COMPARING ELECTRICITY DEREGULATION IN CALIFORNIA AND PENNSYLVANIA: IMPLICATIONS FOR THE APPALACHIAN REGION

FINAL REPORT TO
APPALACHIAN REGIONAL COMMISSION
ARC CONTRACT NUMBER CO-12884

JANUARY 15, 2002

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ACKNOWLEDGEMENTS

In the course of this project, we had helpful conversations with a number of people, including Tim Brennan, Howard Gruenspecht, and Karen Palmer of Resources for the Future, Terry Boston, Wayne Gildroy, and Mark Medford of the Tennessee Valley Authority, Doug Hale, Gary Merinholz, and Tracy Terry of the Energy Information Administration, John Hangar of Citizens for Pennsylvania's Future, Udi Helman, David Hunger, Paul Sotkeiwicz, and Roland Wentworth of the Federal Energy Regulatory Commission, John Kelly and Michael Nolan of the American Public Power Association, Steven Kirchoff of the National Rural Electric Cooperative Association, and Irwin Popowsky, Consumer Advocate for the State of Pennsylvania, Samantha Slater of the Electric Power Supply Association. We also thank Roy Hampton, Joseph Rix, Supawat Rangsuriyawboon and Bo Yang for excellent research assistance, and Gregory Bischack of the Appalachian Regional Commission for excellent comments.

EXECUTIVE SUMMARY

Energy policy is once again in the national spotlight. The U.S. economy grows ever more dependent upon foreign sources of energy. The promise of alternatives to conventional fossil fuels has yet to materialize. While great strides have been achieved in energy conservation, the rising tide of economic activity has steadily eroded these gains so that after a decade of strong economic growth, energy supply constraints and rising prices are once again a concern.

Nowhere have these concerns been more pressing than in California. With soaring electricity prices, blackouts, and bankrupt utility companies, the economic and political fabric supporting regulatory reform of the electricity industry in California has been severely frayed. Based upon this experience, many states are hesitating or delaying plans to deregulate their electricity industries. Pennsylvania, however, has progressed down the path of reform with no apparent deleterious effects. This study attempts to understand why there is such a sharp dichotomy in these experiences, serving as a primer on electricity deregulation for state policy makers in the Appalachian region.

The basis for historical regulation of the electricity industries has been to deal with natural monopoly[1] issues in the production of electricity. While it may be the case that distribution, system operation, and perhaps transmission are, in some sense "natural monopolies," the same cannot be said about the generation of electricity. In most significant economic regions, electricity is generated at a large number of locations. In

[1] A natural monopoly occurs when the costs of production in an industry can be minimized by having only one firm. See, for example, Carlton and Perloff (2000, 100).

addition, there is no obvious reason why the retailing of electricity constitutes a natural monopoly.

Restructuring the electricity sector promises a more competitive industry that over the long run would generate efficiency gains. Producers of electric power would more efficiently utilize primary fuels, labor, and other resources to generate power. Power transportation networks would be better planned and managed so that the grid is supplied with the lowest cost combination of plants. On the demand side, consumers would make more efficient choices because they would be paying the true incremental cost of electric power, which could vary by time of day.

Unlike the deregulation of many other industries in which government involvement was phased out completely, as with price controls on natural gas and oil, deregulation of electricity is more complicated. In many ways, electricity markets are not really deregulated but restructured. The unique aspects of electricity, both real and perceived, are discussed in this report to provide some insight into what electricity restructuring actually means.

Our comparative analysis of restructuring efforts in California and Pennsylvania raises a number of broader regulatory policy issues. These issues include monitoring markets for excessive markups over marginal cost, consumer protection and marketing, nuclear power re-licensing and permitting, and some rather thorny issues involving market coordination between generators and transmitters of electric power.

States within the Appalachian region have responded in different ways to the possibility of electricity restructuring. In Pennsylvania, Maryland, West Virginia, Ohio, and Virginia, the legislature has passed bills requiring restructuring. (West Virginia's plan is currently on hold.) Pennsylvania's restructuring is complete, while New Jersey's is well under way. In addition, the regulatory commission in New York has approved restructuring, and restructuring in that state is underway.

In contrast, North Carolina, South Carolina, Kentucky, and Mississippi have investigations on restructuring pending, but none has implemented restructuring. No official actions on restructuring are taking place in Tennessee, Georgia, or Alabama. Several countries around the world have also restructured their electricity sectors.

More than 70 percent of electricity generation capacity in the ARC is coal-fired steam generators, reflecting the relative abundance of coal in the Appalachian region. Another 15 percent of capacity is hydroelectric power while nuclear capacity comprises 12 percent of total capacity. The remaining 2 percent of capacity is primarily steam generators using fuel oil and natural gas. This mix of power is likely to create far less volatility in market prices than a sector based largely on natural gas generation, such as in California.

It is important to understand that there is no one method to undergo electricity restructuring. We examine closely the two most prominent examples of electricity restructuring in the United States, in California and Pennsylvania, as well as the experience with restructuring in England and Wales. Each of these systems has their advantages and disadvantages. Recent events in California have shown the disadvantages of the approach chosen there. All three systems have acted to limit opportunities for retail choices.

A combination of factors contributed to the spike in wholesale electricity prices in California from June 2000 through early 2001. The chief culprits were an unanticipated surge in electricity demand and a lack of low cost electricity supply. For over a decade, it had been extremely difficult to site new power plants in California. The state had become highly dependent on hydroelectric sources, power from natural gas plants, and imported power. To exacerbate the problem, available supplies from hydroelectric facilities were greatly reduced during this time period. The regulatory system, which froze retail rates, contributed to blackouts and utility company bankruptcies. Much, though not all, of the increase in price can be attributed to the reduced supply of power and the increase in the price of natural gas. The exercise of market power is a natural candidate for the remaining part of the price increase.[2] It is important for policy-makers in the Appalachian region to understand, however, that the structure of electricity supply in Appalachia is much different than it is in California.

Many unanswered regulatory questions still remain for restructured markets. The future role of nuclear power is unclear, and may depend on how issues of waste disposal and insurance indemnity are dealt with by the Congress. Market power issues remain important, and regulators continue to learn more about the potential for the exercise of market power in electricity markets. The creation of independent system operators, and their continued effective governance, is important in the efficient operation of electricity markets. It is unclear how markets to build new transmission capacity will evolve, and how new transmission lines will gain regulatory approval.

[2] Market power refers to the ability of firms to profitably affect price by restricting supply.

The regulated electricity system has a number of important structural deficits. Most importantly, it provides poor incentives for cost-reduction, as well as acting to reduce choices that are available to consumers. By putting the production and marketing of electricity into a competitive market, restructuring offers the opportunity for substantial gains for society.

This is not to say, however, that electricity restructuring is a panacea. The gains from restructuring will take substantial time to accrue. In this sense, we suspect that its proponents oversold restructuring. We suggest that real price reductions and increases in consumer choice will occur, but that they may not take place immediately upon the beginning of restructuring. Further, any new efforts at restructuring must take into account the results of previous restructuring efforts. In this light, we have several recommendations for any state wishing to restructuring its electricity market.

- Restructuring should not place any limits on trading in wholesale markets, as occurred in California
- Restructuring plans often call for the use of price caps to deter the exercise of market power in both wholesale and retail markets. Unfortunately, price caps have significant negative consequences, in that they send the wrong price signals to both consumers and producers.
- An integral part of any restructuring plan is the recovery of utilities' stranded costs. Unfortunately, the method chosen for doing so in California and Pennsylvania had important drawbacks. We suggest that a stranded cost "tax" be attached to every kilowatt-hour of power sold in relevant areas. This would act to encourage innovation in the retail market for power.
- Part of the rationale for restructuring is to allow new firms into the market for generation of electricity. This requires that environmental and zoning restrictions on generation should allow for the construction of new power plants within a relatively short amount of time.
- Independent System Operators serve to facilitate trade between parties in wholesale power markets. We, therefore, applaud the Federal Energy Regulatory Commission's (FERC) efforts to create such organizations, though this may prove difficult.

- Any gains from restructuring can be diminished by the exercise of market power. We therefore suggest that regulators review carefully the ownership structure of generation in the industry prior to the onset of restructuring, and require the appropriate divestitures.

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CHAPTER I. INTRODUCTION

Energy policy is once again in the national spotlight. Despite the 1970s dream of Project Independence to eliminate oil imports by the year 2000, the U.S. economy grows ever more dependent upon foreign sources of energy. The promise of alternatives to conventional fossil fuels has yet to materialize. While great strides have been achieved in energy conservation, the rising tide of economic activity has steadily eroded these gains so that after a decade of strong economic growth, energy supply constraints and rising prices are once again a concern.

Nowhere have concerns been more pressing than in California. With soaring electricity prices, blackouts, and bankrupt utility companies, the economic and political fabric supporting regulatory reform of the electricity industry in California has been severely frayed. Based upon this experience, many states are hesitating or delaying plans to deregulate their electricity industries. Pennsylvania, however, has progressed down the path of reform with no apparent deleterious effects. This study attempts to understand why there is such a sharp dichotomy in these experiences, serving as a primer on electricity deregulation for state policy makers in the Appalachian region.

The seeds of deregulation were sown in 1978 when Congress passed the Public Utilities and Regulatory Policy Act (PURPA) that among other things allowed independent generators to sell their electricity to utilities at rates which were typically the highest marginal cost of generation. Also during this time, new electric power generation technology utilizing jet engines recycling exhaust gases became commercially viable, operating efficiently at relatively small scale with clean and relatively inexpensive natural gas. Given long lead times, substantial environmental control costs, and the high capital costs of building large coal-fired electric power stations and similar obstacles facing nuclear power, most new generation capacity in the U.S. since 1985 has come from independent power producers using combined-cycle natural gas turbine technology.

During the early 1990s it became clear that fundamental change was occurring in the generation of electric power and that regulatory policy needed to respond. The vision of a competitive market in electric power generation appeared feasible with the correct regulatory stance. Congress acted in 1992 by passing the Energy Policy Act, which induced the Federal Energy Regulatory Commission (FERC) to issue Order 888 in 1996, forcing utilities with transmission networks to deliver power to third parties at nondiscriminatory cost-based rates.

With this door open, several state public utility commissions adopted customer choice programs and other policies to disaggregate retail prices into generation, transmission, distribution, and transition charges (Joskow, 1996). These policy initiatives recognize that while electrical transmission and distribution remain natural monopolies, competition in generation is possible with open access to transportation networks. Under these emerging regulatory regimes, generation companies would no longer operate under guaranteed rates of return on capital or automatic fuel cost adjustment clauses.

Unlike the deregulation of many other industries in which government involvement was phased out completely, as with price controls on natural gas and oil, deregulation of electricity is more complicated. In many ways, electricity markets are not really deregulated but restructured. The unique aspects of electricity, both real and perceived, are discussed in the next chapter of this report to provide some insight into what electricity restructuring actually means.

With this background, our report then provides some perspective on the role of the electricity industry in the Appalachian region and its relationship with adjacent regions and the U.S. electricity market as a whole. One of objectives of this study is to provide some factual information on how capacity, costs, and demand growth varies between regions. This is an essential first step in understanding why deregulation has turned out so differently in California and Pennsylvania. This analysis will reveal that having an adequate and diverse mix of generation capacity is an important consideration in reducing the volatility of electricity prices.

With an appreciation for the fundamental technological and economic factors affecting the performance of the electricity industry, our analysis then shifts to policy. What are some alternative approaches to restructuring? To address this question, we compare restructuring plans in England and Wales, Pennsylvania, and California. Restructuring legislation is inherently complex, involving a compromise between various segments of the electricity industry and different classes of consumers, such as large industrial consumers and households. Surprisingly, Pennsylvania law allows retail price caps, which are often denounced as one of the principal factors contributing to California's problems. Nevertheless, there are substantial differences between these restructuring plans, differences that are discussed in Chapter four.

The next chapter examines the performance of electricity markets in California and Pennsylvania after restructuring. Performance is measured using a variety of indices, including costs, prices, profitability, reserve margins, and new capacity additions. Using the structural cost analysis from Chapter three, we estimate the composition of factors contributing to higher electricity prices in California after restructuring. We find that even if California did not deregulate its electricity industry, it would have faced higher electricity prices for several reasons, including a shortage of generation capacity and bottlenecks in producing and delivering additional natural gas supplies for power generators.

Our comparative analysis of restructuring efforts in California and Pennsylvania raises a number of broader regulatory policy issues that are addressed in Chapter six. These issues include monitoring markets for excessive markups over marginal cost, consumer protection and marketing, nuclear power re-licensing and permitting, and some rather thorny issues involving market coordination between generators and transmitters of electric power. Roughly two-thirds of all electric power in the U.S. is generated from coal and Appalachia is the one of the leading coal producing regions. The tumult in electricity and natural gas markets are having an impact on the coal industry, which appears to be emerging from a long slump. Our goal here is to define and explain what the issues are and identify some potential solutions.

Chapter seven examines the implications of electricity restructuring for economic development. The ARC region enjoys some of the lowest electric power rates in the country, which bodes well for future economic development, but also may reduce incentives for restructuring. The chapter provides an overview of economic development programs by private utilities and the Tennessee Valley Administration (TVA). We also examine restructuring issues facing the TVA. Our report concludes with a summary of our policy recommendations.

CHAPTER II. WHAT IS ELECTRICITY RESTRUCTURING?

Deregulation generally entails the removal of some form of overt government controls on decisions by firms. Until recently, nearly all investor owned electric utilities in the U.S. were subject to rate of return regulation, in which companies petition state public utility commissions for permission to charge customers rates that would cover expenses and a rate of return to stock and bond holders. Most of these companies are vertically integrated; owning generating plants, inter-city transmission lines, and local distribution networks. Eliminating rate of return regulation generates a number of potential benefits but also creates the need for a market to determine electricity rates. *Restructuring* essentially involves the creation of these markets and the dissolution of the vertically integrated structure of the industry.

We begin this chapter with an explanation of why society should consider restructuring the electricity industry, noting the importance of electricity to the economy, pointing out the lessons learned from deregulating other industries, and identifying the potential gains from restructuring. Our discussion then provides an overview of the basic economics of electric power generation, transmission, and distribution. Given these basic economic features, we then develop the rationale for regulation and restructuring in the industry. From this context, we then describe the general forms of deregulation and what states in the Appalachian region have restructured the electricity sectors of their economies.

WHY RESTRUCTURE?

Restructuring the electricity sector promises a more competitive industry that over the long run would generate efficiency gains. Producers of electric power would more efficiently utilize primary fuels, labor, and other resources to generate power. Power transportation networks would be better planned and managed so that the grid is supplied with the lowest cost combination of plants. On the demand side, consumers would make more efficient choices because they would be paying the true incremental cost of electric power, which could vary by time of day.

While there may be a large potential for gains from restructuring, there are also potential drawbacks. These potential gains may not be realized. If restructuring is not handled properly, unregulated generation firms could exercise market power and raise the price of electricity above competitive levels. Gains from metering may only be available to large consumers, or consumers who can gain access to the knowledge needed to implement a cost-effective metering in their homes.

IMPORTANCE OF ELECTRICITY

These benefits of restructuring could be substantial. Households and businesses in the U.S economy spent about $228 billion on electricity during the year 2000, constituting slightly more than 2 percent of gross domestic product. The importance of electricity to the economy, however, is larger than its share of national output. Almost every major facet of a modern home and business, from lights to cooking utensils to computers to internet connections, depends upon electricity. Recent electrical blackouts in California have shown how dependent society is upon the delivery of electricity.

While significant efficiency losses occur during the generation and transportation of electricity, it is a very efficient fuel in end-use applications, particularly in motors, metal smelting, and other industrial applications. Moreover there are many applications in which electricity is the only practical source of energy, such as illumination. In addition, electricity powers the digital economy including computers and the telecommunications equipment supporting the internet. These end-use efficiency advantages and the growth of electricity intensive sectors have contributed to an increasing electrification of our economy. Providing an economic service of this importance more efficiently and in a way that is more attractive to consumers would be unambiguously good for the economy.

LESSONS FROM OTHER INDUSTRIES

Much of the impetus for electricity restructuring comes from the success of deregulatory efforts in other industries, such as airlines, railroads, and natural gas. These experiences provide some important lessons for electricity restructuring.

Prior to 1978 the airline industry was subject to both price and entry regulation. For an airline to provide service on a particular route, it had to gain approval from the Civil Aeronautics Board (CAB). The CAB, however, only had authority over interstate routes. Unregulated intrastate markets existed in California and New York. The rates on the unregulated intrastate routes were significantly lower than rates on comparable interstate routes, leading to calls for interstate deregulation. A similar disparity in electricity rates between regions motivated Pennsylvania's move toward deregulation.

In 1978 the airline industry was deregulated at the Federal level. New firms entered the market, and prices, in general, fell. Over time, markets became more concentrated as many airlines dropped out of business. The decline in prices has not been consistent across city pairs. One of the largest recent problems facing the airline industry is the stress on the capacity of the air traffic system (which is still run by the Federal government). This stress, however, is viewed as a measure of the success of deregulation in stimulating the supply of commercial air transport. Indeed, transportation network bottlenecks are a significant concern as more states deregulate their electricity industries.[3]

Also prior to 1978, the Interstate Commerce Commission (ICC) directly regulated the railroad industry. The ICC set rates on rail shipments across the country. In addition, the ICC directly mandated the way in which railroad service was provided. In large part, ICC regulation of railroads appeared designed to increase profits in the trucking industry, which was also regulated by the ICC.

In the 1970s the regulatory system was placed under serious strain due to the financial difficulties facing railroads. It was believed that the 1978 Staggers Act would help railroad regain their financial health by allowing them to raise prices. Instead, what occurred was that deregulation allowed railroads to dramatically cut costs, reductions estimated by Wilson (1997) to average 40 percent. Concerns continue, however, about a number of routes where service is perceived as less than competitive.

Natural gas decontrol provides several important lessons for electricity restructuring. After more than forty years of regulation, the Natural Gas Policy Act of 1978 gradually decontrolled wellhead natural gas prices. The 1979-80 oil price increases and unrealistic contract provisions disrupted the smooth transition envisioned by the

[3] It is commonly believed that airline deregulation reduced service to small communities. The available literature, however, does not support this view. See Butler and Huston (1990).

framers (Considine, 1983). The main problem was that many contracts tied wellhead gas prices to oil prices between 1978 and 1984. Gas prices rose with oil prices during 1979-80 and continued to rise even though oil prices started to slide from their 1981 peak. With the severe recession in 1981 and the evaporation of a substantial segment of the industrial gas market due to the permanent closure of many gas intensive industries in the US, many pipeline companies faced very large contractual obligations. As we shall see below in our analysis of electricity restructuring, unforeseen market shocks can disrupt a smooth transition to a more competitive market structure.

After decontrol in 1985, substantial supplies of gas from old fields began to displace new, higher cost supplies developed during the phased decontrol period. These higher cost supplies were in part developed because federal regulations allowed very high price ceilings for these categories of gas, while at the same time controlling so-called old gas, developed prior to 1978 at very low price levels. Rather than forcing average prices up after decontrol, market forces prevailed and prices dropped sharply. Pipelines companies with the misfortune of having high cost contracts simply refused to pay or take delivery of natural gas. The ensuing litigation dragged on for several years during the late 1980s as the bubble of excess take-or-pay gas worked its way to market.

These low prices forced substantial cost reductions in gas extraction and long distance pipeline transmission. The Federal Energy Regulatory Commission (FERC) played a major role in this transition by issuing regulatory orders addressing a number of industry issues. While maximum pipeline rates are now set by the FERC, firms are free to trade pipeline capacity. In addition, pipeline firms are now allowed to offer a variety of pipeline services that aid producers and consumers of natural gas. Winston (1998) finds that the restructured environment has induced more technological efficiency in the operation of pipelines, and more efficient operation of pipelines during peak demand periods.

Another important milestone was the repeal of the Fuel Use Act prohibiting new gas-fired electrical generation capacity. This Act assumed that natural gas was a premium fuel for essential social needs, such as home heating and industrial applications, with no close substitutes. Repeal substantially stimulated natural gas consumption by utility and non-utility power producers in the US. These regulatory and market developments led to the revival of the natural gas industry in North America during the 1990s.

One issue of contention in the deregulation of the airline and railroad issues was the question of service to small communities. This is less likely to be important in electricity restructuring. As discussed below, under restructuring, consumers of power will purchase electricity from suppliers, who will be responsible for delivering that electricity to the power grid. Once the power is in the grid, the relevant distribution company, which will continue to be regulated, will deliver the power to the consumer. From the power supplier's point of view, it is not important where a particular customer lives, but where the relevant power needs to be injected into the power grid that supplies that customer.

THE POTENTIAL GAINS FROM RESTRUCTURING

Deregulation in airlines, railroads, and natural gas have lead many observers to believe similar gains can be realized from restructuring electricity sector. In particular, there are two areas in electricity markets where it is hoped restructuring will bring about significant economic gains.

First, restructuring frees electricity generators from rate of return regulation and fuel adjustment clauses. Generators thus have important incentives to cut costs, which will result in lower prices for consumers in the long run. No longer able to pass fuel costs on to customers via fuel adjustment clauses, electric generating companies would take a much tougher stance in negotiating contracts for coal, natural gas, and other fuel sources. In addition, power generation firms would be forced to take a similar approach in their negotiations with hourly and salaried employees. Considine (2000) estimates that restructuring fossil fuel fired steam electric power generation alone would lower annual long-run costs by $7 billion. Even more significant savings are possible in nuclear power generation. In areas with excess capacity, these lower costs in a competitive market will naturally decrease the price of power.

Second, restructuring eliminates the monopoly on retailing held by local distribution companies. In a properly restructured market, any number of providers can compete on both price and quality of service when offering retail electricity to consumers. Consumers could choose their electricity producer just as they select their long distance telephone provider. This competitive environment could lower rates and improve the quality of service. Moreover, competition would improve the efficiency of allocating electricity because a competitive structure matches consumer preferences with production realities.

The gains from restructuring, should they occur, would have important consequences for local development. In particular, many industries are energy intensive.

If restructuring can produce lower electricity costs in one particular area, that area becomes more attractive for such industries.

BASIC ECONOMICS OF ELECTRICITY

The generation and provision of electricity involves a network of generators and high voltage transmission lines connecting these generators with transformers that reduce the voltage of the electric power for distribution to final consumers. Nearly all electric power is generated by the rotation of a magnet inside a coil of copper wire. The energy input required to spin the magnet is usually provided by high-pressure steam produced using fossil fuels. There are two types of generators. Base load generators support a minimum base load and essentially run continuously. They are usually large, capital intensive, coal-fired generators with low variable costs that are not quickly brought on line or quickly taken off line. Peak-load generators, on the other hand, generate electricity during peak demand are much smaller and far less capital intensive but have relatively high variable costs and are more easily brought on line than base-load generators.

Figure 1 summarizes the composition of technology used in electricity generation. Fossil-fuel-fired boilers producing steam for turbine generators remain the dominant electricity generation technology in the United States, comprising 60 percent of total generation in 1996 (EIA, 1996). Of this amount, coal-fired generation comprises 84 percent, natural gas constitutes 12.7 percent, and petroleum accounts for the remaining 3.3 percent. The fastest growing source of electricity supply in recent years has been nonutility generators, who now supply nearly 11 percent of total net generation using fossil-fuel-fired technologies, including conventional steam-driven turbines and combined cycle gas turbines. Many of these nonutility sources sell power to electric utilities at rates based upon avoided cost, which in many cases is the marginal cost of power from steam electricity generation. Hence, the marginal cost of steam electricity generation is an important issue for nonutility generators.[4] Even though nuclear power

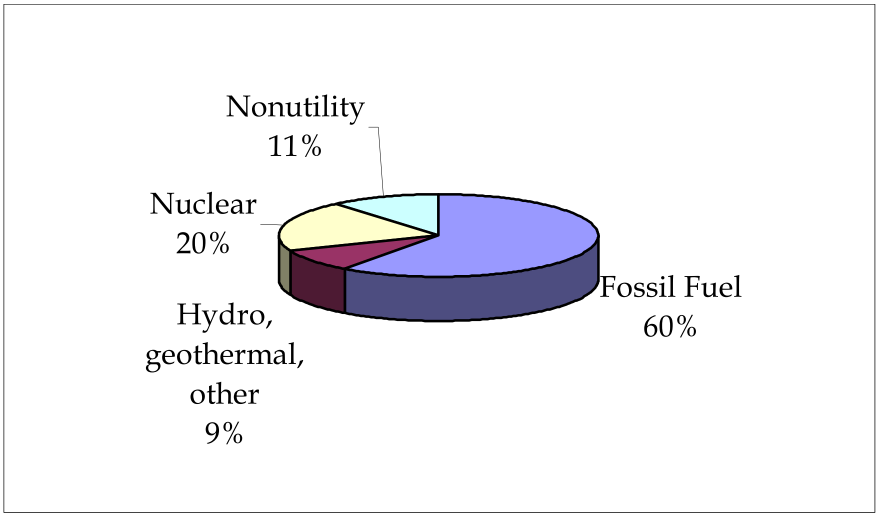


Figure 2.1:Composition of technology used to generate electricity

constitutes nearly 20 percent of total net generation, no new nuclear plants have been ordered in the United States in recent years. Economic and technological problems, including safety and waste disposal issues, may continue to limit growth prospects for nuclear power. Hydro, geothermal, and other sources of power constitute the remaining 9 percent of generation and also have limited growth prospects.

Once the power has been generated, it is sent over transmission lines to the relevant market. Transmission lines are often expensive, and must travel through a variety of rural and urban areas. One difficulty with building new transmission lines is

[4] Marginal cost is the additional cost incurred from producing one addition unit of the relevant good. See. For example, Carlton and Perloff (2000, 29).

that many communities do not wish to have new lines in their area. This makes obtaining approval for these lines difficult.

Power comes through transmission lines into a particular "control area." Electricity cannot be stored (at least inexpensively),[5] and thus there is a requirement that the demand for power in a control area be set equal to the supply In addition, power flows must be controlled so that a variety of system requirements are met. Historically, each relatively large utility controlled its own "system operations." In recent years, however, several independent system operators (ISOs) have arisen to control systems spanning across several utilities.

Once power comes into a particular control area it is dispatched through lower density distribution lines to consumers' homes and businesses. Generally speaking, production costs appear to be minimized if only one distribution line exists to particular customers. In other words, distribution appears to be a retail monopoly.

RATIONALE FOR REGULATION AND RESTRUCTURING

Economic theory teaches that if the proper conditions are in place, unrestricted entry and price competition will create the outcome that creates the most economic wealth for the relevant society. The success of free market economies over the last century supports the teachings of this theory.

One important condition for a viable free market is a sufficient number of viable independent competitors. This, in turn, implies that having only one firm in the market does not minimize the total cost of supplying customers. In other words, the market is not

[5] Technically speaking, hydroelectric facility can store power by choosing when to spill the water that generates electricity.

a "natural monopoly." Indeed, the apparent rationale for the regulation of electricity, beginning in the early years of the twentieth century, implied that competition was not viable in this industry.[6] Today, the distribution of power appears to fit this natural monopoly criteria, as well as system operation. For example, it would seem less costly to have one distribution network in a particular residential neighborhood. Similarly, there seems to be a need for only one system operator in a particular control area. Transmission lines, at least in some areas, may also fit the criteria for a natural monopoly. Given this, restructuring is not designed to create competition in distribution and transmission, though changes in the regulation of those areas may occur to facilitate restructuring.

While it may be the case that distribution, system operation, and perhaps transmission are, in some sense "natural monopolies," the same cannot be said about the generation of electricity. In most significant economic regions, electricity is generated at a large number of locations. In addition, there is no obvious reason why the retailing of electricity constitutes a natural monopoly.

The potential competitive nature of the generation of electricity was revealed by the implementation of the Public Utility Regulatory Policies Act of 1978 (PURPA). PURPA mandated that independent producers of electricity have access to the regulated utility grid. Dismukes and Kleit (1999) find that PURPA increased the number of

[6] We note that there is a long and on-going debate in the economic literature about the motivations for electricity regulation in the early part of twentieth century. See, for example, Jarrell (1978) and Emmons (1991).

electricity producers, in particular producers not affiliated with local regulated electricity providers.

Analysts should always be careful in weighing alternatives to be aware of the flaws of any system. In particular, while "market failure" may support the concept of regulation of electricity markets, regulation itself is not perfect. In particular, regulation in the United States frequently compensates utilities on a "rate of return" basis. Often, the more the utilities spend, the more profits they can make. This leads to poor incentives for cost control, and higher prices to consumers.

GENERAL FORMS OF DEREGULATION

There is no one particular model for restructuring. Restructuring in large part involves the deregulation of generation assets. Because generation is clearly not (at least no longer) a natural monopoly, Joskow (1997) argues that the fundamental rationale for regulation no longer exists.

Thus, restructuring calls for customers to obtain access to competitively generated electricity through monopoly distribution and transmission lines. There are two basic methods by which access can be gained. Green (1999) calls the first "POOLCO," which was used in the England and Wales. In this arrangement, the price of power is determined on an exchange, and that price is passed along to consumers. The second is "direct access," in which consumers can either buy power on an exchange or with a contract. This is the approach used in the Pennsylvania-New Jersey-Maryland (PJM) market.

Even with restructuring, electricity supply must equal demand and the system must be reliable. In several markets, an Independent System Operator (ISO) performs this task. Questions remain, however, about the appropriate scope of an ISO's powers, and the appropriate corporate governance structure for ISOs.

Transmission pricing is another source of debate. Competition in the transmission of electricity is difficult for two reasons. First, economies of scale in transmission may preclude effective competition in that area. Second, as Chao and Peck (1996) among others, have illustrated, electrical transmission is subject to "loop flow," where one party's transmission decisions can affect another party's transmission capacity. Loop flow occurs because electricity flows along the path of least resistance, rather than according to a particular economic contract. Thus, a firm could find its transmission lines constrained due to the activities of other firms, which it had no role in.

CREATING WHOLESALE MARKETS

Over the past ten years there has been a growing amount of trade of electricity in wholesale markets. These trades are often between electric utility companies and between producers and consumers of electricity. Often, firms that are buyers of power at one point in time are sellers of power at another point in time.

These trades create a great deal of economic wealth in electricity markets. Firms buy power when the market price of power is less than their cost of producing it. Firms sell power when the reverse is true. Trades between firms reduce the total cost of producing power in the economy, creating increased profits for firms and, in the long run, lower prices for consumers.

The increased trading has come about because the costs of trading electricity are lower. For electricity trades to take place, the relevant power (or its economic equivalent) must be sent over transmission lines between firms. Historically, transmission fees have been based on the number of utility “areas” a particular transaction crosses. Trading in electricity has been deterred because many trades cross over a number of firms’ territories, creating transmission rate “pancaking.” Actions by the Federal government, and the creation of system operators in some areas have served to reduce pancaking and increase trade in electricity.

Trading of electricity futures has also increased. In an electricity futures market, a buyer of power pays a certain amount of money for the delivery of a specified amount of power at a specified date in the future. In this manner, a buyer can insure itself against fluctuations in the price of power. Future markets in a variety of commodities are used as a method of reducing risk, and therefore increasing consumer satisfaction. Unfortunately, as we will discuss below, the original California restructuring plan prohibited the exchange of futures contracts.

ALLOWING CUSTOMER CHOICE

In regulated states, consumers generally pay a constant price for power, no matter what the wholesale price of power is. This can generate serious economic inefficiencies. While the retail price of power paid by a consumer may be constant across a particular day, the marginal cost of producing that power can vary widely, as demand fluctuates. The result is that too much power is consumed during high demand periods, and too little power is consumed during low demand periods.

Restructuring may allow consumers to pay a price for power that is a function of its contemporaneous wholesale price. If these consumers could shift their electrical consumption to low demand periods, they could gain from such "time of day" pricing.[7] Time of day pricing may be especially advantageous to firms that can shift their production activities to the night time or to weekends.

In particular, consumers have shown a desire to pay a premium for "green power" power produced from "environmentally friendly" sources, such as windmills. Incidentally, there does not appear universal agreement on the definition of "green power." Restructuring gives consumers the opportunity to contract with producers to create green power, and potentially reduce the environmental consequences attendant with the production of electricity.

WHO HAS RESTRUCTURED?

States within the Appalachian region have responded in different ways to the possibility of electricity restructuring. In Pennsylvania, Maryland, West Virginia, Ohio, and Virginia, the legislature has passed bills requiring restructuring, though the West Virginia plan is currently on hold. Pennsylvania's restructuring is complete, while New Jersey's is well under way. In addition, the regulatory commission in New York has approved restructuring, and restructuring in that state is underway.

In contrast, North Carolina, South Carolina, Kentucky, and Mississippi have investigations on restructuring pending, but none has implemented restructuring. No official actions on restructuring are taking place in Tennessee, Georgia, or Alabama.

[7] Time of day pricing refers to the possibility that electricity consumers could pay an fee based on the wholesale price of power when it is used, rather than the average price that is currently paid. See Doucet and Kleit (2001).

Several countries around the world have also restructured their electricity sectors. As discussed above, the generation and retailing of power is deregulated in England and Wales. Several states in Australia, though not the more geographically isolated ones, have also restructured their electricity sectors. Chile and New Zealand have restructured both their wholesale and retail sectors. At the time of this writing, restructuring is ongoing in the Canadian provinces of Alberta and Ontario.

CHAPTER III. THE ELECTRICITY INDUSTRY IN THE APPALACHIAN REGION

Identifying some of the factors affecting the potential for restructuring the electricity industry in the Appalachian region requires an understanding of the structure of the industry in the region and its relationship to the rest of the nation. Since electricity networks must be balanced at any point in time, regional agreements for load balancing have evolved. The next section describes how the ARC region is essentially a crossroads between the Eastern, Midwestern, and Southern electric reliability regions. After this panoramic view of the regional context of the electricity industry in Appalachia, this chapter then describes the major players in the region, including public and private companies that generate, transmit, and distribute electric services to households and businesses. We then examine generation capacity in the region, finding that the electric power generation in the northern and central portions of the Appalachian region is much more reliant on coal than the rest of the U.S. and that nearly 50 percent of capacity in the Southern portion uses hydroelectric and nuclear energy. The chapter concludes by examining the level and composition of demand growth in the region.

REGIONAL DIMENSIONS

The North American Electric Reliability Council (NERC) promotes coordination among electric utility service providers to ensure reliability of service, organizing the electric utility industry in the United States and Canada to operate under several regional reliability agreements. If electricity is short in one region, power is drawn from other regions to keep the system balanced.

There are four major areas in North America with interconnected electrical transmission systems: the Western, Texas, Eastern, and Quebec. The counties of the Appalachian Regional Commission illustrated in Figure 3.1 lie in the Eastern Interconnection, which is subdivided into eight regional councils depicted in Figure 3.2. Four of these councils include portions of the Appalachian region. The Southeastern council contains Appalachian counties in Tennessee, North and South Carolina, Georgia, Mississippi, and Alabama. The central portion of Appalachia containing counties from eastern Kentucky, Virginia, and West Virginia primarily operates under the East Central Area Reliability Coordination Agreement. The northern counties of the ARC operate under the Mid-Atlantic and Northeast reliability councils.

Other more recent, regional organizations include independent system operators. These are either governmental or industry organizations that coordinate the dispatching of generation units to service electricity demand in wholesale power markets. Currently, there are six ISO's in the United States with the Pennsylvania-New Jersey-Maryland (PJM) constituting the most important one in power markets affecting the ARC. The New York ISO encompasses the northern fringe of the ARC. The Southern region currently does not have an ISO, as several large regional electric utilities, such as the Tennessee Valley Authority and American Electric Power, perform many of the technical functions of an ISO.

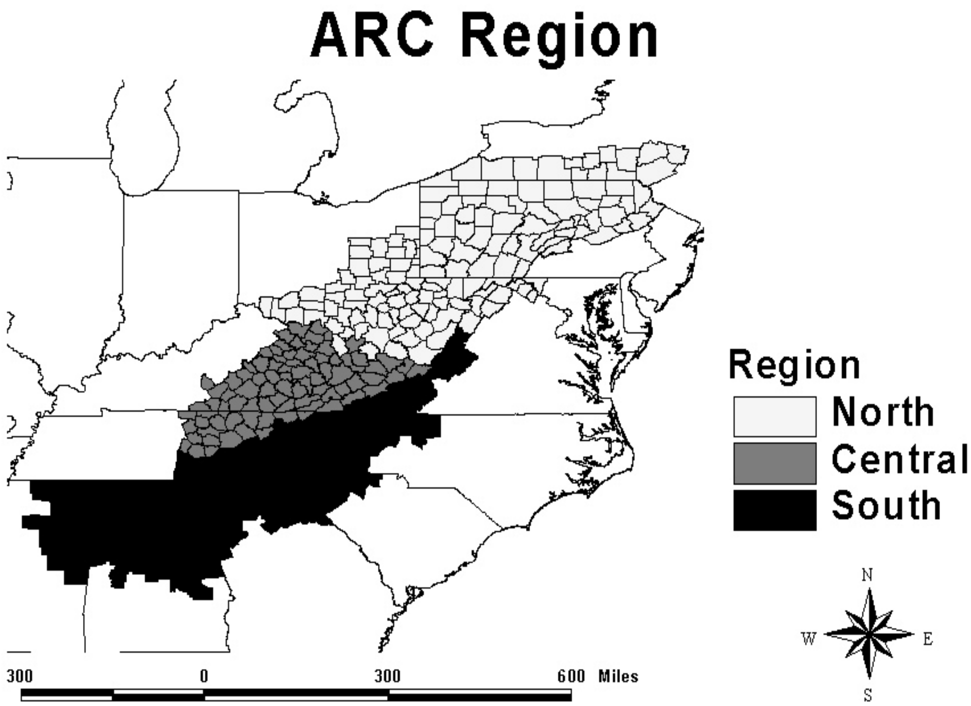


Figure 3.1:Counties of the Appalachian Regional Commission

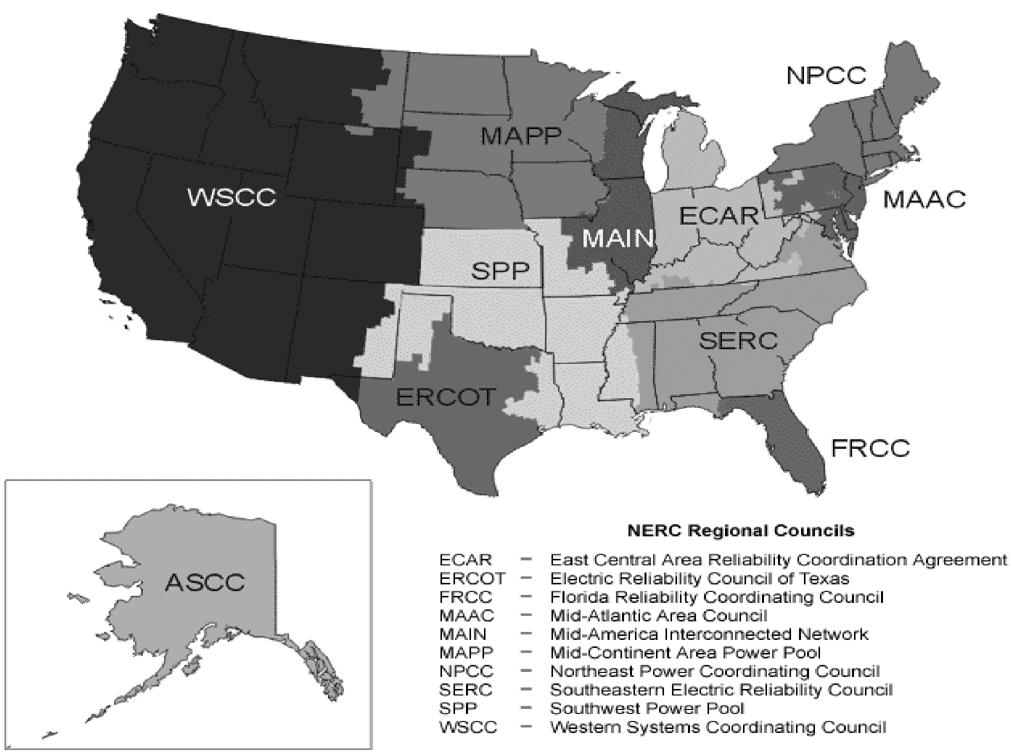


Figure 3.2:Regions of the North American Electric Regional Council

OWNERSHIP

The geographical area served by the Appalachian Regional Commission (ARC) overlaps numerous utility service areas. To circumvent this problem, we define three regions: the ARC region with three sub-regions identified below in Figure 3.3, the greater ARC (GARC) including the service areas of electric utilities with part of their service areas in the ARC Region, and the rest of the U.S.

There are 319 private and public entities that own and operate portions of the electricity industry in the region. This includes 160 municipal and 111 cooperative utility companies. There are 46 investor owned utilities with service areas covering Appalachian counties. The remaining two players include the Tennessee Valley Authority and the New York Port Authority.

Most municipal and cooperative utilities do not generate electricity. Only 11 of the 160 municipal utilities and 5 of the 111 cooperatives operating in the greater ARC region operate electric generation plants. Instead, most of these utilities simply purchase power for resale to consumers. The average net annual sales of a municipal utility in the greater ARC during 1999 are 379,639 megawatt hours (Mwh). The average cooperative utility is substantially larger at 624,701 Mwh of net sales and this average size does not include two very large cooperative utilities in the region, East Kentucky Power Coop. Inc. and Oglethorpe Power Corp. that have over 10 and 20 million Mwh of net sales respectively.

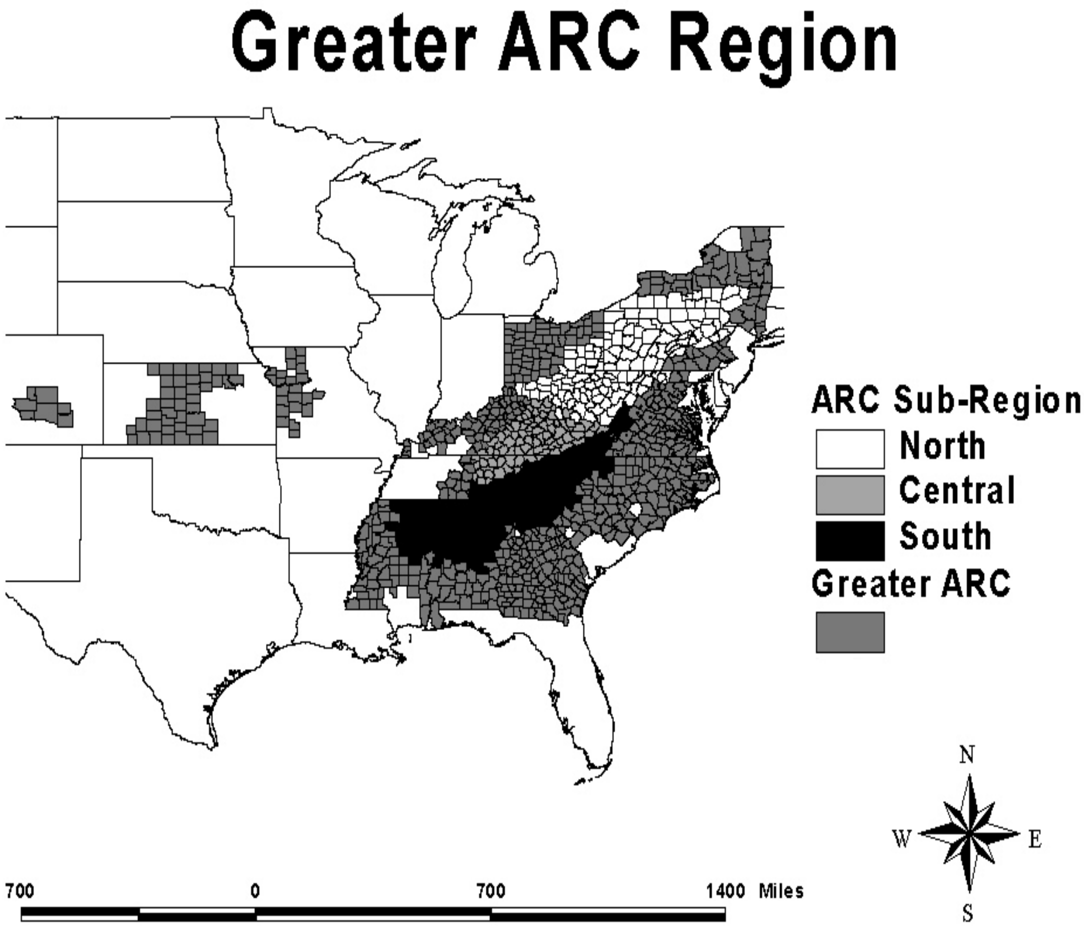


Figure 3.3:Definition of the Greater ARC Region

Most investor owned utility companies (32 of 46) operating in the ARC region have generation facilities. Several of these companies are part of very large electric utility holding companies. Four of the five companies comprising America's largest electric utility company, American Electric Power, operate in the ARC region, including Ohio Power, Appalachian Power, Kentucky Utilities, and Columbus Southern Power. Georgia Power and Alabama Power, also operating in the greater ARC region, are part of the next largest holding company, the Southern Company. Another substantial holding company with subsidiaries operating in the region is Allegheny Power with West Penn

Power and Monongahela Power. Twenty-nine of the private companies operating in the region are vertically integrated, owning generation, transmission, and distribution assets.

Generation Capacity

More than 70 percent of electricity generation capacity in the ARC consists of coal-fired steam generators, reflecting the relative abundance of coal in the Appalachian region, see Figure 3.4. Another 15 percent of capacity is hydroelectric power while nuclear capacity comprises 12 percent of total capacity. The remaining 2 percent of capacity is primarily steam generators using fuel oil and natural gas.

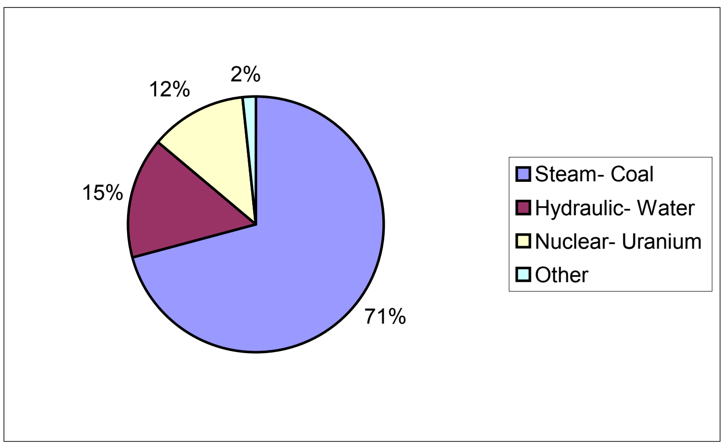
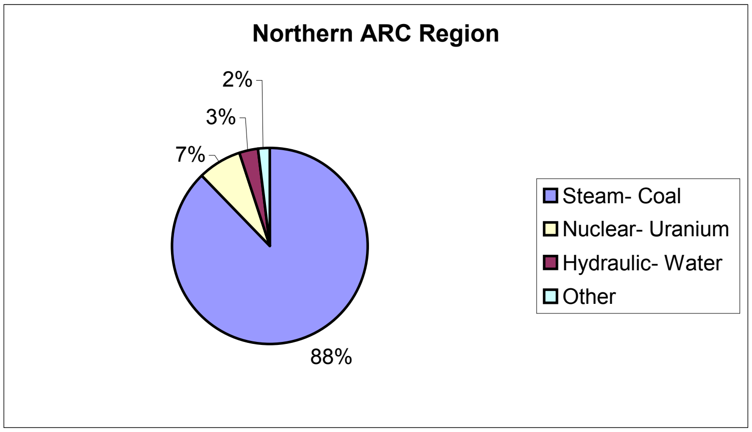
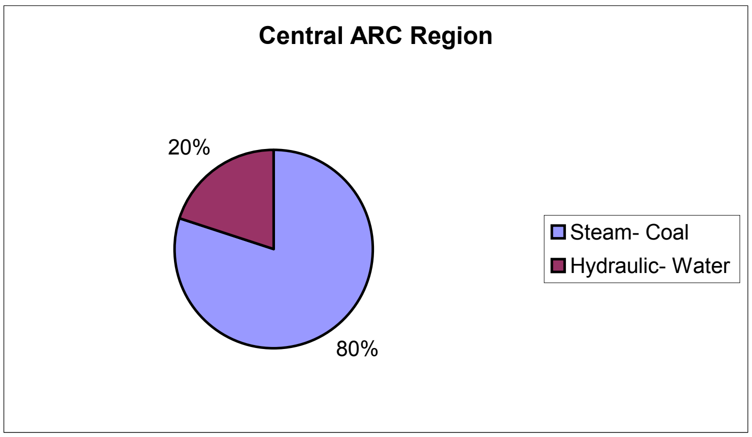


Figure 3.4:Composition of electricity generation capacity in the ARC, 1999

A different picture emerges from examining capacity within each of the three ARC sub-regions, illustrated in Figure 3.5. The Southern Sub-Region is significantly less dependent on coal-fired steam generators than the Northern and Central Sub-Region. Coal-fired steam generator capacity decreases from the Northern Sub-Region to the Southern Sub-Region while hydroelectric capacity increases from the Northern Sub-Region to the Southern Sub-Region. The Southern Sub-Region is dominated by the Tennessee Valley Authority (TVA) and is much more dependant on nuclear power than





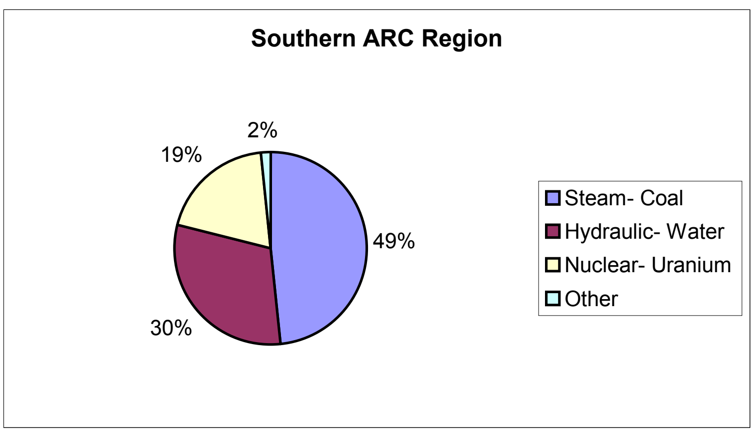


Figure 3.5:Regional comparison of generation capacity in the ARC, 1999

the other two Sub-Regions. Operating costs for nuclear and hydroelectric generators are generally very low, far lower than oil and natural gas-fired capacity and often significantly lower than coal fired capacity.

In the Greater ARC, coal-fired steam generators play a slightly less important role than the ARC as a whole. Only 61 percent of nameplate capacity in the GARC is coal-fired steam generators versus 71 percent in the ARC Region. Figure 3.6 also shows that nuclear energy in the GARC has a relatively larger role in terms of nameplate capacity with 18 percent of total capacity than the 12 percent in the ARC (see Figure 3.4). In contrast, hydroelectric capacity comprises only 6.4 percent of total capacity in the greater ARC versus 15 percent in the ARC. Another difference is that the greater ARC is relatively more dependent upon natural gas, fuel oil, and other fuels. While these fuel capacity types comprise only 2 percent of capacity for the ARC, they constitute 14 percent of greater ARC capacity.

The rest of the United States, however, has a significantly different energy mix. Less than 40 percent of nameplate capacity in the rest of the United States is from coal-fired steam generators. Both hydroelectric and nuclear power capacity shares outside of the ARC are each 14 percent. Both of these figures are comparable to those for the ARC and the GARC Regions. Of special note, natural gas fired generators, including steam, turbines, and combined cycle plants, make up nearly 23 percent of nameplate capacity outside of the GARC. In the GARC Region natural gas comprises less than 8 percent of nameplate capacity and less than 1 percent in the ARC Region.

For non-utilities in the ARC Region, almost 50 percent of all nameplate capacity is from steam turbines. Of that figure, coal is the most popular fuel source (62.1 percent). Hydroelectric power is the second largest contributor with 11 percent of nameplate capacity. Interestingly, with few exceptions, most other prime movers are fueled by nontraditional energy sources, which include bituminous gob, black liquor, wood, landfill gas, waste heat, and petroleum coke.

Net Generation

The Northern and Southern Sub-Regions have orders of magnitude greater net generation than the Central Sub-Region (See Figure 3.6). The main reason for this discrepancy is that there are few major cities within the Central Sub-Region. The largest population centers, Ashland and Richmond, have less than 500,000 inhabitants. Additionally, many power plants and major cities lie just outside of the Region.

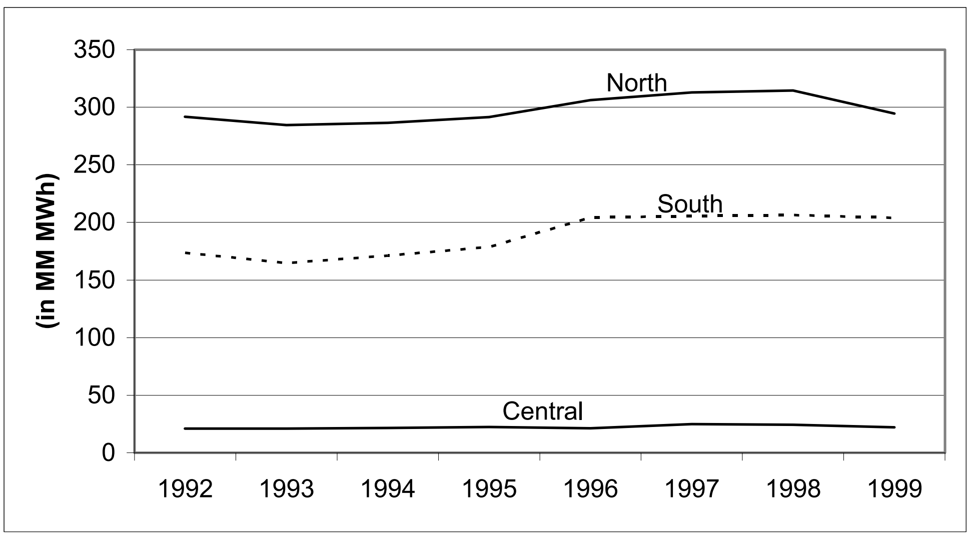


Figure 3.6:Power generation by region within the ARC, 1992-99

Since 1992 electricity generation in the ARC region has increased 7 percent. Most of the growth occurred in the Southern Sub-Region, where it grew by 17 percent. The Central and Northern Sub-Regions grew 5 percent and 1 percent, respectively. However, as Figure 3.7 indicates, net generation by utilities dropped 4.5 percent in 1999. Figure 3.8 can explain this phenomenon. These charts display decreasing nameplate capacity, reflecting the sales of generating assets from utilities to non-utilities. In the

ARC, the number of generators dropped 9.25 percent while capacity declined 3.9 percent since 1992. Most of the asset sales occurred in 1999, primarily due to restructuring in Pennsylvania and New York as utilities exited the generation business. Similarly, since 1992, there has been a 16 percent drop in the number of operating generators in the GARC and a 5.7 percent drop in nameplate capacity. The geographical distribution of net generation within the ARC is illustrated in Figure 3.9. Note that the southern region has relatively more counties with power generation than the north and central regions. This reflects the relatively large number of hydroelectric facilities in the southern region, most of which are operated by the Tennessee Valley Authority.

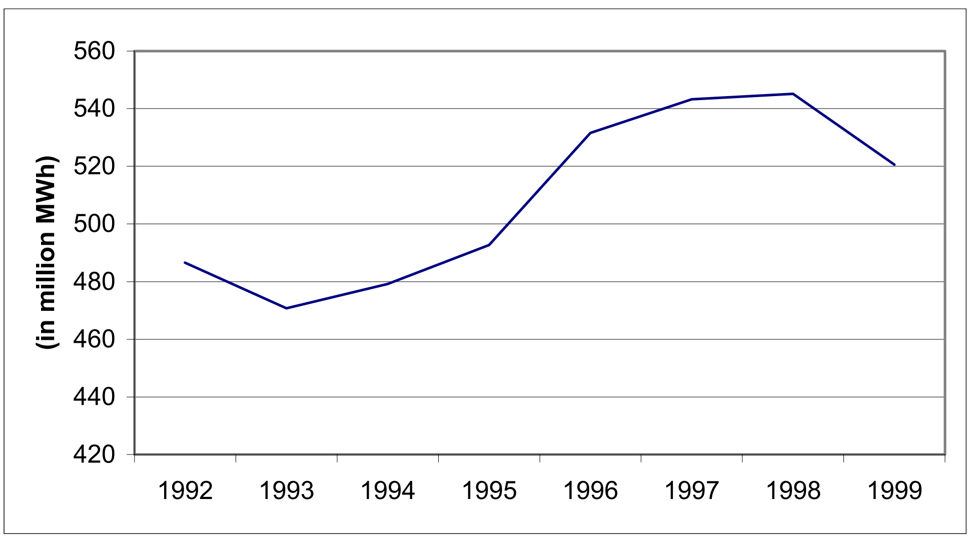


Figure 3.7: Total net power generation in the ARC region, 1992-99

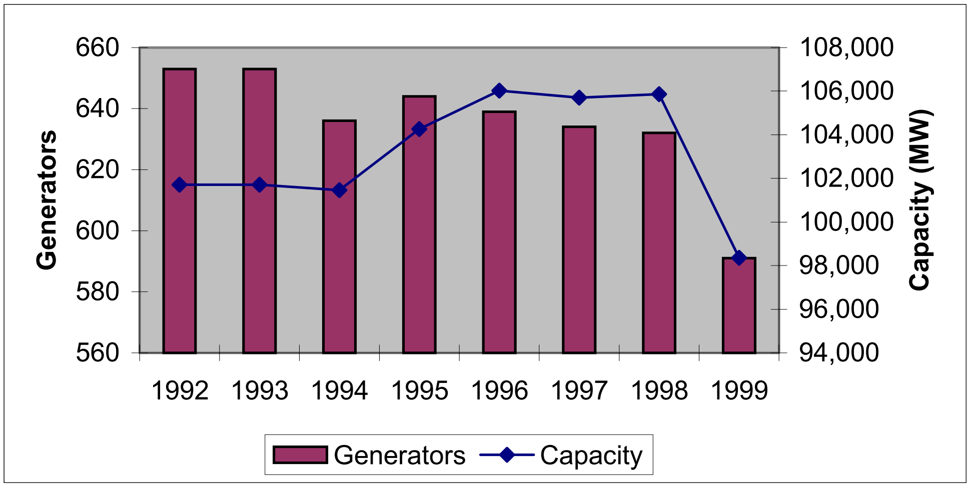


Figure 3.8: Number of utility generators and capacity in the ARC, 1992-99

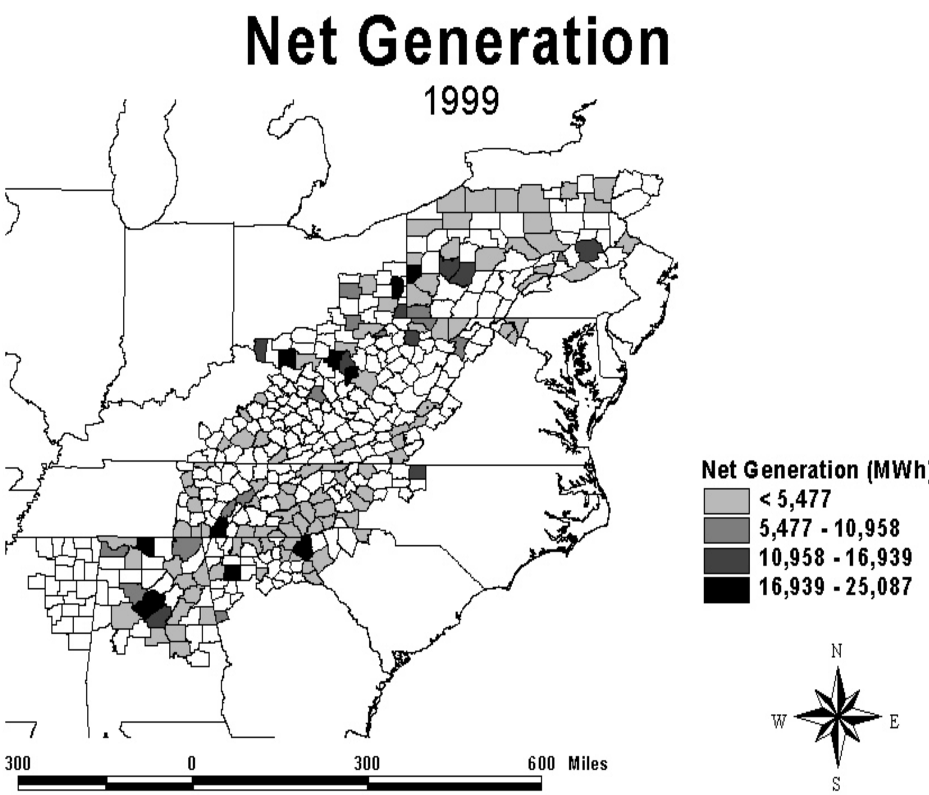


Figure 3.9: Geographical distribution of net power generation in the ARC, 1999

STEAM ELECTRIC GENERATION COSTS

The objective of this section is to provide an overview of the costs of generating electricity and how these costs vary with fuel prices and generation levels. We analyze the costs of steam electric power generation using fossil fuels and nuclear electric facilities owned by major investor-owned utilities in the United States. The Energy Information Administration (EIA) (1996), which is the primary source of data for this study, classifies major utilities as those companies that have had sales and transmission services that exceed either one or more of the following over three consecutive years: one million megawatt hours of total annual sales, 100 mwhs of annual sales for resale, or 500 mwhs of annual wheeling or power exchanges. EIA identifies 179 major private utilities and 64 small investor-owned utilities. Together these utilities account for more than 75 percent of sales to ultimate consumers. A large number of publicly owned utilities (2,010) and cooperatives (932) and ten federal utilities supply the remaining 25 percent of total electricity sales.

We use a cost model developed by Considine (2000) that describes how costs vary with production, input prices, technology, and capital stocks. We reduce our original panel of 111 companies to 82 because many companies are subsidiaries of holding companies. Christensen and Greene (1976) show that failure to recognize holding companies results in underestimating scale economies. The distribution of average annual production for each firm from 1987 to 1999 appears in Figure 3.12. Most firms produce between 10 and 25 million-megawatt hours, see Figure 3.10. Average firm output over the period ranges from a low of 1.1 million mwh to nearly 105 million mwh. Average

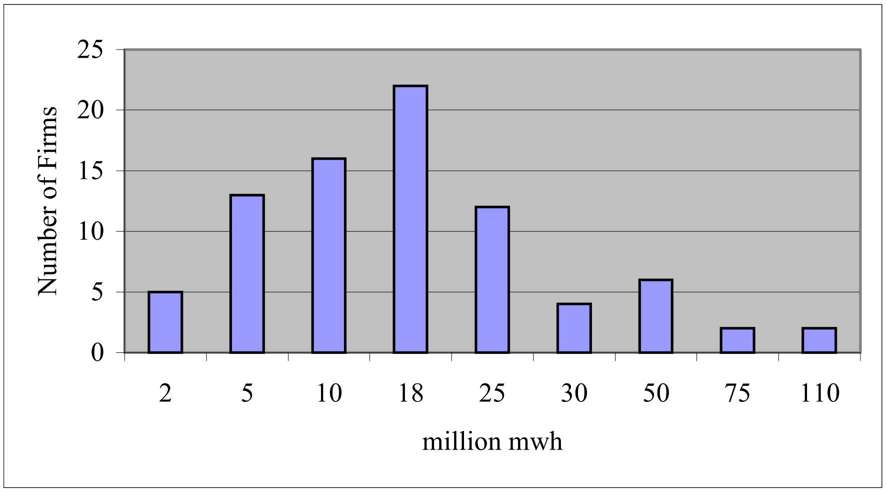


Figure 3.10:Distribution of firm output

production across all firms is 17.3 million mwh with a standard deviation of 18.9 million mwh. There are 53 firms with generation below the sample mean. Two firms have output nearly five times larger than the industry average. These firms are as large as the federally owned TVA, which generated roughly 89 million megawatt hours (mmwh) in 1999.

In Figure 3.11, we present the distribution of average total cost or the sum of average variable cost and average capital charges, calculated using the user cost of capital and real capital stocks. Average total cost ranges from a low of 2.15 cents per kilowatt (kwh) to slightly under 6.6 cents per kwh with a mean of 3.32 cents per kwh. In contrast, reported production expenses by TVA imply were 1.7 cents per kilowatt hour in 1998. These costs for TVA, however, are not directly comparable because capital costs for TVA are not computed on a comparable basis. Nevertheless, TVA production costs are most likely at or below some of the lowest cost power in the U.S. The standard deviation of average total cost is 0.92 cents per kwh. Notice that the distribution of average total cost is skewed with the largest number of firms producing power around 3 cents per kwh, roughly one–half cent below the mean. In addition, there is a long tail in the distribution on the high end of the cost range, which reflects the pressures on the industry from regulators to restructure and reduce cost.

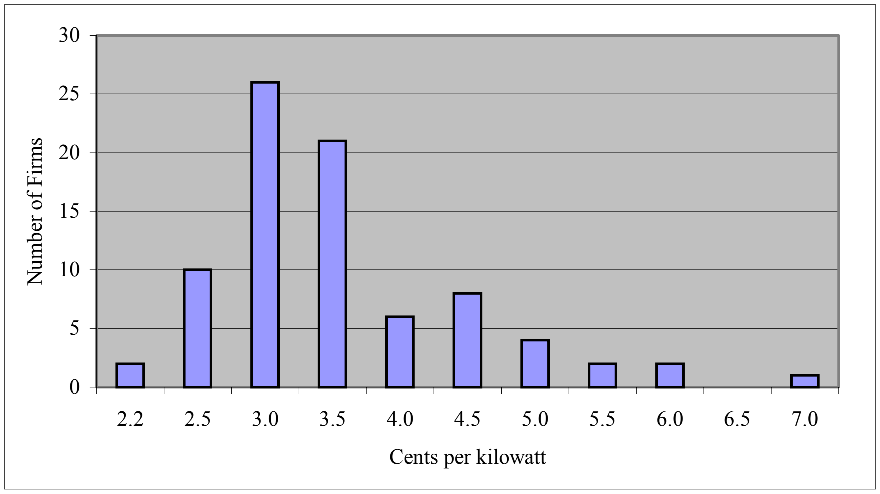


Figure 3.11:Distribution of average total cost

Table 3.1 reports average annual production and average total cost for each firm from 1987 to 1999. The companies in bold are located in the greater ARC region and the companies in italics are the three California utilities. The largest firms are concentrated in the south and midwest. The smallest firms are located generally in the Northeast. The largest ten firms produce 40 percent of total steam power production.

Montana Power had the lowest generation costs of 2.17 cents per kwh, while utilities operating in the ARC region (in bold), such as Ohio Edison, Allegheny Power, Kentucky Utilities, and American Electric Power also had relatively low average total costs, less than 2.5 cents per kilowatt hour. Notice that the three California utilities are

Table 3.1:Steam electric generation and cost, firm means, 1986-1999

Company	*Generation million megawatt hours*	*Total Cost (¢/kwh)*	*Company*	*Generation million megawatt hours*	*Total Cost (¢/kwh)*
St Joseph Light & Power	1.15	2.78	**Niagara Mohawk Power Corp**	12.59	3.37
Central Maine Power	1.16	6.00	New England Electric System	13.21	3.60
Madison Gas & Electric	1.60	2.84	Indianapolis Power & Light	13.61	2.77
Rochester Gas & Electric	1.92	3.95	Northern Indiana Pub Serv	14.27	3.56
Eastern Utilities Associates	1.95	4.10	Illinois Power	14.42	2.51
Empire District Electric	2.33	2.32	**New York State Elec & Gas**	14.52	2.69
Otter Tail Power	2.57	2.38	**Dayton Power & Light**	14.80	2.90
Atlantic City Electric	3.11	4.35	**Kentucky Utilities**	14.89	2.33
Orange & Rockland	3.16	4.45	Public Service Colorado	14.99	2.29
El Paso Electric	3.19	3.33	Baltimore Gas & Electric	15.97	3.18
Interstate Power	3.52	2.65	Consolidated Edison NY	15.99	6.57
Portland General Electric	3.53	3.63	Tampa Electric	16.17	3.33
Sierra Pacific Power	3.59	3.14	Wisconsin Electric Power	17.50	2.87
Central Hudson Gas & Elec	3.85	3.85	Consumers Power	17.61	2.91
Commonwealth Energy	4.18	4.07	**General Public Utilities**	18.18	3.24
San Diego Gas & Electric Co	4.33	5.92	Southwestern Public Service	18.81	2.84
UtiliCorp United	4.60	2.65	Centerior Energy	19.51	3.23
United Illuminating	5.05	3.69	**Potomac Electric Power**	19.63	3.17
Hawaiian Electric	5.08	4.63	Commonwealth Edison	19.92	5.40
Southern Indiana Gas & Elec	5.53	3.17	Oklahoma Gas & Electric	20.50	3.03
Central Illinois Light	5.53	2.84	Florida Power	20.65	3.43
Central Louisiana Elec	5.84	3.46	Gulf States Utilities	21.27	2.87
Minnesota Power & Light	5.88	2.32	CINergy	22.63	2.73
Nevada Power	5.90	3.00	Union Electric	23.69	2.79
Montana Power	6.09	2.15	**Carolina Power & Light**	23.85	2.91
Public Service Co of NM	6.21	2.74	*Pacific Gas & Electric*	24.94	4.56
Kansas Gas & Electric	6.43	2.61	PSI Energy	26.46	2.52
Wisconsin Public Service	7.15	2.68	**Pennsylvania Power & Light**	26.87	3.11
Boston Edison	7.24	4.35	*Southern California Edison*	27.85	4.44
Wisconsin Power & Light	7.76	2.44	**Virginia Electric & Power**	29.27	2.70
Delmarva Power & Light	8.04	3.46	Florida Power & Light	31.18	4.27
South Carolina Elec & Gas	9.45	3.03	**Entergy Corporation**	31.22	3.43
Philadelphia Electric Power	9.71	4.83	**Duke Power**	32.69	2.85
Long Island Lighting	10.14	4.75	**Allegheny Power Systems**	41.12	2.34
Duquesne Light	10.38	2.90	Detroit Edison	41.78	2.74
Central Illinois Pub Serv	10.58	3.29	**Ohio Edison**	42.19	2.25
Kansas City Power & Light	10.63	2.35	Houston Lighting & Power	47.16	3.45
Northeast Utilties	11.09	4.29	Central and Southwest	52.76	3.07
Louisville Gas & Electric	11.75	2.73	Texas Utilities Electric	71.84	2.77
Arizona Public Service	11.95	2.73	**American Electric Power**	102.54	2.49

among the highest cost companies in the country. On average, capital costs account for approximately one cent per kwh with a standard deviation of 0.41 cents per kwh. Kansas Gas and Electric, Montana Power, Public Service Company of New Mexico, and Centerior Energy have among the lowest capital costs in the industry. Those companies burdened with relatively high fixed costs include Portland General Electric, Public Service Electric & Gas, Central Maine Power, Consolidated Edison Company of New York, and San Diego Gas and Electric Company. With the exception of Portland General Electric, these companies also have high average variables costs as well.

The main component of variable cost is fuel. Montana Power has the lowest average fuel costs of 0.70 cents per kwh and Hawaiian Electric had the highest at 3.43 cents per kwh. On average fuel costs are 1.84 cents per kwh with a 0.53 cents per kwh standard deviation. Fuel prices vary widely by firm with coal–based utilities paying considerably less than oil and natural gas-based utilities. The four largest firms, accounting for more than 23 percent of total production in the sample, have production costs substantially below average and are largely coal–based operations. The high cost firms are generally smaller with less coal base capacity.

There are also substantial differences in labor and maintenance (L&M) costs by firm. Average L&M costs are 0.58 cents per kwh, about 31 percent of fuel costs, small but significant. These costs also vary substantially by firm due to the age and condition of generating facilities. Southwestern Public Service has the lowest average labor and maintenance cost of 0.19 cents per kwh. Many firms with low labor and maintenance costs are in the southern and western regions of the US. Most of the high labor cost firms are in the Northeast.

In a competitive market, wholesale prices for power reflect marginal production cost, which can be estimated using an econometric model of generation cost. While this approach yields numerous insights into the nature of input demand by electric utilities, the focus here is the responsiveness of marginal cost to generation levels, fuel prices, and technological change.

The elasticities reported below in Table 3.2 suggest that technological progress reduces cost function over time. While our technological change elasticities are statistically significant, they are relatively small, which suggests that the pace of technological progress in steam power production may have slowed during our sample. Unlike the stable energy price era from the 1950s through the early 1970s, fuel prices represent the most important factor shifting steam electricity production cost curves.

Short–run marginal cost is estimated to be 1.84 cents per kwh at the sample mean, which increases to 2.30 cents per kwh in the long–run (see Table 3.2). Marginal costs vary considerably by firm, ranging from a low of less than 1 cent per kwh to more than 5 cents per kwh. Long–run marginal costs, also reported in Table 3.2, reflect the adjustment of capital stocks over time as firms invest in new plant and equipment. For several firms, marginal costs fall in the long–run because additional capital investment improves their efficiency, thus reducing their generation costs.

Our measure of economies of scale is equal to the difference between average and marginal cost divided by average cost. Positive values indicate economies of scale while negative values identify diseconomies. We find substantial short–run scale economies at low output levels and large diseconomies at higher output levels. In other words, the incremental cost or producing electricity is falling at low output levels but the rises sharply as capacity constraints are approached. We will present graphical illustrations of this feature in Chapter V when we analyze the cause of electricity price shocks.

Table 3.2:Estimates of other cost and scale measures for steam generation

Scale economies	Percent	Technological change	Percent
Short run	0.387	Short run	–0.051
	(0.019)		(0.004)
Long run	0.213	Long run	–0.020
	(0.025)		(0.002)
Marginal cost	**¢/kwh**	**Capital stock**	**Percent**
Short run	1.838	Shadow value	0.068
	(0.088)		(0.006)
Long run	2.278	Optimal/actual	0.541
	(0.108)		(0.050)
		Capacity utilization	0.865
Average cost	**¢/kwh**		(0.012)
Long run	2.893	Tobin's Q	0.510
	(0.054)		(0.047)

Notes: Standard errors are in parentheses. Elasticities evaluated at sample means.

The mean shadow value on capital, reported in Table 3.3, is nearly 7 percent, which is considerably below the average user cost of capital of about 15 percent. Tobin's Q is slightly less than 55 percent, implying that, on average, firms have market values less than their replacement cost. The average rate of capacity utilization is 87 percent indicating excess capacity in the industry, also consistent with optimal capital stocks being lower than existing levels. Each of these measures tells essentially the same story—current capital stocks levels in the steam electricity generation industry are too high. Long–run average cost is 2.90 cents per kwh, roughly one–half cent below actual total average costs (see Table 3.2). Total average annual production in our sample is 1,398 million megawatts and this half-cent reduction would lower total production costs by $7 billion. These cost savings would be achieved as the industry adjusts to make more efficient use of capital and labor.

NUCLEAR ELECTRIC GENERATION COSTS

There are approximately 130 nuclear power generating units in the U.S., most operated by 32 investor owned utilities. This technology is very capital intensive with substantial variation in plant construction costs. According to the Nuclear Energy Institute (2000), there are approximately 20 generating units that each cost $200-$500 million, 45 generating units with costs between $500-$2,000 million dollars and 34 generating units costing more than $2 billion, see Figure 3.12.

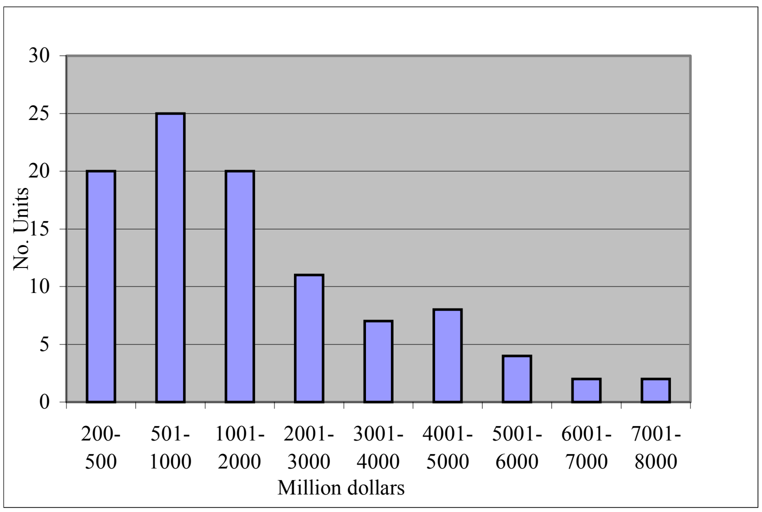


Figure 3.12:Total nuclear plant construction costs in constant 1990 dollars

The distribution of nuclear generation by firm is illustrated in Figure 3.13. Average production across all firms is 11.2 million Mwh with a standard deviation of 12.4 million mwh. There are 20 firms with generation below the sample mean, and one firm nearly five times larger than the average firm.

Production costs average 4.85 cents per kilowatt hour, and vary substantially with a standard deviation of 3.3 cents per Kwh, see Figure 3.14. Average total generation cost reported in Table 3.3 ranges from 2.1 cents per Kwh by Virginia Electric and Power Co.

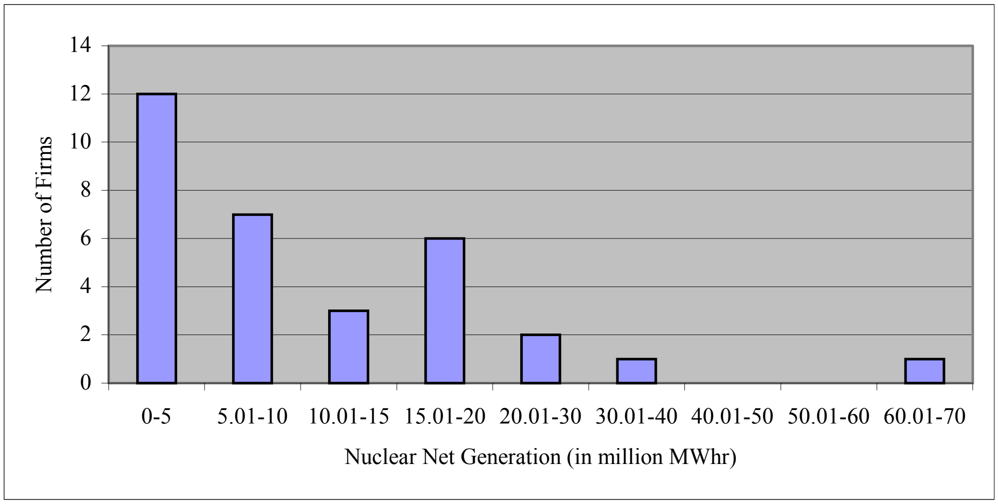


Figure 3.13:Distribution of nuclear generation by firm,

to 15.2 cents per Kwh by Public Service to New Hampshire. Notice that most of the firms operating at relatively low cost are located in the South. In addition to Virginia Electric and Power, Duke Power, the Southern Company, Entergy, and Carolina Power and Light (in bold) are low cost producers of nuclear electricity in the greater ARC region. The Tennessee Valley also operates two nuclear power plants in the ARC region.

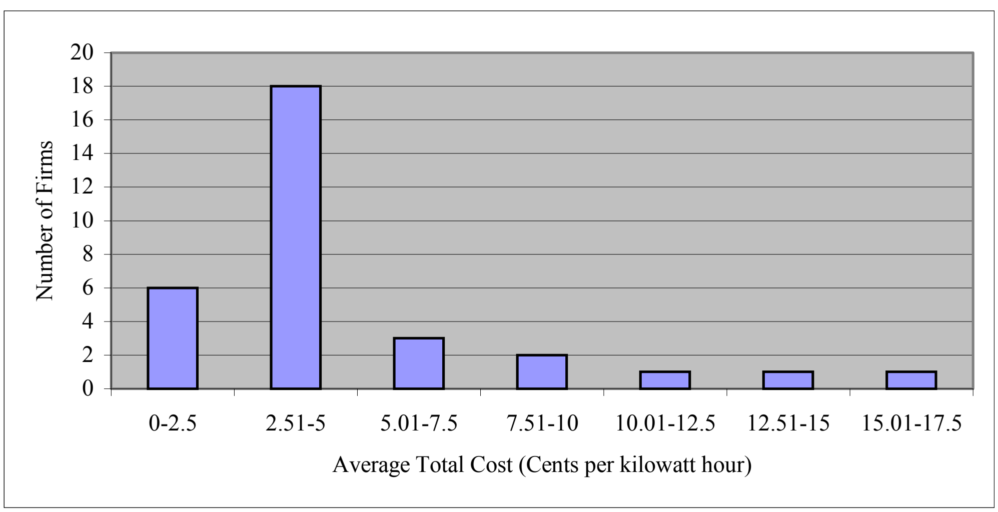


Figure 3.14:Distribution of nuclear generation costs

Using the cost function model developed by Considine (2000), Wang (1999) estimates that short-run marginal cost for nuclear is 0.386 cents per Kwh at the sample mean. Long-run marginal cost is also very low at slightly less than 0.5 cents per Kwh, see Table 3.4. Note that this is less than one-fourth the marginal cost of steam electric power generation. Long-run average cost is 2.199 cents per Kwh, which it is approximately half

Table 3.3: Nuclear electric generation and cost, firm means, 1986-1999

Company	*Generation mmwh*	*Total Cost (¢/kwh)*	*Company*	*Generation mmwh*	*Total Cost (¢/kwh)*
Eastern Utilities Associates	0.50	13.43	**Ohio Edison**	6.97	8.28
Madison Gas & Electric	0.65	2.65	Union Electric	7.34	2.46
Wisconsin Power & Light	1.50	2.69	Baltimore Gas & Electric	10.04	4.18
Wisconsin Public Service	1.51	2.40	**General Public Utilities**	10.21	5.13
Delmarva Power & Light	1.62	4.02	Centerior Energy	11.65	6.94
Public Service Co of NH	2.09	15.16	**Pennsylvania Power & Light**	13.58	2.40
United Illuminating	2.42	12.17	*Pacific Gas & Electric*	15.72	3.81
San Diego Gas & Electric	3.25	3.91	*Southern California Edison*	15.89	4.03
El Paso Electric	3.65	4.06	Public Service Electric & Gas	16.18	4.44
Kansas City Power & Light	3.86	3.53	**Carolina Power & Light**	16.94	4.62
Kansas Gas & Electric	4.19	2.32	**Entergy Corporation**	18.96	2.65
Consumers Energy	4.65	3.71	Florida Power & Light	19.30	3.07
Consolidated Edison NY	5.36	4.83	**Virginia Electric & Power**	21.74	2.13
Niagara Mohawk Power	5.66	6.35	**Southern Company**	24.43	3.72
Wisconsin Electric Power	6.71	2.70	**Duke Power**	34.89	2.33
Arizona Public Service	6.71	7.86	Commonwealth Edison	61.84	3.14

of actual total average cost, which suggests very substantial potential savings from more efficient use of capital in this sector. As with steam electric power, progress in nuclear technology reduces costs but at a very slow rate. The estimates also indicate very strong scale economies in nuclear power generation, with declining average and marginal costs over all relevant ranges of output. This explains why many companies have sought and achieved substantially higher operating rates for nuclear plants over the past 10 years.

Table 3.4: Estimates of other cost and scale measures for nuclear power

Marginal cost	¢/kwh	Technological change	Percent
Short run	0.386	Short run	–0.100
	(0.374)		(0.011)
Long run	0.493	Long run	–0.003
	(0.390)		(0.002)
Average cost	**¢/kwh**	**Scale economies**	**Percent**
Long run	2.199	Short run	0.895
	(0.220)		(0.095)
		Long run	0.776
			(0.156)

CHAPTER IV. APPROACHES TO RESTRUCTURING

There is no one method to undergo electricity restructuring. The three most prominent examples of electricity restructuring are in England and Wales, California, and Pennsylvania. In this chapter, we examine the restructuring decisions made in each jurisdiction.

ENGLAND AND WALES

The evolution of the electricity industry in England and Wales has been recently studied by Newberry (1999). After World War II, the electricity sector in Britain was acquired by the national government. The government owned the distribution, transmission, generation, and dispatch of electricity (system operation). In the late 1980s the British government decided to restructure and privatize the electricity system in England and Wales. The electrical sectors in Scotland and Northern Ireland were subject to differing governance arrangements, and to restructuring programs with different details.

The generation of electricity was deregulated, and fossil fuel plants were sold to private interests. The distribution network was broken into twelve regional companies that were also privatized. The distribution companies' prices were set subject to rate of return regulation.

Initially, only the largest customers could choose their own electrical suppliers. The remainder was required to be supplied by their regional distribution company. The threshold on electricity choice was gradually reduced through the 1990s. At the end of the decade, all consumers had the opportunity to choose their own electricity supplier.

Control of system operation continued to be run by a government entity. In addition, electricity generators were required to sell all their power not already allocated by long-term contract into a government run power pool, commonly called a "POOLCO." The requirement to use the POOLCO was gradually phased out during the 1990s.

One issue in the England and Wales restructuring was how to deal with the costs of decommissioning the government-owned nuclear power plants. A transitional tax was levied on the sale of fossil fuels of 10.8 percent to pay for these costs.

One substantial advantage for restructuring advocates in England and Wales was the lack of "stranded costs." Stranded costs are investment made by private utilities that would be non-remunerative in a competitive market. Electricity companies who face stranded costs as a result of restructuring can be expected to oppose it. In England and Wales, however, there were no private firms. This is not to say that there were no non-remunerative investments made in the pre-restructured electricity industry in England and Wales. Rather, because the government was implicitly covering much of these losses, through its ownership of non-remunerative investments, the presence of such poor investments did not cause opposition to restructuring. Of course, there was opposition to restructuring in England and Wales. Opposition came from several places, including the bureaucracy of the state-owned electrical utility and coal interests, who realized that their coal could be replaced by more efficient natural gas in a restructured industry.

Probably the most puzzling decision in the England and Wales restructuring was the breakup of the electrical generation supply. As discussed above, competition in generation is a crucial aspect of the efficiency gains from restructuring. In England and

Wales, however, electrical generation was only broken into three different companies. In addition, one of those firms, consisting of all the nuclear plants in England and Wales, which remained owned by the British government, was not considered to be an effective competitive force. The reason for this is that nuclear power, while it has high fixed costs, has very low marginal costs of operation, as discussed in the previous chapter. Thus, if a nuclear power plant is in operation, it makes economic sense for the operator of that plant to run it at capacity for a wide range of market prices.

The net impact of this was that, at the competitive margin, only two major firms affected the price of power in England and Wales, giving these two firms market power.[8] There were imports from Scotland and France, but these were considered to have only minor impacts on the market price of power. This implied that consumers in England and Wales often paid more than the competitive price for their electricity.

Market power was alleviated, however, by the presence of new producers. These producers, in order to finance their costs of entry, often sold long-term supply contracts to the regional distribution companies. These contracts served to reduce the demand for power on the spot market, decreasing the potential exercise of market power. In addition, the regulatory system gave the existing suppliers incentives to sell their power in the form of long-term contracts.

Two important lessons come out of the England and Wales experience. First, restricting contract choice in the sale of power is likely to be inefficient, as consumers

[8] Market power is the ability of a firm to affect the price it receives for its product. See, for example, Carlton and Perloff (2000, 92).

have demand for long-term contracts. Second, when establishing markets for power it is important to minimize the potential for the exercise of market power.

California

The California situation was far different than that occurring in England and Wales. Most customers in California were served by privately owned utilities. While major areas of the state, including the cities of Los Angeles and Sacramento, were served by municipal utilities, these utilities were not owned by the major regulating entity, the State of California.

In March 1998 the State of California began its experience with restructuring, and wholesale electricity prices were no longer regulated. Municipal utilities, however, were not required to restructure. In order to alleviate concerns about the exercise of market power, the privately owned utilities were required to sell 50 percent of their generating capacity. These utilities eventually decided to sell 100 percent of their power, though much of it was sold to their own unregulated subsidiaries. This left the formerly major utilities in California, at least their regulated elements, as simply regulated distribution companies, subject to traditional rate of return regulation.

Utilities in California had made significant investments in nuclear power, investments that would be non-remunerative in a restructured world. The state restructuring plan allowed for these "stranded costs" to be paid by a state-mandated fund. The fund gained its monies by the difference between the allowed retail price, and the appropriate expenses, such as wholesale power acquisition, transmission and distribution fees and other charges, incurred by the relevant distribution company. The amount of stranded cost recovery allowed each utility was determined administratively by the California Public Utility Commission.

All power that was to be sold to final consumers in the state was required to be sold into a power exchange operated by the state. No long term contracts were allowed. Thus, producers of power were forced to sell their products in the hourly spot market and consumers were forced to buy at this price. This requirement was eliminated in August 2000, as the wholesale price of power in California surged. (The power exchange was disbanded in January 2001.) In addition, the state of California spent over $1 billion to create its own Independent System Operator. This ISO served to combine the control areas of the three major privately owned utilities in California.

Individual retail customers were given the option of finding their own sources of electricity. However, the system was arranged so that the discount any consumer received from their distribution company for choosing their power supplier was set equal to the power pool price. This implied that customers could not receive lower prices by choosing their own suppliers. Once this plan became known, most retail power suppliers left the market. This left room, in economic terms, for only "green power," because it represented a different product.

With the onset of restructuring, retail prices in California were reduced 10 percent. Retail prices were fixed at this level until, at least according to the original plan until stranded costs were paid off. Once stranded costs were paid off, the marketplace would determine the price of power. Presumably, at this point, other retail suppliers would have found it economical to enter the market. Note this system implied that retail prices would not initially be a function of wholesale prices. In the period 2000-2001, this would prove to be a serious mistake, as we discuss below.

In the year 1999, San Diego Gas and Electric was paid its stranded costs. Consistent with the regulatory plan, the utility then set prices reflecting the wholesale price of power. In the summer of 2000, however, the wholesale price of power soared. These price increases were passed through to customers in the San Diego area, until new regulations were enacted reducing the price of power in San Diego to its previous level.

Independent power producers are allowed to create their own electricity generating plants in the state of California. Such plants, however, must meet local zoning and environmental regulations. As prices increased in the year 2000, many observers commented that such regulations in California were far too strict, contributing to the electricity shortfall in the state.

PENNSYLVANIA

Electricity restructuring in Pennsylvania was phased in during the period July 1998 to January 2000. As with the California restructuring, this plan only applied to privately owned utilities. Several small cooperative utilities in Pennsylvania were thus unaffected by this change. Electricity generators were set free to charge whatever price the market would bear for their product. No divestitures were required, as the state Public Utility Commission determined that there would be no significant market power problems upon restructuring. Several utilities independently chose to sell many or all of their generation facilities.

As in California, arrangements were made to pay off electric utilities' stranded costs. The value of these stranded costs was determined in administrative proceedings.

Funds equal to the difference between the retail price of power, and the costs of transmission, distribution, and the price of wholesale power were used to account for stranded costs. As in California, the retail price of power to consumers was fixed and, therefore, independent of fluctuations in the wholesale price of power.

Upon passage of the restructuring bill in 1996, electricity rates were frozen across the state. The state PUC then entered into restructuring agreements with several local utilities that reduced power rates for a limited period of time. In addition, utilities no longer had the right to pass along their increases in power costs to customers. As was the case in California, these rate freezes are planned to continue until stranded costs are paid off.

Consumers who chose to pick an independent supplier were given a "shopping credit." These credits reduce consumer charges from their local distribution company. The value of the shopping credit is designed to proxy the value of power that these consumers are no longer buying from their distribution company. In perhaps simpler terms, consumers benefit if they can buy power from independent suppliers at a lower rate than the shopping credit.

The shopping credit is set administratively by the state PUC for each local distribution company, and was initially designed to be slightly below the wholesale price of electricity. This was meant to give an inducement to retail suppliers to enter the market. Unfortunately, the shopping credit does not fluctuate with market prices. During the 2000-2001 period, with higher natural gas prices, the wholesale price of power rose above the relevant shopping credit level, and most retail suppliers withdrew from the Pennsylvania market.

The Commonwealth of Pennsylvania did not set up its own system operator to merge the system operations of utilities. In the eastern part of the state, the utilities had already pooled their system resources into the PJM system operator. In the western part of the state, utilities continued coordinating their own systems. In 2001, however, these utilities agreed to enter into an extension of PJM, often referred to as “PJM-West.”

Independent power producers were given the right to access the power grid with their own production, and many have done so. The chief impediment here does not appear to be local zoning regulations, though independent producers must address these issues. Rather, it appears that access to the system operator is difficult to obtain. There continues to be a waiting line of firms seeking access to the PJM, though several have already gained access. In the western part of the state, because there is no system operator, it is unclear what the status of independent producers seeking to connect to the power grid are.

EMERGING PLANS IN OTHER STATES

Other than Pennsylvania, electricity restructuring plans are currently on-going in Maryland, Virginia, New York, and Ohio. In this section we will briefly discuss and critique these plans.[9]

MARYLAND

Currently, the state is gradually rolling out retail options to consumers. This process should be completed by 2003. The state required a 3 percent reduction in rates upon restructuring. Much like the Pennsylvania plan, Maryland customers are offered a

[9] Much of the information in this section is taken from the Energy Information Administration’s Electricity Restructuring page, http://www.eia.doe.gov/cneaf/electricity/chg_str/regmap.htmland the citations listed there.

"shopping credit" based on which local distribution company serves them. The price of power is capped, depending on the relevant distribution company, from 2003 to 2008.The State-mandated universal service program will be funded by a charge on consumer bills that will raise about $24.4 million during the next three years. Residential consumers will pay about $5 each per year amounting to a share of $9.6 million.

NEW YORK

Under the New York plan, the state regulatory commission negotiated restructuring plans with each of the major utilities. Stranded costs are paid via an add-on to the price of power. Some of the utilities imposed price caps on retail prices for approximately three years, much like in Pennsylvania. Others, however, imposed "floating caps" where the standard distribution company offers to customers floated with the wholesale market price of power. (Some utilities offered their customers a choice between the two plans.) Customers are required to pay a systems benefit charge to pay for environmental and low income programs.

In line with our previous comments on Pennsylvania, we view the establishment of retail prices based on wholesale market prices as more conducive to the entry of retailers in the market. In addition, it brings the price customers pay more in line with the actual opportunity cost of the power.

OHIO

In Ohio consumers began to have access to retail choice starting at the beginning of 2001. . The new law requires 5% residential rate reductions and a rate freeze for 5 years. A $33 million electric choice education campaign by the state public service commission, the Ohio Consumers Council, and several utilities is underway. The campaign will include television, radio, billboard, and print advertising, a 12-page consumer guide, a toll-free hotline, and an educational website. Low interest loans for energy efficiency are also available. The state has also emphasized how much new generation it has allowed to occur.[10]

VIRGINIA

Residential prices in Virginia are capped until February 2007. Each year the state projects what the average market price of power will be. It then gives each customer a "shopping credit" equal to that amount. The state has a fund generated from a regulatory tax that supports consumer education projects. There is, however, no low-income program.

The Virginia plan for annual updates of shopping credits is, from our point of view, less responsive then the Pennsylvania plan, which does not provide for periodic updates. It is, however, less responsive than the regime in some parts of New York, where the effective shopping credit fluctuates with the wholesale market price of power.

Each state discussed above, in varying degrees, has price caps on residential rates. As we discuss in the text above, we do not view these restrictions as conducive to competitive retail markets. In contrast to the California plan, however, all of these states permit customers to enter into long-term contracts for power.

[10] See http://www.puc.state.oh.us/Consumer/Electric/ohiovscalif.html.

CHAPTER V. MARKET PERFORMANCE UNDER RESTRUCTURING

The problems in California under electricity restructuring are well known; bankrupt utility companies, blackouts, and sharply higher prices. In contrast, the restructured electricity market in Pennsylvania has enjoyed reliable supply at relatively low and stable prices. The objective of this chapter is to understand the reasons for such radically different outcomes under restructuring. Our principal finding is that the higher prices in California were inevitable due to a shortage of electricity production capability and a heavy reliance on power generation fired by natural gas. Blackouts and many of the financial difficulties resulting from the market meltdown California, however, were due to fatal flaws in the restructuring provisions.

Another important finding is that Pennsylvania and the greater ARC region are much less dependent on natural gas than California. Indeed, most new power plants now under construction in the U.S. will be fired by natural gas, primarily due to environmental considerations. The experience of California suggests that price volatility may be one consequence of this reliance on natural gas. More generally, policy makers contemplating restructuring electricity markets should consider the role of environmental regulations in achieving a diversified portfolio of electric power generators.

The discussion in this chapter begins with an overview of the performance of electricity markets under restructuring in California and Pennsylvania. A shortage of electricity capacity was a major factor behind the spike in electricity prices in California during late 2000 and into early 2001. Another major contributing factor was a dramatic increase in natural gas prices. To understand the role of capacity constraints and natural gas in the electricity industry, we present a comparative cost analysis of electricity generation in the United States. We conclude the chapter with a look ahead. Surprisingly, recent market developments hint at the emergence of excess supplies of electricity and a substantial increase in natural gas exploration and development.

THE CALIFORNIA EXPERIENCE

As the previous chapter explains, the California restructuring plan forced the three main electric utility companies in the State – Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric – to sell half of their generation capacity. The restructuring plan required most power to be bought and sold in the California wholesale power exchange set up by the State. Also beginning January 1, 1998, residential customers of the investor owned utilities received a 10 percent reduction in their monthly bills. Consumer rates include a distribution and transmission charge, a generation charge, other miscellaneous charges, and a competitive transition charge (CTC) that was used to pay off stranded costs. For example, a customer of Southern California Edison on average paid 12.7 cents per kilowatt hour in 1999 (see Table 5.1). More than 4.6 cents of that reflected a still-regulated transmission and distribution charge. The generation charge was approximately 3.2 cents. Other miscellaneous charges amounted to a shade over 2.3 cents. The CTC picked up the remainder, 2.5 cents per kilowatt hour. Under the plan, consumer rates were frozen until stranded costs were paid off. Note that the CTC charge is a residual equal to the fixed price to consumers minus transmission, distribution, and other charges, and minus the fluctuating generation price. As long as the generation price did not go “too high”, this system was financially stable.

Table 5.1:Average electricity rates for Southern California Edison Co., 1998-2001

	Average rate in cents per kilowatt hours			
Component	1998	1999	01/2000-04/2000	05/2000-02/2001
Generation Charge	3.34	3.22	3.78	17.36
Transmission & Distribution	3.34	4.64	5.66	3.44
CTC	3.28	2.50	1.18	*-10.11*
Other Charges	2.76	2.31	2.10	2.17
Amount paid per month	12.72	12.67	12.72	12.86

Under this scheme, generators have important incentives to cut costs, one of the two objectives of restructuring. In the California system, however, there was little room for retail competition. Any consumer who chose to purchase power from a retailer other than the local distribution company received a rebate equal to the wholesale price. This meant that a retailer could not show a profit unless it was able to purchase power below the wholesale price for power, which was close to impossible. For example, if the wholesale price was 3.5 cents per kilowatt hour, 3.5 cents was the amount of the rebate. Since no one would sell to retailers at less than 3.5 cents when they could get this amount in the wholesale market, no electricity retailer could make money in California. Thus, the California system precluded retail competition until stranded costs were paid off.

Unfortunately, by the summer of 2000, the California system unraveled as the wholesale price of electricity rose over ten fold. Figure 5.1 displays weekly average wholesale prices for electricity in California Power Exchange and in the Pennsylvania-New Jersey-Maryland (PJM) market. Prices in California were relatively low and stable from April 1998 to June 2000. In fact, prices in PJM were more volatile than prices in the California wholesale market during this period. After June 2000, however, the magnitude and duration of the prices spikes are much larger in California.

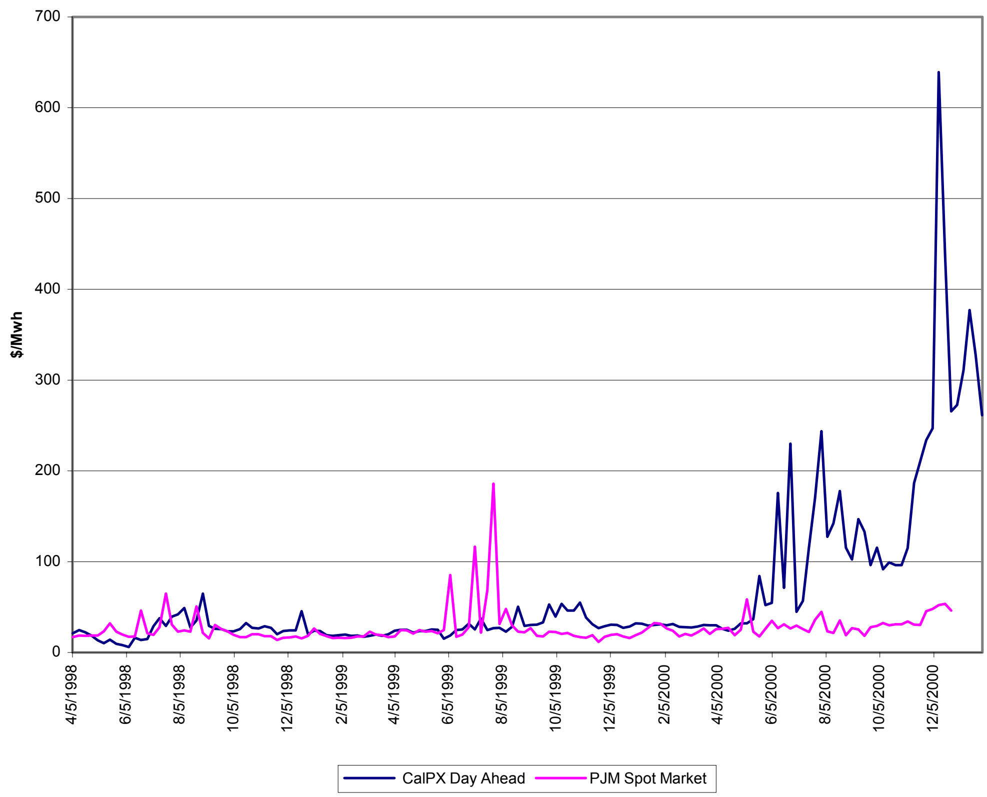


Figure 5.1: Wholesale electricity prices in California and Pennsylvania, 1998-2001

Electricity price spikes occur as demand approaches the capacity limits of the power system, either at generation sources or at critical transmission points. Sharp, temporary price increases also occur in other industries, such as petroleum refining, natural gas, and many markets for metal commodities. In these markets, consumers often draw from stocks or use financial instruments as insurance for these price shocks. The unfortunate configuration of restructuring in California, however, created serious financial problems.

Distribution companies in California, with their retail prices fixed by law, were losing nearly 10 cents for every kilowatt hour sold during the latter half of 2000, incurring huge financial losses. The problem was further exacerbated by the requirement that distribution companies buy their power on the California Power Exchange spot market. Distribution companies, unable to shield themselves against price risk though the use of futures and option contracts, had to suffer the full financial exposure of the price increase.

By January 2001, the major distribution companies in California were essentially bankrupt. Power generators refused to sell these companies power for fear of non-payment, and widespread blackouts resulted. The state of California stepped in, eliminated the California Power Exchange, and subsidized electricity markets, at a cost of approximately $40 million per day. The state acquired the power through a series of long-term contracts. The details on these contracts have not yet been released, though their general nature is known.

As the sections below will demonstrate, restructuring did not cause the power supply shortage in California. But the form of restructuring – with generators and distributors essentially required to buy on the spot market – exposed the distributors to the risk of relying on spot transactions. The regulated retail prices meant that distribution companies held all the risk. When prices exploded, bankruptcy and blackouts were the natural response. The state of California, by not allowing prices to rise, exacerbated the problem.

THE PENNSYLVANIA EXPERIENCE

The Pennsylvania restructuring plan was similar to the California plan in several ways. Generation was freed from rate of return regulation, and power was sold in a largely unregulated market. Generation divestitures were not required, though many took place voluntarily. Prices to consumers were lowered, and capped for the period of stranded cost recovery. Again, prices to consumers were set to the sum of transmission, distribution, generation, and CTC charge (see Table 5.2).

Table 5.2: Average electricity rates in Pennsylvania, 1999

	Rate in cents per kilowatt hours		
Component	PECO	GPU	Allegheny
Generation Charge	5.75	4.00	3.22
Transmission & Distribution	4.57	3.03	3.06
Transition Charge	1.82	0.73	0.64
Amount paid per month	12.14	7.76	6.92

There were, however, two important differences from the California structure. First, power could be sold on a spot or long-term basis, whatever the parties thought was in their best interest. Second, consumers choosing a supplier other than their local distribution company were given "shopping credits" set administratively by the state Public Utility Commission. Shopping credits were set originally above the generation cost component of retail prices, which allowed retailers to enter the market.

Electricity retailers did enter the market, selling at one point up to 10 percent of customers. Of special significance is the success of Green Mountain Power, which has sold environmentally friendly power to customers at a premium price. Unfortunately, as market prices have risen (and shopping credits remained fixed), retailers have been squeezed out of the market.

Wholesale electricity prices have risen in Pennsylvania in the last two years by approximately 25 percent. Power in Pennsylvania comes largely from coal-fired generators, with natural gas plants representing only the marginal suppliers. New power plants are being allowed into the system, though the required administrative and regulatory procedures slow this process down.

The Pennsylvania price cap, just like its California equivalent, does create the possibility of a squeeze on utility margins if wholesale prices rise too high. But that has not happened, and is not likely to. The supply of power in Pennsylvania is very stable, and is not highly dependent on the price of natural gas and on natural factors, such as the amount of rainfall. Summer peaking prices can get very high, but only for relatively short periods of time.

THE CALIFORNIA ELECTRICITY PRICE SHOCK

A combination of factors contributed to the spike in wholesale electricity prices in California from June 2000 through early 2001. The chief culprits were an unanticipated surge in electricity demand and a lack of low cost electricity supply. For over a decade, it had been extremely difficult to site new power plants in California. The state had become highly dependent on hydroelectric sources, power from natural gas plants, and imported power.

Total electricity sales in California increased more than 6 percent during 2000, exceeding historical average annual demand growth by more than a factor of three. Although direct evidence is unavailable, much of this growth may have been associated with an increase in computer and telecommunications manufacturing activity in the state. Another factor is electricity consumption by computer networks supporting internet traffic.

While previous generation capacity could have serviced this load without major disruption, this surge hit just as hydroelectric capacity was about to be greatly reduced.

The winter of 1999-2000 in the Western U.S. was very dry, greatly reducing the snow pack in Oregon and Washington. In normal years, the summer melt of this snow drives hydroelectric dams and much of this electricity is transmitted to California to meet their summer power needs. During 2000, however, hydroelectric power generation declined more than 18 percent in Washington and Oregon and 22 percent in the Rocky Mountain region, substantially reducing the availability of power for export to California, see Table 5.3. There was also a 13 percent reduction in electricity from other, non-conventional sources of power in California during 2000, apparently associated with difficulties in the production of geothermal power.

Table 5.3:Changes in western U.S. power generation, 1999-2000

	Total	*Gas*	*Hydro*	*Nuclear*	*Other*	*Coal*	*Oil*
Mountain	4,161	7,256	-10,226	-35	-4	6,970	200
California	-2,261	-1,618	-993	1,804	-1,546	0	93
Oregon & Washington	-22,941	3,591	-24,063	2,522	92	-5,347	264
Changes in Non-Utility Generation in million Kwh							
Mountain	16,583	2,657	1,462	0	107	12,407	-51
California	15,667	17,284	-273	0	-1,525	94	87
Oregon & Washington	7,853	1,355	0	0	142	6,207	149
Changes in Total Generation in million Kwh							
Mountain	20,744	9,913	-8,764	-35	103	19,377	149
California	13,406	15,666	-1,266	1,804	-3,071	94	180
Oregon & Washington	-15,088	4,946	-24,063	2,522	234	860	413
Pecentage Changes in Total Generation							
Mountain	6.4	33.2	-22.0	-0.1	4.4	8.7	17.6
California	6.7	16.0	-3.2	5.3	-13.3	3.9	7.9
Oregon & Washington	-9.1	37.8	-18.5	34.7	11.8	6.7	206.5

Nonutilities are generation companies not subject to rate of return regulation

The shortage in hydroelectric generation was offset by a substantial increase in natural gas fired electric power generation. Gas powered generation increased more than 15,000 million kwh in California during 2000 and another 14,000 million kwh in the rest of the western U.S., (see Table 5.3). Even under relatively low gas prices, the marginal cost of gas-fired electric power is more than three times greater than the marginal cost of hydroelectric power.

This large switch to natural gas placed considerable strain on the natural gas transmission system and substantially reduced gas storage levels. As a result, prices for natural gas delivered to the city-gate in California increased more than four-fold, rising from \$2.90 per thousand cubic feet (mcf) in March 2000 to a peak of \$12.64 in December 2000 (see Figure 5.2). These higher gas prices directly increased the cost of operating natural gas-fired electrical generation capacity.

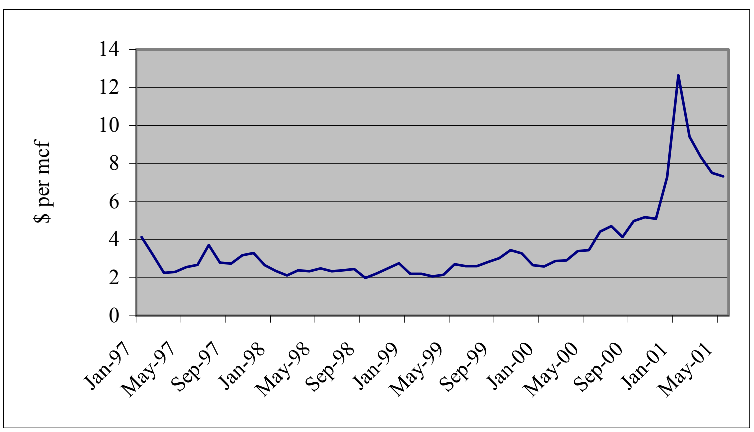


Figure 5.2.City-gate natural gas prices in California, 1998-2000

The cost model discussed above in Chapter III provides a tool for estimating how these higher natural gas prices affect the marginal cost of electric power generation. Our cost model was estimated using data for utilities before they sold their generation assets.

Most of the California utilities sold their assets during 1998 and 1999. As a result, our model only provides estimates of marginal cost for the last year that each utility operated those assets. Nevertheless, the model can be used to estimate what impact higher natural gas prices alone would have on short-run marginal costs of steam electric power generation. Indeed, the assets sold to non-utility entities (entities that were not regulated utilities prior to restructuring) are unlikely to have radically different cost efficiencies after than before divestiture. Private operation of these assets would improve plant efficiency and so the estimates reported below may be underestimated.

Table 5.4 presents the results from our calculations. We calculated marginal generation cost in the year before divestiture at then prevailing natural gas prices paid by

Table 5.4:Impact of higher natural gas prices on marginal cost for electricity

	Southern CA Edison Co	Pacific Gas & Electric Co	San Diego Gas & Electric Co
	1997	1997	1998
Before natural gas price increase			
Gas price ($ / mcf)	2.964	2.713	2.668
percent share of gas in steam generation	96.140	99.10	98.60
Marginal cost ($ / Mwh)	24.561	32.982	33.734
After natural gas price increase			
Average gas price in 2000 ($ / mcf)	6.040	6.040	6.040
Marginal cost ($ / Mwh)	42.670	58.340	72.390
Average gas price in Jan 2001 ($ / mcf)	12.350	12.350	12.350
Marginal cost ($ / Mwh)	75.020	105.760	139.980

these utilities. Natural gas prices varied between $2.67 and $2.96 per mcf and the corresponding marginal costs for electricity were between $24 and $34 per Mwh. We then re-calculated these prices under average natural gas prices during the year 2000, which were slightly above $6 per mcf. As a result, marginal generation costs rise between $42 and $72 per Mwh (see Table 5.4). These short-run marginal costs rise over to $130 per Mwh at the peak of natural gas prices during January 2001.

A similar story emerges if we take a somewhat different approach to compute marginal cost. In Figure 5.3 below, we plot the marginal cost of electricity generation for all generators in the State of California during January 2000. Marginal cost is defined

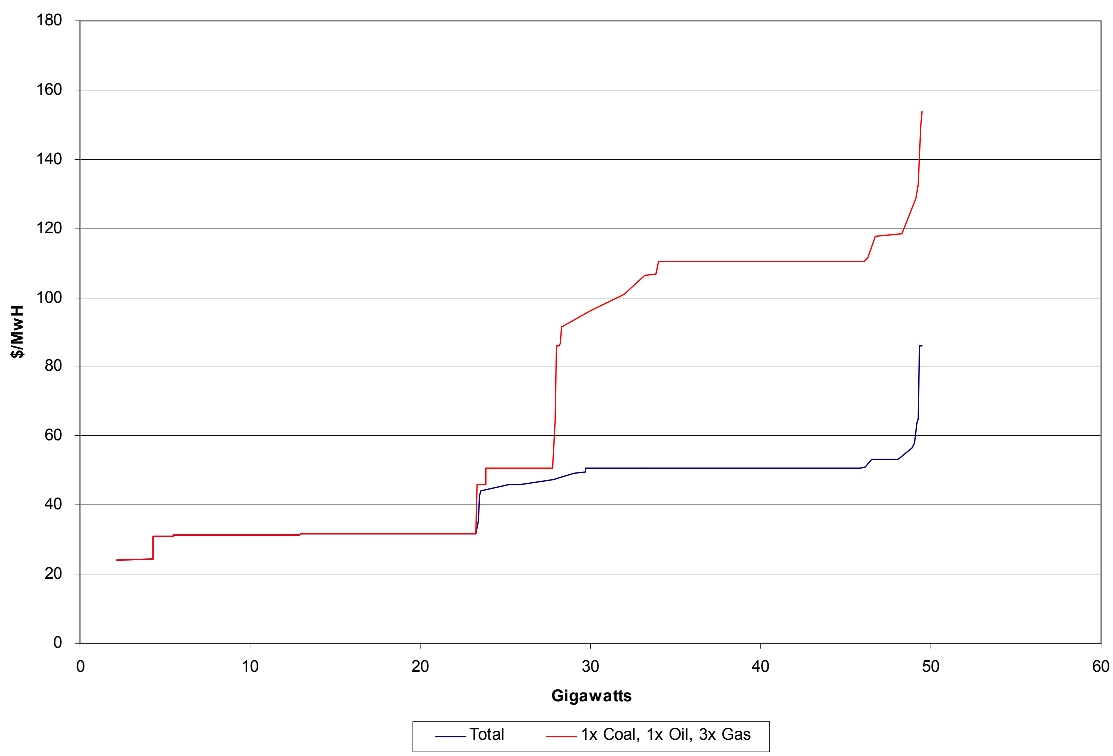


Figure 5.3:Marginal cost of electricity in California, January 2000

here to include the incremental cost, in terms of dollars per Mwh, for fuel, labor, and environmental allowances. We use our cost function estimates for marginal cost from nuclear electric power generation and estimates of hydroelectric marginal costs reported in the literature. Marginal fuel costs for fossil fuel fired units are equal to product of the generator heat rate and the fuel price. The curve illustrated in Figure 5.3 has characteristic "hockey-stick" shape with a long flat handle that includes low cost sources of power, such as nuclear and hydro, and a sharp upward section including higher cost sources, including gas and oil turbines.

This diagram provides a useful reference point to understand the cost implications of the California situation. First, as the diagram illustrates a four-fold increase in natural gas prices shifts the cost schedule sharply upward at higher output levels. Second (this is not illustrated in Figure 5.3 but easily envisioned), the shortfall in hydroelectric capacity shifts back the entire schedule so that higher cost generators are used earlier in meeting load requirements. If the system was operating at the capacity limit, as it no doubt appears to have been during late 2000, the diagram illustrates that the marginal cost of the last generating unit would be approaching $200 per Mwh.

Now what is interesting and important for policy makers in the Appalachian region to understand is that the cost schedule for a typical utility in their region is much different. A good example is the corresponding cost schedule for Pennsylvania illustrated in Figure 5.4. Notice that the handle of the "hockey stick" is much longer, illustrating a greater share of low marginal cost nuclear and coal-fired capacity. Unless demand approaches capacity limits represented by the vertical portion of the schedule, this comparison suggests that price shocks of the magnitude witnessed in California are unlikely in Pennsylvania. This conclusion is likely to apply to the rest of the Appalachia given the preponderance of coal and hydroelectric capacity throughout region.

Another implication of this analysis is that there appears to be a rather sizeable unexplained difference between wholesale prices in California and the marginal costs estimated in this study under higher natural gas prices during the peak in electricity prices in December 2000. Between June and November 2000, weekly average prices were between $50 and $240 per Mwh, near the boundaries of our estimated cost schedules. Prices during December 2000, however, shot up to more than $600 per Mwh.

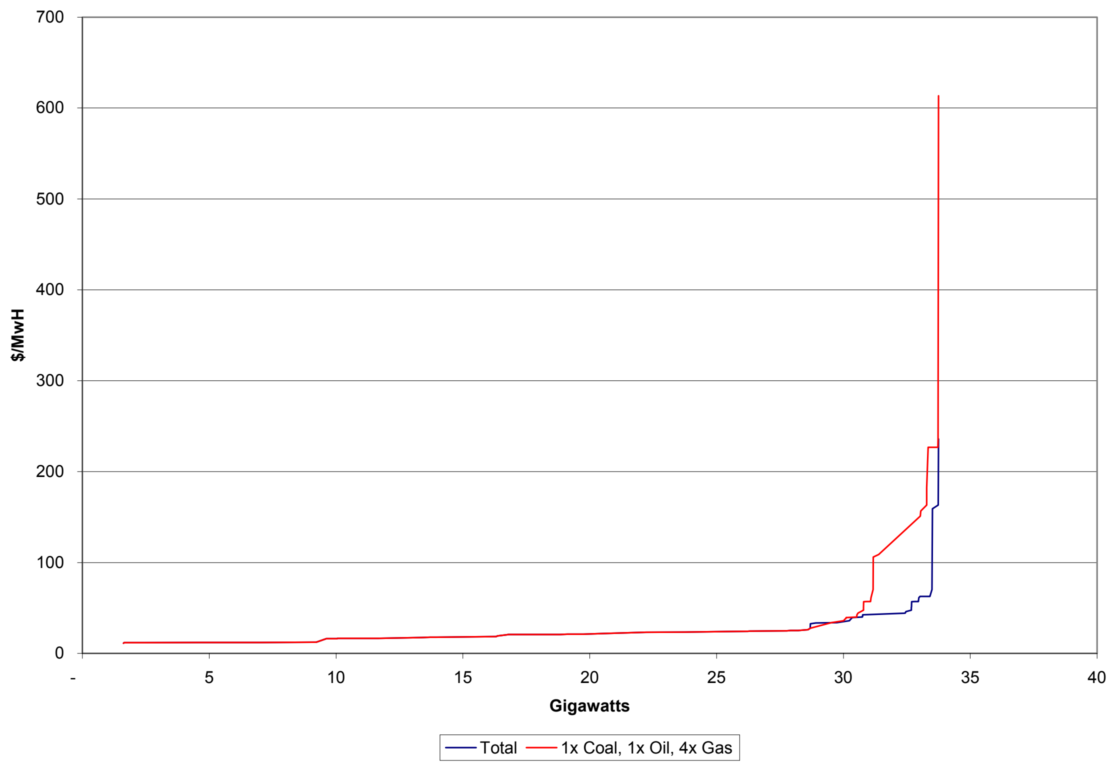


Figure 5.4:Marginal cost of electricity in Pennsylvania, January 2000

There are several possible explanations for this discrepancy. First, our estimates of environmental permit prices may be underestimated and may not reflect the temporary bursts sometimes observed in tightly regulated areas, such as Southern California. Also, transmission capacity constraints may create a congestion premium on electricity prices. Our estimates of marginal cost is at the generation point and do not include such premiums.

A third possibility is that the market price of electricity may have contained a risk premium associated with the financial insolvency of the major utility companies in the state. In this case, generators would place a premium on bids to compensate for any unpaid bills. For example, on January 17, 2001, Pearlson (2001) reported that Duke Power offered to operate an inefficient, and polluting generator for $3,880 per Mwh with most of the proposed fee representing a "credit premium," because they estimated that there was only a 20 percent chance that they would ever get paid. The California grid operators reluctantly agreed to pay this high price, figuring that this amount would be far less than the costs of a blackout. The Federal Energy Regulatory Commission found that a "just and reasonable" price would have been $273 per Mwh and ordered Duke to return the excess. Ironically, there was nothing to return because Duke received only $70.22 per Mwh, precisely the type of outcome they had feared.

Yet another possibility is that electricity producers were withholding generation capacity at certain critical times to drive market prices upward. Pearlson (2001) reports that Joskow and Kahn find that there were four times as many scheduled and unscheduled plant shutdowns during the fall and winter of 2000-2001 that in the previous year. Other analysts note that these plant maintenance shutdowns were necessary because these facilities were so intensively operated during the previous 12 months. Nevertheless, the closing of these plants at critical times, such as peak power demand periods, would create a shortage and drive prices upward. Other claims of the exercise of market power are more subtle, involving bidding strategies. For instance, generators would offer extremely high bid prices for power on their last units offered for sale, knowing that their competitors would match these bids. This type of signaling strategy works as long as supplies are tight and as long as no competitor seeks to gain advantage by submitting substantially lower prices. Proving whether these strategies were employed and identifying their motivations could be a daunting challenge. As the following section illustrates, however, market forces may be a powerful disciplinary force against persistent use of such tactics and on the wielding of market power in general.

AFTER THE PRICE SHOCK

Since January 2001, the price of electricity in California has dropped considerably, see Figure 5.5. From January through early May 2001, the price fluctuated between $150 and $250 per Mwh. During May and into June 2001, however, the price dropped to $50 per Mwh and has stayed at that level through the end of August 2001. Several factors have contributed to this decline. The demand for electricity fell due to a cooler than anticipated summer, weak economic conditions, and conservation efforts, spurred by high prices and by changes in energy consumption habits spurred by public appeals for conservation.

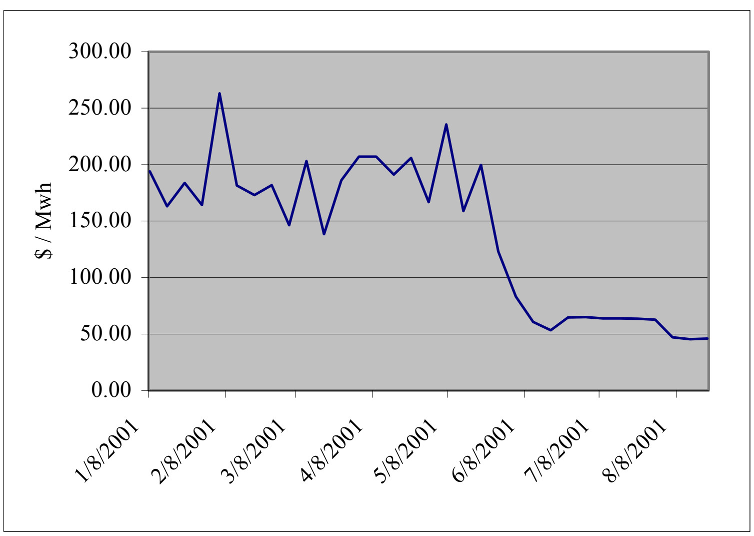


Figure 5.5:Price on the APX California energy market, 2001

Several supply side factors are also contributing to a decline in electricity prices. California elected officials urged that the FERC impose tough wholesale price controls during the Spring of 2001. During late June, FERC imposed cost-based controls on wholesale electricity prices. Behr (2001) reports that some analysts argue that FERC action was a decisive factor in lowering electricity prices.

Market forces, however, are also another major factor. Natural gas prices are considerably lower, sliding steadily through the spring and summer as additional supplies substantially rebuilt natural gas storage levels nationwide. The price for natural gas on the New York Mercantile exchange steadily declined through the year from roughly $10 per million British Thermal units to under $3 during August 2001.

Another important factor is a very significant increase in electric power generation capability (see Table 5.5). During June and July 2001, more than 1,400 MW

Table 5.5:Power plant project status in California, 2001-2003

Project	Status	Capacity (MW)	Type	Decision	On-line
Sunrise	Operational	320	Green Field	Dec-00	Jun 26-01
Sutter	Operational	540	Green Field	Apr-99	Jul 2-01
Los Medanos	Operational	555	Brown Field	Aug-99	Jul 9-01
Operational		1,415			
Huntington Beach	Construction	450	Repower	May-01	Sep -01
On line summer 01		1,865			
La Paloma	Construction	1,048	Green Field	Oct-99	May-02
Delta	Construction	880	Brown Field	Feb-00	Apr-02
Moss Landing	Construction	1,060	Expansion	Oct-00	Jun-02
On line summer 02		2,988			
High Desert	Construction	720	Brown Field	May-00	Jul-03
Elk Hills	Construction	500	Brown Field	Dec-00	Mar-03
Blythe	Construction	520	Green Field	Mar-01	Apr-03
Pastoria	Construction	750	Green Field	Dec-00	Jan-03
On line summer 03		2,490			
Total On line		7,343			

Source: California Energy Commission

of capacity came on line in California and significant new capacity is slated to come on-line over the next two years. This suggests that unless demand increases, the state could be facing a surplus of electric power generation. Indeed, the long-term contracts signed by the state of California to secure future supplies are now under severe criticism since the state may be force to sell power at a loss.

All of this new capacity in California is fired by natural gas. A critical long term concern is whether there will be enough natural gas to supply these plants. The evidence thus far indicates that there will be enough gas to supply these plants. As Figure 5.6 illustrates, gas drilling has increased sharply approaching levels not seen since the last drilling boom in 1981. Given the advances in drilling and resource recovery technology over the past twenty years, these wells are likely to be very productive. The price

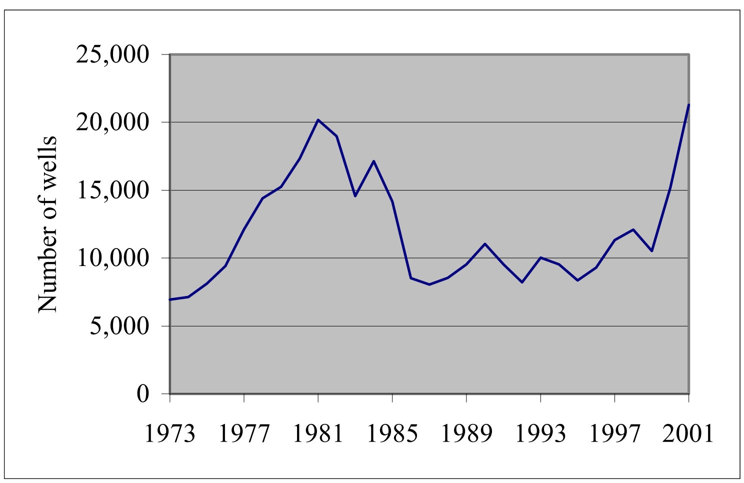


Figure 5.6:Number of natural gas wells drilled in U.S., 1973-2001

increases necessary to induce such a response, however, clearly involve significant economic and financial adjustment costs. Given the nature of electricity cost schedules and the volatility of demand due to weather and other random events, adjustment costs may be unavoidable but, as the California case illustrates, could be reduced with policies that promote more open and flexible markets.

In summary, the California restructuring scheme was not sufficiently robust to handle significant price shocks in the market for electricity. Further, given the sources of power in California, such shocks were not unlikely. The Pennsylvania regulatory scheme has similar problems. The sources of power for Pennsylvania, however, are not as vulnerable to price shocks as the sources of supply for California.

CHAPTER VI. REGULATORY POLICY ISSUES

The electricity industry, whether it is restructured in particular states or not, will be involved in a large variety of regulatory issues. In this section we discuss these issues and the choices public policy makers face.

GREEN POWER

The production of electrical power, especially from coal sources, creates a great deal of pollution. Coal-fired electricity is the primary source of acid rain, and an important source of pollution for a variety of particulates. Coal-fired pollution is heavily regulated by the Federal Environmental Protection Agency under the Clean Air Act. Under these regulations, each coal facility is given the right to emit a certain amount of emissions. Firms can buy, sell, or trade these rights between each other.

Despite these limits, there are considerable concerns in society about the amount of pollution caused by the consumption of electricity. In particular, Robert Ethier, et. al. (2000) find that there is clear evidence that at least some consumers are willing to pay a premium for "green power" – power that is, at least in some dimension, cleaner than typically generated power. We note that in choosing to pay extra to consume green power, consumers are creating a "public good" – a cleaner environment that is shared by all. In this sense, the motivation by consumer to buy green power is similar to the motivation by economic actors to contribute to charity.

In Pennsylvania green power has found a successful niche. Green power is available to consumers across the state. However, it is significantly more expensive than traditional sources of power. For example, during the summer of 2001 in the GPU service area in eastern Pennsylvania, green power generation costs are 7.5 cents per kilowatt hour, versus a price of 4.53 cents from the incumbent utility, according to the Office of Consumer Advocate of Pennsylvania (2001). (These prices do not include charges for distribution, transmission, and stranded cost recovery.)

Several consumer protection issues arise with the sale of green power. In particular, it is unclear exactly what constitutes "green power." For example, hydroelectric power does not typically create air pollution. However, the use of hydro power may have significant adverse ecological consequences in the relevant rivers. In addition, much of the hydroelectric power from Quebec, which is a major source of supply into the eastern United States, was created by flooding the lands of local Indian tribes against their politically expressed will.

NUCLEAR ENERGY

One of the important methods by which electrical power is generated in the United States is through the use of nuclear fission. This is a field that has had great promise, and great difficulties. Five years ago it appeared that nuclear power was a rapidly declining industry. Today, there are new prospects for the use of nuclear power.

THE STRANDED COST PROBLEM

After World War II there were many proponents of nuclear power. In a famous statement, one advocate asserted that power from nuclear fission would be "too cheap to meter." Nuclear power plants were built across the United States. This building program accelerated in the late 1960s and 1970s, when alternative power sources from natural gas and coal were less attractive, due to issues of supply security and environmental consequences.

Unfortunately, nuclear power construction was subject to serious cost overruns. There are several possible sources for these large costs. First, important safety and environmental concerns motivated extensive regulation of nuclear power plants by the Nuclear Regulatory Commission. Many critics have suggested that this regulation was excessive and lead to larger than necessary costs. Second, many different designs of plants were used, precluding firms from being able to learn from others' mistakes. Third, utilities, who were being reimbursed under rate of return regulation, had limited or non-existent incentives to keep prices down. Finally, the advocates of nuclear power may have simply oversold their product.

In most industries, firms that incur cost overruns suffer financial losses. In a regulated utility industry, however, those losses are simply passed on to consumers. Today, the losses due to nuclear power are generally referred to as "stranded costs." One important rationale for electricity restructuring is to avoid the recurrence of the stranded cost problem. Removing rate of return regulation removes any incentive to incur cost overruns, hopefully making the electric power system more efficient in the long run.

THE RESURGENCE OF NUCLEAR POWER?

While nuclear power has been a poor investment in the past that does not imply current nuclear facilities are uneconomical to operate. Though current nuclear power plants have large fixed costs, their marginal costs of operation are often quite low. Thus, once a nuclear plant has been built, it makes economic sense to operate it as much as possible.

Several factors have prompted to at least a small resurgence in interest in nuclear power over the last few years. The first is that nuclear power plants have become more efficiently operated. This increase in efficiency may be the result of the rise of firms specializing in the operation of nuclear power plants.

Second, policy makers have become increasingly interested in the environmental consequences of emissions from fossil fuel plants. Nuclear power, because it does not emit any air pollution or carbon dioxide, is thus considered, at least in this respect, environmentally friendly. Third, the rising price of natural gas in the period 2000-2001 has caused electricity suppliers to look for other options.

Nuclear power plants operate under licenses from the Nuclear Regulatory Commission, which have fixed term lengths of twenty years. A number of power plants are now in the process of obtaining license renewals.

Advocates of nuclear power in the U.S. contend that the industry will require an extension of the Price-Anderson Act to remain in operation, at least with the technology currently in place. The Price-Anderson Act limits liability as a result of a nuclear accident to approximately $500 million. The latest extension of the Price-Anderson act expires in August 2002. Economists criticize the Price-Anderson Act as being an unwarranted interference in the free market, although the magnitude of that interference is subject to question.

Finally, recent advances in "pebble bed technology" have created a new method of generating nuclear power. Pebble bed reactors are smaller and are claimed to be safer than earlier reactors, leading to lower costs. Prototype reactors have been built in France and Japan. A commercial size reactor is now under construction in South Africa. At the time of this writing, several firms appear on the verge of applying to the NRC for the authority to build such reactors. However, these applicants may have been deterred by the fears of terrorism brought on by the events of September 2001.

Disposal of Waste

Unfortunately, one important issue for nuclear power in the U.S. has yet to be addressed. Nuclear fission creates nuclear wastes, which must be disposed of properly. Further, because nuclear wastes are hazardous for extremely long periods of time, disposal must be done extremely carefully. Nuclear facilities now largely store their nuclear wastes on site, but this is widely considered not to be a long-term solution to the problem.

The Federal Department of Energy has focused on creating a long-term storage facility in the Nevada desert, away from major population centers. Congressional representatives from Nevada, however, have strongly opposed the creation of this site because of environmental concerns. In addition, there are many groups who have worked actively to attempt to prohibit nuclear waste shipments across their states. At this point in time the political question of where to locate nuclear wastes is unsettled.

Coal Fired Utilities in Post Kyoto Era

Electricity restructuring raises several issues affecting the coal industry, which is an important source of income and employment in the Appalachian region. A more competitive electricity market will increase pressure to cut costs. As the previous sections illustrate, fuel costs are far and away the single largest component of steam electric power generation. Independent power producers would likely take a tougher stance in negotiating coal contracts since they cannot automatically pass on fuel price increases as their predecessors did during the old days. Another possibility is that they could purchase coal on the spot market or tie their contract prices to the price on the newly created coal futures contract now traded on the New York Mercantile Exchange.

As the previous chapters illustrate, the Appalachian region, indeed the entire U.S. east of the Mississippi River, heavily relies upon coal-fired power generation. Coal is abundant and easily accessible in the region. The control of emissions from coal-fired power generation, however, is costly. These environmental costs and the relatively large capital investments to build coal power stations, explain why a vast majority of recent and planned power capacity in the U.S. in recent years is largely based upon natural gas. The recent experience in California, however, illustrates some of the problems that arise from heavy reliance on one or two fuel sources. This in turn implies that diversification of our energy portfolio, particularly toward the inclusion of coal-fired generation, may be a prudent risk reduction strategy for society.

Like nuclear, coal is primarily used in base load power generation. Large capital costs dictate that coal and nuclear plants should be operated as much as possible. Unlike nuclear, coal fired power generation generates substantial air pollution. The environmental problems created by this pollution in the Appalachian region are significant. Acidic precipitation created from sulfur dioxide emissions damage ecological systems and related economic activity, such a tourism and recreation. Nitrous oxide emissions also create ecological problems, contributing to ground level ozone that creates health problems and haze that reduces visibility. Coal burning on a large scale also emits significant amounts of mercury into the environment with potentially serious, toxic effects on ecosystems and human health. Particulate emissions are another problem linked to higher incidence of asthma and other respirator ailments. Perhaps the most serious problem facing the long-term future of coal is that coal burning is a major source of greenhouse gas emissions.

The failure of the Kyoto treaty to control greenhouse gas emissions illustrates the difficulty in achieving an international consensus to deal with long-term environmental issues. While this development may appear to be good news for the coal industry, most large industrial companies anticipate that there is a distinct possibility that some form of emission controls on greenhouse gases will emerge over the next 20 years. Given the breakdown of the Kyoto approach, a more flexible market based form of regulation may emerge, perhaps not worldwide but in some regions, such as Northern Europe. British Petroleum, for example, has recently begun trading CO_2 permits within their divisions. The company directors set a CO_2 reduction goal and engineers within various divisions can devise reduction strategies and in the process generate excess permits to sell to other divisions. Divisions with relatively high emission control costs can then purchase these excess permits. Both sides win and the company learns how trading works and develops new technologies that may create new markets or generate cost advantages over its competitors. This realization that innovation in pollution control can lead to cost reduction and competitive advantage may not be universal, but it may emerge as important motivation for investment in new technology.

Many primary fuel producers and large industrial energy consumers are supporting research and development of new technologies that dramatically reduce emissions of acidic pollutants and greenhouse gas emissions from coal-fired power generation. The U.S. Department of Energy and other state and federal agencies are also supporting this research. The integrated gasification combined cycle (IGCC) technology is perhaps the most promising. This technology involves a sequence of steps in which coal or some other carbon-based fuel is converted to a gas, which is then cleaned and sent to a turbine that generates power and recoverable waste heat. With matching funds from the U.S. DOE, Tampa Electric Company (TECO) built a demonstration plant for $300 million and has successfully operated the plant for nearly five years. As a result of this demonstration, the project sponsors consider IGCC commercially and environmentally suitable for electric power generation utilizing a wide variety of feedstocks. Sulfur capture for the project is greater than 98 percent, while NOx emissions are 90 percent lower than a conventional pulverized coal-fired power plant. TECO Energy is working with Texaco to commercialize the technology in the United States but also has been contacted by European power producers to discuss possible technical assistance on using the gasifier technology.

Despite their promise, adopting these technologies is expensive and retrofitting existing plants with these technologies may not be an economically viable proposition. In this case, meeting a stringent CO_2 emission goal would involve switching to another fuel, most likely natural gas given the relatively low capital cost of building a gas power plant. As the recent natural gas price spike illustrates, however, extensive fuel switching over the short term is expensive. Over the long term, an extensive switch to natural gas in power generation in the region will no doubt substantially raise equilibrium natural gas prices in the U.S., which will in turn make more advanced coal technologies competitive. With these competitive pressures combined with abundant coal reserves and well developed transportation infrastructure, coal will remain a dominant source of fuel for electric power generation in the Appalachian region.

MARKET POWER CONCERNS

While the generation of electricity may not be a natural monopoly, it is not immune from the exercise of market power, or monopolization. In the United States, almost all industries are subject to antitrust enforcement, referred to in other parts of the world as "competition policy," which seeks to prevent markets from being monopolized. In the electricity area, antitrust review can be undertaken by the U.S. Department of Justice, the Federal Energy Regulatory Commission (FERC), which is the federal agency responsible for the regulation of electricity markets, and state regulatory commissions.

COMPETITION AND MARKET POWER

Proponents of restructuring base their arguments in large part on the belief that restructured electricity markets will be at least "workably" competitive. Here we will briefly describe what competitive means in an economic sense, and then explain why it may not apply to some electricity markets.

Consider a firm that believes that its output can have no effect on market price – a "price taker." Such a firm would have to have a very small market share. If a firm were a price taker it would produce output until the point at which its marginal costs were equal to the market price. The market price is equal to the incremental value the last consumer in the market places on the relevant good. Thus, in a perfectly competitive market the marginal cost of production equals the marginal benefit of use. In such circumstances the market is said to work "efficiently" and to create the most benefit for society.

In contrast, consider a firm that knows that the market price depends, at least to some extent, on the amount it produces. It then knows that the more it sells, the lower its profits on its output already produced. In such circumstances, the firm will reduce its output below the competitive level, raising market prices and its own profits, while reducing the benefits to consumers. On net, the effect to society of the exercise of market power is negative, creating what economists refer to as "deadweight loss." This loss represents the gain society would have realized had the company decided to produce more electricity.

No market is likely to reach the textbook conditions needed for perfect competition. However, markets are often considered "workably competitive" if there is "enough" competition in them so that they approximate perfectly competitive markets. The antitrust authorities at the Department of Justice and the Federal Trade Commission consider markets to be "highly concentrated" if the relevant Herfindahl-Hirschman index (HHI) is greater than 1800. The HHI equals the sum of the squares of the market shares of the relevant firms in the market.

An analysis of market shares found California electricity markets to be highly concentrated prior to restructuring, and divestitures were accordingly ordered there. In Pennsylvania, markets were not found to be concentrated, and no divestitures were ordered.

Unfortunately, these analyses of markets in California and Pennsylvania did not take account of two factors. First, the demand for electricity is highly variable across time periods. Electricity cannot generally be stored and this contributes to considerable price variation by season and time of day, depending upon how close demand is to capacity constraints. Second, the analysis failed to consider that all power plants do not have the same cost structures. In particular, there are a number of "peaking" plants that only are economical to operate when the price of power is high.

Consider the incentives of a firm with a great deal of "base load" capacity that is economical to use most of the time, and one plant that is only economical to use when a "peaking" situation occurs. This firm may realize that it can achieve greater profits by not running its peaking facility when electricity prices are high, even when the price of power makes running that plant on a stand-alone basis remunerative. The reason for this is that not operating the peaking plant may increase the market price of power. Thus, by not running the peaking facility, the firm can increase the price that its base load plants receive, increasing its profits.

The province of Alberta in its ongoing restructuring program has implemented one possible solution to this problem. In this program, parties who also own substantial base load capacity cannot directly acquire the rights to the electricity produced by peaking units. Because market power problems are apparently generated by this ownership combination, it is hoped that this ownership restriction can result in more competitive markets.

The evidence on the exercise of market power in California electricity markets is mixed. The working paper by Hogan (2001) casts doubt on the possibility of market power. On the other hand, the working paper by Puller (2001) indicates that electricity producers were exercising market power in California prior to the year 2000. Another working paper by Mansur (2001) argues that suppliers in the PJM market exercise market power. Detecting and measuring market power, however, is quite difficult because it involves measuring marginal cost at the plant or in some cases the generator level for very small intervals of time. Often the data for such estimation are unavailable. At this writing, there are no published studies that provide convincing evidence that electricity producers in California exercised market power during the period 2000-2001.

MERGERS

While several agencies have authority to review mergers with respect to competition issues, many important decisions are made by FERC. FERC has reviewed approximately 60 mergers since 1995. Many analysts believe that these mergers have been motivated in large part by the desire of firms to achieve economies of scale in various aspects of the supply of electricity. While most mergers may have a desire to achieve economic efficiency as their primary motivation, some mergers may have the potential to create market power and raise prices to consumers. FERC's role is to review mergers and determine what remedies, if any, are necessary before a merger is consummated.

Much of FERC's concern in the merger area has dealt with the hypothesized exercise of "vertical market power" made possible by a merger. One example of vertical market power would occur if a firm had a large share of both transmission and generation capacity in a particular area. It could act to deny transmission capacity to its generation rivals in order to increase the price of its generation. Reiffen and Kleit (1990) show that this theory is most plausible when one of the vertical levels (in this example, transmission) is highly regulated, creating competitive distortions. Here we will briefly review three recent important mergers reviewed by FERC: American Electric Power Company and Central and Southwest (AEP-CSW), Dominion Electric – Consolidated Gas, and Commonwealth Edison-PECO.

AEP-CSW (91 FERC ¶ 61,242, March 15, 2000) involved the proposed merger of two large integrated utilities. AEP owned subsidiaries that served approximately three million customers in Indiana, Kentucky, Michigan, Ohio, Tennessee, Virginia, and West Virginia, as well as thirty-eight power plants, with an aggregate capacity of approximately 23,800 megawatts, and owns approximately 22,000 miles of transmission lines. CSW operating subsidiaries served approximately 1.7 million customers in Arkansas, Louisiana, Oklahoma, and Texas.

The two electrical systems were only slightly connected, making concerns about the exercise of market power somewhat counter-intuitive. However, FERC (over the dissent of one commissioner, who found no competitive issues) found that the combined firms' transmission capacity could be used to restrict "imports" of electricity into several areas with high market concentration. Thus, the combined firm would have an incentive to deny other firms access to the combined firms' transmission lines. Doing so could increase the price of electricity paid by the combined firms' customers, increasing the firms' profits, but harming consumers.

In FERC's view, the problem will be eliminated once the combined entity joins a Regional Transmission Organization (RTO, which is similar to an independent system operator), which would control access to the firms' transmission lines. AEP has promised to join the Alliance RTO, with a starting date that is currently uncertain. Until that time, AEP is required to hire market monitors to observe and report on its use of the transmission system, and to determine if any anticompetitive denial of access is occurring.

Dominion Electric – Consolidated Natural Gas Company (89 FERC ¶ 61,162, November 10, 1999) involved the proposed merger between the largest electric utility in Virginia and a natural gas pipeline company. In this matter, the anticompetitive theory was that the combined entity would deny competitors of the electric utility access to natural gas. This would increase the costs of the competitors, raising the price of the generation of power and benefiting the utility.

FERC approved this merger subject to the condition that the natural gas pipelines involved adopt codes of conduct and other behavioral remedies such that the pipelines would act as "open access" suppliers, giving both generators owned by Dominion, as well as generators owned by Dominion's competitors, the same access to pipeline services.

Commonwealth Edison-PECO (91 FERC ¶ 61,036, April 12, 2000) dealt with the proposed merger of a large integrated utility based in Chicago with a large utility based in Philadelphia. While both firms had significant numbers of retail customers, and extensive transmission capability, both had sold off much of their non-nuclear generation capacity. In particular, PECO appears to have had a corporate strategy of specializing in the generation of power from nuclear facilities.

While several issues were raised in the proceedings, the two major ones involved PECO's use of transmission lines to raise the market price of Commonwealth Edison's power into the PJM region, and horizontal concentration resulting from the merger in several areas. With respect to PECO's use of transmission lines, FERC found that because PECO's transmission lines were controlled by PJM, there could not be anticompetitive use of them by PECO.

There were also claims that the merger would increase horizontal competition in various regions, resulting in an increase in prices. For such an increase to occur, however, the combined entity would have to reduce production from its nuclear facilities. Nuclear facilities, however, have very low marginal costs of production. In addition, starting and stopping a nuclear facility is costly. Therefore, the combined entity, while it would have the ability to raise price, could not do so profitably, as it would be forgoing significant profits at the margin. Accordingly, FERC allowed this merger to take place.

FERC has also been subject to criticism because its merger review process takes much longer than the equivalent procedures at the Department of Justice. DOJ review generally takes on the order of four to six months, while FERC review can take more than a year. The basis of the discrepancy appears to be in the agencies' legal structure. The DOJ acts as a prosecutor, which allows it to make agreements with merging parties in a relatively informal manner. FERC, in contrast, is an administrative agency, which precludes informal meetings between agency officials and merging parties. Instead, exchanges of information generally take place in official proceedings, which slows down the agency decision-making process.

SYSTEM OPERATION

Electricity markets require a system operator who can insure that the delivery of electricity remains reliable, and that the supply of electricity equals the demand. In the regulated era, most electric utilities performed their own system operation. However, in a deregulated environment, the suppliers of power are independently owned and operated. This generates the need for an independent system operator (ISO) to manage the needs of the electricity system. Currently there are operating ISOs in California, New England, New York, the Pennsylvania-New Jersey-Maryland area (PJM), and Texas. Several other ISOs are being planned across the country. These ISOs are all organized as not-for-profit entities. Similar organizations called Regional Transmission Organization (RTO) are beginning to be established.

In addition to balancing the supply and demand of power, the ISO provides ancillary services such as reactive power (required to keep the system itself operating) and spinning reserve (to deal with sudden power losses). An ISO also acts to plan transmission capacity increases in the relevant region. Each proposed transmission line requires evaluation for its contribution to overall system reliability.

Another important role of an ISO is to serve as a platform for trading between parties in the electricity market. When electricity is traded between entities, the transaction is potentially subject to a series of transmission fees, one for every electric utility the contract path of electricity crosses. This "transmission pancaking" can preclude the efficient trading of electricity. By acting as a single entity for the purposes of transmission fees, an ISO can serve to eliminate transmission pancaking across the relevant area. The larger the area of the ISO, the more transmission fees can be reduced, and the larger the gains from trade, all other things being equal.

A number of system design questions must be addressed by each ISO. Each market run by an ISO has a set of rules, and various rules can either increase or decrease the competitiveness of the market. Further, when designing new markets, it is difficult to *a priori* determine which rules will assist in increasing competition. To assist in this task, each ISO has a market monitoring unit, a group of analysts who investigate how competitive the ISOs markets are, and how to make them more competitive.

Several issues arise surrounding ISOs. The first is their governance structure. Firms in private industry are run primarily with the purpose of making profits. ISOs, being non-profit, do not have such an incentive. Presumably, the goal of an ISO is to run an electricity system that maximizes the wealth available to the relevant portion of society. However, defining what policies will achieve those goals is often quite unclear.

ISOs are generally run or are subject to the influence of a group of "stakeholders." These involve representatives from both producers and consumers of electricity. Stakeholders may also include representatives of "public interest" organizations or of local governments. These stakeholders may have interests that differ from that of the public at large.

For example, assume that transmission congestion has led to a proposal for new transmission capacity in a particular area. While such capacity might well be in the public interest, the owner of the current capacity would suffer reduced profits were that new capacity to be installed. The incumbent owner might use the stakeholder process to delay or prevent the transmission capacity expansion, arguing a variety of technical points.

The complete role of the ISO is also not without controversy. ISOs run a series of markets in current power, power to be delivered in the future, and in transmission rights. There is no particular reason to believe that the ISO is the most efficient party to run such markets. It may be the case that markets would perform more efficiently if private, for-profit, parties were to run them. On the other hand, perhaps markets need to be oriented in a manner consistent with smoother system operations.

FERC has had a policy for several years of encouraging utilities to form ISOs. Many utilities, however, have not been eager to do so. In July 2001, FERC issued orders requiring utilities to present plans to form ISOs in regions that currently do not have them. This goal, however, may be difficult to accomplish. An ISO is a complex organization, and if utilities do not wish to form them, they can use such complexity to create a host of administration problems.

TRANSMISSION

Electricity must be transmitted from its place of generation to its place of consumption. In the regulated era, the vertically integrated electric utility was responsible for transmission, and received a rate of return approved by the relevant regulatory commission for its investment in transmission.

Electricity systems have always been connected to each other for reliability reasons. For example, if one system has problems with its operating equipment, it can draw on another system's power through use of transmission lines. Starting in the 1960s, and perhaps earlier, electricity firms began using their transmission networks for trading between systems, as Kleit and Michaels (1994) discuss. For example, systems with summer peaks are often adjacent to systems with winter peaks. Transmission lines allow trade between these two systems, reducing the costs to both systems of supplying power to their customers.

Economic trading grew in the 1980s, as more firms sought to the gains from doing so. Trades were discouraged by two factors. First, electric utilities were not required to allow firms to use their transmissions systems to undertake trades. Second, because trades often had to go through many different utility systems, the cost of such trades was subject to "pancaking." These several charges served to reduce the opportunities for efficient trade.

The Energy Policy Act of 1992 and FERC Order 888 require that utility companies open up their transmission lines to third party trades. Pancaking has been reduced by two factors. First, there have been a series of mergers in this industry, reducing the number of firm boundaries any electricity trade must take. Second, the establishment of ISOs has served to create trading platforms where electricity trades do not have to cross any firm boundaries.

In the short-run, the challenge is to price transmission facilities to reflect their scarcity value. During most hours, transmission capacity is not scarce and, therefore, has no opportunity cost. During peak hours, however, transmission capacity can be very scarce, and pricing it is important so that power goes to where it has the highest opportunity costs. Counterintuitive physical laws govern the scarcity of transmission lines. Further, transmission lines are subject to "loop flow," where power sent between two different sources can flow across a third party's lines without compensation going to that third party.

Many of the short-run problems accruing to the use of transmission lines appear to be largely solved in the PJM system. There, each of several dozen nodes has (at least during certain periods of time) its own price of power, and, implicitly, its own transmission costs. Similar transmission pricing systems are used elsewhere.

It is less certain how longer-run problems will be dealt with. There is a clear consensus that more transmission lines will be needed in the future. Obtaining permission to build new transmission lines, however, is quite difficult. It often takes approval from numerous political entities that do not wish to have unsightly (and allegedly unhealthy) power lines running across their jurisdictions. To deal with this issue, the Bush Administration in the spring of 2001 proposed allowing builders of transmission lines to use the eminent domain authority of the Federal government to obtain permission to build new power lines. Many parties, however, objected to this proposal based on concerns about the environment.

The second long-term transmission capacity issue revolves around the incentives for firms to build new capacity. Unfortunately, there seem to be sufficient economies of scale in transmission capacity such that building new capacity, at least in some circumstances, would eliminate (perhaps completely) any transmission scarcity. This would eliminate any return to building such lines. Further, much of the opportunity to build new transmission lines is possessed by current owners, as they are often in a position to expand their capacity. Thus, it is unclear what incentives would exist for entry in an unregulated transmission market.

THE APPROPRIATE ROLE OF THE FEDERAL GOVERNMENT

Jurisdiction over electricity regulation is divided between the federal and state governments. In general state governments are responsible for regulating distribution and generation of power. The Federal government shares responsibility with state governments in such areas as system operations and transmissions. The basic rationale for Federal involvement is for economic activities that cross state lines, which occurs quite often in the electricity industry.

This diffusion in authority has led to different paths toward restructuring. Each state that has decided to restructure has chosen its restructuring plan. Further, a large number of states have chosen, at least so far, not to restructure. These different state-level policies have led to a variety of proposals in Congress to require states to restructure under a Federal program.

Such a strong Federal policy, however, has important drawbacks. The Federal regulatory process can often be very time consuming. Numerous people that we held interviews with indicated that the FERC was extremely slow to respond due to its current burden of policy issues. Increasing Federal responsibilities would likely only slow this process down further.

It is also not currently clear precisely which method of restructuring is optimal. Given this, it may be appropriate to allow individual states to act as "laboratories" for restructuring, each learning from the other. Further, if one state makes a mistake in its restructuring plan, the harms of that mistake may be limited to that state. For example, there would have been even larger economic harm to the country if California's restructuring plan had been enacted nationwide.

CHAPTER VII. RESTRUCTURING & ECONOMIC DEVELOPMENT

Reliable, low cost electric power is a key element in economic development. Firms locate businesses on the basis of many factors, including accessibility to transportation markets, customers, and inputs, such as labor and utility services, including electricity. Many policy makers across the development community fully recognize the importance of an efficient electric power network.

Successful electricity restructuring that reduces electric power rates clearly promotes economic development. The failure in California clearly hinders future development and, in fact, may force firms to re-locate to areas with lower cost and more reliable electricity. So it is very important to get restructuring right to prevent an exodus of firms and to promote future growth as the long-term benefits from restructuring emerge.

As the previous chapters explain, electricity restructuring raises a number of regulatory policy issues. The creation of commodity market for electricity implies that the traditional vertically integrated structure of the industry would be broken. This breakup could potentially render uneconomic many of the economic development activities once promoted by these integrated utility companies. The capital base of these companies would be smaller and, therefore, they would have fewer financial resources to support community and economic development.

This prospect may be unlikely because transmission and distribution companies will continue to have powerful incentives to develop new markets. Indeed, without the need to generate electricity, these companies could become more efficient at providing network information services, since utilities have very detailed knowledge of the size and composition of commercial and industrial establishments. In providing local service to every business in their service area, these companies are a natural source of information for community and economic development. The identification of these functions and how they could be transformed under restructuring is the focus of the next section.

Another dimension of economic development uniquely important to the Appalachian region is the economic development role of the Tennessee Valley Administration (TVA), which provides electric service and a variety of important public goods, including flood control recreation services, to the Southern counties of the ARC. In fact, the federal statute founding the TVA envisions it essentially as an economic development agency. This chapter will provide an overview and analysis of the economic development efforts of TVA and discuss how these efforts would be affected by efforts to reform TVA electricity policies in light of the newly, emerging competitive realities.

PRIVATE SECTOR DEVELOPMENT PROGRAMS

Most privately held electric utilities have community development programs. The nature and character of these programs varies by company. These programs involve a team of professionals in economic development that provide detailed information on sites, communities, incentive packages, and the work. Some provide confidential tours of potential business sites for business location or expansion. These teams also work with federal, state, and local development organizations.

Allegheny Energy is a good example how these programs are generally retained even though its generation units were spun off to a subsidiary, Allegheny Energy Supply.

Allegheny Power is the transmission and distribution subsidiary and they apparently are providing the same services they were providing before Allegheny Energy Supply became a separate subsidiary. Information is unavailable on resources devoted to these programs before and after restructuring. These programs, however, are already modest and it seems unlikely that they would diminish even further under restructuring.

Moreover, these transmission and distribution companies remain regulated monopolies that operate under rate of return regulation. While the profit margins for these firms in the Appalachian region could conceivably be squeezed, like those in California, they would still have strong incentives to preserve and expand their sales base, given the large fixed cost of their transmission network. These programs also could enhance public support for their rate hearing requests.

In addition to bolstering sales revenues, economic development programs build goodwill with their customers. Often inextricably linked with these programs are community development programs, which are another important strategy for building good relations with customers. These programs involve utilizing the technical and managerial expertise of these companies to enhance education, revitalize downtown areas, and create recreational activities for local communities.

TVA ECONOMIC DEVELOPMENT PROGRAMS

Give its charter, the TVA has more extensive economic development programs that many of the privately held utilities operating in the region. Their programs include industrial development and expansion, community development, technical services, and small and minority business support. All of these efforts are involve substantial cooperation between TVA, power distributors, and state and local development agencies and governments. For example, their Quality Communities program offers a planning process that helps rural communities to improve their economic competitiveness and quality of life.

Unlike privately held utilities, the TVA has an economic development loan fund, which has been in place since 1995, originating from a proposal from distributors of TVA power. The Loan Fund is a revolving pool of money that relies on electricity revenues. TVA offers the loans in conjunction with distributors. Loan commitments are over $88 million as of 2001. The loans support new building construction, plant expansion, industrial parks, and speculative buildings. The guidelines include a limit of $2 million for one project and a requirement that at least one job for every $5,000 loaned. These loans are often used in conjunction with other loans from private and public sector investors.

The economic development program at TVA also offers technical services, including economic research and analysis, engineering and architectural design, and environmental review. TVA economists draft business opportunity reports designed to help communities identify industrial sectors for development, identifying the comparative advantages that each community may offer. These economists also conduct analyses for specific industries, commissioned by a company or local economic developer. TVA engineers and architects evaluate sites on the basis of terrain and drainage, rail accessibility, utility infrastructure, and interstate exposure. Architects also provide preliminary renderings of buildings or plant expansions for initial project evaluation by potential investors. A review by these professionals is required for the project evaluation by the TVA Economic development Loan Fund.

This technical services team also maintains an innovative web site that contains a comprehensive database of available industrial sites and buildings in the TVA region. Power distributors and local economic development agencies use this site selector as a marketing tool by to recruit new businesses. Local communities use it to post any plant of building vacancies that may appear, including detailed schematics of the plant and aerial photographs of the facility.

Our objective here is simply to describe the role that TVA plays in regional economic development, not program evaluation. If TVA were privatized, which seems unlikely, most of these development efforts would remain except perhaps for loan development program. The viability of this program depends in part upon the overall financial health of TVA and how it adapts to market developments outside its service territory. There are a number of policy issues affecting this interaction that are the focus of the next section.

TVA AND ELECTRICITY RESTRUCTURING

In several important ways, TVA has already restructured to reduce costs and improve operational efficiencies. The capacity utilization rates for their nuclear facilities are up substantially over the past five years after they hired more experienced operators and offered financial incentives for improving productivity. Their long-term debt has been substantially reduced. TVA has refurbished existing coal and hydropower units to increase generation without new plant construction. Several transmission enhancements were also accomplished. On the other hand, TVA faces significant expenditures to meet EPA guidelines on SO_x and NO_x.

There are several legislative proposals in the U.S. House of Representatives and the U.S. Senate that would reform the relationship between TVA and its customers, who are primarily cooperative distributors. These proposals provide an interesting contrast to the restructuring efforts in California and Pennsylvania, since they involve negotiations between a federal power agency and cooperative distributors.

The first provision would remove restrictions that prohibits outside suppliers from selling to high volume customers in the TVA area. A similar entry limitation provision called the TVA 'Fence' would be repealed. TVA transmission rates and terms would be subject to regulation by the FERC.

Another set of provisions would establish rules governing TVA power sales to promote open competition. The first proposes that TVA will only sell wholesale electricity outside its existing service area. Moreover, these sales are limited to those in excess of demand by its customers in the TVA service area. The second allows TVA to sell to its existing retail customers inside its service area. In addition, if a TVA distributor adopts open retail access, then TVA would be allowed to sell under the same conditions as other competing suppliers. The third power sale provision prohibits TVA from making long-term contracts for energy sales to customers outside the TVA service area at lower rates that those offered to distributors, unless the distributors agree.

The legislation would also give TVA the authority to borrow money to expand generation capacity necessary to supply the needs of distributors and TVA retail customers within the Fence. In addition, distributors are allowed 45 days to reviews all TVA plans and projections for new generation prior to acquisition.

The proposed restructuring agreement also would provide rules for renegotiation of wholesale power contracts between TVA and distributors. One proposal is that if the parties cannot agree, the distributor has the option of maintaining its existing contract with TVA, or each year on three (two) years notice on three years notice canceling the contract or choosing to take 10 percent or more (less) of its power requirements from another supplier.

Individual distributors would be provided the choice of remaining under TVA retail regulation or exercising their regulatory authority under state laws. TVA would be allowed to recover stranded costs until September 30, 2007 subject to the same FERC guidelines applicable to private utilities. TVA would use all recovered funds to repay outstanding debt. Finally, TVA would be subject to injunctive relief and criminal penalties, but not the civil damage provisions, under the anti-trust laws of the United States.

If enacted these proposals could substantially change the nature of the relationship between TVA and its distributors. It would also some degree of choice by distributors, requiring TVA to compete for customers for the first time. In addition, TVA transmission rates would be subject to FERC regulation and antitrust protections would apply. These proposals could potentially improve the efficiency of the electricity network in the southern portion of the Appalachian region in the long term. Prospects for passage, however, probably have been hampered by the well-publicized problems in California.

CHAPTER VIII. POLICY IMPLICATIONS

The regulated electricity system has a number of important structural deficits. Most importantly, it provides poor incentives for cost-reduction, as well as acting to reduce choices that are available to consumers. By putting the production and marketing of electricity into a competitive market, restructuring offers the opportunity for substantial gains for society.

This is not to say, however, that electricity restructuring is a panacea. The gains from restructuring will take substantial time to accrue. In this sense, we suspect that its proponents oversold restructuring. We suggest that real price reductions and increases in consumer choice will occur, but that they may not take place immediately upon the beginning of restructuring. Further, any new efforts at restructuring must take into account the results of previous restructuring efforts. In this light, we have several recommendations for future restructuring efforts.

First, restructuring should not place any limits on trading in wholesale markets. The California power exchange is an idea that is an obvious failure. Financial markets in commodities, which the California power exchange precluded, exist for a great number of reasons. In particular, financial markets, using instruments such as futures and options contracts, act to allocate risk efficiently among parties. There is no reason that consumers in electricity markets should be denied access to the market for risk.

Restructuring plans often call for the use of price caps to deter the exercise of market power in both wholesale and retail markets. Unfortunately, price caps have significant drawbacks. Retail price caps send the wrong signal to consumers. For example, electricity became scarce in California in the period 2000-2001. Consumers in California, however, had no incentive to reduce their consumption of electricity, as their prices were fixed. Fixed consumer prices served to both bankrupt utilities in the state and to place tremendous strain on the electrical grid. Variable prices, on the other hand, act to give consumers incentives to seek out the best power supply contract for themselves, as well as to reduce demand for power during periods of high prices.

There is some reason to support wholesale price caps equal to the level of costs at the highest generator in a relevant market. The difficulty arises because in markets without substantial metering there may be no finite ceiling to the free market price. We are concerned, however, that wholesale price caps, however temporary they are designed to be, may become permanent. Permanent price caps that are binding for a significant amount of time deter the creation of new electricity supply, and may cause power blackouts.

While there was previously a debate over whether stranded-cost recovery was appropriate, that debate is now over. An integral part of any restructuring plan is the recovery of utilities' stranded costs. Unfortunately, the method chosen for doing so in California and Pennsylvania had important drawbacks. We suggest that a stranded cost "tax" be attached to every kilowatt-hour of power sold in relevant areas. Alternatively, households could be assessed a fixed "access fee" that would not vary with usage. Consumers would then be free to contract for their power supply. This would eliminate the need for administratively set "shopping credits," as in Pennsylvania, which should allow market conditions in the retail market to more readily react to changes in the wholesale market

Innovation in the retail market for power has been limited. While green power marketers have had some success, other sellers of retail power have not. In Pennsylvania, for example, retailers have been forced to leave the market as the price of power rose above the administratively set shopping credit. Hence, another reason to eliminate such shopping credits is the positive impact that this might have on retail market activity and innovation. In this context, events in 2002 in western Pennsylvania, where some customers will stop paying for stranded costs, and will face market prices for power, should prove interesting.

Part of the rationale for restructuring is to allow new firms into the market for generation of electricity. This requires that environmental and zoning restrictions on generation to allow for the construction of new power plants within a relatively short amount of time. Much of the power problems in California were aggravated by the lack of new power plant construction. In Pennsylvania, by way of contrast, new power plant construction is occurring, though regulatory delays occur. We recommend that any jurisdiction planning to implement restructuring consider the impact of existing and proposed regulations on the permitting process and construction of new power plants.

Independent System Operators (or similar Regional Transmission Organizations) serve to facilitate trade between parties in wholesale power markets. As such, they are helpful to reaching the full potential of restructuring. We therefore applaud FERC's efforts to create such organizations. We would also encourage state regulatory agencies to do what they can in this regard. It is important to note, however, that regulators may have difficulty inducing utilities unwilling to support restructuring to effectively join in creating ISOs.

The current regulatory structure allows each state to choose its own path toward restructuring. In essence, each state acts as its own restructuring "laboratory." In contrast to a regime where restructuring was required by the Federal government, this regime permits states to learn from each other, and to limit the economic harm that could occur from a mistake made by any particular state.

Any gains from restructuring can be diminished by the exercise of market power. Jurisdictions having already embarked on restructuring were aware of this problem. They conducted standard market power reviews, and, in the case of California, required divestiture. A new difficulty, however, has arisen due to the structure of the electricity supply curve. During periods of high prices, decisions made by producers of high cost facilities (which only come on line during these periods) can materially affect the market price of power. If a producer owns both a low cost facility and a high cost facility, it may be able to increase its net profits by not operating the high cost facility, even though the market price may be greater than the cost of operating that high cost facility. This action would increase market price and harm consumers. We therefore suggest that regulators review carefully the ownership structure of generation in the industry prior to the onset of restructuring, and require the appropriate divestitures.

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APPENDIX A—DATA SOURCES

The total variable cost of electric power generation includes expenditures on fuel, labor, and maintenance. Since firms generally pay the market price for fuels and labor, they control costs by adjusting their purchases of these variable inputs. The technology of generating plants, often represented by their thermal efficiency, also affect a firm's cost structure. These efficiencies slowly improve over time as technology advances and firms modify existing boilers. The vintage and composition of a firm's capital stock will also influence variable costs. A firm can adjust its capital stock by retiring old plants and investing in new ones.

Variable costs also vary with the level of generation. Fixed costs do not vary with production and include expenditures on debt payments, dividends, rents, and other fixed payments related to structures and equipment. Total cost is the sum of variable and fixed cost. Average variable cost is total variable cost divided by output. Marginal cost is the change in cost for a change in output and varies with the level of production. The relationship between marginal cost and output depends upon technology. For electric power generation, at low output levels, marginal cost and average cost generally decline with higher output.

If marginal cost is below average cost over some range of output, the firm has economies of scale. If the reverse holds, the firm encounters diseconomies of scale and needs increasingly higher prices to justify further expansion of output. For example, after fully utilizing its base load capacity to meet higher demand, a generating company typically uses higher cost sources of power, such as gas turbine peaking generators. At the firm level, rising marginal costs often reflects this switch from base-load to peaking plants. How a firm manages its plant mix would determine its cost and profit performance.

Our cost model contains certain features that reflect the unique characteristics of the electricity generation industry. First we assume that electrical generation companies face competitive variable input prices and that rate-of-return regulation prevents capital from reaching equilibrium levels in the short run. Over the sample period used in this study, 1986 to 1999, most state public utility regulations required that electric utilities must supply all electricity demanded at regulated prices. Hence, utility firms could not choose the level of production to maximize profits.

In any given year, utility firms inherit their generating capacity from the previous year. They retire old plants, modernize generating units, and occasionally build new plants, generally after a lengthy period of licensing, regulatory review, and construction. Electric utility firms have added very little new capacity in recent years. Instead, they have met any shortfalls in demand by purchasing from nonutility generators. For these reasons, assuming capital is fixed in the short run appears plausible. With this constraint, the economic decision is to find the least-cost levels of variable inputs, such as fuel, labor, and maintenance, subject to these output and capital constraints.

We measure two categories of variable costs for power production: fuel and an aggregate of labor and maintenance costs from data collected by the Federal Energy Regulatory Commission. The details of this data are discussed in Appendix A. Until recently, EIA reported these costs by firm. Fuel costs for a typical firm in our sample comprise about 80 percent of total variable generation costs, including expenditures on coal, natural gas, and petroleum products. By definition, fuel costs equal fuel consumption multiplied by fuel price. To compute fuel prices, we compute a price index for each firm using plant level data on fuel consumption and prices paid upon receipt. We use a special price index called a divisia that is superior to other indices of fuel prices, such as dollars per British thermal units (BTU), which imply perfect substitution between fuels. The divisia avoids this problem and is invariant to base year changes, unlike fixed weight indices.

We form a second input category that includes the aggregate of labor and maintenance costs because they are difficult to separately identify. The price index for this category is a weighted average of the wage rate—or total labor expense per employee, company wide, and a price index for electrical supplies from the Bureau of Labor Statistics. The weights are the labor cost share of nonfuel variable costs for those utilities with entirely steam power production.

Another key measurement issue involves the capital stock. One approach is to aggregate nameplate plant generation capacity to the firm level. The problem with this approach is that companies make capital improvements that effectively increase nameplate capacity. Our method captures these enhancements by estimating a benchmark capital stock value based upon installed capacity in a base year valued at replacement cost and then updating this value each year using annual plant and equipment retirements and capital expenditures. The benchmark capital stock for each firm is a weighted average of plant capacities where the weights reflect the thermal efficiency of each plant relative to an industry–wide average efficiency rate. Replacement cost is based upon the average price of newly installed capacity. We also adjust the capacity data for joint ownership, allocating capacity based upon joint venture ownership shares. These calculations essentially translate production capacity into a dollar amount that reflects the replacement value of installed generation capacity. This method is equivalent to the market valuations that appraisers do when homeowners refinance their mortgage.

Unlike a homeowner, however, a utility company raises capital by selling bonds and equity. The prices for these financial instruments vary by firm. We develop an average user cost of capital for each firm that reflects the firm's bond rate, debt–equity ratio, and equity return. The cost of capital is also adjusted for depreciation and inflation. Firm capital payments for steam electricity generation plant and equipment equal the product of the user cost and real capital stocks.

The primary source of data for this study is from the *Financial Statistics of Major U. S. Investor-Owned Electric Utilities, EIA Form 1* (*Financial Statistics*) published by the Energy Information Administration (EIA). We also used data on generation and consumption of fuels at power plants (EIA *Form 759*) and cost and quality of fuels at electric power plants (EIA *Form 423*). Recent data are available at its EIA web site. We obtained historical data directly from EIA in electronic format and appreciate their assistance.

The *Financial Statistics* contains all relevant financial and cost data for major electric utilities in the United States. The data include Statement of Income and Retained Earnings, Balance Sheet (Table 37), Statement of Cash Flows (Table 39), Electric Operating and Maintenance Expenses (Table 41), Utility Plant (Table 42), Electric Energy Account (Table 43), and financial indicators for investor–owned utilities in the

U.S. (Table 44). Over the period of the sample the total number of utilities in this report ranged from 135 to 185.

EIA Form 759 (*Monthly Power Plant Report*) reports monthly net power generation, consumption of fossil fuels, and month-ending stocks of coal and oil at power plants in the United States. Specific data also include prime mover-type including hydro, steam, internal combustion, gas turbines, combined-cycle steam, combined-cycle gas turbine, wind, and solar; and fuel type including nuclear, oil (light and heavy), petroleum coke, coal (anthracite and bituminous), lignite, and natural gas. There are around 700 respondents to this form, including all major investor–owned utilities. Each plant is assigned a unique code, as is each utility company.

Some power plants are jointly owned by two or more electric utilities. Data on percentage ownership is available in Appendix C of the *Inventory of Power Plants*. We identified 120 plants jointly owned from this inventory. We then extracted data from Form 759 and assigned it to the utility companies that owned the plants before reinserting them into the database. We assume the joint ownership data from 1996 represents the entire sample. The plant level data was then aggregated to the utility level. Net power generation by prime–mover type and fuel consumption and stocks at the utility level (also by prime–mover type) were extracted into another database. Specific fuel types were aggregated into three broad categories of coal, oil, and natural gas.

Form 423 (*Monthly Report on Cost and Quality of Fuels of Electric Plants*) provides monthly data on the quantity, quality, and cost of fuel received at power plants with a steam–electric and combined–cycle nameplate capacity of 50 megawatts or more. Data include fuel type, delivered cost per million Btu, type of purchase (spot, contract, firm, or interruptible), and quality of fuel (Btu, sulfur, and ash content). These data are based on specific spot purchases or contracts and are reported, at times more than once a month, and at times once every few months, especially for oil and natural gas. The heat content of monthly fuel receipts for three broad categories of fuels was calculated along with average annual prices, per quantity unit, and per million Btu.

The price of the energy aggregate P_{1t} above is a divisia price index of fuels:

$$\ln P_{1t} - \ln P_{1t-1} = \sum_{i=1}^{n} \frac{1}{2}\left(w_{it} + w_{it-1}\right)\left[\ln P_{it} - \ln P_{it-1}\right], \tag{A1}$$

where

$$w_{it} = \frac{P_{it} Q_{it}}{\sum_{j=1}^{3} P_{jt} Q_{jt}}, \tag{A2}$$

and where P_{it} is the price of the *i*th fuel, from EIA Form 423, and Q_{it} is the joint venture corrected consumption of the same fuel from EIA Form 759. The price has also been adjusted to reflect joint ownership—parts of plants that belong to a utility but were counted as separate plants.

We compute the divisia by using the chain-linked derivation (Diewert, 1976). We define:

$$\alpha_t = \sum_{i=1}^{n} \frac{1}{2}\left(w_{it} + w_{it-1}\right)\left[\ln P_{it} - \ln P_{it-1}\right], \tag{A3}$$

and consider the divisia in the base year, when $P_b = 1$:

$$\begin{aligned} \ln P_b &= \alpha_b + \ln P_{b-1} = 0, \\ \ln P_{b-1} &= -\alpha_b, \\ P_{b-1} &= e^{-\alpha_b}. \end{aligned} \tag{A4}$$

Now consider two periods before the base year:

$$\begin{aligned} \ln P_{b-1} &= \alpha_{b-1} + \ln P_{b-2}, \\ \ln P_{b-2} &= -\alpha_b - \alpha_{b-1}, \\ P_{b-2} &= e^{-\alpha_b - \alpha_{b-1}}. \end{aligned} \tag{A5}$$

A similar chain pattern emerges as one goes back in time from the base period. The derivation for periods after the base period is a mirror image. To calculate fuel quantities, we divide the steam power production fuel costs reported by firm in the *Financial Statistics* by the divisia price index for fuels.

We calculate labor and maintenance costs by subtracting these fuel costs from total steam power expenses reported in the *Financial Statistics*. Quantities of labor and maintenance equal expenditures divided by a cost share-weighted price index for labor and maintenance. The price of labor is a company–wide average wage rate. The price of maintenance and other supplies is a price index of electrical supplies from the Bureau of Labor Statistics. Cost shares equal average shares for the eleven year period for firms having only steam generation. Steam power generation by firm is from Table 43 of the *Financial Statistics.*

Our capital rental rate for each firm is the following:

$$u_{kt} = p_{kt}\left[r_{dt} + \pi\left(r_{et} - r_{dt}\right) + \upsilon_t - i_t\right], \tag{A6}$$

where p_{kt} is a price index for electrical generation plant and equipment, r_{dt} is the adjusted corporate bond rate based on Moody’s ratings, π is the equity share of total capital, r_{et} is the equity rate of return computed as the ratio of net income to total primary capital, υ_t is a depreciation rate assuming 30 year straight line depreciation, and i_t is the rate of change in overall wholesale prices.

As reported above, we estimate capital stocks using a perpetual inventory approach. Nameplate capacity data from the Inventory of Power Plants (EIA) is reported in EIA Form 759 along with generation and fuel use data. The generation and fuel use data were used to generate a plant efficiency measure which measured megawatts produced per million Btu. Using an industry–wide average efficiency rate, each plant capacity was adjusted (upward for more efficient plants and vice versa) to reflect its efficiency as compared to the industry average. Jointly owned plants were assigned to individual owners based on the joint ownership data.

The nameplate capacity in the base year was then valued at replacement cost using the price of new capacity in 1986:

$$K_{nt} = P_{ct} C_t , t = 1986, \tag{A7}$$

where K_{nt} is the nominal capital stock, P_{ct} is the price of new generation capacity in dollars per megawatt, and C_t is nameplate capacity also in megawatts. The Financial Statistics of Investor–Owned Utilities (EIA) reports prices for newly installed capacity since 1992. We calculated an annual average from 1992 to 1996. Values prior to 1992 are backcast using a price index for gas and steam turbine generating units from the Bureau of Labor Statistics. For subsequent years, the estimated nominal capital stock in a particular year was depreciated using straight-line depreciation for a 30-year lifetime. This was adjusted for any change in real price using the price index for electrical generating plants. Additions to steam power plant and retirements were then added and subtracted, respectively, and a nominal time series was generated:

$$K_{nt} = (1-\upsilon)\left(\frac{K_{nt-1}}{p_{kt-1}}\right)p_{kt} + A_t - R_t, t = 1987,\ldots,1996. \qquad \text{(A8)}$$

The real capital stock in the model K_t is equal to the nominal stock divided by the price index for electrical generating plant and equipment p_{kt} from the Bureau of Labor Statistics.

Bond rates in the capital user cost given by (B6) are from the Federal Reserve Board and are adjusted by firm, based upon its bond ratings by Moody's Investor Service reported by EIA. The equity rate of return is equal to net income divided by total proprietary capital. The share of equity capital is equal to total proprietary capital (TPC) divided by the sum of TPC and TOTB, which is the total outstanding debt of the utility. The inflation rate is equal to the rate of change in the wholesale price index.

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