your home costs $150. Typically investments in transmission and distribution (T&D) facilities represent 50 percent of a utility's total system investment.

A utility transmission and distribution system includes a vast array of components besides lines and transformers. Substations in the system contain voltage regulators, circuit breakers, protective relays and other switching equipment. There also are relays, fuses and sectionalizing switches throughout the distribution system. This equipment helps maintain acceptable voltage levels and provides protection against excessive currents, unbalanced voltages and currents between phases, and other abnormal conditions known as faults. When a fault is detected, circuit breakers and fuses open in order to isolate the malfunctioning circuit. In some cases, the circuit breaker or fuse is equipped with a recloser to clear temporary (called transient) faults such as those that occur when two lines momentarily touch.

The electrical grid system is awesome in its complexity. Yet it is not perfect. Despite the best efforts of modern electrical engineers and system designers, things can and do go wrong. One such event occurred the evening of 13 July 1977 in New York City. At the time there was plenty of generating capacity available in the pool of adjacent utilities with which Consolidated Edison of New York (Con Ed) was interconnected. But events developed in such a manner that there was no way to deliver that power to the city. The grid system didn't work. Philip Boffey provides an excellent description of the failure sequence and a clear warning against engineering hubris in the following excerpt from his story in *Science* magazine:

> *The trouble began at 8:37 P.M. on 13 July when lightning struck a tower [which was imperfectly grounded] in northern Westchester County and short-circuited two 345-kilovolt lines. . . . Once the short circuit occurred, protective relays, the next line of defense, triggered circuit breakers to open at both ends of the affected lines, thus isolating the problem from the rest of the system. That is exactly*

what the circuit breakers are supposed to do. However, they are also supposed to reclose automatically once the fault dissipates, and this they failed to do. One transmission line failed because of a loose locking nut [which released air pressure from a circuit breaker] in a circuit; the other because a reclosing circuit had been disconnected and not yet replaced. . . .

Two other facilities also tripped out of service. . . . A nuclear reactor [Indian Point Three] shut down automatically when the circuit breakers that opened to contain the lightning fault also [by a design fault] deprived the reactor of any outlet for its power—a design feature that has since been criticized by most investigators. And another 345-kilovolt line—a major tie across the Hudson—tripped out because a protective timing device was designed improperly by Con Ed. . . .

Thus, in one stroke of misfortune, Con Ed lost three major transmission lines and its most heavily loaded generator.

Even so, Con Ed regained its equilibrium by importing more power on the remaining tie lines and by increasing its own generation somewhat. . . . Then lightning struck again . . . and short-circuited two more 345-kilovolt lines. Again there was a malfunction. One line reclosed automatically as it was supposed to; the other remained open because a relay had been set primarily to protect a nuclear reactor (which, ironically, was out of service) rather than to facilitate reclosing of the line. . . . The loss of the line triggered still another malfunction; it caused a temporary power surge that tripped out another 345-kilovolt line. This should not have happened but did, because of a bent contact on a relay. . . .

Con Ed's control room succumbed to confusion and panic. . . . [The] system operator [assumed] . . . a particular transmission line was still in service [and] . . . failed to read a teletype [saying it was down]. . . . Moreover, because of Con Ed's antiquated control room layout, he was unable to see a more dramatic indicator in another room—a flashing screen with a high-pitched alarm. The personnel there knew the line was out but failed to tell him.

As it was, he ignored repeated suggestions from the power pool that he shed load. Then, as the situation deteriorated, he essentially abdicated and dumped the decision-making responsibility on his boss, the chief system operator, who sat at home in the dark reading diagrams by a kerosene lantern and issuing orders over the phone. . . . The chief ordered voltage reductions—but they were too little and too late. Eventually he also ordered that a block of customers be disconnected. Whereupon the confused system opera-

tor pushed the disconnect buttons and nothing happened. Under stress, he apparently turned a master switch the wrong way.

The performance of Con Ed's reserve generators was equally erratic. Con Ed's system operator delayed 8 minutes after the first lightning strike before requesting a fast load pickup from generators that were supposedly able to respond in 10 minutes. He got only half the power he expected—and only 30 percent of what Con Ed had incorrectly told the power pool it could provide. Some equipment malfunctioned; other units were undergoing routine inspection but had not been removed from the fast-start availability list; some were not even manned. [All the night shift operators had been sent home, and the remote-start capability had been removed some years earlier. At most 55 percent of Con Ed's total in-city generating capacity was actually operable.] Similarly, when Con Ed sounded the maximum generation alarm some 10 minutes after the second lightning strike, it again failed to get the anticipated response from its 30-minute reserve generators.

As the system cascaded toward collapse, heavy overloads caused the failure or deliberate disconnection of all remaining ties to neighboring utilities. Con Ed was now an island, isolated from outside help. Its last hope was an automatic load shedding system that had been installed after the 1965 blackout. The system worked beautifully to disconnect customers. . . . But it also unexpectedly caused a rapid rise in system voltage that caused a major generator to shut down. That sealed the system's doom. . . . The remaining generators could not restore equilibrium. Eventually, protective relays shut them down to prevent damage. By 9:36 P.M. the city was blacked out.[1]

The point of this story is that despite all the relays, regulators, fuses and other fail-safe equipment the utilities use, and despite the use of very sophisticated computers to monitor their entire system, things can and do go wrong. Things happen quickly, too. The Con Ed system went down in just nine minutes. And, given the interconnectedness of the modern grid systems, when things go wrong the results can affect millions of people. This story also exemplifies the fact that most blackouts occur because of failures in the transmission or distribution systems, not because of power plant failures.

An interesting footnote to the 1977 blackout is that now whenever the probability of a thunderstorm rises above a certain level, New York City is cut off from the upstate transmission system. During storms Con Ed generates electricity from very expensive gas turbines. Thus, New

York continues to pay millions of dollars each year as a penalty for the 1977 blackout.

Attention is now given to the generation portion of the electrical system, the modern power plant.

The Modern Steam Plant

The vast majority of power plants now operating are steam plants. The equipment that makes electricity is complex, but the theory behind electric generation is quite simple. Imagine a teakettle, a fan, a magnet and some coiled wire connected together. Fill the teakettle with water, and apply heat. When the water boils, it generates steam, which has tremendous power. As it shoots out of the teakettle, it hits the fan blades, turning the fan shaft. The revolving shaft turns the magnet inside the coils of wire. The motion of the magnetic field near the wire moves electrons inside the wire, and this electron movement is electricity.

A giant steam-electric generating plant operates on this same principle. But instead of teakettles, fans and magnets, the plant uses boilers, turbines and generators.

In a steam generating plant, liquid water is boiled by applying heat from some source, such as coal or oil combustion or nuclear fission. In a coal-fired plant, combustion temperatures may reach 2,600°F. The water changes from a liquid to a vapor (steam) and, in the process, increases its volume many times. The steam expands out of the boiler through a turbine and turns the fanlike blades. The steam is superheated, reaching more than 1,000°F. It is then collected and at more than 2,500 pounds of pressure per square inch, shoots into the high-pressure section of the turbine. The turbine shaft turns a generator to produce electricity.

When low-pressure steam leaves the turbine, it condenses back to a liquid by cooling. This occurs in a condenser where the piped steam is brought into contact with cooling water, which draws away heat, causing the steam to condense into water. Since large volumes of cooling water are required, plants are located near large bodies of water. Power plants are capable of raising the temperature of entire lakes and rivers several degrees by using their water for cooling. (Cooling can also be accomplished with huge cooling towers that use massive amounts of air to take away the heat.) The same water is then pumped back into the boiler and the process is repeated.

Steam power plants only achieve a 35 percent overall efficiency. Every plant keeps records of how much fuel is burned and how much electrical energy is generated over a period of time. The ratio of fuel energy used to electrical energy generated is called the *heat rate*. A heat rate for a power plant might be 10,000 British thermal units (Btu) per kilowatt-hour (kwh). In other words, 10,000 Btu of fuel (a gallon of gasoline contains 120,000 Btu) are burned to produce 1 kwh of electricity. Since a kwh represents 3,413 Btu, this plant operates at 34 percent efficiency. Plant heat rates are very important because they account for most of the utility's short-run variable costs. They are known as the utility's energy costs. Heat rates range from 9,600 Btu for the newest high-efficiency *combined cycle* plants up to 23,000 Btu per kilowatt-hour for old, quick-start jet turbines used only in high-demand emergencies.

Some Basic Electrical Concepts

The complex nature of the electrical system requires a fairly exact understanding of the three most important electrical elements: current, voltage and wattage.

Current is measured in *amperes* (amps for short). An amp represents the number of electrons flowing past a given point in a given period of time. Modern science allows us to quantify exactly how many electrons there are in an amp. With a current of exactly 1 amp, the number of electrons passing a given point in one second is 6,242,000,000,000,000,000 or, as physicists say, 6.242×10^{18}.

Direct current (DC) electrons move in only one direction. This is the type of one-way current that batteries deliver. In *alternating current* (AC), electrons reverse directions. This type of current is used in almost all of our electrical systems. The number of times electrons move back and forth determines the *frequency* of the current. The standard frequency in the United States is 60 cycles per second (60 *hertz* or Hz).

The load on a circuit is characterized by its resistance to the flow of electrons. This resistance is measured in *ohms*. The amount of resistance varies greatly depending on its composition, thickness, density, temperature and so forth. Insulators have very high resistance while conductors have very much lower resistance.

The pressure with which a generator pushes electrons through a circuit is called *voltage*. Like amps, volts can be DC or AC. The voltage of electricity that enters homes in the United States is 120 v. The higher the voltage the more easily the electricity can pass through materials. For example, a flashlight battery gives off about 1.5 v. A simple patch of rust on the switch or grease on the contacts will cut off the bulb. Anything less than a substantial thickness of material will not interrupt the flow of 120-v electricity.

Low voltages are safer to handle because they cannot penetrate the skin. Below 50 v there is little danger of a dangerous shock. A car battery operates at 12 volts direct current (vdc) and a heavy-duty truck battery at 24 vdc.

Higher voltages can be quite dangerous. At 132 kv, for example, sparks can jump through 2 inches of air. At 765 kv sparks can jump almost 2 feet through the air. The force of the electricity moving through high-voltage lines literally creates a crackling sound. The danger from these high voltages is one reason bulk power transmission towers are built so high off the ground.

As electrons move through a load (a light bulb, a motor) they do work. The rate at which work is done is known as *power* and is measured in *watts* (w) or *kilowatts* (kw). One kw equals 1,000 w, which in turn equals 1.34 horsepower (1 HP equals 0.75 kw). Incidentally, the basic unit of power, the watt, is named after James Watt, inventor of the steam engine.

The best way to think of electric power is "energy per hour," just as speed is defined in terms of distance per hour. If we multiply power (in watts) times the duration of power usage (in hours), we arrive at watt-hours or *kilowatt-hours* (kwh), the familiar measure of electrical energy. A 100-w bulb burning for 10 hours consumes 1 kwh of electrical energy. One kwh equals 3,413 Btu. Btu stands for British thermal unit and is the amount of heat required to raise the temperature of 1 pound of water 1 degree Fahrenheit. Incidentally, there are 4 Btu in a Calorie. Therefore, the 3,000 Calories the typical person consumes every day could, if converted into electrical energy at 100 percent efficiency, light a 100-w bulb for more than 40 hours!

Appliances are rated by manufacturers according to their power consumption. General Electric, for example, makes 25-w, 60-w and 100-w light bulbs. The power consumption of appliances is usually on the back plate. Sometimes the amps but not the watts are given, but watts are calculated as the product of volts times amps. Thus, by multiplying the household voltage (120) by the amp rating, you can derive the appliance's wattage. At household voltage, a 25-w bulb will draw a current of about one fifth of an amp (25w ÷ 120v), while the 100-w bulb will draw about four-fifths of an amp.

Just as appliances are rated according to power consumption, so are a utility's power plants rated according to the power they produce. Large central power plants are rated in millions of watts (megawatts). A 1,000-megawatt (Mw) plant running continuously for 24 hours will produce 24,000 megawatt-hours (Mwh) or 24 million kwh.

The power demand determines how many kilowatts of capacity a power plant must have on-line at any given time. The maximum amount of power demand experienced during a year tells the utility how much total capacity it must have available. Power demand and load are essentially the same thing.

Energy and power are two distinct elements. The timing of one's demand for energy is as important in planning an electrical system as the power or wattage of a particular appliance. The distinction between power and energy may be better illustrated by an example using the water consumption of a household sink and a garden hose. Each provides water at 5 gallons per minute (gpm). The sink holds 10 gallons and watering the garden requires 10 gallons as well. If you fill the sink and water the garden at the same time, the demand for water will be 10 gallons per minute (5 gpm + 5 gpm). The load imposed on the local reservoir, then, is 10 gpm. If the reservoir is designed to serve 100 customers, and all the customers use their faucet and hose simultaneously, the reservoir must be able to deliver water at 1,000 gpm. This in turn requires a powerful pump and a wide-diameter pipeline.

However, you could fill your sink first and water your garden afterward. The total amount of water needed remains the same at 20 gallons. But the instantaneous load imposed on the reservoir would be only 5 gpm. If all 100 customers use each outlet separately, the reservoir would need to pump only 500 gpm. The water-flow load is thus halved and thus a less-powerful pump and smaller-diameter pipeline can be used.

Water flow in gallons per minute is analagous to electricity flow rates in kilowatts. The reservoir is the counterpart of the electric power plant. The total water volume in gallons is comparable to the total energy consumption in kilowatt-hours. Both amounts are determined by the amount of time the faucets or appliances are operated.

Since power multiplied by time equals energy, the same amount of energy can be used but over a longer time period with less demand for power. For example, burning ten 100-w bulbs for one hour consumes 1 kwh of electrical energy. Burning one 100-w bulb for ten hours also uses 1 kwh. However, in the first case, the ten bulbs use ten times as much power as the single bulb. Although the energy (work done) is the same, the ten bulbs burning simultaneously require ten times as much power plant capacity. The dominant consideration in utility economics is demand for power, or *load*.

An understanding of the relationship of energy to power can aid a small power producer in understanding the dynamics of the Public Utility Regulatory Policies Act of 1978 (PURPA). Electricity produced at peak times of the day (when the load or demand is greatest) will receive a higher price than electricity produced during off-peak times (when the load or demand is much lower). Moreover, if the small power producer can generate sufficiently reliable power so that the utility can actually displace future generating capacity, the producer receives a bonus, a capacity in addition to the energy credit.

Load Characteristics

What effect does load have on a utility? To see how the use of household appliances might affect a utility, assume there is a group of 100 residential utility customers. For simplicity, also limit the appliance mix for each customer to the following:

10 electric lamps:	100 w each
4 portable space heaters:	1,322 w each
1 air conditioner:	1,566 w
1 hot water heater:	4,474 w

To analyze the power demand for this group you must know how a customer uses each appliance in relation to other appliances and how all customers combined use their appliances. Suppose all 100 customers simultaneously use all their appliances at their rated power demand. For each customer the load imposed would be 12.3 kw:

Electric lamps:	10×0.1 kw = 1.0 kw
Portable space heaters:	4×1.3 kw = 5.2 kw
Air conditioner:	1×1.6 kw = 1.6 kw
Hot water heater:	1×4.5 kw = 4.5 kw
	12.3 kw

The entire group of 100 customers would impose a peak load of 1,230 kw or 1.23 Mw. These 100 customers would need roughly 1.23 Mw of electric power generating capacity to meet their combined peak load. Generating plants are expensive. The typical plant starting up in 1980 cost about $1,000 per kilowatt to build. Therefore, this group of customers would have to pay roughly $1.23 million for the capacity needed. Each customer would have to pay $12,300 just to pay for the machines to generate enough power to be able to run their appliances all at once.

Fortunately, the situation is not this onerous. All the appliances don't run at the same time. The total system load is usually less than the sum of the individual loads. Appliances such as electric water heaters or refrigerators have intermittent demand characteristics. Water heater elements, for example, typically operate on a 25 percent *duty cycle*. That means the heating elements are on 25 percent of the time, and it can be said that the probability is that only 25 percent of all water heaters will be drawing power simultaneously. This is called a 25 percent *load diversity factor*. By applying the load diversity factor to the power consumption of a typical water heater, there is a diversified load of 0.25×4.5 kw = 1.125 kw.

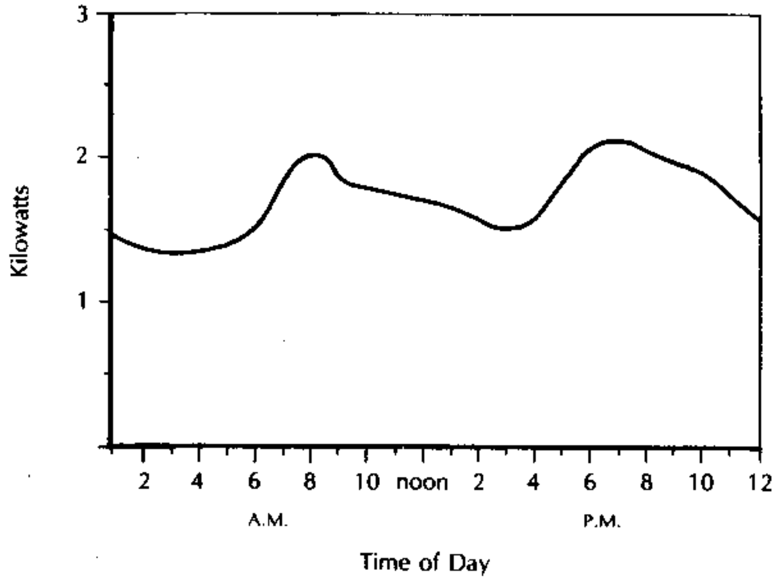

Figure 2–2: This graph represents a typical residential load pattern for customers of the Pennsylvania Power and Light Company for the month of January 1981. This represents loads for the entire residential class. The load pattern for an individual household would demonstrate higher peaks and lower valleys. Notice peaks at breakfast time before people leave for work and at dinner time after they return from work.

Actually, load diversity will vary somewhat over the day. People will do the laundry or shower or wash dishes at different times. Demand for hot water doesn't vary greatly by season, but demand for space heating and lighting does. Since most work is done during the day, the peak load for most electric utilities occurs sometime between 12 noon and 9 P.M. The *base load,* or the minimum demand on the system, occurs sometime late at night. The diurnal or daily load curve of a utility as well as the seasonal load curves can be graphed. These curves will depend greatly on the climate, the saturation of major appliances and the composition of the consuming classes. Some utilities might sell most of their power to industries that operate 24 hours a day, 365 days a year. These would tend to have flat load curves on a daily or seasonal basis. Other utilities that have a large air-conditioning load are called *summer peaking,* and those with a large space-heating load are called *winter peaking.*

When off-peak demand and peak demand are similar, the system is said to have a *high load factor.* When there are sharp spikes in

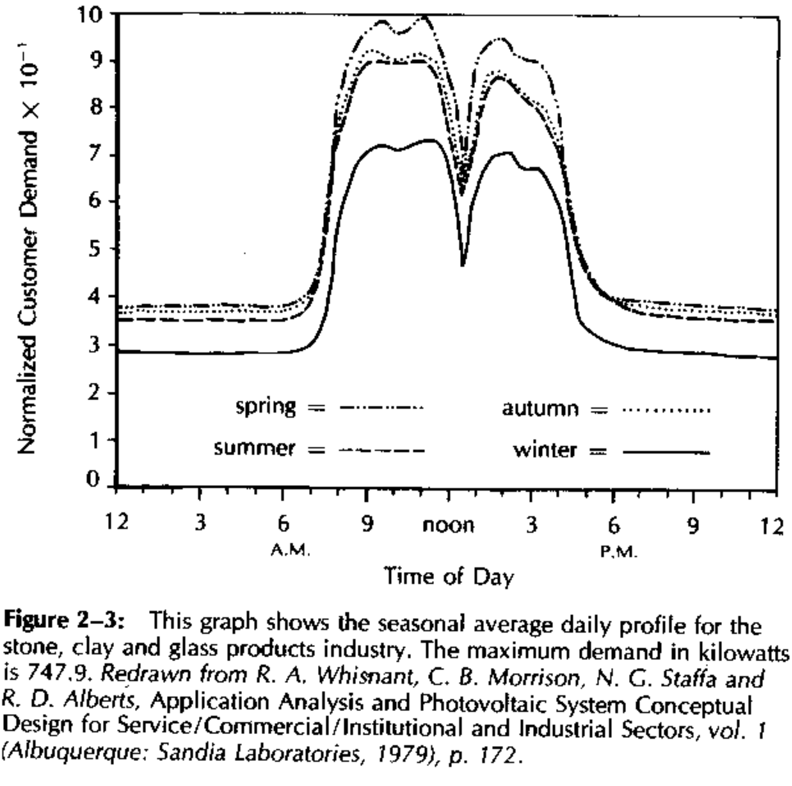

Figure 2–3: This graph shows the seasonal average daily profile for the stone, clay and glass products industry. The maximum demand in kilowatts is 747.9. *Redrawn from R. A. Whisnant, C. B. Morrison, N. G. Staffa and R. D. Alberts,* Application Analysis and Photovoltaic System Conceptual Design for Service/Commercial/Institutional and Industrial Sectors, *vol. 1 (Albuquerque: Sandia Laboratories, 1979), p. 172.*

demand at brief intervals during the day or year and the rest of the time demand is low, the system is said to have a *low load factor*. The higher the utility's load factor, the more baseload capacity it will have relative to total capacity. In other words, the closer base load is to peak load, the more the utility can fill the total demand with efficient baseload power plants, which usually generate inexpensive electricity. This is because the total utility plant is being used more fully so that the cost of the plant itself is spread over more kilowatt-hours sold.

The more of the utility's load curve that can be met with baseload power, the lower the buyback rate for the small power producer. Baseload power, as will be seen, is the cheapest to operate.

Load curves for individual industries have their own special characteristics. A load curve for the textile industry would show that it runs on three shifts all year long. The vast amount of electrical energy is used to power its looms. It has a flat seasonal and daily profile. At 2 A.M. in December it needs about the same power as at 3 P.M. in the spring. Figure 2–3 illustrates the load profile of the stone, clay and glass

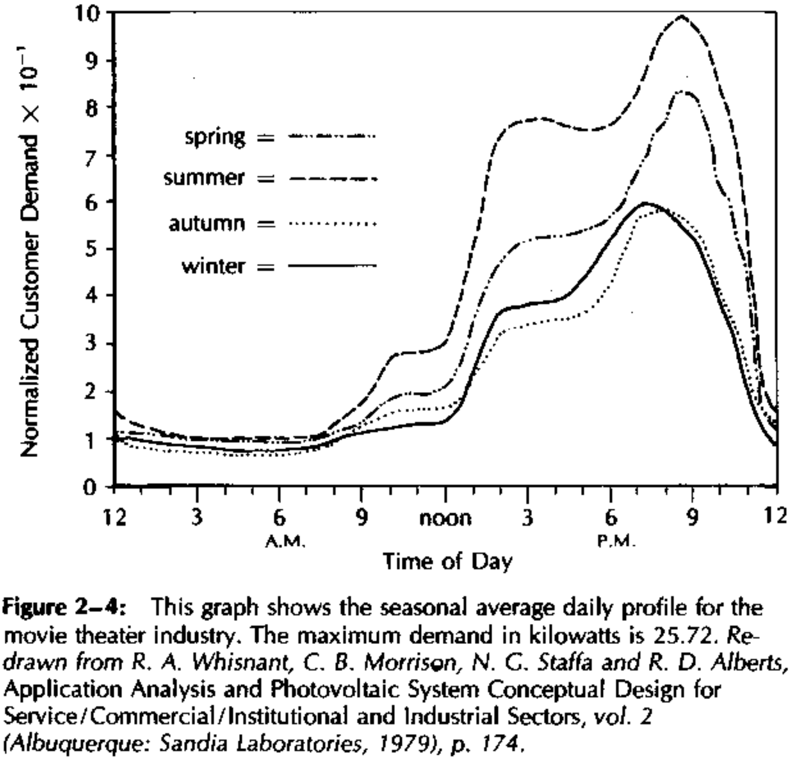

Figure 2–4: This graph shows the seasonal average daily profile for the movie theater industry. The maximum demand in kilowatts is 25.72. *Redrawn from R. A. Whisnant, C. B. Morrison, N. G. Staffa and R. D. Alberts,* Application Analysis and Photovoltaic System Conceptual Design for Service/Commercial/Institutional and Industrial Sectors, *vol. 2 (Albuquerque: Sandia Laboratories, 1979), p. 174.*

products industry. It demonstrates a one-shift operation, with greater production in the warmer months. The steep drop at noontime indicates a highly unionized labor force that gets an hour for lunch and a plant that basically shuts down during that time. A load curve for the personal services industry would show the demand for services begins in the morning from 7 to 8 A.M. and reaches its maximum at about noontime, steadily declining till 8 P.M. The peak summer demand for power in these businesses is about twice that of its demand in winter, autumn or spring. The industry pattern illustrated by figure 2–4 is obvious even if the name weren't given. The very low demand in the early morning hours that rises gradually as the businesses begin to open at about noon or 1 P.M. and then the steep rise at about 3 P.M., continuing to rise to the peak demand at 8 P.M. and then collapsing quickly at 11 P.M. clearly illustrates the entertainment, more specifically, the movie theater industry.

Filling the Load Curve

The utility fills the load curve by bringing into operation different types of power plants. It meets the demand from the bottom up. The *base load* represents constant demand or load that is always present. Since the utility is required to generate electricity as cheaply as possible, this constant portion of load is met with the most efficient capacity. The utility wants to use a plant with the lowest heat rate that uses the cheapest fuel. It is now known that the heat rate represents the amount of fuel burned to generate a kilowatt-hour of electricity. So the plant wanted is the one that burns the least amount of the lowest-cost fuel to generate a kilowatt-hour (see Appendix 4 for prices of electricity from various utilities).

Baseload plants are efficient but expensive. Today's baseload power plants cost between $800 and $3,000 per kilowatt. Fired by coal or uranium, or in some cases "heavy" or less refined oil, they have heat rates of about 10,000 Btu per kilowatt-hour. California, for example,

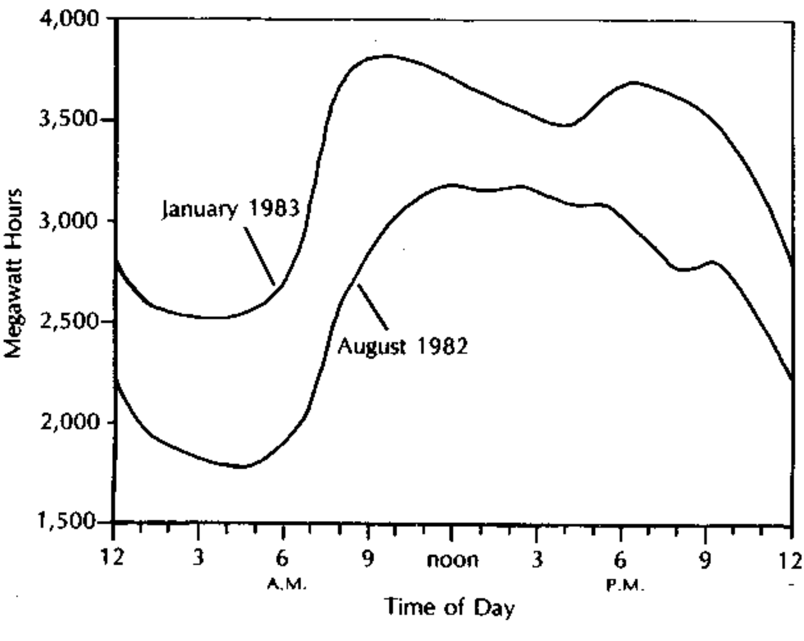

Figure 2–5: This graph shows average weekday load curves for January 1983 and August 1982 for the Pennsylvania Power and Light Company. *Redrawn from a graph provided by the Pennsylvania Power and Light Company.*

has strict environmental regulations that prohibit coal burning, so most of California's baseload plants are oil fired. Baseload plants also tend to be the newest plants. These plants operate 4,000 to 6,500 hours out of an 8,760-hour year.

Intermediate load is met with cycling units, which are usually fired by oil. These are less efficient than baseload units but cheaper to build. They have heat rates of about 11,500 Btu per kilowatt-hour. They tend to be middle-aged plants, that is, former baseload units relegated to less frequent service. Intermediate load plants operate about 1,000 to 4,000 hours a year.

Peak load is met by plants that are the cheapest to build and the most expensive to run. A typical peaking plant costs between $300 and $600 per kilowatt. Peaking plants are characterized by high heat rates, usually in the range of 13,000 to 16,000 Btu per kilowatt-hour, and the use of expensive fuels, such as oil and natural gas. Some very old oil-fired peaking plants might have heat rates as high as 25,000 Btu per kilowatt-hour. But because of their function, peaking plants usually operate only 50 to 1,000 hours a year.

Because of the higher capital cost of baseload plants, they are cost-effective only if they are run as much as possible. In this way they can spread the high capital cost over more kilowatt-hours of production, thereby lowering the average cost per kilowatt-hour. Baseload plants don't operate 100 percent of the time in part because of their forced outage and maintenance schedules.

Power Plant Performance

Each power plant facility has a name. Because of increased attention to electric rates and nuclear power, some of these names have become almost household words: Seabrook, Diablo Canyon, Bailey, Three Mile Island. The name refers to the entire complex, though each complex often contains two or three power plants, called units. Three Mile Island, for example, has three units. While Units I and II were shut down during the accident in 1979, Unit III continued to operate.

About 80 percent of our country's electricity comes from 900-odd steam plants. In 1980 steam plants generated about 58 percent of their electricity from coal, 12 percent from oil, 17 percent from natural gas and 13 percent from uranium. About half of our total electrical capacity comes from fewer than 300 power plants. About 12 percent is generated by 1,200 hydroelectric dams and 8 percent by 1,200 gas turbines (which run on average only 7 percent of the time). One percent comes from nearly 1,000 diesel generating engines located mainly in rural areas or used as small peaking plants.

Each power plant has its own unique operating characteristics. Large power plants are rated in millions of watts (Mw). An 800-Mw power plant, operating at nameplate capacity 100 percent of the time, would generate 8,760 hours times 800,000 kwh, or 7 billion kwh a year. However, no plant operates at full capacity nor all the time. The performance of the plant can be evaluated by comparing its energy production in kilowatt-hours with its nameplate rating in kilowatts. This relationship is known as the plant's *capacity factor*.

The capacity factor is a useful tool because it indicates how often the plant is generating electricity. The capacity factor includes all types of *downtime* (called outages). A failure in a major component may shut the plant down completely or partially. In the latter case the plant is said to be temporarily *derated*. Planned outages for maintenance may also be partial or complete and usually take place during off-peak periods.

Different types of plants have different outage characteristics. Nuclear plants tend to have longer outage periods than nonnuclear plants. For example, if Metropolitan Edison's Three Mile Island plant had been a coal plant instead of nuclear, the anxiously awaited "cold shutdown" would have happened in a matter of hours instead of weeks. In addition, repair crews would have had to worry only about temperature and noxious gases instead of radiation contamination.

Capacity factors directly affect the cost of electricity. For example, utility planners initially believed that even if nuclear plants were more expensive to install than coal plants, their low fuel costs would make nuclear-generated electricity cheaper than that derived from coal. But nuclear power is cheap only if the plants are running most of the time. Since nuclear plants include a higher proportion of fixed capital costs than any other type of power plant, an idle nuclear plant is a heavy financial burden on a utility. And since nuclear plants are relatively new, planners relied on the industry's estimates of 70 to 80 percent capacity factors to determine the cost per kilowatt-hour. But major studies conducted by economist Charles Komanoff in the middle and late 1970s concluded that the average nuclear plant delivered less than 60 percent of its nameplate rating during a typical year.[2] Accordingly, the cost of a kilowatt-hour of nuclear electricity is as much as 25 percent greater than previously assumed.

There is also a growing body of evidence supporting the view that there are significant diseconomies of scale. Komanoff demonstrated a clear relationship between scale and performance for both nuclear and coal plants. For each 100 Mw increase in size, the capacity factor fell off 3 percent for a nuclear plant and 2 percent for a coal plant. Robert Mauro of the American Public Power Association has remarked:

The disappointing availability record of many large units has diminished, if not entirely dissipated the theoretical savings expected from bigness. . . . Many small . . . electric utilities, which have been jeered at for operating "obsolete" plants with "teakettles" have had fewer problems in maintaining adequate power supply than some larger systems with modern large-scale units.[3]

Amory and Hunter Lovins point to one reason for the greater unreliability of large plants. "A five-hundred megawatt boiler has approximately ten times as many miles of tubing as a fifty-megawatt boiler, so 'a tenfold improvement in quality control is necessary to maintain an equivalent standard of availability for the larger unit.' A larger turbine has high blade-root stress, often forcing the designer to use exotic alloys with unexpected characteristics: highly skilled turbine designers in several advanced industrial nations have watched their turbines explode because the metal did not behave as hoped. . . . A more complex control system runs up against the discouraging mathematics of unreliability."[4]

One of the difficulties investigators have had in estimating the costs of electricity from various plants is the poor quality of plant-operating data. Up until 1979 data was collected by the Edison Electric Institute, and the reporting of data by member utilities was strictly voluntary. Now data collection responsibilities have been given to the National Electric Reliability Council, that arm of the utility industry charged with reliability planning. Many utility leaders are concerned with past inaccuracies and recognize the importance of these data for planning purposes. Also section 133 of the Public Utility Regulatory Policies Act (PURPA) requires large utilities to make public accurate cost data.

The capacity factor is a revealing statistic, but it has its limitations. It is most applicable to baseload plants because these are supposed to run full time. Since the capacity factor includes all types of plant derating and downtime, both planned and unplanned, it can distort some plant economics. Intentional curtailment of plant output, called *load following,* is supposed to occur only with cycling and peaking generating units. Utilities "follow" rises in the hourly load curve by throttling up the next-cheapest generating plant and likewise throttling back the most expensive as demand recedes. Load following is not supposed to occur with baseload plants. For optimum economic efficiency, baseload plants are supposed to be fully loaded at all times. They should be shut down only by component failure and for scheduled maintenance or refueling. Thus Komanoff initially found that coal plants have a relatively low capacity factor of 67 percent. But many coal plants are old and are used for load following. Almost 10 percent of the lost capacity factor for coal plants was due to load following. (Only 2 percent of the lost capacity factor for nuclear plants was for this reason.) If this discrepancy is taken into account, the capacity performance of coal plants rises to 75 percent.

Small power producers can expect to become expert at discussing capacity factors with utilities and public service commissions. Capacity factors serve as the basis for providing a capacity credit. Utilities will try to exaggerate their plants' capacity factors in order to reduce the amount they have to pay independent power producers. For example, some utilities will cite an 80 percent capacity factor for their own power plants and then require the independent producer to have at least that level of reliability to qualify for any capacity credit whatsoever. In this instance, a small power producer that can convince the public service commission that such a capacity factor is unreasonably high has a better chance of gaining a higher price for his or her electricity. In some states small power producers have persuaded regulatory commissions to require utilities to pay a proportional capacity credit. Thus if the small power producer achieves a 60 percent capacity factor but the utility standard is 80 percent, the capacity credit will be three-quarters the amount received if the independent producer had achieved parity.

System Load Variations and Plant Dispatch

Utilities with their own generating plants (as opposed to those that purchase all their power) have a central *dispatcher* whose job is to monitor system load and to ensure that the load is met at a minimum energy cost. In fact, the dispatcher has an unenviable task. The dispatcher (with the aid of sophisticated computers) must be familiar with the typical daily swings in system load and must anticipate these changes by making sure that adequate *spinning reserve* is on-line at any given time. Spinning reserve is a plant that is only partially loaded, ready to be "throttled up" to fuller output to accommodate greater system demand. Maintaining adequate spinning reserve makes it hard to run the system at the absolute minimum energy cost. For example, suppose a utility has one large coal plant (800 Mw), one 600-Mw, oil-fired cycling plant, and one 200-Mw peaker. Suppose further that demand at 8 A.M. is 750 Mw and is expected to rise to 1,000 Mw by 10 A.M. To meet load at the "absolute" minimum cost, the dispatcher would want to meet that 8 A.M. demand entirely with inexpensive, coal-fired generation. However, since the load will increase by 250 Mw within 2 hours, the oil-fired plant must be "spinning" in time to take on the additional load. Some large plants take 24 hours to get up and running. Smaller units can be called into service within hours from a "cold start."

Spinning reserves are made up mostly of partially loaded cycling plants. *The efficiency of plants varies directly with the fraction of the capacity that is being used.* A partially loaded plant has a higher heat rate and, therefore, high energy costs. Returning to the example, the dispatcher will probably not meet the 750-Mw load at 8 A.M. entirely with the coal plant. Instead, the load will be served by something like 700 Mw of coal and 50 Mw from the cycling unit. As the system load begins its daily ascent, the coal plant will follow the load up to its full capacity, or close to it, with the cycling plant resting for most of the rest of the day. Running the next plant at partial output in anticipation of a load swing is sometimes called *ramping*.

In the real world, things get even more complicated. Most utilities operate within power pools. Because of interchange agreements, utility dispatchers often end up shopping around among one another on the grid in search of power that can be bought more cheaply than it can be generated at the margin. *In other words, if the next kilowatt-hour can be imported more cheaply than it can be produced, then it will be bought rather than generated.*

This policy is reasonable and provides the basis for utilities to purchase power from small power producers. However, in practice, utilities are much more comfortable buying electricity from other utilities than from individual small producers. Independent producers will increasingly discover that utilities refuse to buy from them, or reduce the buyback rate because they are getting cheaper electricity from the interties. For example, in 1983 the heavy rains of 1982 and diminished electrical demand in the Pacific Northwest gave the system such a surplus of hydroelectric power that it literally had to dump water from its dams. This so-called dump power was sent through the Pacific Intertie to California at an extremely low rate, competing with small power producers who were counting on long-term contracts at much higher rates. Although the dump power was a temporary situation, it was sufficient to discourage some from entering the power production market.

Case Study: Boston Edison

Every year investor-owned electric utilities must file a report with the Federal Energy Regulatory Commission (FERC), the independent agency charged with regulating interstate sales of gas and electricity. The annual report, also known as FERC Form 1, contains a wealth of information about the operating characteristics of the utility's power plants.

Since the small power producer is going to negotiate a contract based on the avoided cost of power to the utility, he or she needs to know intimately the costs of operating the utility system. To obtain a copy of your utility's Form 1, contact the corporate finance department. If the company will not mail you one, contact your state utility regulatory commission. It has a Form 1 available for public inspection.

Form 1 contains financial statements, expense statements, and production and sales statements. Financial statements will probably be comprehensible only to trained accountants. The expense sheet lists just about every aspect of corporate operation, including political and social contributions, expenditures for regulatory proceedings, advertising, research and development, and current construction outlays. The production and sales section contains data on plant efficiency and availability.

Under the heading "Steam-Electric Generating Plant Statistics," Form 1 contains the following information about each facility.

1. Type of plant and years when first and last generating units were added
2. Total capacity in kilowatts
3. Net peak demand on plant
4. Hours connected to load
5. Net continuous plant capability
6. Net generation in kilowatt-hours
7. Cost of plant, total and per kilowatt
8. Production expense—total, fuel and per kilowatt-hour
9. Fuel—kind, quantity consumed, heat content, cost per unit, cost per million Btu burned, average cost per kilowatt-hour generated
10. Average plant heat rate

These figures apply only to each plant. They are not broken out by each unit of each plant.

The information on the following pages is from Boston Edison's Form 1 for 1981. Boston Edison's generating plants are oil-fired except for one nuclear plant, Pilgrim I. Adding up the nameplate ratings of all the oil-fired plants totals 2,079 Mw of capacity. The Pilgrim I nuclear station has a nameplate rating of 687 Mw. Therefore, Boston Edison's supply capability mix is 72 percent oil and 28 percent nuclear.

Boston Edison uses its nuclear plant more than its oil-fired plants. Form 1 shows that the generation output mix for 1981 was 68 percent

TABLE 2-1

Plant Capacity Factors and Energy Costs for Boston Edison (1980)

PLANT	CAPACITY (Mw)	CAPACITY FACTOR (%)	ENERGY COST (¢/kwh)
Edgar GT*	28.4	0.2	11.22
Framingham GT*	42.6	0.2	10.26
L Street GT*	18.6	1.0	10.53
Mystic GT*	14.2	0.2	10.28
Mystic 200	468.7	32	5.96
Mystic Unit 7	617.0	51	4.84
New Boston	717.0	68.2	4.98
Pilgrim 1	687.0	57	0.4
West Medway GT*	135.1	1.7	4.61
W. F. Wyman Unit 4†	37.2	0.2	5.65

SOURCE: Information in this table is from Boston Edison's FERC Form 1 for 1981.

* GT means the plant is a gas turbine.

† Boston Edison owns 5.881 percent of this plant.

oil and 32 percent nuclear. That should come as no surprise. Pilgrim I's fuel cost in 1981 was 0.40¢ per kwh, or 4.0 mills. The oil cost at the time for the New Boston plant was about 12 times that or 5¢ per kilowatt-hour. Indeed, given the low operating cost, Boston Edison should want to operate its nuclear plant as much as possible. In 1978 its capacity factor was 72.7 percent, but in 1981 it dropped to 57 percent. The plant was only connected to load 65 percent of the year, indicating serious operating problems.

Table 2–1 gives the plant capacity and capacity factor and energy cost for each plant. The capacity factor can be estimated by multiplying the nameplate rating by the number of hours in a year, 8,760, and then dividing that into the total electricity actually generated by the plant during the year. For example, the New Boston plant is rated at 717 Mw. If it had operated 100 percent of the time, it would have had an output of 6,300 gigawatt-hours (gwh; 1 gwh equals 1 billion kwh). But it only produced 3,500 gwh for a capacity factor of 68 percent.

As seen, the merit order dispatching procedure should lead to the cheapest operating plant being used the most. There should be an inverse relationship between the capacity factor and energy cost. This proves to be true here. The very high cost gas turbines operate at less than 1 percent capacity factor. The only plant that appears to be an exception is the West Medway GT. It used gas as well as oil and with its relatively low operating cost, one might expect it to have had a higher capacity factor. This reveals that the plant was probably not kept from operating because of economy dispatching but because of forced outages.

Table 2–1 can be used to classify Boston Edison's plants according to dispatching merit order: base, intermediate and peak load. Pilgrim I, New Boston and Mystic Unit 7 could classify as baseload plants. Thus its baseload is in the neighborhood of 687 + 718 + 617 = 2,022 Mw.

Cycling or intermediate plants should demonstrate a capacity factor of 20 to 40 percent. Plants having capacity factors of less than 10 percent would be peaking facilities. However, the plants must show appropriately higher energy costs to fit these categories.

Another guidepost in determining plant type is to determine the hours connected to load. Form 1 provides a means to do this. Peakers usually operate fewer than 1,000 hours. Cycling plants operate 1,000 to 4,000 hours, and baseload plants operate over 4,000 hours.

The relative use of intermediate and peaking facilities will depend on two factors: (1) The shape of the utility's load curve, and (2) its access to power from neighboring utilities at lower cost than power available from its intermediate and peaking facilities. In general, the lower the cost and the greater the availability of electric power from the grid, the less use your utility will make of peaking and intermediate plants.

If short-run capacity needs can be met with purchased power at a price lower than the marginal operating cost, utilities will substitute purchased power for electricity they generate themselves. Usually purchased power does not displace baseload generation unless the base load is oil fired.

Mystic 200 at 469 Mw is Boston Edison's only candidate for an intermediate load plant. It was connected to load 98 percent of the time (8,604 hours) but with an average load of 150 Mw, it had a 32 percent capacity factor.

All other Boston Edison plants demonstrated capacity factors of less than 1 percent. These are exceptionally low and suggest the influence of purchased power availability or a flat load curve (high load factor). Form 1 helps here. The page titled "Electric Energy Account" shows that Boston Edison purchased about 10 percent of its electricity from the interchange. It also shows its load curve. The peak demand comes in the summer months. The peak hours in the summer are in midafternoon, while the winter secondary peak occurs in the early evening. Interestingly, Boston Edison in 1981 sold 10 percent more electricity during the month of January than it did in the month of July, even though its July hourly peak was 10 percent higher than its January peak.

The marginal costs for each load category can now be determined. Marginal or avoided costs will be explored in greater detail in the next chapter. To complete this exercise, take the highest cost of the plants in each load category, because, according to PURPA, the qualifying facility (QF) must be paid a price equal to the cost of the most expensive plant operating at the time. For base load in 1981 the cost was 4.98¢ per kilowatt-hour. For intermediate load electricity from the single Mystic 200 plant, the cost was 5.96¢ per kilowatt-hour. Boston Edison has several peaking plants. Including the Medway GT as a peaking plant, the cost ranges from 4.61¢ to 11.22¢ per kilowatt-hour. The average is 7.59¢ per kilowatt-hour.

Updated fuel statistics are available on a monthly basis from the U.S. Department of Energy's Energy Information Administration. The report is called *Cost and Quality of Fuels for Electric Utility Plants*. It shows fuel prices and Btu content for gas, oil and coal, as well as wood chips, coke and refuse-derived fuel for the third preceding month. In other words, the utility fuel prices listed are three months old.

According to PURPA, the small power producer must be paid the full avoided costs to the utility. PURPA will be discussed in detail in the next chapter. One of its primary tenets is that utilities pay the small power producer their full avoided costs. That is, the utility should pay the small power producer the price that it would cost the utility to generate an additional kilowatt-hour of electricity. Included in this cost are the line losses incurred when the utility delivers electricity over long distances. When a producer generates power in the distribution secondary, he or she avoids not only the fuel costs but the line losses as well. Form 1 indicates what the utility's line losses are. In 1981, 5.9 percent of the electricity generated by Boston Edison was lost in transmission and distribution. Thus the above prices should be multiplied by 1.059.

There are several reasons not to recompute the short-run energy costs of the nuclear plant, Pilgrim I. The main reason is that nuclear units are rarely "throttled back" for economy dispatch. The capital costs are too high for nuclear plants to follow load. Nuclear plants rarely carry the top of the utility's load for a significant portion of the time. The reader will see that, as a result, the Pilgrim I plant has a very low energy cost, but a very high capacity cost.

The following chapter will examine in detail the issue of nuclear power in PURPA calculations. The utility has, it will be seen, in effect substituted capital for energy. Higher fixed capital costs have been substituted for lower variable fuel costs. Therefore the $2,500 per kilowatt cost of nuclear is not, strictly speaking, the capacity cost of nuclear power. A portion of it could be viewed as the energy cost. A kilowatt of capacity for a new combined cycle peaking plant is $300 per kilowatt. The difference between the nuclear capital cost and the conventional capacity cost is known as the *energy related capital cost.* It reflects the long-run marginal energy costs of nuclear power. As will be explored in more detail later on, the utility's marginal energy costs are not simply its fuel costs in the long term. And while capacity costs are composed entirely of capital costs, not all capital costs are capacity costs.

It is worthwhile to explore the relationship of Boston Edison to its regional power pool. It has an interchange agreement with the power pool. For the pool as a whole it makes economic sense for several utilities to coordinate output under a common merit order dispatch. For example, one utility may peak at a different time than its neighbor. Instead of each utility individually meeting system load with expensive peaking plants, they could together use idle cycling or baseload generating units to serve each other's load partially on a reciprocal basis.

The extent to which utilities coordinate output in this way tends to vary according to how significantly their individual loads differ and the amount and types of generating capacity they have on-line. In the most extreme and most centralized case, one utility owns a number of subsidiary utilities, each with its own generating mix. All are coordinated by a "common economy dispatch" as if there were just one utility service area. Such is the case with the New England Electric System, the Southern Company and the American Electric Power Company. Normally, however, utilities alternately buy and sell from one another under a wide variety of wholesale purchase agreements approved by the FERC. For example, Public Service Electric and Gas (PSE&G) is a member of the Pennsylvania-New Jersey-Maryland power pool (PJM). It serves member utilities in Delaware, Virginia and Washington, D.C., as well. The transmission system delivers emergency power from sources in Canada, the Midwest, New York and elsewhere. In 1981 over 40 percent of PSE&G's energy requirements were satisfied from sources outside of New Jersey. The same year it sold 270,000 Mw hours of electric energy to other systems, which meant it was buying more than it was selling. PSE&G has 14 transmission and distribution interconnections that link its service territory with the other New Jersey utilities and 13 other transmission and distribution interconnections to utilities in New York, Pennsylvania and Delaware.

The exchange position of any utility will depend on regional circumstances. Regional demand and supply conditions are fluid. The following describes the interstate power market as of 1980.

Some systems are net exporters of electricity, such as those in the Southwest. Other systems, such as those in New England or California, are net importers. However, at any given time any system can be importing or exporting. And within regions we will find individual utilities that import most of their electricity even though the region is a net exporter. Once again, the small power producer must know the position of the local utility in the broad regional power pool to negotiate a contract intelligently.

New England, especially Massachusetts, depends heavily on oil, most of which is imported. Considerable nuclear capacity is currently under construction or seeking licensing. Boston Edison's abnormally low peaking plant capacity factors suggest that it relies on economy interchange agreements to cover its peak loads. New York State has been a big supplier of electric energy and capacity to the New England region, largely via the Power Authority of the State of New York. While New York City's Con Ed is relatively oil-dependent, the state has a good mix of hydro, nuclear and coal generation. The region is currently a big exporter with relatively little power imports.

The Mid-Atlantic/Midwest utilities are primarily exporters with a predominance of coal and nuclear generation. The giant American Electric Power Company, a holding company in the Midwest, is an especially big interchange supplier because of its access to a large capacity of reliable coal generation.

Southeastern United States is dominated by another holding company, Southern Companies, Inc. Nuclear is a heavy contributor in the region.

The South-Central region is dominated by the Tennessee Valley Authority (TVA), which is the federal bulk power supplier to many public and private distributors. It relies on hydro, nuclear and coal, although gas represents a significant part of the generation fuel outside of TVA in this region.

The far Western region, specifically California, has become a large interstate buyer recently, because the state Public Utilities Commission (PUC) wants to decrease the use of the state's preponderance of oil-fired plants and restricts the construction of coal or nuclear plants. While California's unique water pumping needs have been met from the Pacific Northwest via the federal Bonneville Power Administration

(BPA), purchases of all types from the Southwest region (Arizona, New Mexico, Utah and Colorado) are increasingly important.

The Pacific Northwest has long been a bulk power exporter because of its enormous hydroelectric capacity and the fact that its peak output coincides with southern California's peak demand. However, this region will reach the limits of its hydro capacity by the mid 1980s. Coal and nuclear will play an increasing role in its supply mix after that time.

System Reliability

System reliability is an important consideration in utility planning. *Reliability* is the predetermined acceptable rate of failure of a utility's entire system (when demand exceeds available supply). The utility standard is that such a situation should occur only one day in ten years. This is a very high quality service, and one that costs a great deal to maintain. All utilities install a certain amount of *reserve margin capacity*. As load grows and capacity remains fixed, the reserve margin shrinks, and the loss of load probability (LOLP) increases (reliability deteriorates). Conversely, if load were fixed and capacity were added, LOLP would fall (reliability improves). Reliability planning is most correctly applied to a *power pool*—a group of neighboring utilities—rather than to a single utility in isolation.

Recommended reserve margins have increased in the last 15 years. The reserve margin is the amount of capacity that's held in reserve, over and above the capacity to meet the peak demand. The recommended amount of reserve capacity has increased from 15 percent of peak demand in 1960 to 25 percent today. Still many utilities in the Midwest and Mid-Atlantic regions have reserve margins above 30 or even nearer 50 percent. Utilities in New York State have on average half of their entire system capacity standing idle even at peak periods of the year. This is taking place even while utilities learn that the vast majority of power disruptions occur because of failures in transmission and distribution facilities and not because of generating capacity shortages.

System reliability is under scrutiny because some customers who don't require a very high reliability factor may be paying the cost of maintaining the extremely high utility reliability standard. What exactly are the consequences if a utility lets its LOLP rise above one day in ten years? Another way of posing the same basic question is to ask what is the cost of underinvestment in capacity. Utilities would have the public believe that the cost is enormous—that a power shortage would produce calamity. The truth is that a temporary capacity deficit does not inevitably lead to a system collapse. Peak demand can be cut by reducing unnecessary power consumption and by automatically cutting off or cycling certain appliances (cutting off air conditioners 15 minutes on the hour in rotating fashion, for example).

The issue of reliability could have some important ramifications for small power producers. If customers decide to choose lower reliability (that is, a higher incidence of outages) in return for lower rates or internal storage or backup systems, the rates paid small power producers will change.

The costs of inadequate load-carrying capacity are different for different customer classes. A low-income residential community might not require the type of total system reliability standard for which utilities now strive. For them the only end use considered essential during the system peak might be food storage (refrigeration). On the other hand, an expensive hotel district might demand sufficient electrical capacity to meet all of its guests' needs and desires all of the time (especially for air conditioning). The residents of that district might accept a LOLP of one day in ten years. An industrial enterprise might need very high reliability because of the economic loss due to a plant shutdown even for a few hours. In fact, industries such as these often have an internal backup capacity. That is, they require even a higher degree of reliability than the utility can now guarantee. Hospitals also cannot afford a power blackout at any time. They are legally required to have back-up systems available in case of power outages.

The issue of reliability will play an increasingly important role as communities begin to install their own generating capacity. For example, a community might contract for a certain amount of firm service to supply what the members view as essential end uses. The rest of the desired service will come from a mix of wind, photovoltaics and cogeneration—electricity produced by and for the neighborhood itself with the surplus fed back into the grid for resale to other customers. These sales would be credited against the cost of the neighborhood's guaranteed minimum supply from the utility. Lowering the reliability requirements leads to cheaper power costs. Reliability refers to service quality with respect to system peak. An agreement to provide firm power off-peak carries with it no capacity costs, because by definition off-peak periods are those during which the utility has an abundance of unused generating capacity.

Residences do not yet have the ability to contract as proposed by this hypothetical community. But commercial and industrial enterprises now have the ability in most states to contract for "interruptible" power. The utility charges them less in return for being able to turn off their power at certain times of the year. The system saves money that would have had to be spent in adding new capacity, and the commercial customer shares in these savings.

Utility Planning

These days, a utility's plan to build a new power plant is a billion-dollar effort based on uncertain information about the future. Large generating stations may take 2 or 3 years for licensing and an additional 8 to 9 years for construction. If these plants are to come on-line in timely fashion, the utility must take action over a decade in advance of the actual need for electric power. To anticipate the amount of new capacity that should be initiated, the utility prepares 10- to 12-year forecasts of the demand for power.

Historically, electric demand followed a rather smooth growth trend, growing at an exponential rate of 6 to 7 percent a year. It doubled every ten years. One of the reasons for this fast growth was the decline in the price of electricity. Fuel prices dropped, and it was cheaper to build new power plants than to operate older, existing plants. Therefore, if the utility tended to overestimate future demand and build too many new plants, it could simply retire the older, more expensive ones somewhat sooner without imposing a large price penalty on the consumer.

Beginning in 1970, fuel and electricity prices began to rise. At first utilities and their regulators continued to use the old rules of thumb to predict future demand. As late as 1973, commissioners and utility staff maintained that, even if electric prices were to rise, the effect on customer demand would be negligible. They argued that the cost of power still represented such a nominal part of a business or household budget that higher prices would not change demand.

They were wrong. Mathematician Edward Kahn, of the Lawrence Berkeley Laboratory, examined the forecasts of the Edison Electric Institute, the industry's trade association, from the late 1960s through the late 1970s. Writing in 1979, he concluded "that forecasts are almost always too high and that accuracy is poor. Only once during the last eleven years has the industry underpredicted, and this was only by a tenth of a percent. More important, the consistent pattern of overestimates became much more exaggerated after 1974." Forecasts that were on average 2.1 percent too high between 1968 and 1972 were on average 5.1 percent too high after 1974. Kahn added, "The average forecast error is larger than the average annual growth rate over the last five years."[5]

The financial penalty attached to incorrect forecasts was exacerbated by the rising cost of power plants. Plants built since 1970 have proved to be substantially more expensive than their predecessors. Poor forecasting translates directly into higher rates. According to a 1979 article by *Public Utilities Fortnightly,* a utility trade magazine, the industry's reserve margin as of year-end 1978 was 38 percent. If one willingly accepts the industry's standard reserve margin of 20 percent, there is still an excess capacity of 18 percent. The investment (by investor-owned utilities) in this excess capacity exceeded the total of all new plant additions in the preceding four years, representing a total investment of $65 billion! Given the average cost of capital for utilities of 15 percent, this can be converted into an annual revenue burden for the entire industry of $10 billion, or 10 to 15 percent of these investor-owned utilities' total revenue requirement!

The revolution in the cost of power and the nature of demand changes led regulatory commissions to adopt a more aggressive role. Until the mid-1970s, regulatory commissions did little more than divide up the surplus money generated by new power plants and increasing sales. But as rates began to escalate and utility-sponsored demand forecasts proved inaccurate time and again, the regulatory commissions began to assume a role in overseeing investment strategies. Aided by state legislatures that gave them this increased authority, commissions began to examine the resource plan of utilities. In an increasing number of cases, commissioners recommended delay or cancellation of proposed power plants in the light of softening demand.

Increasingly they forced utilities to justify new plant expansions or specifically refused to allow rate increases to pay for additional capacity. In several states, encouraged or directed by state legislatures, the public service commissions required utilities to encourage energy conservation. California and Minnesota, for example, required utilities to become bankers and finance energy conservation. Wherever the utility could save a kilowatt-hour for less than it could generate an additional kilowatt-hour, the public service commissions required it to do so.

Some utilities, such as the New England Electric System, needed relatively little persuasion to move in the new direction. Their executives realized that conservation improved their internal balance sheet, improved the value of their stock and allowed them to borrow money at lower costs. Most utilities refused to be so farsighted. Commonwealth Edison and Con Ed were among the most reluctant to encourage conservation. Although they argued that with an excess system capacity conservation could do no more than raise the rates, they also argued that they would need additional capacity within the decade. Regulatory commissions increasingly found such arguments self-serving and internally inconsistent. The federal government added its authority to encourage this change.

In 1978 the U.S. Congress enacted two pieces of legislation intended to redefine the role of utilities. The National Energy Conservation and Production Act required utilities to provide energy audits for residential customers and to provide assistance in encouraging energy conservation programs. PURPA required state regulatory commissions and large unregulated utilities to collect and examine data that would exactly identify the costs of serving various customer classes. PURPA also required an examination of rate structures to identify how they might be changed to encourage investments in cost-effective energy conservation or renewable energy measures. Many states required utilities actually to finance energy conservation or solar technologies.

Utilities and regulatory commissions also improved their forecasting models, but this alone could not eliminate planning uncertainties. Differences in demand forecasts are unavoidable. Depending on the assumptions that are employed, a variety of different forecasts can be obtained. Andrew Ford and Irving Yabroff, two utility experts at the Los Alamos Scientific Laboratory, conclude, "The development of more sophisticated forecasting methods will not eliminate the underlying uncertainty that will accompany every forecast of the future demand for electrical power."[6]

One way to reduce uncertainty is to encourage smaller power plants to come on-line more rapidly. As Kahn says, "The extended planning horizon required for large projects imposes a serious risk of excess capacity. Shortening the lead time for supply reduces exposure to this risk."[7]

Looking at it from the insurance company's perspective, small power plants reduce the risk premium. They can more easily match changes in demand with changes in supply. Rather than making 12-year forecasts, the utility need only accurately forecast demand for 3 to 5 years.

Another advantage to small-scale systems was that they increased the overall system reliability. Systems with a diversity of small power plants tend to have smaller forced outage rates than those dependent on one or two large plants. Moreover, the reserve margins can be lower. One 1,000-Mw plant requires an equally large one in reserve, but ten 100-Mw plants require far less reserve capacity to guarantee the same reliability.

Rate Schedules and Marginal Cost Pricing

In 1975 *Business Week* reported, "Without some fundamental changes, the situation will soon mount to crisis proportions. Rate reform seems inevitable. Big users will have to pay more per kilowatt-hour rather than less, and customers who want power during peak demand periods will have to pay a premium for this privilege."[8] The problem with the traditional rate structure was that it assumed a declining marginal cost of power, so electricity was priced on the basis of past, rather than future, investments. The price paid for electricity today is based on the cost of all the transmission and distribution lines and power plants already built. Much of this investment occurred decades before, when power plants and transmission lines were much less expensive. In fact, much of this investment has already been written off through depreciation.

This investment represents a utility's rate base. State regulatory commissions allow utilities certain rates of return on their rate bases. The return varies depending on the state and the utility. Today it ranges from 11 to 17 percent. To this cost is added the cost of fuel, and the total is divided by the number of kilowatt-hours purchased. That gives the average retail cost per kilowatt-hour, which forms the basis for rates.

When the marginal cost of energy began to increase in 1970, the electric utility ratemaking structures no longer gave customers accurate price signals. New power plants cost considerably more than old ones. Yet customers have continued to pay prices that encouraged more consumption. The greatest discrepancy between old and new is still taking place in the Pacific Northwest. Most of its power comes from hydroelectric facilities built a half century ago. The investments in these facilities have long been repaid. Free hydropower "fuel" and low operating and maintenance costs combine to give the Pacific Northwest the lowest electric rates in the nation—an average of 2.5¢ per kilowatt-hour in 1982.

But with its large-scale hydroelectric capacity fully taken up by demand, the region has had to meet additional demand with coal or nuclear steam generating plants. New electricity from these plants can cost the utility 7¢ to 15¢ per kilowatt-hour. But when a new coal or nuclear plant begins operating, customers don't "see" that price. The new, high-cost electricity is blended in with the much larger quantity of very low-cost, old electricity. Rates creep upwards. Customers don't pay 7¢ to 15¢ but instead pay 2.8¢ or 3¢.

The result of this pricing policy is that the customer has no incentive to save electricity even though by doing so the entire region could save money by avoiding the need for new power plants. By installing attic insulation, for example, a customer might be able to save a kilowatt-hour of electricity for 3¢ (per kwh saved). To the utility, a kilowatt-hour saved is equivalent to a kilowatt-hour generated. The customer could thus "generate" a kilowatt-hour at less than half the cost of even the cheapest new steam generating plant. But the customer will not undertake such conservation, because the investment, while cost-effective from the utility's vantage point, is not cost-effective from the homeowner's perspective. Electricity is just too cheap for the homeowner to worry about conserving it. Meanwhile, huge rate increases wait just around the corner as the utility builds very expensive new power plants to meet demand that is increasing in large part because electricity prices are so low.

A utility's rate structure is described in its *tariffs*. Each class of customer has a different tariff, and there can be several tariffs for each category. Separate tariffs can exist for small businesses and large businesses, for residences with electric space heating and for those without, for street lighting and so forth.

Your monthly bill usually consists of three components: a customer charge, an energy charge and a demand charge. The *customer charge* is a flat amount that is paid whether you use electricity or not. This charge is supposed to represent the costs of administrative overhead, meter reading and billing associated with that customer class.

The customer pays a minimum *energy charge* even if the consumption that month were only 1 kwh. Thus the first 50 kwh consumed can cost up to 20¢ per kilowatt-hour. The energy charge can be flat, meaning that no matter how much one consumes, the charge per kilowatt-hour remains constant. Or the energy charge can be divided into tiers, with each block of energy usage charged at a different rate. The practice used to be that the more one used, the less one paid per kilowatt-hour. This is changing rapidly. Now flat rates and even inverted rates are increasingly common.

The third component of the monthly bill is the *demand charge.* Residences do not pay demand charges. These are charges based on the highest amount of power consumed in any small time interval during a month. Often the separate demand meter has a ratchet on the register. The highest demand reached for any 15-minute period is the demand for billing purposes for the entire month. Many utilities carry over the ratchet effect so that one pays in succeeding months the highest demand reached during that quarter or that year. The utility argues that it must have capacity available all year to meet the highest momentary demand and therefore should charge all year for that one 15-minute spurt.

For examples, examine three different tariffs from Green Mountain Power Corporation. For the Residential Rate 01, the customer charge is $5.50, an amount that a customer pays even if no electricity is used that month. Energy charges vary by season. The two tiers of energy charges represent a sharply inverted pricing structure, especially for the peak season, for that is when one is paying for capacity that is in excess (unused) during the off-peak months. (This utility's peak occurs during the five winter months.) This tariff is unusual in that it gives Green Mountain the right to install load management equipment for electric water heaters and storage space heaters. It can send a radio signal to turn off power to the storage systems at peak times essentially to limit peak loads.

Green Mountain's General Rate 06 applies to nonresidential applications where the demand is less than 500 kw during the peak months. A commercial customer pays a slightly higher minimum charge than the residential customer. The flat-rate structure of this tariff varies dramatically by season. The commercial business also pays a demand charge of 50¢ per kilowatt of connected load. Those with connected loads greater than 40 kw pay $1 for each kilowatt of measured demand. An interesting provision is that 1 HP is taken as 1 kw, even though it actually translates into 0.75 kw. Load control is also permitted here as in the first tariff.

Green Mountain's Power Rate 14 tariff is available to all customers except for use as supplemental or standby power. It is characterized by a flat demand charge and flat energy charge. The demand charge is almost twice as high in the peak as in the off-peak season, and the energy charge drops by one-third in the off season. This tariff illustrates ratcheting carried over into later months. The demand charge for any given month is based on a measured demand not less than 50 percent of the highest 15-minute peak occurring during the preceding 11 months.

This tariff also contains a provision for power factor adjustments, an efficiency factor that will be discussed in greater detail in the interconnection chapter. Basically, the lower the power factor the more power the utility has to supply to meet a given load. Here the demand charge is increased by 1 percent for each 1 percent by which the average monthly power factor lags below 85 percent.

The Power Rate 14 tariff also gives the customer a credit for avoided transformer losses if the power delivered is measured on the primary side of the step-down transformer. The customer charges are discounted by 2.5 percent. If the customer uses 2.3-kv electricity directly or furnishes the transformer, it receives a credit of 24.1¢ per kilowatt of demand used for billing purposes.

Rate structures are changing rapidly. Title I of PURPA encourages utilities and regulatory commissions to restructure rate schedules to encourage cost-effective conservation and small-scale power facilities. The review of existing rate structures is mandatory. But the revision of the rate schedules is voluntary. Most states are moving toward *marginal* *cost pricing,* which revises rates so that the customer pays the genuine cost of his or her demand on the electric system. This means introducing flat or even inverted rate structures in which the customer pays more for the last unit of electricity consumed than for the first. It also means introducing *time-of-day pricing,* where the customer is charged more for electricity consumed during the peak hours of the day or year than for those purchased during the off-peak hours. These new rate structures encourage customers to invest in conservation and also to level or flatten their load curves. Using automated equipment, some commercial enterprises have found that their individual load factors (base load divided by peak load) can thus rise from 50 percent or less up to 95 or even 99 percent. A 50 percent load factor means that the peak load is twice that of the base load. The firm saves by reducing its demand charges from the utility. The rest of the utility's customers and stockholders save by sharing in the savings gained from not having to borrow money for new power plants.

This chapter has described the basic functioning of the present electrical generation and transmission system, but the coming years should see a massive structural change in this system. Millions of additional generating facilities will be added to the existing 4,000 power plants. Compared to conventional plants, each of these new additions will generate only an infinitesimal quantity of electricity, but their combined capacity will be substantial.

The new era began in 1970 when for the first time in 100 years the marginal cost of energy increased. That event changed the nature of our electric pricing system. When marginal costs are declining, it is economical and efficient to encourage greater usage. The more demand, the lower the costs. But when marginal costs are rising, an opposite dynamic occurs. It becomes more efficient to discourage demand and encourage conservation. It also becomes more efficient to promote cost-effective small power production, especially of renewable-based technologies that are immune from future fuel price increases.

For the homeowner, apartment dweller and businessperson, the change was formalized in 1978 with the passage by Congress of the Public Utility Regulatory Policies Act. Along with regulations already discussed, that act made the development of decentralized power generation a national policy and made illegal any efforts by utilities or state regulatory commissions to obstruct that development. Chapter 3 provides further explanation of that act and its consequences.