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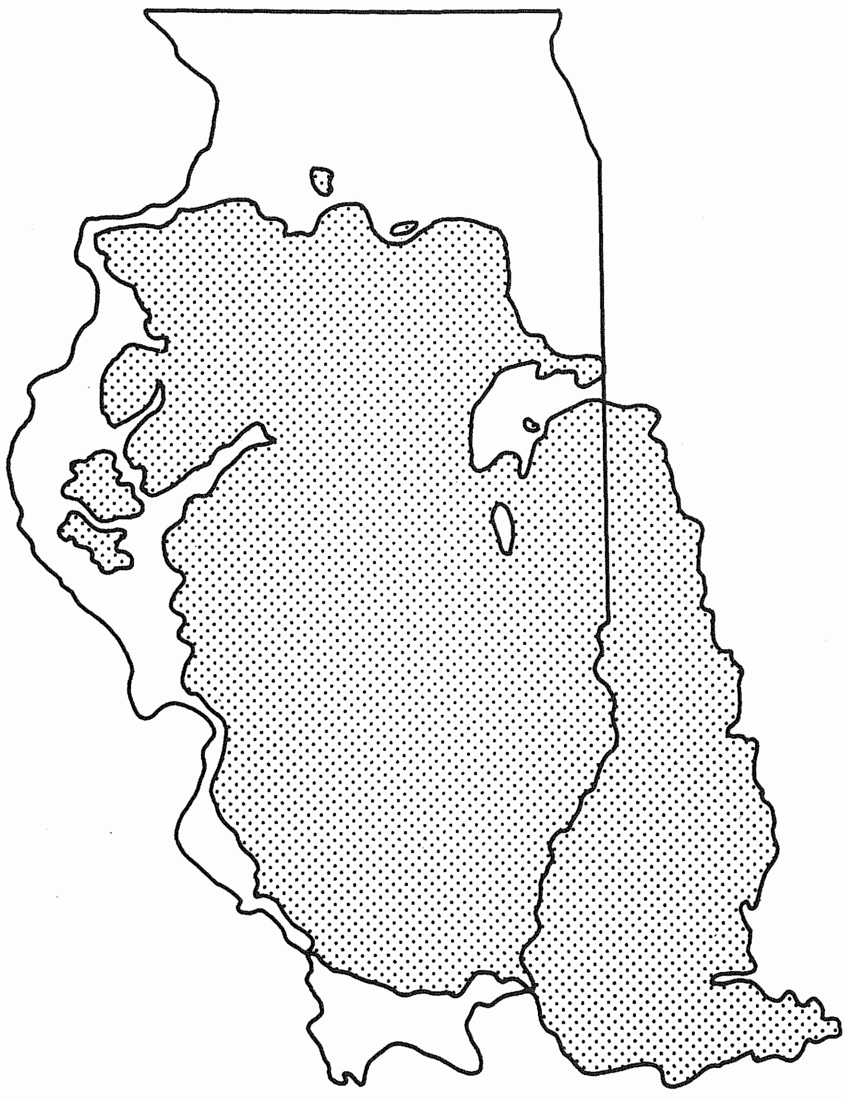
The Future of Illinois Basin Coal: 1994 and Beyond

Subhash B. Bhagwat



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The Future of Illinois Basin Coal: 1994 and Beyond

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ABSTRACT

Since the Clean Air Act was implemented in 1971, production of high-sulfur Illinois Basin coal has stagnated, while total U.S. coal production has continued to increase. Illinois Basin coal production figures for the years 1975 through 1985 show that low-sulfur western coals have successfully captured newly developing coal markets that traditionally would have been Illinois Basin coal markets, despite revisions in the Clean Air Act aimed at reducing the disadvantage of high-sulfur coals in the marketplace. The continuing weak position of Illinois Basin coal is attributed to a lack of cost competitiveness. It is predicted that Illinois Basin coal production will continue to lag through 1994 and beyond if current clean air regulations are enforced and the price of Illinois Basin coal does not become competitive. If acid rain legislation is enacted, production of Illinois Basin coal will undoubtedly decrease, resulting in the loss of thousands of mining jobs.

INTRODUCTION

By 1994, the most stringent clean air standards in U.S. history could go into effect. This legislation could further reduce the markets for Illinois Basin coal, already seriously eroded. The Illinois Basin, which covers a large part of Illinois and extends into southwestern Indiana and western Kentucky, has extensive reserves of bituminous coal; however, because of the coal's high sulfur content, production has been virtually stagnant since implementation of the Clean Air Act in 1970, even after later revisions to the act aimed at improving the market for high-sulfur coals. Total U.S. coal production has continued to increase in the same time period.

This paper analyzes the utility and non-utility markets for Illinois Basin coal for 1975 through 1985 and projects Illinois Basin coal production under two different scenarios: (1) continued enforcement of current legislation and (2) enactment of acid rain legislation. Background information is provided on the Clean Air Act and on U.S. coal production.

THE CLEAN AIR ACT

Although the Clean Air Act was passed in 1963, it was not until 1970 that the federal government empowered the U.S. Environmental Protection Agency (USEPA) to set uniform air quality standards. Under the act, the USEPA has set National Ambient Air Quality Standards (NAAQS) for ambient pollutant concentrations for seven of the most common and widespread pollutants: sulfur dioxide (SO_2), nitrogen oxides (NO_x), particulate matter, lead, carbon dioxide, hydrocarbons, and ozone. The Clean Air Act limits the amount of SO_2, NO_x, and particulates that may be emitted by coal-fired boilers.

For enforcement purposes, the United States was divided into 274 air quality control regions. Each region has to meet the limits imposed by the NAAQS. Control regions within state boundaries where the ambient pollutant concentrations are below or meet the NAAQS are designated as attainment areas. Areas where the ambient pollutant concentrations are above the NAAQS are designated as nonattainment areas. In nonattainment areas, the states are required to devise a strategy to ensure that the minimum standards set by the USEPA are met and maintained. This strategy is incorporated into State Implementation Plans, or SIPs. New and modified pollution sources within nonattainment areas are required to meet the lowest achievable emission regardless of cost.

For plants built prior to 1971, SO_2 emissions are to be gradually lowered via the SIPs, with the ultimate goal of bringing their emissions down to meet the NAAQS. The time for achieving this objective was not fixed. However, the SIPs were subject to approval by the USEPA. In the early 1980s, the SIPs were revised, and although they still permit relatively high levels of SO_2 emissions from some plants, there is general consensus among the states that plants built prior to 1971 should not emit over 2.0 pounds per million British thermal units (10^6 Btu) of heat input.

The 1971 New Source Performance Standards (NSPS) issued by the USEPA required that utility coal-fired boilers of 73-megawatt (MW) output or greater, on which construction or modification had begun after August 17, 1971, could not emit more than 1.2 lbs $SO_2/10^6$ Btu. Plant operators were required to use "continuous emission monitoring" to measure the SO_2 emission levels in the flue gas outlets of coal-fired boilers. If the average emission level exceeded that specified by the NSPS for more than 3 hours, the plant could be cited for violation.

In 1977, the Clean Air Act was amended to require that states set limits on the existing pollution sources within nonattainment areas. It was specified that such sources must use "reasonably available pollution control technologies" (RACT). Both technological and economic feasibility are considered when applying RACT to existing sources. In attainment areas, new and modified pollution sources are regulated to "prevent significant deterioration" (PSD) of the clean air within the control region. These sources are required to use the "best available control technology" (BACT). BACT is an emission limitation based on the maximum degree of reduction that can be achieved when energy, environmental, and other costs are considered.

In 1979, the USEPA issued the Revised New Source Performance Standards (RNSPS). These standards are more stringent than the NSPS and apply to all coal-fired utility plants capable of producing more than 73 MW of generating capacity and on which construction or modification began after September 18, 1978.

The RNSPS retain the 1971 NSPS standard of 1.2 lbs $SO_2/10^6$ Btu of heat input as a ceiling for emissions, but additionally requires that SO_2 emissions from all new or modified (post-1978) boilers be reduced on a sliding scale of percentages that considers the different sulfur contents of U.S. coals. All coals burned must have at least 90 percent of the SO_2 removed from their emissions, unless 90-percent removal reduces emissions to less than 0.6 lbs/10^6 Btu. If emissions go below that level, reductions between 70 and 90 percent are permitted, depending on the sulfur content of the coal. Utilities are required to monitor SO_2 emissions continuously, both at the flue gas inlet and at the outlet of these new sources, to determine whether the required removal is attained on a 24-hour rolling average. The RNSPS regulations require the use of some form of flue-gas desulfurization (FGD) unit, or scrubber, for all new or modified utility boilers, since only scrubbers can reduce emissions by more than 70 percent.(1)

THE LAST QUARTER-CENTURY OF U.S. COAL PRODUCTION

Since 1961, the U.S. coal-mining industry has grown an average of 3.3 percent per year, although there have been significant year-to-year fluctuations (fig. 1). Total U.S. coal production increased from about 410 million tons in 1961, to 650 million tons in 1975, to an estimated 900 million tons in 1986. Coal exports to other countries accounted for 8.5 percent of U.S. production in 1960, 7.6 percent in 1975, and is estimated at 10 percent for 1985.

Low-sulfur western coals have accounted for an increasing percentage of total U.S. coal production the last 10 years, due to both increased demand for electricity in the western states and the implementation of clean air regulations throughout the U.S. In 1975, about 15.5 percent (100 million tons) of U.S. coal came from the western coal basin states. By 1985, western coal basin states accounted for 30.5 percent (270 million tons) of U.S. coal production. In the same 10-year period, coal production in the rest of the U.S. increased by only 13 percent (70 million tons).

None of this 13 percent increase in non-western coal production came from the Illinois Basin. From 1975 through 1985, coal production in the Illinois Basin stagnated at between 120 and 140 million tons (except for 1978 and 1981, which were strike years).

MARKETS FOR ILLINOIS BASIN COAL, 1975-1985

The most important market for Illinois Basin coal is electric utilities. From 1975 through 1985, about 89 percent of Illinois Basin coal was shipped to electric utilities. The remaining 11 percent of Illinois Basin coal is used by coke and gas plants and small industrial users that generate steam (see section "Non-utility Markets").

Utility Markets

Figure 2 shows total sales of Illinois Basin coal to utilities from 1975 through 1985, with estimates for sales for 1986. As one can see, there have been fluctuations in total sales to utilities during this period. Data on shipments for 1978, 1979, 1981, 1982, 1984, and 1985 were adjusted to account for the effect on sales of the mine worker strikes in 1978 and 1981 and the threat of a strike in 1984. Stocks are depleted in strike years and they must be replenished in the years following the strikes. It is, therefore, appropriate to average the sales for these years. Adjusted sales figures are represented by a star in figure 2.

When shipments are averaged for these strike-affected years, sales of Illinois Basin coal to utilities show a declining trend from 1975 through 1983. From 1984 through 1986, sales appear to have recovered. However, it is inappropriate to conclude that the decline in sales has been reversed from just three years of data.

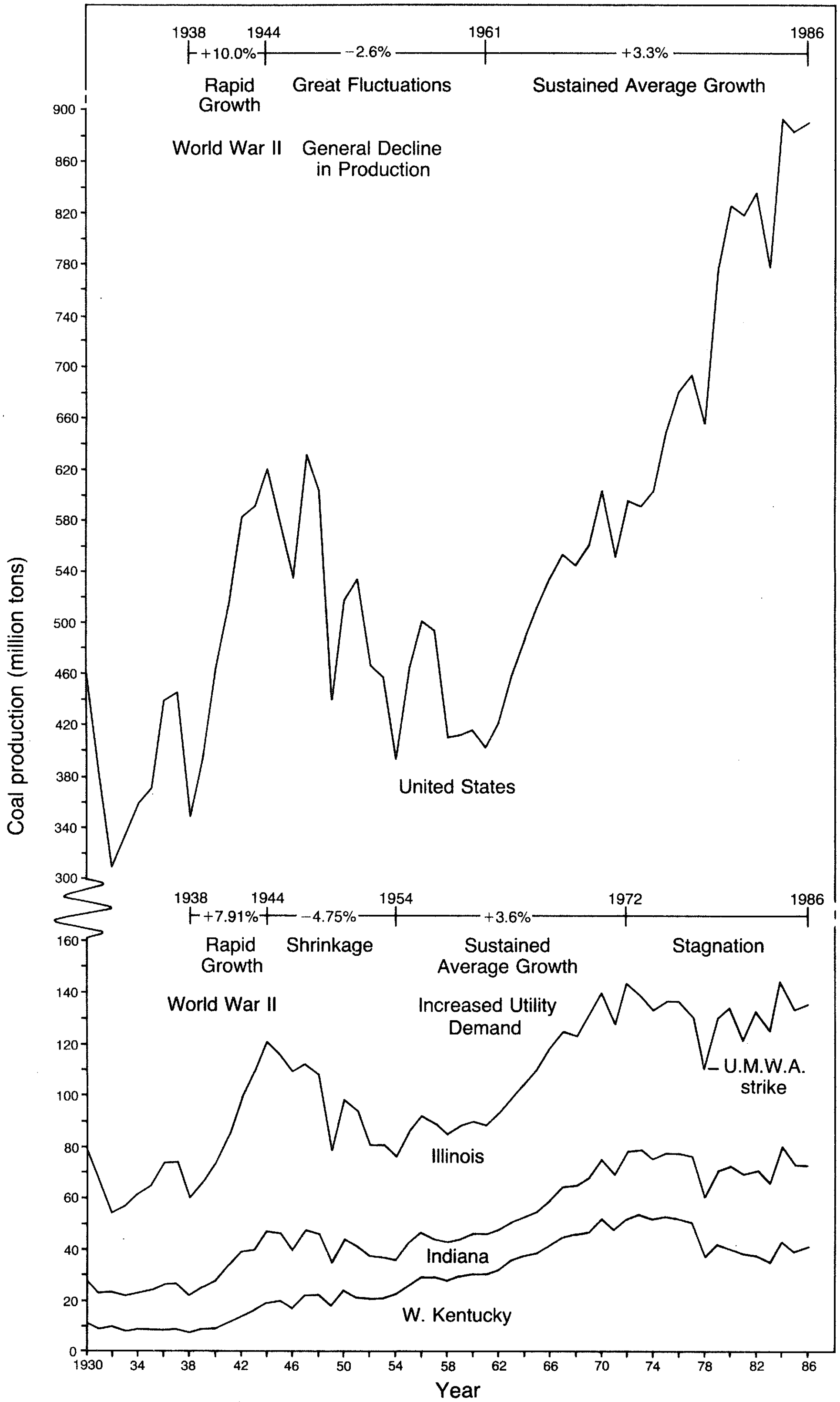

Figure 1 Trends in U.S. and Illinois Basin coal production, 1930–1986 (data adapted from U.S. Dept. of Energy, Bituminous Coal and Lignite Distribution).

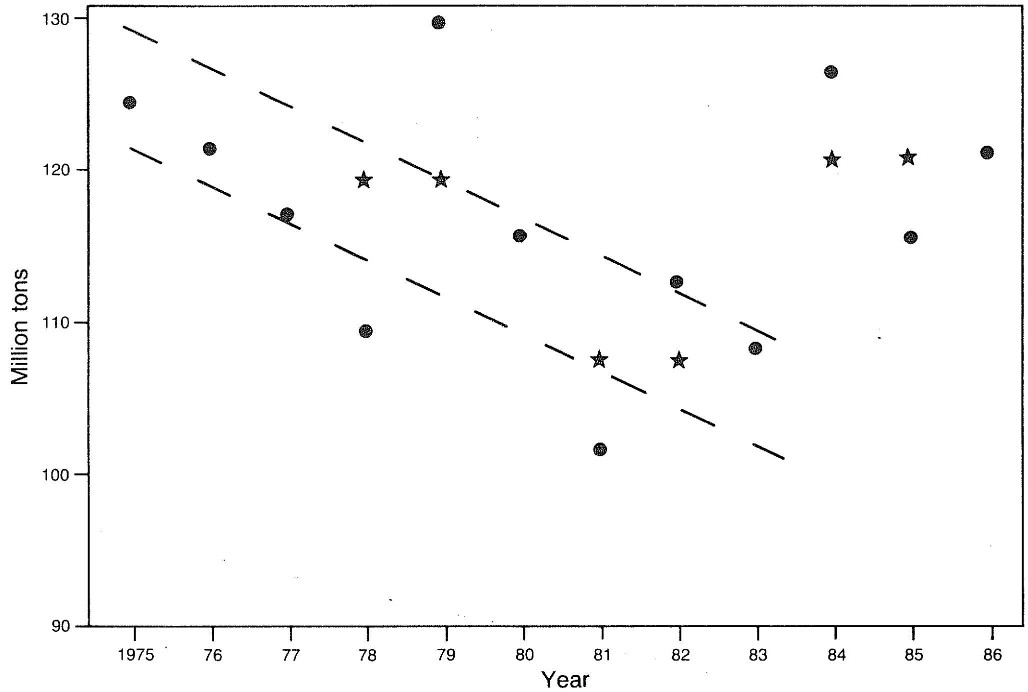

Figure 2 Shipments of Illinois Basin coal to electric utilities, 1975–1985 (data adapted from Bituminous Coal and Lignite Distribution 1975, U.S. Dept. of the Interior, Bureau of Mines and Coal Distribution Jan–Dec 1985, DOE/EIA-0125(85/4Q). Sales figures that were averaged to reflect effect of strike years are represented by a ★.

State-by-state breakdown of utility market shares. Tables 1, 2, and 3 show the dependence of Illinois, Indiana, and western Kentucky coal producers, respectively, on demand from utilities in states in their market areas. In 1985, the total market area for Illinois Basin coal extended into 17 states, compared with 14 states in 1975. The largest single market for any state remained within its own boundaries, although the percentage of coal consumed by utilities within the state declined from 45 to 31 for Illinois and from 80 to 72 for Indiana. In-state consumption of western Kentucky coal increased to 35 percent of total sales to utilities in 1985, as compared with about 31 percent in 1975.

Illinois' shipments to utilities in states immediately north and west of Illinois declined due to competition from low-sulfur western and eastern coals, but the decline was more than offset by increases in shipments to utilities in Missouri, Georgia, Florida, Tennessee, Alabama, and Indiana.

There are several reasons Illinois coal producers increased sales to these states:

- Illinois coal is easily transported to these states via the waterways and railroads. This keeps transportation costs for Illinois coal lower than for coals from western states, thus lowering delivered prices.
- The cost of mining coal in Illinois is lower than in the Appalachian Basin states. Georgia, Florida, Tennessee,

Table 1. Shipments of Illinois coal to utilities by state

	1975		1985	
	(million tons)	(percent)	(million tons)	(percent)
Alabama	0.389	0.8	2.819	5.3
Florida	**	**	3.723	7.0
Georgia	0.987	2.0	3.131	5.9
Illinois	22.006	44.9	16.541	31.3
Indiana	3.081	6.3	7.653	14.5
Iowa	2.290	4.7	1.959	3.7
Kansas	--	--	0.481	0.9
Kentucky	1.982	4.0	0.117	0.2
Michigan	0.334	0.7	0.027	--
Minnesota	1.399	2.9	0.242	0.5
Mississippi	0.924	1.9	0.149	0.3
Missouri	10.496	21.4	13.419	25.4
Tennessee	0.521	1.1	1.389	2.6
Wisconsin	4.595	9.4	1.248	2.4
	49.004	100.1*	52.898	100.0

* Does not total 100% due to rounding.

** Included in Georgia.

Sources: Bituminous Coal and Lignite Distribution 1975, U.S. Dept. of the Interior, Bureau of Mines and Coal Distribution Jan-Dec 1985, DOE/EIA-0125(85/4Q).

Table 2. Shipments of Indiana coal to utilities by state

	1975		1985	
	(million tons)	(percent)	(million tons)	(percent)
Alabama	0.025	0.1	--	--
Georgia	0.482	2.2	1.301	4.8
Illinois	0.371	1.7	1.310	4.9
Indiana	17.222	79.8	19.413	71.8
Iowa	--		0.378	1.4
Kentucky	1.689	7.8	2.487	9.2
Michigan	0.092	0.4	0.098	0.4
Minnesota	--	--	0.148	0.6
Missouri	0.390	1.8	--	--
Ohio	0.045	0.2	0.028	0.1
Tennessee	0.449	2.1	0.208	0.8
Wisconsin	-.816	3.8	1.661	6.1
	21.581	99.9*	27.032	100.1*

*Does not total 100% due to rounding.

Sources: Bituminous Coal and Lignite Distribution 1975, U.S. Dept. of the Interior, Bureau of Mines and Coal Distribution Jan-Dec 1985, DOE/EIA-0125(85/4Q).

Table 3. Shipments of western Kentucky coal to utilities by state

	1975		1985	
	(million tons)	(percent)	(million tons)	(percent)
Alabama	6.459	12.1	0.981	2.7
Arkansas	--	--	0.014	--
Florida	4.102	7.7	4.444	12.1
Georgia	3.783	7.1	2.230	6.1
Illinois	0.844	1.6	1.116	3.0
Indiana	4.159	7.8	2.853	7.8
Iowa	0.064	0.1	0.051	0.1
Kentucky	16.587	31.0	12.929	35.2
Michigan	1.058	2.0	0.101	0.3
Minnesota	0.101	0.2	0.059	0.2
Mississippi	0.467	0.9	0.188	0.5
Missouri	0.372	0.7	0.006	--
Ohio	1.896	3.5	1.605	4.4
Pennsylvania	--	--	0.056	0.2
Tennessee	11.475	21.5	8.020	21.9
Wisconsin	2.070	3.9	2.043	5.6
	53.437	100.1*	36.696	100.1*

* Totals may not add to 100 percent due to individual rounding

Sources: Bituminous Coal and Lignite Distribution 1975, U.S. Dept. of the Interior, Bureau of Mines and Coal Distribution Jan-Dec 1985, DOE/EIA-0125(85/4Q).

Alabama, and Indiana received the majority of their coal from the Appalachian Basin States.

- Some utilities in these states converted from oil and/or gas to coal. This conversion was partly a result of the 1978 Fuel Use Act and partly due to the 1979-80 oil price increases. It led to increased total coal demand and an increase in demand for Illinois Basin coal, which benefited Illinois coal.

- About half of U.S. FGD capacity (≃ 25,000 MW) is installed in the market states for Illinois Basin coal. An estimated 20 to 25 percent of this capacity is installed on plants built prior to 1971, while the remaining is on plants built in the 1975-1985 period. Illinois coal could take advantage of the demand stabilization resulting from FGD installations because of its relative cost advantage.

Indiana also increased its shipments to utilities by about 5.5 million tons from 1975 through 1985. However, Indiana coal has been more successfully marketed in its adjoining states, such as Illinois and Kentucky, and states in close proximity, such as Wisconsin, than in distant states such as Georgia. One of the reasons for the increase may be the decrease in average sulfur content of Indiana coal from 3.12 percent in 1975 to 2.54 percent in 1985; it may also have been the result of lower prices due to lower transportation costs and of marketing strategy.

In 1985, Illinois Basin coal shipments from western Kentucky to electric utilities totaled about 37 million tons, nearly 17 million tons less than in 1975. In this same time period, western Kentucky coal producers also became much more dependent on utilities in Florida, although their tonnage shipments to Florida did not increase significantly. In a smaller total 1985 market, western Kentucky coal producers lost sales in Alabama, Kentucky, Tennessee, and Mississippi to coal producers from Illinois and eastern Kentucky. The majority of those sales were lost in Alabama.

From 1975 to 1985, the total demand for coal by electric utilities in the 17-state Illinois Basin market area increased from about 306 to 373 million tons (table 4). Table 4 data indicate that Illinois has increased its market shares in southern states and lost shares in northern states. These states are the same to which shipments in absolute tons also increased or decreased (table 1). Illinois coal thus has taken advantage of opportunities in the southern markets but lost a significant share of the northern markets. Similarly, Indiana has increased its shares of the utility coal markets in Illinois, Kentucky, and Wisconsin in absolute as well as relative terms. Western Kentucky, on the other hand, has lost market shares in nearly all the states in 1985 compared with 1975.

From 1975 through 1985, total coal shipments to utilities from the Illinois Basin declined from 124 million tons to 117 million tons (tables 1, 2, 3) and the market share of Illinois Basin coal in the 17-state market area declined from 41 percent in 1975 to 31 percent in 1985 (table 4). The data indicate a shift in strength within the Illinois Basin in favor of Illinois and Indiana coal at the expense of western Kentucky coal. From 1975 to 1985, Illinois' and Indiana's share of total shipments to utilities increased from 57 percent to 68 percent. The production curves in figure 2 confirm this shift.

Impact of western coals on Illinois Basin utility markets. Increased demand for low-sulfur western coals has eaten into the utility markets for Illinois Basin coals. Western coals are those produced in districts 16-20, 22, and 23 as defined in the Bituminous Coal Act of 1937 and its amendments (fig. 3). Of these seven districts, mines in district 18 (Arizona, California and most of New Mexico) and district 23 (Washington and Alaska) did not ship any coal to the Illinois Basin coal markets. Districts 18 and 23 have, therefore, been excluded from table 5, which shows shipments from western coal districts to states served by Illinois Basin coal. As table 5 indicates, in both 1975 and 1985, only coal producers from districts 19 and 22 shipped significant amounts of coal to the Illinois Basin coal market states. These districts represent mainly Wyoming and Montana coals. In 1985, Colorado coals from district 16 also figure significantly in the statistics, while districts 17 and 20 disappear as exporters to the Illinois Basin market states.

In 1975, coal shipments from western states to utilities in the 14 states in the Illinois Basin market area totaled about 32 million tons. When, by 1985, the Illinois Basin market area had grown to 17 states, shipments of western coals to these states totaled 82 million tons. Western coals' share of total utility coal demand in the 17-state area increased from about 11 percent in 1975 to 22 percent in 1985. About 74 percent of the total increased coal demand by utilities in the Illinois Basin coal market area was met by western states.

As table 5 indicates, most western coals were exported to northern and midwestern states: Minnesota, Wisconsin, Michigan, Iowa,

Table 4. Total 1975 and 1985 utility markets and shares held by Illinois Basin states

	Total Market (million tons)		Illinois Share (%)		Indiana Share (%)		W. Kentucky Share (%)	
Market State	1975	1985	1975	1985	1975	1985	1975	1985
Alabama	19.246	21.525	2.0	13.1	0.1	--	33.6	4.6
Arkansas	--	11.861	--	--	--	--	--	0.1
Florida	5.451	16.640	--	22.4	--	--	75.3	26.7
Georgia	14.619	24.201	6.8	12.9	3.3	5.4	25.9	9.2
Illinois	34.853	31.682	63.3	52.2	1.1	4.1	2.4	3.5
Indiana	28.715	36.224	10.7	21.1	60.0	53.6	14.5	7.9
Iowa	5.560	12.345	41.2	15.9	--	3.1	1.1	0.4
Kansas	3.220	14.088	--	3.4	--	--	--	--
Kentucky	25.724	23.405	7.7	0.5	6.6	10.6	64.5	55.2
Michigan	21.802	23.005	1.5	0.1	0.4	0.4	4.9	0.4
Minnesota	8.782	11.397	15.9	2.1	--	1.3	1.2	0.5
Mississippi	1.573	3.873	58.7	3.8	--	--	29.7	4.9
Missouri	17.741	22.065	59.2	60.8	2.2	--	2.1	--
Ohio	46.412	47.861	--	--	0.1	--	4.1	3.4
Pennsylvania	35.778	39.573	--	--	--	--	--	0.1
Tennessee	24.659	18.178	2.1	7.6	1.8	1.1	46.5	44.1
Wisconsin	11.598	15.357	39.6	8.1	7.0	10.8	17.8	13.3
	305.733	373.280						

Sources: Bituminous Coal and Lignite Distribution 1975, U.S. Dept. of the Interior, Bureau of Mines and Coal Distribution Jan-Dec 1985, DOE/EIA-0125(85/4Q).

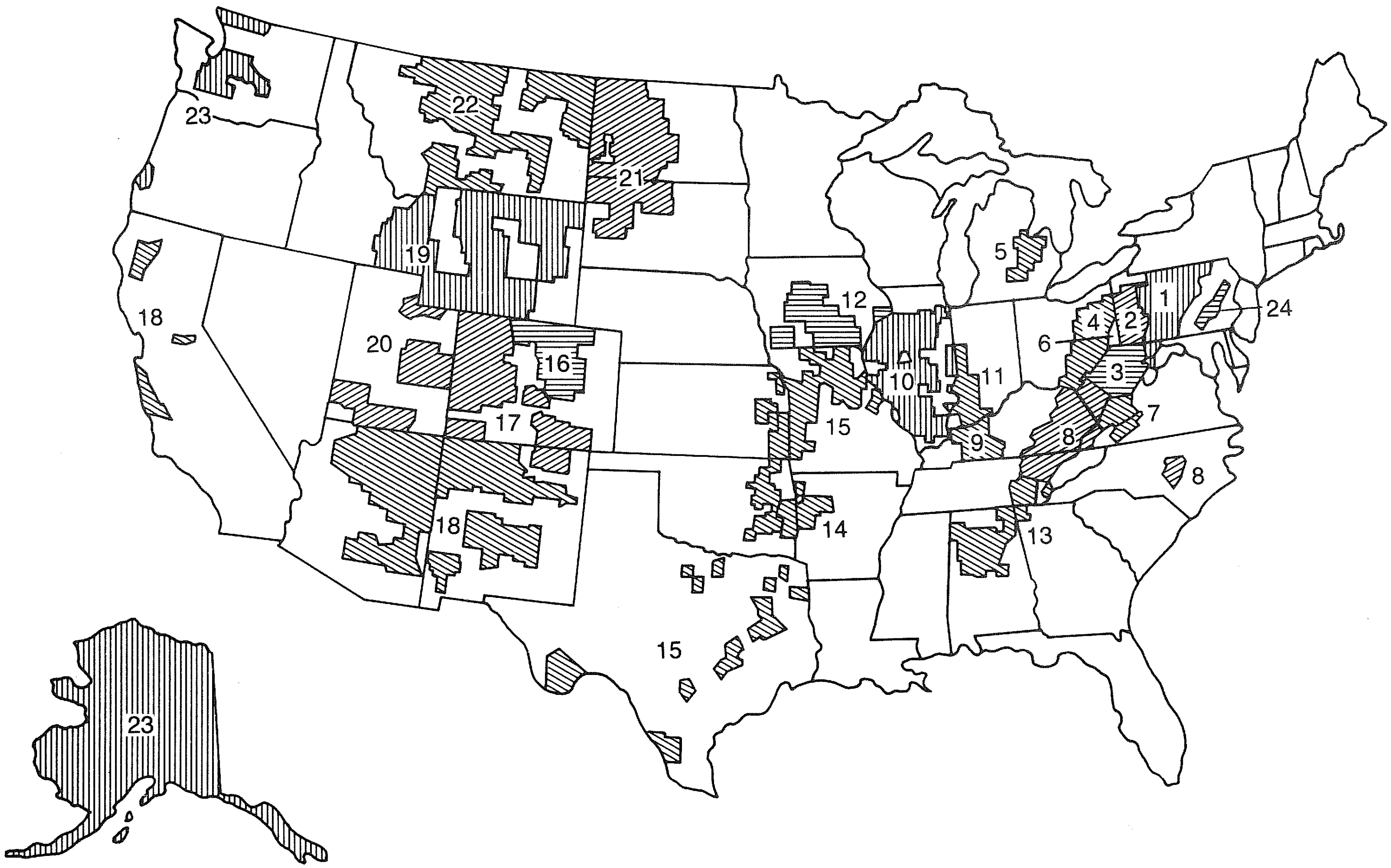

Figure 3 Districts in the U.S. that produce bituminous and subbituminous coal and lignite.

Table 5. Western coals[1] (by district) sold to utility markets of Illinois Basin coal, 1975 and 1985 (million tons)

From / To	District 16		District 17		District 19		District 20		District 22		Total	
	1975	1985	1975	1985	1975	1985	1975	1985	1975	1985	1975	1985
Alabama	--	--	--	--	--	--	--	--	--	--	--	--
Arkansas	--	--	--	--	--	11.861	--	--	--	--	--	11.861
Florida	--	--	--	--	--	--	0.031	--	--	--	0.031	--
Georgia	--	--	--	--	--	--	--	--	--	--	--	--
Illinois	--	0.347[2]	0.014	--	2.054	7.839	0.121	--	9.466	3.258	11.655	11.440
Indiana	--	0.573[2]	0.002	--	2.987	4.047	0.131	--	0.420	1.286	3.540	5.906
Iowa	--	--	0.160	--	1.870	9.578	--	--	0.285	--	2.315	9.578
Kansas	--	--	--	--	1.254	12.123	--	--	--	--	1.254	12.123
Kentucky	--	--	--	--	--	--	--	--	0.170	--	0.170	--
Michigan	--	--	0.031	--	--	--	0.180	--	1.030	6.541	1.241	6.541
Minnesota	--	--	0.101	--	0.043	0.274	--	--	6.144	10.268	6.288	10.542
Mississippi	--	1.182[2]	--	--	--	--	--	--	--	--	--	1.182
Missouri	--	--	--	--	1.005	3.580	--	--	--	--	1.005	3.580
Ohio	--	--	0.063	--	0.927	--	0.412	--	--	--	1.402	--
Pennsylvania	--	--	0.005	--	--	--	--	--	--	--	0.005	--
Tennessee	--	--	--	--	--	--	--	--	--	--	--	--
Wisconsin	--	--	--	--	1.103	7.201	--	--	2.464	2.286	3.567	9.487
Total	--	2.102[2]	0.376	--	11.243	56.503	0.875	--	19.979	23.639	32.473	82.244

[1] Excluding North and South Dakota lignite (District 21).

[2] Includes District 17.

Sources: Bituminous Coal and Lignite Distribution 1975, U.S. Dept. of the Interior, Bureau of Mines and Coal Distribution Jan-Dec 1985, DOE/EIA-0125(85/4Q).

Illinois, and Indiana. Western coal producers also captured the major new utility markets that developed when Arkansas and Kansas experienced economic growth and when utilities in those states switched to coal. Even in Missouri (a state in which Illinois Basin coal has been sold in increasing quantities in the last 10 years), western coal producers' share of the utility market increased from 5.6 percent in 1975 to 26 percent in 1985. Western coal producers' share of the Ohio market declined between 1975 and 1985, while their share of the Illinois market remained nearly unchanged.

Non-utility Markets

From 1975 through 1985, overall non-utility demand for Illinois Basin coal declined. Non-utility markets are divided into (1) coke and gas plants and (2) other industrial uses. Shipments of coal from Illinois to coke and gas plants declined and could not be completely offset by increases of shipments from Indiana or western Kentucky (table 6). The decline in demand for Illinois Basin coal used for coke-making was due to the economic conditions in the steel industry in the Chicago area. (The entire U.S. steel industry has lost markets to lower priced steel imported from Europe and Asia.)

The sales of Illinois Basin coal (about 12 million tons) for other industrial uses remained virtually unchanged in this time period. Decreased shipments from Illinois were offset by equivalent increases in shipments from Indiana and western Kentucky. Illinois coal was displaced by Indiana and western Kentucky coals in certain border areas, such as Vermilion and Massac counties, as well as areas in western Illinois where barge access may have reduced transportation costs.

Table 6. Shipments of Illinois Basin coal to non-utility markets (million tons), 1975 and 1985

	By state of origin						Total	
	Illinois		Indiana		Western Kentucky		Illinois Basin	
Kind of shipment	1975	1985	1975	1985	1975	1985	1975	1985
Coke and gas plants	4.27	2.01	--	--	--	--	4.29	2.01
Other industries	6.45	4.16	3.45	5.64	2.12	2.27	12.02	12.07
Total	10.72	6.17	3.45	5.64	2.12	2.27	16.29	14.08

Sources: Bituminous Coal and Lignite Distribution 1975, U.S. Dept. of the Interior, Bureau of Mines and Coal Distribution Jan-Dec 1985, DOE/EIA-0125(85/4Q).

Cost Competitiveness

Western coal has successfully captured large portions of the growing U.S. coal demand, even though modifications in clean air legislation have made SO_2 pollution less of an issue. In 1984, Illinois Basin coal prices at the mine were on average lower than in the Appalachian states but higher than in the western states (table 7). Since average mine labor productivity in the western states also was much higher, the western states are likely to continue to hold a price advantage over Illinois Basin coal at the mines.

On the basis of delivered price, Illinois Basin coals do not compare favorably with competitors in many states of the market area (table 8). Low-sulfur coals from eastern Kentucky and the western states, as well as imports from South Africa and Colombia, are delivered at competitive or lower prices than Illinois Basin coals. The price competition is intense everywhere except in Illinois and Indiana, and even there the situation could become even worse if attempts to decrease pollution are intensified as they would be under proposed acid rain legislation.

The delivered price of coal includes the transportation cost. In 1985 about 50 percent of Illinois Basin coal was transported by rail and 30 percent by barge. In comparison, most western coal coming into the Illinois Basin market area was carried by rail or by a combination of rail and barge. A comparison of 1985 rail freight rates as a function of distance is presented in figure 4. (Barge transportation costs are not available, but we know they are generally lower than rail costs.) The variations in rates are due to contract specifications such as the annual tonnage, the contract duration, the car ownership, and the size of each shipment (i.e., single car, whole train, unit train). In many market areas the western coal producers, especially those from Wyoming and Montana, are able to absorb the high cost of transportation over long distance and compete successfully with the Illinois Basin coal because their mining costs are low and because transportation costs do not increase proportionately with transportation distance. As figure 4 indicates, the freight rate does not increase proportionally to the distance. The cost per ton per mile generally declines as the distance increases.

In order to be able to regain their market position, the producers of Illinois Basin coal must solve two major problems:

- Ways must be found to improve mine productivity and lower the cost of mining.
- Better methods of cleaning coal must be developed.

  Because the margin of possible quality improvement from conventional coal cleaning is smaller for Illinois Basin coal than for coals from elsewhere in the country, we must find better ways to lower the sulfur content of the deliv-

Table 7. FOB mine price and labor productivity for major coal-producing states, 1984

Market state	Mine Price ($/ton)	Labor Productivity (ton/person/hour)
Illinois	24.98	2.22
Indiana	25.32	2.93
West Kentucky	26.81	2.61
West Virginia	34.18	1.88
East Kentucky	28.61	2.13
Pennsylvania	33.48	1.67
Virginia	31.17	1.61
Ohio	33.17	2.01
Wyoming	11.89	13.77
Montana	13.57	14.27
Colorado	23.07	3.24

Source: Coal Production 1984, DOE/EIA-0118(84) p. 30 and p. 48

Table 8. Average delivered cost of coal supplied to electric utilities, 1985 (¢/10^6 Btu)

	State of Origin								Imports	
State of Destination	IL	IN	WKY	EKY	MT	WY	CO	UT	South Africa	Colombia
Alabama	151	--	136	157	--	--	--	--	--	--
Arkansas	--	--	--	--	--	158	--	--	--	--
Florida	215	--	187	216	--	--	--	--	255	219
Georgia	165	169	--	182	--	--	--	--	--	--
Illinois	164	173	--	195	278	336	--	--	--	--
Indiana	165	139	--	110	270	286	--	--	--	--
Iowa	159	115	--	--	--	145	--	--	--	--
Kansas	248	--	--	--	--	137	--	--	--	--
Kentucky	140	140	130	156	--	--	--	--	--	--
Michigan	--	192	160	192	188	--	--	--	--	--
Minnesota	213	149	--	--	140	152	--	--	--	--
Mississippi	186	--	185	157	--	--	320	330	--	--
Missouri	157	146	--	146	--	119	--	--	--	--
Tennessee	128	154	159	164	--	--	--	--	--	--
Wisconsin	177	176	144	--	188	--	--	--	--	--

Source: Cost and Quality of Fuels for Electric Utility Plants 1985, DOE/EIA-0191(1985), table 48, p. 69-72.

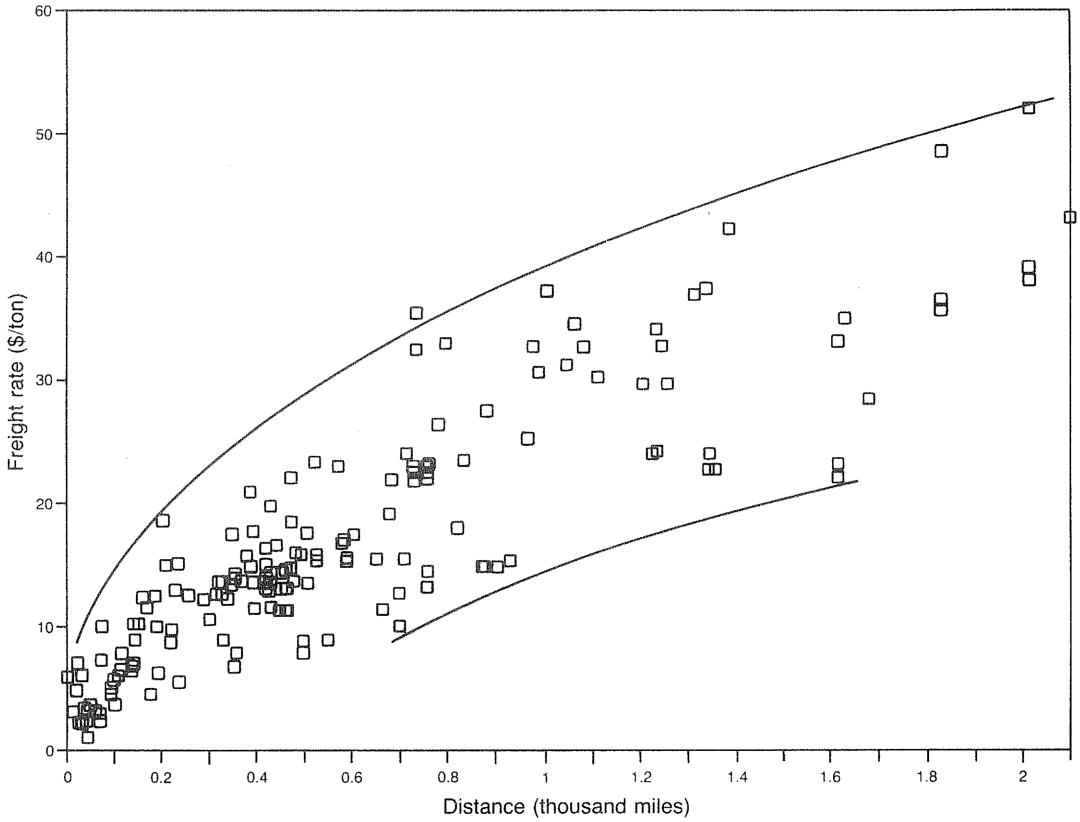

Figure 4 1985 railroad freight rates for coal (source: Coal Week, 1985).

ered coal. About 90 percent of Illinois Basin coal is currently cleaned before shipment, therefore, improvements in coal quality must come from better coal cleaning technologies. Such improvements in technology have been slow in coming, however, partly because of the development costs involved and partly due to the incentives given to the development of post-combustion cleaning of flue gases by clean air regulations. In contrast, western coals do not need much cleaning because of their low sulfur contents. Currently, only about 5 percent of western coals and about 40 percent of the Appalachian region coal production are cleaned prior to shipment.

Conclusions from 1975-1985 Market Analysis

The fact that at least half of the western coal delivered into the Illinois market area in 1985 was burned by electric utilities in plants that did not exist or did not burn coal in 1975 is indicative of the serious problem facing Illinois Basin coal. Until now the main problem with Illinois Basin coal seemed to be its high sulfur content and, at least in the traditional market areas, the delivered cost of Illinois Basin coal was considered to be competitive. As a result, it was safe to assume that newly constructed electric utilities with mandatory FGD equipment would elect to burn the lower cost Illinois Basin coal over the low-sulfur, higher priced western coals. Developments of the past 10 years and especially of the 1981-85 period indicate, however, that western coals have successfully captured newly developing coal markets as close to the Illinois Basin as Arkansas, thereby proving wrong the assumption that the RNSPS would significantly increase sales of Illinois Basin coal. A review of coal-burning electric utilities that started operation in the Illinois Basin market area from 1981 through 1985 (table 9) indicates that Illinois Basin coal represents only 32 percent of this 22,000 MW capacity, while low-sulfur coals from eastern and western states account for the remainder of this capacity. Despite favorable environmental conditions, a majority of the new plants opted for other than Illinois Basin coal. It cannot be assumed without reservations that in the future Illinois Basin coal will be in a strong position to capture newly developing demand in its market area.

MARKETS FOR ILLINOIS BASIN COAL, 1994 AND BEYOND

In the future, markets for Illinois Basin coal will continue to be affected by the same factors affecting markets from 1975 through 1985--environmental regulations and cost competitiveness--with the added burden of possibly even more stringent clean air legislation being enacted. Illinois Basin coal markets for 1994 and beyond are examined under two scenarios: (1) continued application of RNSPS and SIPs and (2) enactment of acid rain legislation requiring further SO_2 reductions.

Scenario 1: Continued Application of Current Regulations

Under the RNSPS, plants capable of producing 73 MW of electricity that have been built since September 1978 are required to reduce SO_2 emissions potential by 70 to 90 percent and, thus, are virtually forced to have an FGD system installed. Plants built prior to 1971 are regulated under the SIPs and are not required to limit their emissions severely enough to require FGD installations. Newer, larger plants will, therefore, be a primary area of expansion for Illinois Basin coal producers.

The USEPA has also released pollution standards for new industrial, commercial, and institutional steam generating units with greater than 29 MW capacity and less than 73 MW capacity (2). These standards require intermediate-size plants to achieve a 90 percent reduction in SO_2 emissions and to meet the limit of 1.2 lbs $SO_2/10^6$ Btu heat input when using conventional FGD systems.

Table 9. Coal-burning electric utilities that started operation from 1981-1985 in Illinois Basin market states

State	Company and Plant Name	Installed Capacity (MW)	Year Started	Origin of Coal	Sulfur Content (%)
Alabama	Alabama Power				
	James H. Miller	706	1985	Alabama	0.57
Arkansas	Arkansas Power				
	Independence	800	1982	Wyoming	0.22
		800	1984	Wyoming	0.22
	White Bluff	800	1981	Wyoming	0.45
Florida	Florida Power				
	Crystal River	740	1982	Kentucky	0.79
		740	1984	Virginia	0.68
				West Virginia	0.68
				Imports	0.64
	Gainesville (City of)				
	Deerhaven	251	1981	Kentucky	0.65
				West Virginia	0.72
	Lakeland (City of)				
	C.D. McIntosh, Jr.	334	1982	Kentucky	1.51
	*Seminole Electric Coop				
	Seminole	620	1983	Kentucky	3.04
		620	1984	Illinois	2.65
	*Tampa Electric Co.				
	Big Bend	486	1984	Illinois	3.00
				Kentucky	2.30
Georgia	Georgia Power				
	Scherer	891	1981	Kentucky	0.68
		891	1983	Virginia	0.70
Illinois	*Central Illinois Power Co.				
	Newton	617	1982	West Virginia	0.67
				Illinois	2.60
				Indiana	0.60
Indiana	*Hoosier Energy REC Inc.				
	Merom 1,2	490	1983	Illinois	3.00
		490	1982	Indiana	3.20
	Indiana and Michigan El Co.				
	Rockport (project 2601)	1300	1984	Wyoming	0.36
	*Indianapolis Power & Light				
	Petersburgh 4	574	1985	Indiana	2.20
	*Northern IN Public Serv.				
	R.M.Schahfer 17,18	848	82/85	Illinois (42%)	3.00
				Colorado (33%)	0.49
				Wyoming (25%)	0.50
	*Public Service Co. of IN				
	Gibson 5	668	1982	Illinois	2.40
				Indiana	2.40
Iowa	City of Ames 8	71	1981	Iowa	1.24
				Wyoming	0.42
	Iowa Southern Utility Co				
	Ottumwa 1	726	1981	Wyoming	0.38
	*City of Muscatine				
	Muscatine 9	160	1982	Illinois	2.90

Table 9 continued

State	Company and Plant Name	Installed Capacity (MW)	Year Started	Origin of Coal	Sulfur Content (%)
Kansas	Kansas City				
	Nearman Creek 1	262	1981	Wyoming	0.33
	Kansas Power & Light				
	Jeffrey Energy Center 3	720	1983	Wyoming	0.34
	Sunflower Electric Coop				
	Holobomb	319	1983	Wyoming	0.47
Kentucky	*Big River Electric Coop				
	D.B. Wilson 1	501	1984	Kentucky	4.00
	*Kentucky Utilities				
	Ghent 3, 4	1,113	81/84	Indiana (50%)	3.10
				Kentucky (50%)	0.75
	*Louiville Gas & Electric				
	Mill Creek 4	544	1982	Kentucky	3.26
Michigan	Detroit Edison				
	Belle River ST1, ST2	698	1984	Montana	0.36
		698	1985		
	*Grand Haven City 3	65	1983	Indiana	1.9
				Kentucky	2.9
	Marquette City				
	Shiras 3	44	1982	Kentucky	0.97
				Montana	0.50
	Michigan South Central Pwr.Agy.				
	Litchfield 1	55	1982	Ohio	3.0
Mississippi	Mississippi Power				
	Victor Daniel Jr. 2	500	1981	Colorado	0.5
				Utah	0.5
	Associated Electric Coop				
	Thomas Hill 3	670	1982	Missouri	4.2
Missouri	*Sikeston (City of)				
	Sikeston 1	235	1981	Illinois	2.5
Ohio	Dayton Power & Light				
	Killen Station 2	666	1982	Kentucky	0.6
				West Virginia	0.6
Wisconsin	*Wisconsin Power & Light				
	Edgewater 5	380	1984	Illinois (45%)	3.3
				Wyoming (55%)	0.3
Total		22,093			
*Total burning Illinois Basin Coal		7,153	(32%)		

Sources: Inventory of Power Plants in the United States, DOE/EIA-0095(85), U.S. Department of Energy (Table 15, p. 34-229 for plant starting date, capacity and fuel type) and Cost and Quality of Fuels for Electric Utility Plants 1985, DOE/EIA-0191(85), U.S. Department of Energy (Table 49, p. 73-114 for origin of coal and sulfur content).

Plants using an emerging SO_2 control technology are required to achieve a 50 percent reduction in emission potential and to meet the limit of 0.6 lbs $SO_2/10^6$ Btu heat input. The 90 percent reduction is similar to the RNSPS and therefore seems to favor the use of high-sulfur coal--provided it is priced lower than low-sulfur coal. The 50 percent reduction, applicable when an emerging SO_2 technology is used, may favor the use of lower sulfur coals and thus not help future markets for Illinois Basin coals.

A 1985 survey by the National Coal Association indicated that by 1994 about 18,500 MW of new coal-burning, electric-generating capacity may be added in the Illinois Basin coal market area as shown in table 10. About 30 percent of this new generating capacity will be added in states where Illinois Basin's market share is already less than 4 percent, namely, Arkansas, Kansas, Michigan, Minnesota, Ohio, and Pennsylvania.

Of the future planned capacity in the Illinois Basin market area, information about planned installation of FGD-systems is available on a total of 8,312 MW. An estimated additional 2,000-MW FGD capacity is likely to be added, but neither the source of coal nor its sulfur contents have been declared (3). Table 11 gives the breakdown of planned scrubber capacities. (It should be noted that table 11 data are not comparable to table 10 data because no time span for planned FGD is given.) The states listed in table 11 are major consumers of Illinois Basin coal and, therefore, are a significant indicator of future FGD deployment and of future prospects for Illinois Basin coal. (It is also significant to note that no FGD systems are planned in such Illinois Basin market states as Missouri and Tennessee.) Illinois Basin coal producers are thus assured of a 3,366-MW market in Indiana and western Kentucky and an estimated 50 to 75 percent of the Florida potential or 1,420 to 2,134 MW, for a maximum of 5,500 MW. Illinois Basin coal producers share of the Florida market has sharply declined in the past decade and competition from low-sulfur Appalachian and imported coal is rising in that state. Neither Ohio, with its locally available high-sulfur coals nor eastern Kentucky with its locally available low-sulfur coal are prospective markets for Illinois Basin coal. Arkansas utility plants use cheaper, western coals and are not a viable market for Illinois Basin coal.

At current rates of capacity utilization a demand of 1,300 tons of coal per 1-MW capacity per year will be generated, adding about 7 million tons to the demand for Illinois Basin coal in 1994. Extrapolating the 1994 estimate for the year 2000, about 12 million tons per year of additional sales will be generated, compared to 1985. Assuming non-utility Illinois Basin coal demand remains at its current level of 14 million tons per year, the total demand for Illinois Basin coal in 1994 is estimated to be 138 million tons (about 143 million tons in the year 2000). Given their current production proportions, Illinois, Indiana, and western Kentucky's shares of total basin demand for the years 1994 and 2000 will be:

	1994	2000
	(million tons per year)	
Illinois	62	65
Indiana	36	37
Western Kentucky	40	41
TOTAL	138	143

These projections of future demand for Illinois Basin coal indicate that coal mining in the Illinois Basin will continue to stagnate until 1994 and beyond if current clean air regulations remain the only applicable sets of regulations and no progress is made with regard to Illinois Basin coal's price competitiveness.

Scenario 2: Acid Rain Legislation Requiring Further SO_2 Reduction

Acid rain legislation introduced in 1986 would have required that SO_2 emissions be below 2.0 lbs/10^6 Btu by 1993 and below 1.2 lbs/10^6 Btu by 1997 (on a monthly state-by-state average basis).

Table 10. New coal-burning electric capacity expected to come on line by 1994 in Illinois Basin market states

State	MW	State	MW
Alabama	1,998	Michigan	655
Arkansas	836	Minnesota	851
Florida	1,986	Mississippi	--
Georgia	1,616	Missouri	1,425
Illinois	--	Ohio	1,300
Indiana	2,409	Pennsylvania	1,350
Iowa	650	Tennessee	--
Kansas	680	Wisconsin	972
Kentucky	1,745		
Total new capacity:	18,473 MW		

Source: Steam Electric Plant Factors 1985, National Coal Association, Washington, DC., table 16c.

Table 11. FGD capacities and sulfur contents of coal in utility plants planned in the Illinois Basin coal market states

State	Capacity (MW)	Sulfur (%)
Ohio	1,386	3.5
	500	unknown
Indiana	1,950	3.5
Kentucky - West	1,416	3.5
- East	1,000	unknown
Iowa	720	0.4
Florida	2,840	unknown
Arkansas	500	unknown
Total	10,312	

Source: Steam Electric Plant Factors 1985, National Coal Association, Washington, DC., table 16c.

These reductions would have to come from utilities built prior to 1971, that is, those presently regulated by the SIPs. This acid rain bill permitted the SIPs to be flexible in terms of fuel mix and technology choice and suggested means of financing the cuts. The targeted SO_2 emission reductions are listed by state in table 12. In 1980 the total SO_2 emissions from utilities in the United States was about 17.3 million tons, of which 13.2 million tons (76%) came from the 17-state Illinois Basin coal market area. The 1986 bill would have required that by 1993 SO_2 pollution be lowered nationwide to 5.7 million tons below 1980 levels. By 1997, SO_2 pollution would have to have been lowered to 10.0 million tons below 1980 levels. By 1993, about 5.2 million tons (90%) of the reduction would have to come from the Illinois Basin coal market area; by 1997 about 8.6 million tons (85%) of the reductions would have been from the Illinois Basin coal market area. Since the newly built plants will be subject to the 1.2 lbs $SO_2/10^6$ Btu limit, all the reductions from the 1980 levels must come from already existing sources of pollution, about 75 percent of which may, on an average, have to be from the utilities.

Illinois Basin coal will suffer a potentially substantial loss of markets if acid rain legislation is passed because many utilities are expected to switch to fuels containing lower amounts of sulfur. How many utilities will switch fuels depends upon an individual plant's economic situation. The cost of retrofitting with and operation of FGD systems will have to be compared to the additional cost of burning low-sulfur fuels. An additional consideration is the age of the plant. In general, the older the plant the greater the chances that switching to a lower sulfur fuel may be more beneficial than retrofitting with FGD. Older plants also experience more outages for repairs (fig. 5). Refurbishing the older plants can reduce outages but if the cost of refurbishment exceeds 50 percent of the cost of building a new plant an older plant may be classified as a new plant and subject to RNSPS. The plant would then be required to install an FGD system. How old a plant needs to be before fuel switching is economical is a matter of research and no definite answer to the question can be offered at this time. In this report it has been assumed that utility plants 20 or more years old may be the prime candidates for fuel switching.

In 1985, about 30 percent of the U.S. electric-generating capacity was more than 20 years old (fig. 6). By 1995, this percentage is expected to increase to 60. Thus it is assumed that about 30 percent (35 million tons) of current Illinois Basin coal sales may be affected by 1994 and about 60 percent (70 million tons) by the year 2000. The ability of Illinois Basin states to increase their production of lower sulfur coals is expected to be limited.

Table 12. Sulfur dioxide reduction targets as per proposed 1986 acid rain bill

	SO_2 emissions baseline (10^3 tons/yr)		Reductions (2.0 lbs/MBtu)			Reductions (1.2 lbs/MBtu)		
STATE	1980 Total	1980 Utility	10^3 tons/yr	% of Total	% of Utility	10^3 tons/yr	% of Total	% of Utility
*Alabama	759	543	118	16	22	307	40	57
*Arkansas	900	88	0	0	0	0	0	0
Alaska	102	27	10	9	36	10	9	36
California	446	78	0	0	0	0	0	0
Colorado	132	78	0	0	0	0	0	0
Connecticut	72	32	0	0	1	0	0	1
Delaware	109	53	23	21	44	23	21	44
D. Columbia	15	5	0	0	0	0	0	0
*Florida	1,095	726	1	0	0	299	27	41
*Georgia	840	737	279	33	38	480	57	65
Idaho	47	0	0	0	0	0	0	0
*Illinois	1,471	1,126	375	26	33	709	48	63
*Indiana	2,008	1,540	880	44	57	1,173	58	76
*Iowa	329	231	42	13	18	126	38	55
*Kansas	223	150	23	10	15	23	10	15
*Kentucky	1,121	1,008	504	45	50	726	65	72
Louisiana	304	25	0	0	0	0	0	0
Maine	95	16	0	0	0	1	1	6
Maryland	338	223	32	9	14	117	35	52
Massachusetts	344	276	57	16	21	120	35	44
*Michigan	907	565	3	0	0	251	28	44
*Minnesota	260	177	0	0	0	59	23	33
*Mississippi	285	129	0	0	0	30	10	23
*Missouri	1,301	1,141	684	53	60	887	68	78
Montana	164	23	0	0	0	0	0	0
Nebraska	75	49	0	0	0	0	0	0
Nevada	243	40	0	0	0	0	0	0
New Hampshire	93	81	31	33	38	52	56	65
New Jersey	279	110	0	0	0	0	0	0
New Mexico	269	85	19	7	22	19	7	22
New York	944	480	5	1	1	137	15	29
North Carolina	602	435	0	0	0	139	23	32
North Dakota	107	83	0	0	0	14	13	17
*Ohio	2,647	2,172	1,143	43	53	1,600	60	74
Oklahoma	121	38	0	0	0	0	0	0
Oregon	60	3	0	0	0	0	0	0
*Pennsylvania	2,022	1,466	411	20	28	880	44	60
Rhode Island	15	5	0	0	0	0	0	0
South Carolina	326	213	11	3	5	101	31	47
South Dakota	39	29	0	0	0	12	29	40
*Tennessee	1,077	934	479	45	51	681	63	73
Texas	1,277	303	0	0	0	0	0	0
Utah	72	23	0	0	0	0	0	0
Vermont	7	1	0	0	0	0	1	17
Virginia	361	164	4	1	3	45	12	27
Washington	272	69	27	10	39	29	10	41
West Virginia	1,088	944	315	29	33	594	55	63
*Wisconsin	637	486	229	36	47	343	54	71
Wyoming	184	121	50	27	41	50	27	41
US Total**	26,480	17,325	5,753	22	33	10,035.5	38	58

* Illinois Basin coal market area.

** Excluding Arizona and Hawaii.

Source: Coal Week, April 14, 1986, p. 7.

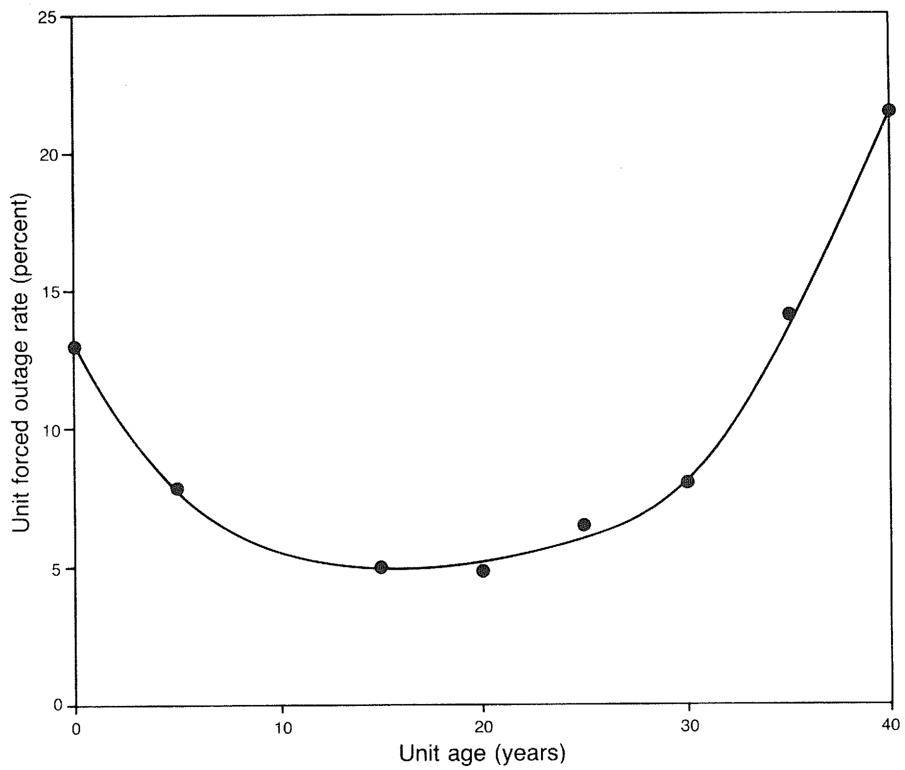

Figure 5 Forced outage rate of coal-fired steam units (source: Annual Outlook for U.S. Electric Power 1986, DOE/EIA-0474(86) p. 27).

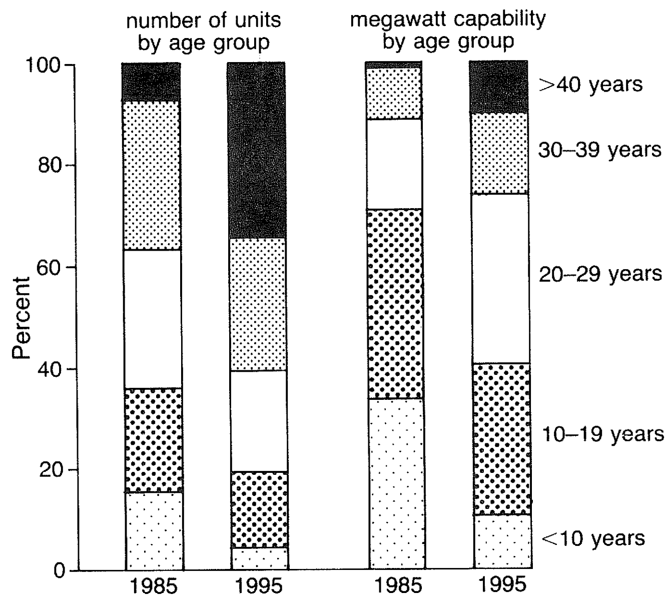

Figure 6 Age and megawatt capability of coal-fired steam units (source: Annual Outlook for U.S. Electric Power 1986, DOE/EIA-0474(86) p. 26).

Tables 13 and 14 contain data on Btu/lb and sulfur contents of coal delivered to electric utilities from the Illinois Basin states in 1975 and 1984, respectively. Although the sulfur content of Illinois Basin coal has been lowered, the improvement is marginal, which means the percentage of compliance-quality coal is low. By comparison, the sulfur content of coal delivered from West Virginia and Kentucky declined significantly from 1975 through 1984. In 1975, about 19 percent of Kentucky coal and about 25 percent of West Virginia coal shipped to utilities contained low enough sulfur to satisfy the 2.0 lbs/10^6 Btu emission limits prescribed by many SIPs and targeted by the acid rain proposals for 1993. In 1984, the percentage of these compliance coals had risen to 41 in Kentucky and 44 in West Virginia. Some of this qualitative improvement was due to better coal cleaning but most of it was due to the ability of these states to shift coal production to areas with compliance-quality coal deposits. Although some shift to medium-sulfur coal is apparent in Indiana, compliance-quality coal reserves in the Illinois Basin are scarce. Therefore, a major change in production of compliance-quality coal appears unlikely--unless significant new low-sulfur deposits are discovered in the near future. Thus the estimates of the percentage of Illinois Basin coal expected to be affected by the proposed acid rain legislation seem plausible.

A worst case scenario for sales of Illinois Basin coal is developed in table 15. This scenario does not account for technological changes that may occur in the future that would allow increased sales of high-sulfur coals. Also unaccounted for are productivity changes in mines and changes in transportation costs that could affect the competititve situation of Illinois Basin coal.

As table 15 indicates, if acid rain legislation is enacted the potential impact of decreased production of Illinois Basin coal on employment could be serious. About 25,000 persons were employed in the coal mines of the Illinois Basin in 1985. They produced about 131 million tons of coal. Increasing coal mining productivity is expected to reduce the number of persons employed in coal mining in the future, even without decreased production. Up to 5,400 jobs could be jeopardized by the year 1994 due to potential production losses. A total of 11,000 jobs could be jeopardized by the year 2000.

In a best-case scenario, all 24 million tons of new annual coal demand expected to be created in the Illinois Basin market area (as a result of the projected addition of 18,500 MW generating capacity by 1994) would indeed come from the Illinois Basin. For a best-case analysis, we would also have to assume that no market

Table 13. Btu/lb and percentage sulfur of Illinois Basin coal received by utilities, 1975

State of Destination	Illinois Btu/lb	Illinois S(%)	Indiana Btu/lb	Indiana S(%)	West Kentucky Btu/lb	West Kentucky S(%)
Alabama	11,735	3.1	10,500	4.7	11,271	3.8
Arkansas	--	-	--	-	--	-
Florida	11,780	3.0	12,783	2.3	11,397	2.9
Georgia	10,900	3.4	11,371	3.6	11,669	2.6
Illinois	10,395	3.3	11,036	2.5	11,047	3.0
Indiana	10,405	2.7	10,750	3.1	10,919	3.6
Iowa	10,615	2.7	10,016	0.6	10,506	3.4
Kansas	--	-	--	-	--	-
Kentucky	10,464	2.8	10,831	3.3	10,555	4.0
Michigan	11,897	2.5	11,204	3.6	11,878	3.3
Minnesota	10,902	3.0	--	-	11,172	4.2
Mississippi	11,682	2.8	--	-	11,451	2.9
Missouri	11,022	3.1	11,371	3.4	11,349	2.7
Ohio	--	-	10,827	3.3	10,941	3.0
Pennsylvania	--	-	--	-	--	-
Tennessee	10,856	3.3	11,209	3.6	10,918	3.8
Wisconsin	11,133	2.7	11,353	3.6	11,096	3.5

(State of Origin)

Source: Annual Summary of Cost and Quality of Steam-Electric Plant Fuels 1975. With supplements on the origin of coal, annual, May 1976. Staff report by the Bureau of Power, Federal Power Commission, Table IV, p. 43-49.

Table 14. Btu/lb and percentage sulfur of Illinois Basin coal received by utilities, 1984

State of Destination	Illinois Btu/lb	Illinois S(%)	Indiana Btu/lb	Indiana S(%)	West Kentucky Btu/lb	West Kentucky S(%)
Alabama	11,885	1.6	10,786	3.3	11,448	3.2
Arkansas	--	-	--	-	--	-
Florida	11,743	2.8	--	-	12,015	2.8
Georgia	11,369	2.5	11,265	2.7	11,657	2.9
Illinois	10,798	2.9	10,935	1.5	11,266	2.2
Indiana	10,773	2.7	10,890	2.6	11,457	3.3
Iowa	11,018	2.9	10,916	3.2	10,965	2.8
Kansas	11,360	2.6	--	-	--	-
Kentucky	--	-	11,072	2.5	11,041	3.5
Michigan	11,579	2.7	10,996	2.8	--	-
Minnesota	12,342	1.9	11,497	1.8	11,900	1.1
Mississippi	12,058	2.6	--	-	12,341	2.7
Missouri	11,144	2.4	10,987	1.3	11,445	3.4
Ohio	--	-	--	-	11,383	3.0
Pennsylvania	--	-	--	-	--	-
Tennessee	11,733	2.0	10,957	1.8	11,759	2.7
Wisconsin	11,063	2.8	11,215	2.3	11,766	2.9

(State of origin)

Source: Cost and Quality of Fuels for Electric Utility Plants 1984, DOE/EIA-0191(84), Table 58, p. 67-71.

Table 15. Projected markets for Illinois Basin coal in 1994 and 2000 if acid rain legislation enacted (million tons)

	Utility				Industrial	Total
Year	1985 sales	New demand	Losses due to acid rain laws	Net utility		
1994	117	+ 7	-35	89	+14	103
2000	117	+12	-70	59	+14	73

losses would be suffered if acid rain legislation is enacted. Given these two assumptions, a comparable proportional increase in demand to the year 2000 would add a market potential of 18 million tons. This would mean that by the year 1994, total coal sales in the Illinois Basin would be 155 million tons. By the year 2000, total tonnage would be 173.

REFERENCES

(1) Energy Information Administration, 1983, Impacts of the proposed clean air act amendments of 1982 on the coal and electric utility industries, DOE/EIA-0407.

(2) Federal Register, June 19, 1986, p. 22384-22419.

(3) Steam Electric Plant Factors 1985, National Coal Association, table 16c, p. 147-149.