

Dynamics of the U.S. Coal Markets 1995 to 2010: How They Will Affect Illinois

Subhash B. Bhagwat

Dynamics of the U.S. Coal Markets 1995 to 2010: How They Will Affect Illinois

Subhash B. Bhagwat

Illinois Minerals 116

ILLINOIS STATE GEOLOGICAL SURVEY
William W. Shilts, Chief
Natural Resources Building
615 East Peabody Drive
Champaign, IL 61820-6964
(217)333-4747

FOREWORD

from the Chief

Coal has been a major resource for Illinois since early in the 19th century. The Illinois State Geological Survey was created in 1905 in large measure to support the development of Illinois mineral industries, especially the coal industry. The state still contains large, potentially valuable coal deposits, but the Illinois coal industry has fallen on hard times in recent years.

In this report, mineral economist Dr. Subhash Bhagwat takes us through the reasons, such as air pollution reduction measures, for the precipitous decline in Illinois coal production from 60 million tons in 1990 to less than 50 million tons in 1995. This decline has shut down two dozen mines and reduced mining employment from more than 10,000 in 1990 to less than 6,000 in 1995.

Dr. Bhagwat forecasts supply and demand for Illinois coal, as well as the continuing and future effects of government policies such as the Federal Clean Air Act and the deregulation of electricity generation. The clean air legislation, which attacks the problem of acid rain by limiting the levels of sulfur dioxide when coal is burned, has had an enormous impact on Illinois coal production. The added expense of removing sulfur in Illinois coal to comply with the Clean Air Act has helped make the use of Illinois coal uneconomical when compared with low-sulfur coal from western states.

Deregulation of the electric utility industry will also add a new element of competition to the market when consumers will be able to shop for the lowest priced electricity. To compete for customers, utilities will have to find the lowest cost generation in terms of fuel, pollution and clean-up, and capital costs.

Already uncompetitive with low-sulfur western coals, Illinois coal will increasingly compete with cleaner sources of energy such as natural gas. This report's value is in laying out the various potential shapes of the economic playing field on which Illinois coal must compete.

Although the short-term prognosis for Illinois coal is not good, Dr. Bhagwat gives us a clear view of the problems facing the Illinois coal industry and the kind of research we need to do now to address these problems in the future. We need to know the potential impact of all the factors affecting Illinois coal before formulating public policy.



William W. Shilts, Chief
Illinois State Geological Survey

Editorial Board

Jonathan H. Goodwin, Chair

Michael L. Barnhardt

Donald G. Mikulic

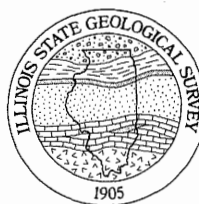
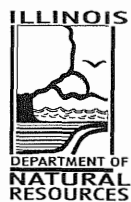
Heinz H. Damberger

William R. Roy

Anne L. Erdmann

C. Pius Weibel

David R. Larson



Printed by Authority of the State of Illinois/1997/600

♻️ Printed with soybean ink on recycled paper

CONTENTS

ABSTRACT	1
INTRODUCTION	1
DEMAND-SIDE DYNAMICS	2
Electric Utilities Demand	2
Electric Demand Forecasts	2
Coal demand for electric generation	
Coking Coal and Industrial Demand	3
REGULATORY DYNAMICS	3
Clean Air Act	4
Sulfur dioxide emissions limits	
Percent reduction clause	
Pollution credits	
Future compliance strategies	
Nitrogen oxide emissions	
Other emissions	
Trade Regulations and Utility Deregulation	6
Consequences of deregulation	
SUPPLY-SIDE DYNAMICS	7
Coal Supplies	7
Other Supply Factors	7
Nuclear energy	
Natural gas electric generation	
Coal-based generation	
Pollution credits	
ISGS PROJECTIONS OF ELECTRIC DEMAND	10
FUTURE OF ILLINOIS COAL	10
WHAT CAN BE DONE?	12
REFERENCES	13

FIGURES

1 Annual growth rates in U.S. electric utility generation	3
2 Coal reserves by sulfur content and region	7

TABLES

1 Annual growth in U.S. electric utility generation (by fuel)	8
2 Coal prices at mine and productivity	9
3 ISGS Industrial Minerals and Resource Economics Section's projection of U.S. demand for electricity by fuel (billion kWh)	10
4 Operable and planned capacity additions 1993–2003	11
5 Utility coal sales and prices 1995	12

ABSTRACT

Illinois coal sales declined from 60 million tons in 1990 to less than 50 million tons in 1995, and the Industrial Minerals and Resource Economics Section of the Illinois State Geological Survey projects them to decline to the range of 26 to 40 million tons by 2010. Public policies, particularly the Clean Air Act (CAA) and its amendments, have dramatically altered coal markets and will continue to do so. These policies will continue to set the market terms under which the Illinois coal industry competes.

The 1970 CAA amendment's limit on SO₂ emissions of 1.2 lb/mmBtu on coal-fired power plants sparked the beginning of a major expansion of the low-sulfur coal mining industry in Wyoming and Montana. Sales of high-sulfur coal produced east of the Mississippi River began to stagnate as low-sulfur western coal became available at low cost. Largely because low-sulfur coal remained highly cost-effective, attempts in 1977 to improve the competitive position of high-sulfur coal by requiring that *both* high- and low-sulfur coal have their emission potential reduced by 90% failed.

The 1990 CAA amendments introduced "pollution credit" trading to promote emission reductions nationally at the lowest cost to the economy. They also extended the emission limits to all previously exempt plants and mandated a nationwide SO₂ emissions reduction of 10 million tons through 2000. Finally, they banned any increase in national emission levels beyond the level mandated for the year 2000. Introducing new competitive elements by which utilities can more economically and efficiently meet regulatory standards, these amendments favor the use of the cleanest fuels and the shifting of electricity generation to the lowest-cost power plants nationwide. The winners will likely be the environment, the economy, and the producers of low-sulfur, low-cost fuels. The immediate cost will be borne by regions that produce high-sulfur coal, such as the Illinois Basin.

Dynamic supply and demand changes in the U.S. coal market, market competition between coal, natural gas and nuclear energy, and changes in the electric utility regulatory environment will bring about major changes in the years through 2010. Continued availability of low-cost western coal, adequate amounts of natural gas, and the continuation of emissions credits are likely to adversely affect Illinois coal sales.

The key to long-term sustainability for the Illinois coal industry is to concentrate research and policy efforts on improving the cost competitiveness of coal produced in the state.

INTRODUCTION

Public policies, particularly the Clean Air Act (CAA) and its amendments, have dramatically altered coal markets, and will continue to do so. To assess how coal markets will affect Illinois coal production in the next 15 years, this report analyzes the changes in coal markets since the beginning of the CAA regulations in the late 1960s, the changes that will ensue from expected future deregulation of the electric generation industry, and projected changes in coal supply and demand.

Before the 1970 CAA amendment that limited sulfur emissions from newly constructed coal-burning power plants, the coal industry in Wyoming and Montana produced less than 5 million tons of coal per year. The amendment provided the necessary incentive to develop these low-sulfur resources and the coal industry in the western United States rose and expanded to the point that it now produces about 350 million tons a year. Low-sulfur coal from the western states captured most of the 1970's growth in coal demand, which due to a slowing growth rate in electricity demand, was not as strong as in previous decades. Because of the clean air regulations, coal production east of the Mississippi River captured little of this growth in demand. The effect was more severe in states that produce high-sulfur coal, particularly Illinois, Indiana, Ohio, and western Kentucky.

The CAA was amended in 1977 in an attempt to help the coal industry in states producing high-sulfur coal. These amendments said that regardless of a certain coal's sulfur content, the sulfur emission from burning that coal had to be reduced by up to 90 percent of what the emission would be if no abatement procedures were used. This restriction applied only to plants built after the amendments took effect. This amendment, commonly referred to as the "percent reduction clause," in effect required all new power plants to install flue gas clean-up equipment, called scrubbers, whether the plant burned high-sulfur coal or not. The intent was that the advantage

from purchasing low-cost, low-sulfur western coal in lieu of installing scrubbers would be negated by mandating investments for scrubbers for *all* new power plants.

This strategy failed to significantly boost sales of high-sulfur coal. Fewer than expected coal-fired power plants were built because of the continued decline in the electricity demand growth rate and because utilities maximized nuclear generation in an attempt to recover the nuclear plants' high capital costs. A perhaps more important reason for the strategy's failure is the fact that the price of low-sulfur coal continued to be significantly lower than the price of high-sulfur coal.

In 1990, the CAA was again amended to introduce efficiencies of competition to sulfur emission reduction activities. The amendment revokes the percent reduction clause but requires that the *national* sulfur emission reduction targets for the years 1995 and 2000 are met. The amendment also revokes the "grandfathering" of older power plants on sulfur emission limits and forces them to reduce pollution to meet the targets. Individual power plants now have flexible targets. They can either reduce actual emissions, or purchase allowances, sometimes called pollution credits, from other power plants that have reduced emissions to levels lower than required by law. This provision promotes competition not only between low- and high-sulfur coals, but also between coal and natural gas.

Further changes in the regulatory environment are expected in the 1995 to 2010 period. Electricity wholesalers have already been freed by the 1992 federal Energy Policy Act to purchase electricity anywhere, instead of only from their regulated monopoly utility. Retail customers will soon be free to purchase power on the open market. This market deregulation will intensify competition to produce power at the lowest cost. Electricity will be much more price sensitive as users shop for the best deal. This will naturally affect the demand for coals and other fuel.

DEMAND-SIDE DYNAMICS

Total coal demand is comprised of the demand for coking coal, demand for industrial use and export, and, by far the largest element, demand for coal for electric generation. Coal demand in the U.S. increased from 523 million tons in 1970 to 941 million tons in 1995. Increased domestic consumption of electricity created most of this rise in demand.

The comparative cost of fuels is the other factor beside electricity demand that determines coal demand. The choice between using coal, natural gas, oil or nuclear generation depends primarily upon the total cost of electricity generation, including fuel price, the cost of fuel transportation, investment in generation and pollution prevention equipment, and the decommissioning cost of nuclear power plants. This aspect is discussed below in the Supply-Side Dynamics section.

Electric Utilities Demand

The portion of U.S. coal production used in electricity generation increased from 66% to 81% between 1970 and 1995. Electric utilities accounted for 61 percent of domestic consumption in 1970, 81 percent in 1980 and 88 percent in 1995.

According to the U.S. Department of Energy, coal-fired power plants generated 46 percent of all electricity in 1970, 51 percent in 1980, and 55 percent in 1995 (*USDOE, Aug. 1996*). Nuclear electricity's share of total consumption rapidly increased from 1.4 percent in 1970 to 11 percent in 1980, and to 22.5 percent in 1995. The oil and natural gas price shocks in 1974 and 1979-81 resulted in significant conservation and fuel switching by individuals, businesses, and electric utilities. By 1995, the share of oil and natural gas in electricity generation had fallen to 2% and 10.3% respectively, well below their 1970 levels of 11% and 24%.

Growth in U.S. electric demand averaged about 2.7% per year between 1970 and 1995. However, there were differences in annual growth rates during periods of stronger and weaker economic cycles: a yearly average of 6.7% between 1970 and 1973, 3.2% in 1973-1979, about 3% in 1984-1989, but only 1.8% in 1979-1984 and 1.2% in 1989-1995 period. The trend in the growth rates of utility generation has been downward, from about 3.1% in 1971 to 1.6% in 1995 (fig.1).

Electric Demand Forecasts

In 1991, the U.S. Department of Energy and four other institutions forecasted U.S. electricity demand to grow at 1.4 to 2.4% per year from 1990 through 2010 (*USDOE, March 1991*). Changed conditions in the interim, however, indicate that electricity demand may grow at lower

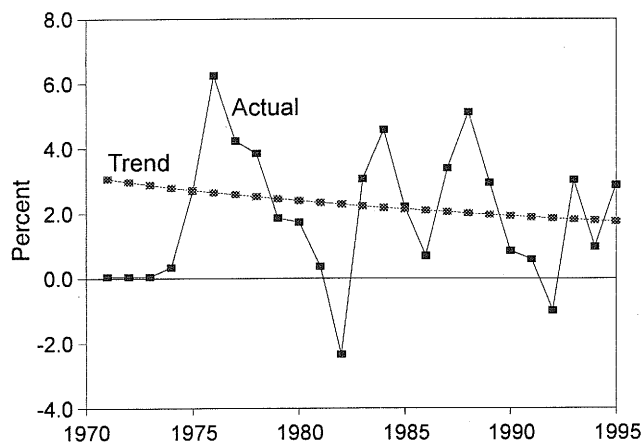


Figure 1 Annual growth rates in U.S. electric utility generation (*USDOE, Aug. 1996*).

rates. The 1993 Annual Energy Outlook revised the forecast to the range of 1.3 to 1.8% annual growth for these years (*USDOE, Jan. 1993*). The 1996 DOE forecast projects total electricity demand to rise an average 1.26% per year between 1995 and 2010 (*USDOE, Jan. 1996*). Generation by electric utilities is projected to rise at a 1% per year rate, and non-utility generation and cogeneration at 3% per year.

Growth rates for electrical generation in the non-utility and cogeneration sectors fluctuated strongly over the period; 7% of total electricity generation in 1970 but only 3% in 1980. Then it increased to 9% in 1990 and exceeded 14% in 1995.

Coal Demand for Electric Generation

The 1994 data on heat consumption indicate that 1 ton of coal is required to generate about 2 billion kWh of electricity. Based on this ratio, U.S. demand in 2010 for coal for electricity generation by utilities and independent power producers together will be about 1025 million tons.

An important aspect to the above forecast is the overall conversion efficiency of coal-burning power plants. Each percentage point increase in thermal efficiency of power plants can reduce coal demand by 2.5%. Although the average thermal efficiency in the U.S. is unlikely to change drastically because of the very small capacity additions expected in the next 15 years, a small change of 1 percentage point can reduce demand forecast by as much as 30 million tons. Such a change is conceivable as load factors for efficient, low-cost plants are increased and less efficient older plants are retired or their usage reduced.

Coking Coal and Industrial Demand

Coke for ore smelting is made from coal. In 1970, coking plants in the U.S. and overseas consumed about 153 million tons of U.S. coal production. Over the past 25 years, total domestic and foreign consumption of U.S. coal for coke-making is down by more than 40% to about 90 million tons in 1995. Although foreign consumption increased over this time, U.S. consumption fell 70%. About 9% of U.S. coal production in 1995 was sold for coke-making.

Domestic consumption by industrial users other than electric utilities and coke plants, and exports of non-coking coal, have together declined from about 121 million tons in 1970 to about 101 million tons in 1995, or about 10.5% of total U.S. coal production.

Coal demand for coke making, industrial uses and exports, which totaled about 190 million tons in 1995, may add another 200 million tons to increase the total U.S. coal demand in 2010 to about 1,225 million tons. The total demand growth rate for coal is thus expected to average about 1.15% per year.

REGULATORY DYNAMICS

Besides traditional demand dynamics, federal regulations and market interventions are critical in determining the overall demand for coal, and demand for Illinois coal in particular.

The two primary sets of regulations affecting coal markets, especially the electricity generating sector of the coal market, are the Clean Air Act amendments of 1990 and electric utility regulations concerning the production, distribution and trade in electric power. Another intervention is the large indirect subsidy provided to the nuclear electric generating industry. The potential for future regulation of "greenhouse gases" may also already be playing a role in fuel choice decisions by utilities.

The Clean Air Act

The Clean Air Act was passed in 1963, its first regulations became effective in the late 1960s, and it was amended in 1970, 1977, and 1990.

Sulfur Dioxide Emission Limits The 1970 amendments limited SO₂ emissions from all new electric power plants to 1.2 lbs per million Btu of energy consumed. Older plants were to be regulated according to schedules to be developed under individual State Implementation Plans. The 1970 amendments provided a strong incentive to mine low-sulfur coal deposits in the western states and sparked the modern, fast-growing coal mining industry there. Its low sulfur content and falling price soon allowed western coal to take market shares away from the higher-sulfur midwestern coals.

Percent Reduction Clause The intense political activity that followed this development led to the 1977 amendments. These retained the maximum limit on sulfur emissions, but introduced a new clause intended to help coals from eastern states regain competitiveness. The “percent reduction requirement” generally required SO₂ emissions to be 90% lower than what they would be without scrubbing, regardless of the sulfur content of the coal. Maximum permissible emission levels remained at 1.2 lbs SO₂ per million Btu. Some plants were allowed a 70% reduction in potential emission if this reduced emissions to less than 0.6 lbs SO₂ per million Btu.

In effect, the percent reduction requirement imposed stricter total emission limits on lower-sulfur coals than on higher-sulfur coals, and created a bias in favor of midwestern coals. This attempt to correct the 1970 amendment’s bias toward low-sulfur western coals ultimately failed because of economic reasons.

Pollution Credits The 1990 amendments were the result of congressional desire to create incentives to develop technologies that would result in even lower emissions than prescribed by law. Congress also wished to lessen the regulatory interference the earlier amendments introduced and rely more on free market mechanisms, while at the same time achieving the objective of cleaner air.

The 1990 amendments eliminated the percent reduction requirement, but mandated a reduction in nation-wide SO₂ emissions of 5 million tons by January 1995 (Phase I) and another 5 million tons by January 2000 (Phase II). The 1990 amendments also capped future SO₂ emissions at the 2000 level.

Congress intended these amendments to provide flexibility in complying with the objectives of the law. The mechanism to do this is the “pollution credit,” which allows plants that reduce emissions below the legal limits to achieve an economic benefit—a credit—that they can sell to plants that are over the limit. The overall national goal of emission reduction is unchanged, and an economic incentive has been added by giving exchangeable value to initiatives that reduce emissions.

The 1990 amendments make emission reduction an economic decision without compromising on the level of overall reduction. In addition, regulations regarding the ambient air quality anywhere in the U.S. were not changed, guaranteeing that regional air quality does not deteriorate. However, future changes in ambient air quality regulations are currently being contemplated.

A sign that the 1990 amendments are having the intended effect is the declining market price per unit of pollution credit traded (1 Unit = 1 ton of SO₂ per year). 1990 predictions for the price of a unit of pollution credit were as high as \$1,500, a price that reflected the avoidance of retro-fitting old plants with new pollution control devices and increased waste disposal. As of March 1996, pollution credits were traded at about \$65 to \$70 per unit (*Coal Week, April 1, 1996*). The falling price indicates an excess of supply of pollution credits over demand, i.e., significant overcompliance on the part of the utilities. (See box on page 5.)

Future Compliance Strategies In the short-term, most power plants will gain compliance by simply switching to low-sulfur western coal. Pollution can be reduced to levels well below the limits set for 1995, and even below the limits for the year 2000, simply by fuel-switching, which avoids additional investment in scrubbers. Because the delivered price of low-sulfur western coal is comparable with the local price of high-sulfur coal in most states, demand for western coal is expected to rise through the year 2000. Depending upon the degree of over-compliance achieved through fuel switching, this demand may continue to rise through 2010. A large majority of

Why Pollution Credits Cost So Little

If a power plant targeted for Phase I clean-up were to burn Illinois Coal (3% sulfur, 11,500 Btu/lb), the plant would emit 5.22 lbs of SO₂, or 2.72 lbs over the permitted level of 2.5 lbs per million Btu of energy consumption. This plant would have to buy 2.72 lbs of emission allowances from another plant, install a scrubber, or switch to lower sulfur fuels such as western coal or natural gas. As the table below shows, the shift to low-sulfur coal for air quality compliance involves little or no additional expense.

In Phase I of the 1990 Clean Air Act Amendments, a major shift to western low-sulfur coal occurred because of the cost advantage. This has significantly contributed to the large number of pollution credits generated due to overcompliance.

Delivered price of coal to utilities in three regions.

	Low-sulfur coal	High-sulfur coal
South Atlantic ¹		
1995 price/mm Btu	\$1.54	\$1.48
1996 price/mm Btu	\$1.51	\$1.56
West North Central ²		
1995 price/mm Btu	\$0.96	\$1.83
1996 price/mm Btu	\$0.92	\$1.22
East North Central ³		
1995 price/mm Btu	\$1.40 ⁴	\$1.22
1996 price/mm Btu	\$1.44 ⁴	\$1.28

¹ DE, DC, FL, GA, NC, SC, VA, WV

² IA, KS, MN, IA, NE, ND, SD

³ IL, IN, MI, OH, WI

⁴ This is more expensive than average because one Illinois utility paid exceptionally high prices for some western coal it was obligated to buy under an older contract agreement.

Many plants have reduced emissions to levels well below the 2.5 lb limit. The EPA reports that 2.3 million units (each unit equals a ton of SO₂) were available for purchase at the end of 1995. Many plants have already reduced emissions to levels below the stricter standards for the year 2000 (1.2 lbs SO₂), and have thus eliminated any need to purchase pollution credits.

The surplus of credits led to a drastic fall in price, from about \$130 per unit in April 1995 to \$65 a year later.

Because some utilities will be unable to reduce emissions by coal switching for technical, economic or logistical reasons, a market for pollution credits will continue to exist. However, it is likely that the prices will remain low due to oversupply.

This low cost reflects the disincentive for plants to invest in equipment that would allow more Illinois coal to be burned, and it reflects the attractiveness of switching to western coal as an alternative to scrubbers for meeting emission standards.

affected plants have indicated that they will follow this strategy in Phase I of the 1990 amendments (USDOE, 1994).

Some plants will include natural gas in the fuel mix as a strategy to meet the Phase I emission limit. This fuel choice will allow some plants to also comply with the Phase II emission limits. The excess emission allowances will be carried over past the year 2000 until new coal-fired facilities use them up. Because only a finite number of credits will be available, sulfur-free fuels such as natural gas will be preferred by users who must comply with the SO₂ emission "cap". Available technologies like Flue Gas Desulfurization (FGD) and Fluidized Bed Combustion (FBC), and emerging ones like Integrated Gasification Combined Cycle (IGCC) would permit coal-burning with little or no SO₂ emission. Decisions to use them, however, will depend on their total generating cost versus the total cost of sulfur-free fuels.

Nitrogen Oxide Emissions Emissions of nitrogen oxides (NO_x) are also regulated under the Clean Air Act. Some NO_x rules apply only to plants that are affected by CAA SO₂ regulations. Each affected unit must hold NO_x emissions below 0.45 or 0.5 lbs per million Btu, depending upon the boiler type. For fossil-fuel-fired units located in ozone non-attainment areas (defined within the law), the NO_x emission limit is either 0.2 lbs per million Btu or a 55-65% reduction below the 1990 emission level in the warmest five months of the year. States must determine what control technology is reasonably available to achieve this goal. If the compliance strategy of reducing NO_x emissions includes burning natural gas, it will affect coal use.

Other Emissions The 1990 amendments also propose to control emissions of Hazardous Air Pollutants (HAPs), but the EPA has not yet studied the issue sufficiently to develop regulations. When such regulations are established, they may affect coal use. Depending upon the coal used, up to 16 HAPs are known to be released by combustion. These include arsenic, benzene, beryllium, cadmium, chlorine, chromium, dioxins/furans, formaldehyde, lead, manganese, mercury, nickel, polycyclic aromatic hydrocarbons, radionuclides, selenium, and toluene. According to the utility industry, their concentrations are not a health risk to humans (*EPRI, 1994*). Any restrictions on HAPs would result in at least some additional fuel switching to natural gas, which would reduce the use of coal in electricity generation. Regulations are also being considered to reduce permissible dust emissions from 10 micron sized particles to 2.5 micron sized particles. Such a regulation may negatively affect the use of all coals.

Trade Regulations and Utility Deregulation

Currently, most investor-owned electric utilities are "regulated monopolies." Within a monopoly utility's geographic area, customers can only purchase electricity from that utility and it must supply all customers in its service area. A state commission determines the utility's rate of return on investment, and must approve all expenses the company charges to consumers.

Electric utilities are now being deregulated under the 1992 National Comprehensive Energy Policy Act. Wholly-owned "independent" power-producing companies that are not subject to the same constraints as utilities are now permitted. These independents are free to produce and sell electricity to anyone anywhere. Utilities are also now permitted to merge and take advantage of synergies in competing for distant and/or major markets. Utility mergers are on the rise, and some have taken place between companies in different states. Wholesalers who buy electricity for resale are now free to purchase it anywhere, and utilities are required to provide transmission for a fair market charge. Retail customers, however, are still required to purchase electricity from the utilities until state laws are amended. Other aspects of the deregulation climate are the international electricity and gas transactions already taking place between the United States, Canada and Mexico. These may intensify in the future due to the North American Free Trade Agreement (NAFTA).

Consequences of Deregulation

The deregulation efforts will likely intensify price competition among producers of electricity and force cost-cutting measures in the industry. Some of the expected and potential consequences of the increased competition are:

- Old low-efficiency and high-cost generating units will be retired earlier than planned.
- Lower-cost units that remain in production will be able to further reduce cost per kWh by increasing the capacity utilization (load factor).
- Investor-owned-utilities may no longer be required to purchase excess electricity generated by independent small producers.
- National or regional electricity distribution networks may emerge as independent service firms.
- Intracity distribution networks may be available for purchase by the cities or private enterprise.
- While producers of electricity may be freed from regulations, distribution networks might continue as some form of "regulated monopolies."

- Gas-fired combined-cycle electricity generation may assume a greater role in production and help lower costs. The natural gas industry is already deregulated, allowing utilities to shop for the least-cost gas deals nation-wide, and from neighboring countries under NAFTA.
- Due to intense price competition in electricity markets, utilities with unamortized investments in nuclear power plants may face economic hardships from these potentially difficult to recover investments.
- Because they are too small to be economically competitive, rural electric power supply companies are already facing loan servicing problems. In addition, several of them have partial ownership interests in nuclear power plants. Federal assistance worth billions of dollars has been granted to several cooperatives. At least \$11 billion of loans are currently in default, requiring remedial action (*Wall Street Journal*, Oct. 3, 1996). The magnitude of public assistance required in this area could determine the speed of deregulation in the electric power business. But there is no doubt that deregulation will put competitive pressures on high-cost power suppliers in the decade ahead.

SUPPLY-SIDE DYNAMICS

Coal Supplies

Coal availability in the United States is not a geological problem. According to DOE, recoverable coal reserves in the U.S. total about 265 billion tons. About 61 billion tons of the U.S. recoverable coal reserves are in the Interior Region and about 80% of that is in the Illinois Basin, which

includes parts of Illinois, Indiana and western Kentucky. Thus, nearly 49 billion tons of recoverable coal reserves, or 18.5% of the national total, are in the Illinois Basin (*USDOE, 1995*).

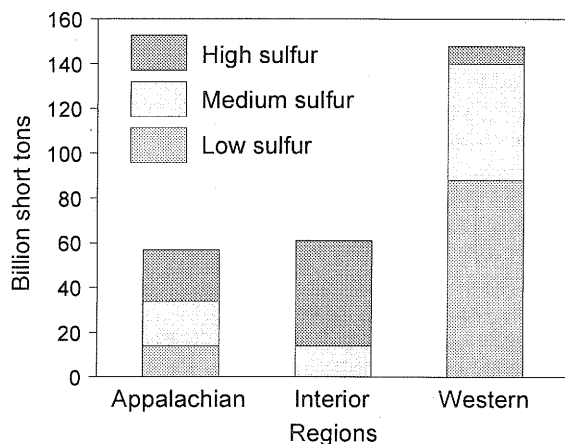


Figure 2 Coal reserves by sulfur content and region (*USDOE, Feb. 1995*).

However, this quantity is limited by the quality of recoverable coal reserves, especially their sulfur content. The low-sulfur (<1.2 lbs SO₂ per million Btu) recoverable reserves in the U.S. are about 100 billion tons, very little of which is in the Interior Region. Little or no Illinois Basin coal can comply with the maximum allowable SO₂ limit through the year 2000 without additional cleaning or other forms of emission controls (fig. 2). About 87% of the nation's low-sulfur coal reserves are in the western states, while 61% of high-sulfur (>3.36 lbs SO₂ per million Btu) recoverable coal reserves are in the Interior Region, mostly in the Illinois Basin. The 1990 Clean Air Act amendments have re-

sulted in a drastic reduction in demand for high-sulfur coal. The demand for medium-sulfur (>1.2 and <3.36 lbs SO₂ per million Btu) coal is likely to be secure for the years through 2000 but may not remain so after that.

Other Supply Factors

Fuel cost is the main determinant of electricity generating plants' operating cost. Operating and capital costs, including capital costs for emission control equipment and waste disposal, as well as building and shut down costs, comprise total generating cost. Fuel choice is thus determined not only by its price but also by the cost of equipment needed to burn it cleanly and to safely dispose of waste. For instance, high-sulfur coal cannot be burned cleanly without expensive investment in emission control devices, but low-sulfur coals can be.

Illinois Coal is in competition with other fuel supplies for generating electricity, and when its total cost (production, consumption, disposal, etc.) is compared to the costs of other fuels, the lowest total cost fuel will be used.

To understand Illinois coals' current and near term disadvantage in comparison to other fuels, the cost structures of these fuels and the comparative costs of various pollution abatement strategies within the current and future regulatory environment must be understood.

Nuclear Energy Pollution control and waste disposal costs of fossil fuels have been included in the price of coal-generated electricity, but the nuclear industry's costs of development and waste disposal have been and remain highly subsidized by taxpayer dollars. It also appears that insufficient money is being set aside to pay for the decommissioning of nuclear plants, which may be higher than the cost of building them (*Heinze Fry, 1991*). These unrealized or transferred costs allowed nuclear energy to capture a larger share of the growth in electric generation than coal (table 1). From 1989 to 1995, nuclear electricity generation grew at 4.1% annually, compared with 1% for coal-based generation.

Because nuclear power plants are highly capital-intensive, their economic operation requires maximum use as base load generating capacity. Their low operating cost due to low fuel costs is also an incentive to maximize their use.

Capacity utilization in U.S. nuclear power plants has increased from near 50% in 1973 to about 78% in 1995 (*USDOE, Aug. 1996*). Some growth in nuclear capacity utilization may still be possible, but the maximum sustainable load factor may

have been reached. A new nuclear plant—the 1170 MW Watts Bar 1—became operational in May 1996, but no other new plants are scheduled to begin production in the coming ten years because none is under construction or in the licensing stage.

Nuclear plants' low operating costs, and the large portion of initial capital investment that remains to be recovered for many plants, will act to keep these plants in service. Retiring them would leave utilities with stranded costs that would have to be recovered either through higher electric rates or taxpayer subsidies. Nonetheless, the DOE forecast assumes some nuclear plant retirements for cost reasons. Smaller, older nuclear plants will be among those to be retired. However, the 1170 MW generating capacity of the newly operational Watts Bar 1 will more than make up for retirements. Although DOE forecasts nuclear electricity generation to decline by 2010, a small increase at an annual rate of 0.5% may be a more appropriate assumption.

Natural Gas Electric Generation. Gas-based generation increased at 2.4% per year during 1989 to 1995, after a sustained 16 year decline. Comparative total costs for coal and natural gas in both the utilities and the independent sectors is likely to favor gas, unless gas prices rise to the point where coal becomes a better choice despite its additional sulfur removal and waste disposal costs. Incremental growth in demand for electricity in the future might promote the construction of gas-fired combined cycle plants with 60% thermal efficiency compared with coal-fired plants with 40% efficiency. Gas-fired plants take only 1 to 3 years to build and cost at least 40% less than coal-fired plants (*EPRI, Sept. 1987*). Unlike in the 1980s, gas is no longer perceived as a commodity in short supply. DOE estimates proven U.S. gas reserves to be about 165 trillion cubic feet (Tcf), the equivalent of ten years of supply at the current rate of production. An additional 1,200 Tcf can be found and produced at current prices and with currently available technology (*USDOE, 1994*). Its ease of use, its ready availability and clean-burning characteristics, and the absence of waste disposal costs and the low initial capital requirements associated with it, make natural gas an attractive fuel for future electricity generation despite its higher price. Planned capacity additions by electric utilities indicate that of the 32,000 MW to be added between 1993 and the year 2000, about 60% will be gas-based and only 20% coal-based (*USDOE, 1992*).

Coal-Based Generation According to the 1996 DOE annual energy outlook, the growth in coal-based electricity generation between 1995 and 2010 will come from an increase in capacity utilization from 62% to about 75%. No net addition to coal-based generating capacity is expected in this period, because added capacity will only replace retired capacity.

Table 1 Annual growth in U.S. electric utility generation (by fuel).

	Coal	Nuclear	Natural gas
1970–1973	6.4%	55.7%	–3.0%
1973–1979	4.0	20.5	–0.6
1979–1984	4.5	5.1	–2.1
1984–1989	3.0	10.1	–2.2
1989–1995	1.0	4.1	2.4

Source: *USDOE, Aug. 1996*

Recent projections of U.S. coal production in 2010 range from DOE's 1,182 million tons to 1,348 million tons by WEFA, formerly the Wharton Econometric Forecasting Associates Group (*USDOE, Jan. 1996*).

Coal mined in the western states enjoys a price advantage over midwestern coal primarily because mining costs in those states are extremely low (table 2), and because average nationwide rail transportation rates declined 17% between 1986 and 1993 as a result of the transportation

industry deregulation in the late 1970s (*Philo, Keefe, et al., 1995*). The competition between railroad companies and the creation of large companies through mergers and acquisitions contributed to increased efficiency and lower cost. Coal represents a major revenue source for railroad

Table 2 Coal prices at mine and productivity.

	Average mine price (\$/t)	Productivity in 1995 (t/person/hr)	Change/yr 1986-1995 (%)
Illinois	23.05	3.87	5.6
Indiana	21.71	4.68	3.7
Kentucky			
East	26.00	3.47	4.6
West	20.75	3.97	3.4
Colorado	19.26	6.14	5.3
Montana	9.62	21.06	2.0
Wyoming	6.58	30.06	7.5

Source: *USDOE, Oct. 1996*

companies and transportation costs are a major cost factor for coal-fired electric utilities (*Vaninetti and Valentine, 1996*).

In 1995, the price of Wyoming coal at the mine was \$6.58 per ton compared with \$23.05 for Illinois coal. Although the average Btu value of Wyoming coal is lower than the Illinois average, the Wyoming coal shipped to Illinois and other eastern states is generally above average in Btu value. The difference in Btu value, therefore, is not large enough to make up for the basic price difference between Illinois and Wyoming coals.

The lower cost of mining in Wyoming and Montana is due to thicker coal deposits buried under thinner layers of overburden than in Illinois. Large-scale surface mining is possible there with productivity five to eight times higher than in Illinois coal mines (table 2). Productivity in Illinois coal mines has grown at an average rate of 5.6% annually from 1986 to 1995. At this rate, mine productivity approximately doubles every 13 years. However, productivity in Wyoming mines rose 7.5% per year in this period, a rate that more than doubles productivity every 10 years. Thus, the cost advantage for Wyoming coal has been further enhanced.

Pollution Credits In addition to its lower price, Wyoming coal also has a lower sulfur content that helps keep emissions to levels low enough to meet the final limits set for the year 2000 by the 1990 CAA amendments. Utilities that switched to Wyoming coal since 1990 have been able to meet or exceed the cleanliness standards for both Phase I and Phase II of the CAA amendments. And they have done this with lower fuel costs and without the added expenses for flue gas clean-up that would be needed for Illinois coal. The use of Wyoming coal also makes the purchase of emission allowances unnecessary.

Emission allowances were traded for \$70 per ton of SO₂ in April 1996. Purchasing of allowances to account for an emission reduction from 2.5 lbs to 1.2 lbs of SO₂ per million Btu would cost only about 5 cents. However, low-sulfur compliance coal is already cheaper than high-sulfur coal, leaving no economic incentive to purchase any emission allowances in conjunction with the purchase of Illinois coal.

The federal EPA reports a 2.3 million unit (1 Unit = 1 ton SO₂) over-compliance at the end of Phase I. During Phase II, the national SO₂ emissions are to be lowered by 5 million units from the Phase I target. With a 2.3 million unit over-compliance in Phase I, almost half of the reductions targeted in Phase II have already been achieved. It is conceivable that the economic advantages of switching to lower sulfur coal in Phase II will favor such a switch and carry a similar or higher level of over-compliance into the next century. An increase in the use low-sulfur coal through the year 2000 is also likely due to the provision in the 1990 CAA amendments that there be no nationwide increase in SO₂ emissions after the year 2000. Any addition to the generating capacity after 2000 that has the potential to emit SO₂ into the atmosphere must be offset by an

equal reduction of emission from existing sources or by way of purchasing emission allowances created by the 1990 CAA amendments. Given the economic advantages of burning low-sulfur western coal over high-sulfur coal, utilities would continue to have an incentive to prefer low-sulfur coals and minimize credit purchases for plants to be built after the year 2000. This would result in a further decline in the sales of high-sulfur coals such as the Illinois coal.

ISGS PROJECTIONS OF ELECTRIC DEMAND

The projections of U.S. demand for electricity in table 3 are based on average growth rates of 1.2% for coal, 3.5% for gas and 0.5% for nuclear electricity, with no growth in the other sources. The overall rate of growth in electricity is 1.3% per year.

For the 1995–2010 period, the USDOE projects coal-based generation by electric utilities to grow 1.26 percent per year. Coal-based non-utility generation is projected to grow an average of 2 percent per year. Gas-based utility generation is projected to rise 2.4 percent per year and Gas-based non-utility generation by 3.9 percent annually. The DOE also projects nuclear generation to decline slightly (*USDOE, Jan. 1996*).

The impending deregulation of the electric utility industry could change this scenario. Currently, utilities are required to purchase excess electricity produced by independent power producers (IPP). Because the price is set at the utilities' marginal production costs, it guarantees a market at the highest possible price for IPP-generated excess electricity. A deregulated electricity industry will abolish this provision and force the IPPs to

compete with the utilities in the open market. Some of the IPPs may receive taxpayer support during the transition period, but in the long run, growth rates in the independent sector will likely be smaller than in the utilities sector.

Table 3 ISGS Industrial Minerals and Resource Economics Section's projection of U.S. demand for electricity by fuel (billion kWh).

Year	Total	Coal	Gas	Nuclear	Other	Change (%/yr)
1995	3405	1714	497	673	521	—
2000	3653	1832	593	703	525	1.2
2005	3878	1938	702	714	525	1.2
2010	4130	2050	830	725	525	1.3

An important footnote to the above forecast is the overall conversion efficiency of coal-burning power plants. Each percentage point increase in thermal efficiency of power plants can reduce coal demand by 2.5 percent. Although the average thermal efficiency in the U.S. is unlikely to change drastically because of the very small capacity additions expected in the next 15 years, a small change of 1 percentage point can reduce demand forecast by as much as 30 million tons. Such a change is conceivable as load factors for efficient, low cost plants are increased and less efficient older plants are retired or their usage reduced.

FUTURE OF ILLINOIS COAL

The Illinois coal mining industry has been particularly hard hit by the dynamics of the coal market. Caught between environmental imperatives and economic constraints, coal production in Illinois began to decline after the passage of the 1990 Clean Air Act amendments. For about 25 years, Illinois coal production averaged about 60 million tons per year, but it began to fall after electric utilities recognized the economic as well as environmental advantages of burning low-sulfur coal produced primarily in the western United States. In 1995, Illinois produced only 49.5 million tons of coal.

An Illinois Coal Development Board (ICDB) report lists eight mine closures in 1994 and 1995 and seven expected mine closures in 1996 (*Keefe, Morey, and Heabert, Oct. 1996*). Twelve other coal mines in Illinois closed in the 1991 - 1993 period (*Philo, Keefe, et al., 1995*). The reasons listed for the mine closures indicate an inability to compete in the market due to exhaustion of marketable quality coal reserves or the high cost of mining. Coal mining employment in the 19 coal-producing counties declined from 10,129 in 1990 to 5,663 in 1995. Unemployment rates in many coal-producing counties in southern Illinois exceeded 10% in 1994 compared with the state average of 5.7%.

The ICDB report also indicates that long-term sales contracts are declining rapidly (*Keefe, Morey, and Heabert, 1996*). Modern capital-intensive mines need stable long-term sales commitments. The market situation since 1990 has led to a decline in demand for high-sulfur coal and falling spot market prices. In 1995, almost 80% of Illinois coal production was under long-term contracts.

In 1996, that proportion fell to 67%. Only 42% of the current production is under contract for the year 2000 and about 20% for 2010. Spot market sales, which accounted for 33% of 1995 sales, would have to rise to 80% in 2010 if total coal sales were to remain at the 1995 level. The decline in sales from 53 million tons in 1994 to 49.5 million in 1995 indicates that the tonnage of contract losses has not been made up by tonnage increase in spot sales. Declining total sales, together with falling long-term utility contractual commitments, indicate difficulties ahead for Illinois coal, more than 90% of which is sold to electric utilities.

The ICDB report projects Illinois coal sales to utilities to decline to 33.3 million tons in the year 2000 (*Keefe, Morey, and Heabert, 1996*). Resource Data International (RDI) projects sales of Illinois coal to electric utilities in year 2000 at 29 million tons. If current sales of 8.5 million tons to non-utility consumers and to other countries remain unchanged, total sales of Illinois coal in 2000 could be 37.5 to 42 million tons according to ICDB and RDI forecasts.

Table 4 Operable and planned capacity additions 1993–2003.

State	Operable (MW)		Planned (MW)	
	Total	Coal	Total	Coal
Illinois	36,909	17,220	881	0
Indiana	23,235	21,623	1,538	0
Missouri	16,842	11,663	1,913	542
Florida	31,109	10,850	3,627	719
Tennessee	18,227	10,020	2,540	0
Georgia	23,149	14,549	4,894	0
Total	149,471	85,925	15,393	1,261

Source: Keefe, Morey, and Heabert, 1996

According to DOE, the total operable generating capacity in 1993 in the six largest consumer states of Illinois coal—Illinois, Indiana, Missouri, Florida, Tennessee and Georgia—was 149,471 MW, of which 85,925 MW or 57.5% was coal-fired (table 4). About 15,393 MW of new capacity is planned to be added through the year 2003, but only 8.2% of it (1,261 MW) is to be coal-fired. This equals a total capacity growth of about 0.8% per year and a growth rate of 0.15% per year in coal-fired capacity in

the six most important coal markets for Illinois. The new coal-fired capacity in the six states would require two to three million tons of coal annually. Whether this would enhance demand for Illinois coal will depend upon price and supply factors. The 1995 average delivered prices of coal in the six states are compared in table 5.

In Indiana and Missouri, low-sulfur coal from Wyoming is delivered at significantly lower prices than Illinois coal. Wyoming coal prices are 25 to 48 cents per million Btu lower than Illinois coal. In Tennessee, Georgia and Florida, coal from Illinois is closely matched in price with other coals used there. However, increasing sales of Wyoming coal and decreasing sales of Illinois coal in Georgia indicate that market competitiveness of Wyoming coal is expanding further into the southeastern states. Only in Illinois does locally mined coal appear to cost less than coal from Wyoming and Montana. Even here, however, long-term contracts signed by one utility many years earlier are the reason for the higher average price of Wyoming coal. In 1994, a utility that paid up to \$3 per million Btu for Wyoming coal on contract was able to purchase large quantities of Wyoming coal on the spot market for \$1.30 per million Btu, which was slightly lower than the price paid for Illinois coal.

While Illinois coal production has declined since 1990 at an average annual rate of 4.3%, sales to electric utilities have declined by 5.4% annually. RDI's projection for sales of Illinois coal to utilities of 29 million tons in the year 2000 reflects an acceleration of this decline through the rest of this century.

Because the quantity of emission reduction to be achieved in Phase II is similar to that in Phase I, it would not be surprising if Illinois coal sales continue to decline 4.3% annually, the rate at which

Table 5 Utility coal sales and prices 1995.

Source state	1000 tons	Cents/ million Btu
Consumed in ILLINOIS		
Illinois	11,879	135
Wyoming	14,081	183
Montana	2,685	250
Colorado	1,526	136
Consumed in INDIANA		
Indiana	16,297	119
Wyoming	18,060	115
Illinois	10,661	140
Consumed in MISSOURI		
Illinois	4,168	135
Wyoming	25,566	88
Consumed in FLORIDA		
Kentucky	12,508	176
Illinois	5,961	179
West Virginia	1,518	175
Imported	2,581	180
Colorado	811	184
Consumed in TENNESSEE		
Kentucky	16,179	116
Illinois	3,949	110
Utah	1,134	118
Tennessee	1,078	122
Consumed in GEORGIA		
Kentucky	15,202	165
Wyoming	6,762	152
West Virginia	3,772	197
Illinois	604	154
Virginia	1,987	164

Source: U.S. DOE, July 1996

they have declined since 1990. This would put Illinois coal production at about 40 million tons in 2000, of which sales to utilities would total about 30 to 32 million tons.

The decline in utility sales of Illinois coal in 1995 over 1994 was only about 2 million tons, compared to a 12 million ton drop from 1992 to 1994. This reflects the fact that most coal switching for compliance reasons was completed in 1994 to meet the January 1, 1995, deadline for Phase I of the CAA amendment. The compliance deadline for Phase II is January 1, 2000. About two thirds of all Phase II affected utilities will likely switch to low-sulfur coal for compliance. As a result of this strategy, the next major decline in Illinois coal sales can be expected before January 2000.

The conditions for Illinois coal in the first decade of the next century remain unchanged: slow growth in electricity demand, an even slower growth in coal-based electricity generation, and a higher price in comparison with the low-sulfur western coal. Illinois mines that can compete with the price of western coal have the best prospects for continued production into the next decade. Under favorable cost conditions, the coal production in Illinois could continue at the 40 million ton level through the year 2010. If, however, mining costs in Illinois continue to be uncompetitive, coal production could continue to fall at the rate observed since 1990 and reach a low of 26 million tons in 2010. Coal production in the first eight months of 1997 is running at an annual rate of about 42 billion tons, which indicates that production in the year 2010 may be lower than predicted. Other factors such as the price and availability of natural gas and whether substantial nuclear capacity will be retired will also have an influence on Illinois coal production in 2010.

WHAT CAN BE DONE?

The root causes of the recent decline in Illinois coal production have been economic, albeit triggered by the CAA amendments in 1990. A new dimension has been added to the market dynamics in the form of the prospects of deregulation in the electricity market. The capital-intensive coal mining industry, with a direct influence of geologic factors, requires time to respond to market changes that are taking place at a fast rate. It is, therefore, imperative that impending market changes are studied and anticipated at least a decade or more ahead of time and appropriate changes made

in research, economic and environmental policies. The Illinois State Geological Survey has been involved in some of the anticipatory research to assist the coal industry in Illinois.

- Geologic research at the ISGS has identified geologic settings under which lower-sulfur coal deposits occur. Application of these geologic models by geologists at the ISGS and in industry has permitted the delineation of lower-sulfur coal deposits over the past 20 years and permitted a significant shift of production toward these lower-sulfur reserves.
- The ISGS analysis of coal markets identified coal mining costs as the cornerstone of competitiveness and provided mining cost estimates for Illinois coal mines. Research and development

policies based on the recognition that cost-competitiveness determines the future of the coal industry have a better chance of success than those that don't.

- Mine subsidence research at the ISGS and other institutions in Illinois has provided knowledge vital for the successful application of high-extraction mining techniques, such as the longwall technique, essential for efficient, low-cost mining of coal.
- Engineering research at the ISGS has contributed to the knowledge of coal and flue gas cleaning, the use of Illinois coal in clean coal technologies, such as the Integrated Gasification Combined Cycle (IGCC) technology, and to the development of new uses of coal, such as in the production of activated carbon.

Coal mines that have survived the competition are primarily high-productivity, low-cost mines. Future market changes are expected to be even more profound than in the recent past, requiring stronger efforts to enhance the economic competitiveness of Illinois coal mines. Research and development to lower the cost of mining, cleaning and transporting coal must be intensified. The goal must be to produce electricity from Illinois coal at a lower cost than from other fuels.

REFERENCES

- Coal Week, April 1, 1996, EPA Credit Auction Shows Mid-\$60 Prices; Announces Massive 1995 Over-compliance, p. 1-2.
- Electric Power Research Institute, September 1987, Proceedings: 1986 Fuel Supply Seminar, Palo Alto, CA., EPRI Project 2369-10, p. 5-10.
- Electric Power Research Institute, 1994, Report: Electric Utility Trace Substances Synthesis; v. 1-4, Report TR-104614.
- Heinze Fry, Gene R., 1991, The Cost of Decommissioning U.S. Reactors: Estimates and Experience: The Energy Journal, Special Nuclear Decommissioning Issue, v. 12, p. 87-104; other papers in the same issue.
- Keefe, Daniel E., Mathew J. Morey, and Dean L. Heabert, October 1996, Outlook for the Illinois Coal Industry: Illinois Coal Development Board, Illinois Department of Commerce and Community Affairs, table 2, p. 4; p. 9.
- Philo, Gary R., Daniel E. Keefe, David W. South, and Koby A. Bailey, December 1995, Outlook for the Illinois Coal Industry: Illinois Coal Development Board, Illinois Department of Commerce and Community Affairs and Argonne National Laboratory, table 2, p. 11; table 3, p. 9; table 5, p. 22; table 4, p. 11.
- U.S. Department of Energy, March 1991, Annual Energy Outlook 1991 with Projections to 2010: Energy Information Administration, Washington, DC, DOE/EIA-0383(91), p. 38.
- U.S. Department of Energy, 1992, Inventory of Power Plants in the United States, Washington, DC: Energy Information Administration, DOE/EIA-0095(92).
- U.S. Department of Energy, 1993, Inventory of Power Plants in the United States, Washington, DC: Energy Information Administration, DOE/EIA-0095(93), Table 17, p. 36-44.
- U.S. Department of Energy, January 1993, Annual Energy Outlook 1993 With Projections to 2010, Washington, DC: Energy Information Administration, DOE/EIA-0383(93), p. 49.
- U.S. Department of Energy, March 1993, The Changing Structure of the Electric Power Industry 1970-1991, Washington, DC: Energy Information Administration, DOE/EIA-0562, table C6, p.86.
- U.S. Department of Energy, 1994, Natural Gas 1994 - Issues and Trends, Washington, DC: Energy Information Administration, DOE/EIA-0560(94), p. 8-9.
- U.S. Department of Energy, March 1994, Electric Utility Phase I Acid Rain Compliance Strategies for the Clean Air Act Amendments of 1990, Washington, DC: Energy Information Administration, DOE/EIA-0582, table 3, p. 6.
- U.S. Department of Energy, February 1995, Coal Data: A Reference, Washington, DC: Energy Information Administration, DOE/EIA-0064(93), p. 47.
- U.S. Department of Energy, January 1996, Annual Energy Outlook 1996 With Projections to 2015, Washington, DC: Energy Information Administration, DOE/EIA-0383(96), table 24, p. 60; p. 94-95.
- U.S. Department of Energy, February 1996, Short-term Energy Outlook: 1st Quarter 1996, Washington, DC: Energy Information Administration, DOE/EIA-0202(96/1Q), table 12, p. 29.

U.S. Department of Energy, July 1996, Cost and Quality of Fuels For Electric Utility Plants 1995, Washington, DC: Energy Information Administration, DOE/EIA-0191(95), table 22, p. 30-33.

U.S. Department of Energy, August 1996, Monthly Energy Review, Washington, DC: Energy Information Administration, DOE/EIA-0035(96/08), p. 95, 105.

U.S. Department of Energy, October 1996, Coal Industry Annual 1995, Washington, DC: Energy Information Administration, DOE/EIA-0584(95), table 48, p. 74; table 80, p. 154.

Vaninetti, Gerald, E. and James J. Valentine, December 1996, Outlining the Impacts of Utility Deregulation on Railroads: Coal Age, p. 51-52.

Wall Street Journal, October 3, 1996, U. S. Giving Electric Co-ops Relief on Loans, p. A3-4.