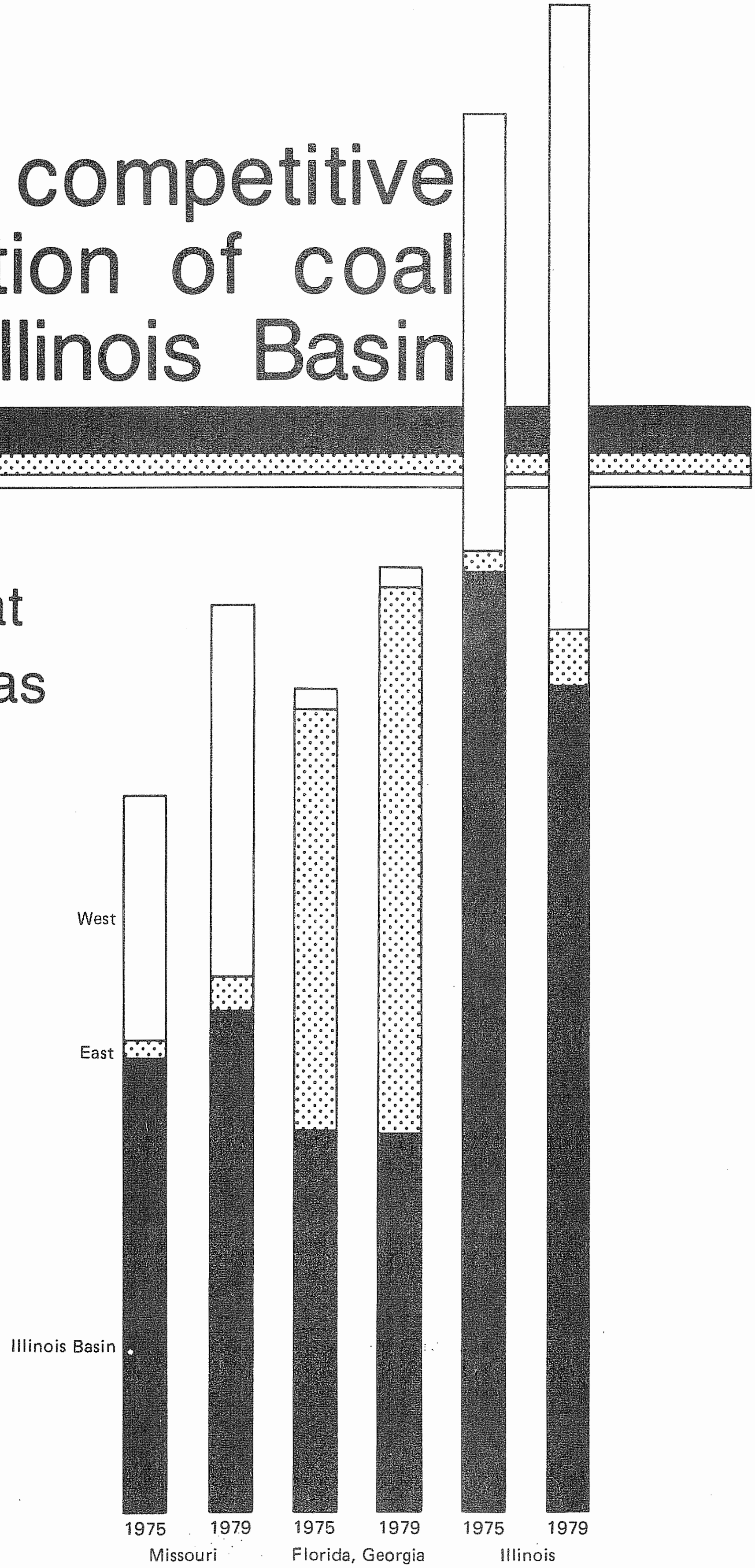
The future competitive position of coal from the Illinois Basin

Subhash Bhagwat
Theodore J. Collias



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ABSTRACT

Eight factors have been analyzed for their impact on the future competitive position of Illinois Basin coal. They are: demand for coal versus other fuels, competition from Eastern and Western coals in markets, environmental standards, coal beneficiation, flue-gas desulfurization, transportation of coal, taxation, and cost of coal production.

Despite increasing demand for coal and its cost advantage over other fuels, Illinois Basin coal has been losing markets to Eastern and Western coals. Environmental regulations such as the Clean Air Act have a significant impact in declining market conditions for Illinois Basin coal. Coal quality can be improved by beneficiation, and the additional cost of beneficiation is expected to be small enough to be offset by savings in the boiler plants. Contrary to the general expectations, however, mandatory installation of "scrubbers" may add to the difficulties for Illinois Basin coal because of the expected cost differential between scrubbing low and high sulfur coals. Deregulation of railroads could benefit Illinois Basin coal, inasmuch as transportation of Western coals would become more expensive. The presently moderate tax advantages of the Illinois Basin coal industry over the Western coals could be reduced because of a move to lower severance taxes in the West. The cost of coal production is greatly affected by government regulations and labor-management relations. Efforts by the legislature, management, and labor to increase mine productivity and ease the cost of compliance with environmental regulations could minimize the negative impact on competitiveness of Illinois Basin coal in the future.

INTRODUCTION

Coal production in the Illinois Basin has not increased during the 1970s despite rising energy prices and increasing demand worldwide for coal. Reasons for this state of affairs have included unfavorable federal and state regulations and other policy decisions. On the other hand, there are optimistic projections for Illinois Basin coal in some market areas such as the southeast and even in the export market. Actually, most factors cited to affect the future of Illinois Basin coal are applicable to coals throughout the United States. The reasons for differences in development of coals in the Illinois Basin as against in the rest of the nation must therefore be sought in the differential effect of the following eight factors:

- Demand for coal versus other fuels
- Competition from Eastern and Western coals in markets
- Environmental standards
- Coal beneficiation
- Flue-gas desulfurization
- Transportation of coal
- Taxation
- Cost of coal production

The cumulative effects of these factors, positive and negative, will determine the background on which the future of Illinois Basin coal must be judged. No quantitative projections are attempted as any developments will depend upon how the governments, the labor force, and the mine owners act to remedy the problems.

TABLE 1. Regional changes in coal consumption in the Illinois Basin coal market

	1975 Total (10^6 tons)	1975 Utilities (10^6 tons)	1975 Others (10^6 tons)	1979 Total (10^6 tons)	1979 Utilities (10^6 tons)	1979 Other (10^6 tons)
East North-Central	~202	144	59	216	160	56
East South-Central	85	71	14	87	72	15
West North-Central	37	32	5	52	47	5
South Atlantic	~ 21	20	0	25	24	1
Total	345	267	78	380	303	77

NOTE: Included in each region are data from only those states in which Illinois Basin coal is marketed. See text, page 3.
Source: William H. Dempsey, President and Chief Executive Officer, Association of American Railroads, Testimony before the Senate Commerce Committee, Feb. 22, 1980.

TABLE 2. Primary energy consumption by electric utilities in the 14-state market area

	1975 Coal (10^{12} Btu)	1975 Coal (%)	1975 Oil (10^{12} Btu)	1975 Oil (%)	1975 Gas (10^{12} Btu)	1975 Gas (%)	1979 Coal (10^{12} Btu)	1979 Coal (%)	1979 Oil (10^{12} Btu)	1979 Oil (%)	1979 Gas (10^{12} Btu)	1979 Gas (%)
East North-Central												
Illinois	653	(90.8)	44	(6.1)	22	(3.1)	774	(87.1)	91	(10.2)	24	(2.7)
Indiana	578	(94.1)	8	(1.3)	28	(4.6)	821	(99.2)	5	(0.6)	2	(0.2)
Michigan	490	(83.8)	85	(14.5)	10	(1.7)	569	(84.6)	88	(13.1)	16	(2.3)
Ohio	1,018	(98.8)	8	(0.8)	4	(0.4)	1,195	(98.6)	16	(1.3)	1	(0.1)
Wisconsin	207	(92.8)	3	(1.3)	13	(5.9)	285	(94.4)	3	(1.0)	14	(4.6)
Subtotal	2,946		148		77		3.644		203		57	
East South-Central												
Alabama	401	(98.3)	1	(0.2)	6	(1.5)	457	(97.9)	2	(0.4)	8	(1.7)
Kentucky	480	(99.8)	1	(0.2)	–	(0.0)	577	(99.6)	1	(0.2)	1	(0.2)
Mississippi	33	(28.4)	56	(48.3)	27	(23.3)	66	(36.3)	55	(30.2)	61	(33.5)
Tennessee	414	(100.0)	–	(0.0)	–	(0.0)	590	(99.8)	1	(0.2)	–	(0.0)
Subtotal	1,328		58		33		1,690		59		70	
West North-Central												
Iowa	98	(71.0)	1	(0.7)	39	(28.3)	233	(93.6)	8	(3.2)	8	(3.2)
Minnesota	133	(86.9)	5	(3.3)	15	(9.8)	234	(95.9)	4	(1.6)	6	(2.5)
Missouri	381	(94.5)	2	(0.5)	20	(5.0)	502	(94.9)	8	(1.5)	19	(3.6)
Subtotal	612		8		74		969		20		33	
South Atlantic												
Florida	133	(19.3)	423	(61.3)	134	(19.4)	193	(24.0)	455	(56.6)	156	(19.4)
Georgia	300	(82.2)	25	(6.8)	50	(11.0)	469	(96.3)	16	(3.3)	2	(0.4)
Subtotal	433		448		184		662		471		158	
TOTAL	5,319		662		368		6,965		753		318	

Source: Cost and Quality of Fuels for Electric Utility Plants: January, 1980, DOE/EIA-0075 (80/01); Steam Electric Plant Factors 1976: National Coal Association, Washington, DC.

DEMAND FOR COAL VERSUS OTHER FUELS

Illinois Basin coal has been sold primarily in 14 states. They include: the East North-Central states—Illinois, Indiana, Michigan, Ohio, and Wisconsin; the East South-Central states—Alabama, Kentucky, Mississippi, and Tennessee; the West North-Central states—Iowa, Minnesota, and Missouri; and the South Atlantic states—Georgia and Florida. In some of these states the demand for coal and for other fuels has significantly changed between 1975 and 1979 (table 1). Total coal demand (in tons) in the market area has grown an average 2.45 percent per year between 1975 and 1979. All the growth has been in the utility sector. However, no significant losses are registered in other sectors of coal use. In 1975 utilities accounted for about 77 percent of coal usage in the Illinois Basin market area; in 1979, about 80 percent. The tonnage consumed by utilities increased about 3.2 percent per year from 1975 to 1979.

Table 2 shows a significantly brighter picture for coal use in the area than tonnage figures in Table 1 indicate. In terms of energy content, coal consumption by utitilites in the 14 states increased 31 percent from 1975 to 1979, indicating an annual 7 percent increase. A comparison with table 1 indicates an increase in average Btu content of coal burned by utilities. Total gas consumption declined by about 9 percent but total oil consumption in electricity generation increased by almost 14 percent in four years. The largest increase (58 percent) in use of coal by utilities has been in the West North-Central states and in the South Atlantic states (53 percent), followed by the East South-Central states (27 percent), and East North-Central states (24 percent).

It is notable that in Illinois the use of coal by electric utilities has declined in relative terms from about 91 percent to about 87 percent of the total energy consumption, while the use of oil increased from 6 to 10 percent. Only Alabama and Kentucky also show a minor decline in relative use of coal. Florida, with about 76 percent of its electricity generation based on oil and gas, is likely to be the most rapidly expanding market for coal. The most significant conclusion from these observations is that hand-in-hand with a moderately expanding sale of coal is an improvement in the quality of coal used by the utilities (table 3). In all the 14 states, the average Btu/lb of coal used by utilities increased between about 1 and 5 percent.

Great changes have taken place in energy prices in the 14 states since 1975. Coal was not the cheapest fuel in Wisconsin, Kentucky, Iowa, Florida, and Georgia in 1975, and coal barely nosed out gas as the cheapest fuel in Mississippi, Missouri, and Minnesota. In 1979 in 13 of the 14 states coal was the cheapest fuel. Natural gas was the cheapest fuel in Florida (table 4).

Table 5 shows the economic advantage for coal use in the 14 states compared with the next most expensive fuel for the utilities. The advantage in 1979 ranged from a low 16 cents/10^6 Btu in Mississippi to a high 347 cents/10^6 Btu in Tennessee.

Competition from nuclear energy figured prominently in the 14 states during 1975 to 1979. Total installed capacity of nuclear electricity generation increased 9.1 percent annually (table 6). In the same period, the generating capacity from all sources increased only about 3.2 percent annually. The use of nuclear energy in the 14 states thus increased from 8 percent to 10 percent.

Nationwide statistics suggest that nuclear power stations had a greater utilization of capacity than fossil fuel units. In 1975 about 7.8 percent of the total installed capacity of electricity generation was nuclear, contributing 9 percent to the total electricity generation in the United States. In 1979 the 9.1 percent nuclear capacity generated 11.6 percent of the total electricity.

COMPETITION FROM EASTERN AND WESTERN COALS IN MARKETS

Utilities

From 1975 to 1979, competition from coal producers in Appalachia and in states west of the Mississippi caused a decrease in the consumption of Illinois Basin steam coal; in this four-year span, annual utility consumption of Illinois Basin coal declined about 11

TABLE 3. Average Btu/lb of coal used by utilities

	1975 (Btu/lb)	1978 (Btu/lb)	Percentage change
Alabama	11,583	11,987	+3.5
Florida	11,546	11,964	+3.6
Georgia	11,876	12,015	+1.2
Illinois	10,135	10,556	+4.2
Indiana	10,615	10,760	+1.4
Iowa	10,195	10,304	+1.1
Kentucky	10,741	11,235	+4.6
Michigan	11,834	11,954	+1.0
Minnesota	9,057	9,447	+4.3
Mississippi	11,628	12,201	+4.9
Missouri	10,754	10,932	+1.7
Ohio	10,960	11,422	+4.2
Tennessee	10,991	11,371	+3.5
Wisconsin	10,635	10,955	+3.0

Source: Steam Electric Plant Factors 1976 and 1979: National Coal Association, Washington, DC.

TABLE 4. Utility fuel prices

	1975					1978						1979		
	Coal ($/10^6 Btu)	(% S)	Oil ($/10^6 Btu)	(% S)	Gas ($/10^6 Btu)	Coal ($/10^6 Btu)	(% S)	Oil ($/10^6 Btu)	(% S)	Gas ($/10^6 Btu)		Coal ($/10^6 Btu)	Oil ($/10^6 Btu)	Gas ($/10^6 Btu)
East North-Central														
Illinois	0.76	(2.4)	1.56	(0.7)	1.13	1.25	(2.0)	2.64	(0.3)	2.86		1.48	3.98	2.77
Indiana	0.59	(2.8)	2.14	(0.2)	0.82	1.11	(2.5)	2.76	(0.3)	1.66		1.17	4.13	2.29
Michigan	0.92	(2.4)	2.09	(0.7)	1.28	1.29	(1.7)	2.72	(0.5)	1.97		1.47	3.33	2.38
Ohio	0.95	(3.0)	2.25	(0.9)	1.23	1.25	(2.7)	2.77	(0.4)	1.57		1.34	3.44	1.82
Wisconsin	0.86	(2.3)	1.85	(1.0)	0.79	1.04	(2.6)	2.56	(0.4)	1.97		1.28	3.12	2.29
East South-Central														
Alabama	0.92	(2.3)	2.25	(0.2)	1.08	1.33	(.17)	2.83	(0.2)	2.01		1.49	4.55	2.29
Kentucky	0.64	(3.3)	2.32	(0.1)	0.60	1.11	(2.3)	2.73	(0.1)	1.03		1.15	4.68	1.71
Mississippi	0.83	(2.7)	1.74	(1.9)	0.92	1.44	(1.7)	2.05	(1.6)	1.51		1.69	2.34	1.85
Tennessee	0.87	(2.9)	–	–	–	1.20	(2.4)	–	–	–		1.39	4.86	–
West North-Central														
Iowa	0.85	(2.0)	2.09	(0.4)	0.68	1.18	(2.2)	2.72	(0.3)	1.65		1.23	3.77	2.00
Minnesota	0.63	(1.4)	1.96	(1.8)	0.64	0.81	(1.2)	2.34	(1.0)	1.46		1.01	2.72	1.75
Missouri	0.54	(3.4)	1.92	(1.5)	0.59	1.00	(3.3)	2.56	(0.6)	1.14		1.06	3.76	1.53
South Atlantic														
Florida	1.01	(2.7)	1.86	(1.5)	0.73	1.47	(1.8)	2.01	(1.4)	1.04		1.63	3.04	1.31
Georgia	0.93	(1.8)	1.90	(1.6)	0.71	1.25	(1.6)	2.66	(0.6)	1.70		1.39	3.07	2.59

Sources: Steam Electric Plant Factors (1976, 1979): National Coal Association, Washington, DC.
Cost and Quality of Fuels for Electric Utility Plants, January 1980: DOE/EIA-0075 (80/01).

TABLE 5. Cost advantage of burning coal for electricity generation versus other fuels in 1979

	Cents/10^6 Btu	Percentage of coal price
East North-Central		
Illinois	129	87
Indiana	112	96
Michigan	91	62
Ohio	48	36
Wisconsin	101	79
East South-Central		
Alabama	80	54
Kentucky	56	49
Mississippi	16	9
Tennessee*	347	250
West North-Central		
Iowa	77	63
Minnesota	74	73
Missouri	47	44
South Atlantic		
Georgia	120	86
Florida**	-32	-20

* No gas used; price compared with oil.
** In Florida gas was cheaper in 1979 than coal by 32 cents/10^6 Btu; however, oil was more expensive by 141 cents/10^6 Btu.

TABLE 6. Nuclear electricity generation capacity in the 14-state market area

	1975		1979	
	(MW)	(%)	(MW)	(%)
Alabama	2,304	15.2	4,344	24.2
Florida	1,520	7.0	3,261	11.7
Georgia	850	6.5	1,700	10.5
Illinois	5,718	22.4	5,718	19.2
Indiana	–	–	–	–
Iowa	566	10.5	597	8.2
Kentucky	–	–	–	–
Michigan	1,976	10.4	3,157	14.3
Minnesota	1,755	25.8	1,755	21.5
Mississippi	–	–	–	–
Missouri	–	–	–	–
Ohio	–	–	962	3.7
Tennessee	–	–	–	–
Wisconsin	1,638	18.4	1,673	16.9
Total	16,327		23,167	

MW = megawatt.
Source: Inventory of Power Plants in the United States, December 1979: DOE/EIA-0095(79); Federal Power Commission (FPC) News: v. 10, no. 12, March 25, 1977.

million tons. The market share of Illinois Basin producers diminished in all the fourteen states in which Illinois Basin coal is consumed (fig. 1).

Several measures are useful in illustrating the nature and extent of shifts in the steam coal market between 1975 and 1979. First is the above-mentioned measure of changes in the market shares of the three major coal production regions (table 7). For each state, the change in tonnage associated with the percentage shift in Illinois Basin market shares is listed in row one of table 7. Had the market remained constant between 1975 and 1979, row one would represent the consumption change in each state that was attributable to the diminished or enhanced market share of the Illinois Basin production region. The coal market, however, grew in every state (table 7) except Alabama.

The effect of this growth on the tonnage of Illinois Basin coal consumed was mostly positive, as shown in row two of table 7. The growth effect, by state, is simply the difference between percentages of the 1975 and 1979 coal markets; for each state, a projection of Illinois Basin's market share (in tons) in 1979 (based on the 1975 coal market) was subtracted from actual 1979 consumption. These figures indicate how growth in the coal markets has helped Illinois Basin producers recoup some of their market share losses. In Indiana and Missouri, for example, the effect of growth in coal consumption in 1979 was to increase sales of Illinois Basin coal by 2.7 and 1.1 million tons, respectively; losses of 0.8 and 1.4 million tons associated with losses in market shares were offset by gains of 3.5 and 2.5 million tons associated with market growth.

Market share changes and observed growth effects do not, however, provide a complete measure of the effect market conditions from 1975 to 1979 had on the competitive position of the Illinois Basin coal production region. If constant market shares had been maintained from 1975 to 1979, growth in the market during this period would have resulted in an additional increase in consumption of Illinois Basin coal. A measure of this increase is provided in row four of table 7 by projecting 1975 market shares in the 1979 coal market and subtracting actual 1975 consumption. Adding the net consumption changes from 1975 to 1979 (row three) to row four, one can assess the total impact of competition from the east and west on the consumption of Illinois Basin coal (row 5).

Analysis shows that in all states except Tennessee, Kentucky, Florida, and Georgia, Western coal gained in share of market. Appalachian coal increased its market share in all states except Michigan and Ohio. The coal market in states served by Illinois Basin producers grew from about 267 million tons per year in 1975 to 303 million tons per year in 1979. Of this growth of 36 million ton per year, Illinois Basin producers supplied 11.5 million tons, or 32 percent of increased

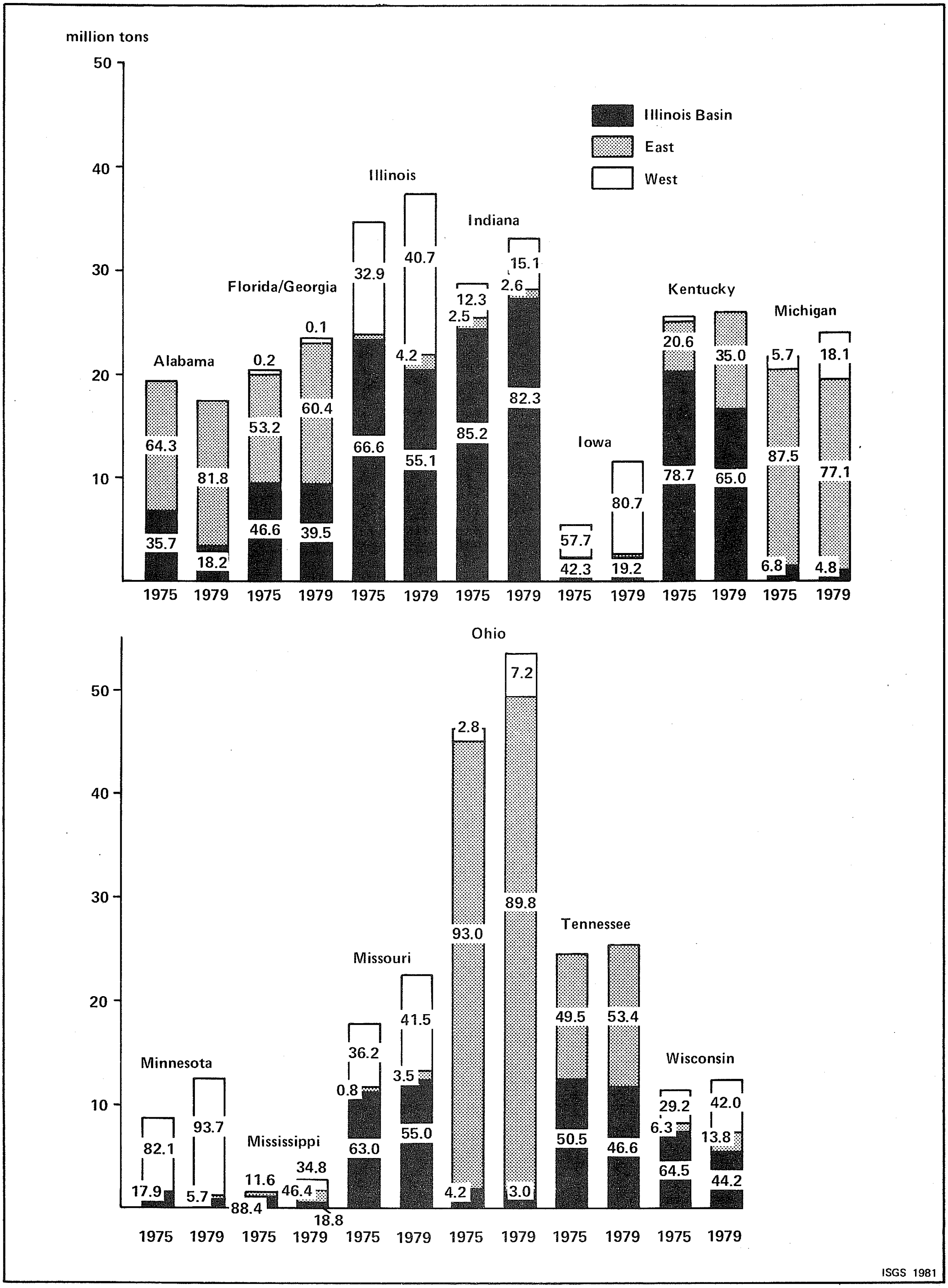

Figure 1. Market shares (%) of the major coal-producing areas in the 14-state Illinois Basin coal market, 1975 and 1979. (Source: Department of Energy, Bituminous and Subbituminous Coal and Lignite Distribution Reports, 1975 and 1979.)

TABLE 7. Change in shares of market of major coal producing regions in the United States. (Includes actual and potential production losses to Illinois Basin in 1975-1979.)

	Alabama	Florida and Georgia	Illinois	Indiana	Iowa	Kentucky	Michigan	Minnesota	Mississippi	Missouri	Ohio	Tennessee	Wisconsin	Total
Illinois Basin coal (%)	-17.50	-7.10	-11.50	-2.90	-23.10	-13.70	-2.00	-12.20	-69.60	-12.00	-1.20	-3.90	-20.30	
Eastern coal (%)	+17.50	+7.20	+3.70	+0.10	+0.10	+14.40	-10.40	+0.60	+34.80	+2.70	-3.20	+3.90	+7.50	
Western coal (%)	–	-0.10	+7.80	+2.80	+23.00	-0.70	+12.40	+11.60	+34.80	+9.30	+4.40	–	+12.80	
1. Change in Illinois Basin coal consumption due to changed market share*	-3.37	-1.43	-4.02	-0.83	-1.29	-3.54	-0.44	-1.07	-1.10	-1.44	-0.55	-0.95	-2.36	-22.4
2. Change in Illinois Basin coal consumption due to market growth*	-0.33	+1.41	+1.33	+3.53	+1.20	+0.18	+0.11	+0.22	+0.22	+2.53	+0.21	+0.45	+0.44	+11.5
3. Net change in consumption of Illinois Basin coal*	-3.70	-0.02	-2.69	+2.70	-0.09	-3.36	-0.33	-0.85	-0.88	+1.09	-0.34	-0.50	-1.92	-10.9
4. Potential losses and gains against 1975 when 1975 shares are projected to 1979 market*	+0.65	-1.66	-1.60	-3.66	-2.64	-0.21	-0.15	-0.67	-1.04	-2.89	-0.30	-0.49	-0.64	-15.3
5. Total market impact (3 + 4)*	-3.05	-1.68	-4.29	-0.96	-2.73	-3.57	-0.48	-1.52	-1.92	-1.80	-0.64	-0.99	-2.56	-26.2

* in million tons.

consumption (row two, table 7). The growth effects (in million tons) were greatest in Indiana (3.5), Missouri (2.5), Illinois (1.3), and the Georgia/Florida region (1.4).

The 11.5 million tons per year gain was offset by a 22.4 million ton per year loss attributable to the market share fluctuations mentioned above. The 10.9 million ton per year residual represents the actual loss in annual production caused by competition from Appalachian and the western states.

Potential coal production in the Illinois Basin region, as represented in row five of table 7, was more severely affected; if the region had maintained its 1975 market share, it would have produced slightly more than 26 million tons more than in 1979. Theoretically, competition from the Eastern and Western coal fields caused a 26 million ton production loss for Illinois Basin coal producers in 1979 as compared with 1975 conditions.

Industry

The second largest market for Illinois Basin coal is in industry. Industry bought 10.5 percent of Illinois Basin production in 1979, as compared with 8.6 percent in 1975; Illinois Basin producers sold 13.7 million tons in 1979 and 12.1 million tons in 1975. Between 1975 and 1979 industrial consumption of coal rose 13.2 percent. The market share of industrial coal shipments from the Illinois Basin declined slightly (20.5 percent of the market in 1975 versus 19.8 percent in 1979). Western coal producers gained in the industrial coal market from 7.8 million tons in 1975 (14.6 percent of the market) to 15.5 million tons in 1979 (23.0 percent of the market). Appalachian coal producers still supply the largest share of the nation's industrial coal, but their market share dropped from 64.9 percent in 1975 to 57.2 percent in 1979; shipments increased only 4.3 million tons from 1975 to 1979.

The distribution of Illinois Basin coal shipments to industry changed considerably from 1975 to 1979. Thirteen states received industrial coal from the Illinois Basin in 1975 as compared with ten states in 1979. In both years seven states received more than 90 percent of these coal shipments. Indiana increased its share substantially from about 29 to about 44 percent of all the shipments (fig. 2).

In Illinois, industrial coal use dropped about 400,000 tons; Illinois Basin's loss in the tonnage of industrial coal resulted directly from this market change. In Missouri, Illinois Basin's market share dropped 2.9 percent although the market held nearly constant. Alabama industry stopped using Illinois Basin coal entirely.

Shipments to Wisconsin increased about 185,000 tons, and shipments to Iowa were up about 160,000 tons in 1979. The real increase in Illinois Basin industrial coal consumption came in Indiana, which consumed 2.5 million tons more in 1979 than in 1975.

Industrial use of Illinois Basin coal in the future will depend upon the economy of using coal or other fuels in general and Illinois Basin coal or other coals in particular. Although the former comparison may have been decided in favor of coal, the latter may continue to be a problem because of the lower prices of Western and Appalachian coals in some areas and the yet-to-be-issued clean air regulations for small coal burning units with less than 73 MW capacity. Any clean air regulations are likely to favor lower sulfur coals as small users cannot afford sulfur removal equipment.

Coke making

Coking coal has been the smallest sector of demand for Illinois Basin coal, accounting for only 4.3 million tons (3 percent of Illinois Basin production) in 1975. This market declined to about 3 million tons (2.3 percent of Illinois Basin production) in 1979. Most of the coking coal has been used in Indiana and Illinois. Small quantities were shipped to Ohio in 1975 and to Missouri and Tennessee in 1979, presumably for gas plants.

There has been a general decline in coking coal production in the entire United States, from about 93 million tons in 1975 to about 77 million tons in 1979. The decline in Illinois Basin production has been significant and is due to competition from the Appalachian Region and imported foreign coals as well as to a decrease in demand for coke.

Coal exports

International demand for coal—metallurgical and steam grades—has taken a sharp upward turn during 1980. World coal trade, which rose to more than 250 million short tons in 1979 from 220 million tons in 1978, is expected to reach nearly 300 million tons in 1980. A major portion of the increased demand is for steam coal. Total U.S. coal exports in 1979 reached nearly 66 million tons, and 1980 exports have reached 89 million tons. Most of these exports originate in the eastern United States; only small quantities of Illinois Basin coal—mostly in blends with low sulfur coals from other regions—are known to have reached export markets.

The high level of these coal exports has led to bottlenecks at the export terminals on the east coast; waiting time for ships has reached up to 50 days. Bottlenecks in coal supply are also being experienced by other major coal exporting countries such as Poland, Australia, and South Africa; delays are due either to

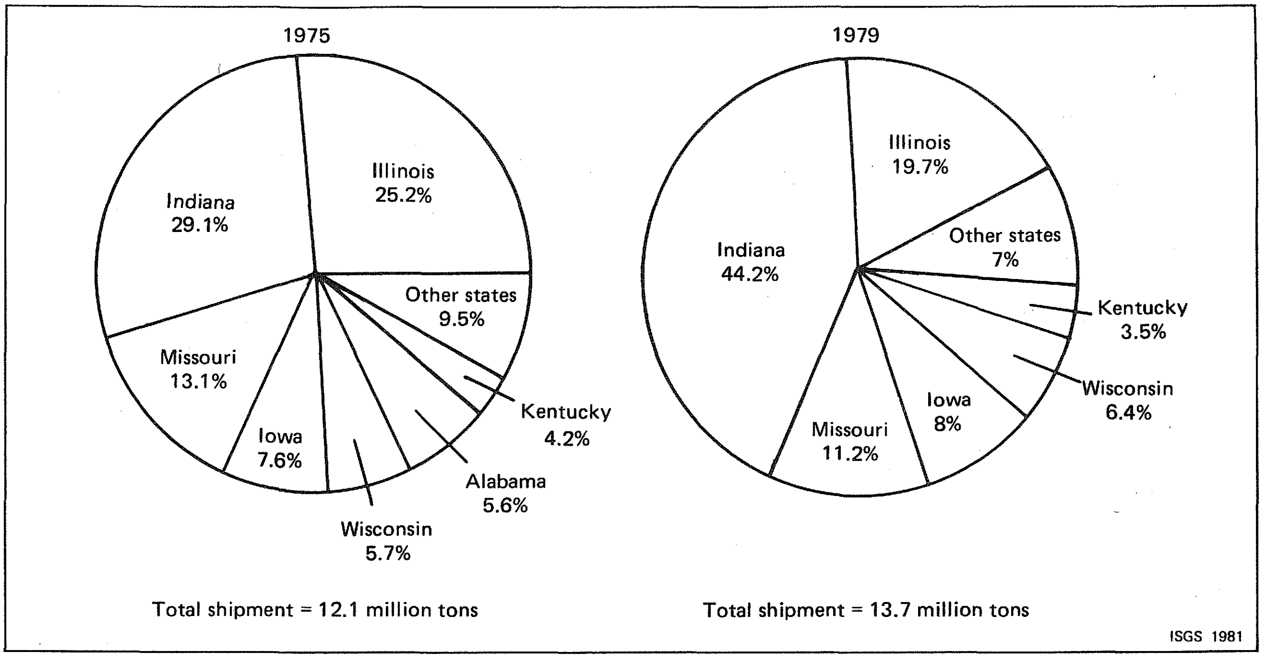

Figure 2. Illinois Basin coal shipped for industrial use, 1975 and 1979. (Source: Department of Energy, Bituminous and Subbituminous Coal and Lignite Distribution, Calendar Year 1979.)

rising domestic demand or lack of adequate port capacity or both. Poland has suffered an additional setback in coal production because of the present wave of strikes and unrest. This situation offers an opportunity for Illinois Basin coal producers to investigate the prospects for their coal in international markets. Illinois Basin coal has ready and economic barge access to the Gulf Coast and the Great Lakes and an extensive network of railroads to serve them. In both cases, however, the availability of barge transfer facilities must be investigated.

Illinois Basin coal could be offered at competitive prices for export, although its environmental acceptability in overseas markets needs to be investigated.

Coal conversion

Conversion of coal to other fuels—gaseous and liquid—is another favorable potential market. Coal of high Btu content is available in ample quantity, and water for conversion is available at many places. However, the most important of the favorable factors may be Illinois Basin's proximity to prospective markets in the midwestern, eastern, and southeastern United States.

Western coal producing states have the advantage of lower basic price of coal at mine site but may face problems of water availability. They are also farther away from major markets. The Appalachian states do not face the problems existing in western states but are faced with higher production costs of coal. Illinois Basin thus offers optimal chances for a future coal conversion industry, although the overall economics of coal conversion and, consequentially, the actual coal demand for conversion remain uncertain.

● ENVIRONMENTAL STANDARDS

The Federal New Source Performance Standards (NSPS) released in June 1979 have confirmed the emission limit laid down by the 1977 amendment to the Clean Air Act of 1970–1.2 pounds of sulfur per 1 million Btu heat input for new stationary utilities using coal or coal-derived fuels and starting construction after September 18, 1978. The standards apply to such utilities 73 MW or larger (250 million Btu/hr heat input) in capacity. The standards also require a 90-percent reduction in potential SO_2 emissions at all times except that when emissions to the atmosphere are less than 0.6 lbs/10^6 Btu only a 70-percent reduction is required.

The limit on emissions from liquid and gaseous fuels not derived from solid fuels is 0.8 lbs/10^6 Btu and 90 percent reduction in potential emissions. No reduction is required when emissions to the atmosphere are lower than 0.2 lbs/10^6 Btu.

For all existing utilities the states are required to issue the State Implementation Plans (SIP) determining the level of permissible emissions. Compliance with the SIP regulations is required by December 1982. The revised SIP regulations have not yet been finalized. However, the emission standards for existing utilities required by the SIPs are expected to continue to be more lenient, especially in the rural areas, than those required for new plants under the NSPS. In spite of the less stringent emission standards for existing units, many plants could not comply with the SIPs and are therefore operating under variance permits issued to them. Those of the existing units that did comply with the SIP standards did so mostly by switching from high-sulfur Illinois Basin coal to low-sulfur Western and/or Appalachian coals, regardless of the prices paid for the low-sulfur coal. It is therefore necessary to investigate the possibilities of permitting the use of high-sulfur coals within the limits of environmental regulations. One such opportunity is available in Illinois, where SO_2 pollution has declined by about one-third between 1970 and 1978. As a result of this decline in air pollution some areas in Illinois could be included in Class III instead of the present Class II, under the Prevention of Significant Deterioration laws (PSD); thus greater SO_2 emission is permitted than presently allowed. The State of Illinois was granted the delegation of authority of the PSD program in February 1980 (Sundberg, 1981). In 1978 a survey of 382 coal-burning utilities, each having a capacity greater than 25 MW, showed that 139 plants (36%) burned at least some high-sulfur coal having greater than 3-percent sulfur. Most utilities blend several coals. As a result, only 51 utilities (13 percent of total) showed an average of greater than 3 percent sulfur content in coal (table 8).

Although the NSPS regulations do not apply to existing power plants, this analysis shows that only about 10 to 15 percent of coal used presently by the utilities contains more than 3-percent sulfur. The question is whether the NSPS would facilitate a radical shift in favor of high-sulfur coal from the present pattern of using low- to medium-sulfur coal.

An analysis of the NSPS shows the following: (1) A minimum of 70-percent reduction in potential SO_2 emission is mandatory to all regardless of the sulfur content of coal used. A 70-percent reduction is sufficient for coals with $\leqslant 1$ percent sulfur content in order to satisfy the 0.6 lbs $SO_2/10^6$ Btu emission limits of the NSPS. (2) Coals with 1 to 3 percent sulfur will have to achieve 70 to 90 percent reduction in potential SO_2 emissions because the highest permissible SO_2 emission for this group of coals is also 0.6 lbs $SO_2/10^6$ Btu.

If the present pattern of coal consumption continues in new plants, 85 to 90 percent of utilities will have an emission level of less than or equal to 0.6 lbs $SO_2/10^6$ Btu and only a small number (less than 15 percent) of utilities will emit between 0.6 and 1.2 lbs $SO_2/10^6$ Btu. The declared intention of the 1979 NSPS is to preclude compliance based solely on the use of low-sulfur fuels. However, the NSPS have merely added the cost of sulfur reduction in using all sulfur categories of coal. Moreover, the added costs are likely to be lower for low-sulfur coals (70-percent reduction, possible application of dry scrubbing) than for high-sulfur coals (90 percent reduction, need for wet scrubbing). As a result, in those areas where the delivered price of Illinois Basin coal has been cheaper than Western and other low-sulfur coals, the price advantage may become less; in those areas where it has been more expensive to burn Illinois Basin coal, the disadvantage would increase. The costs involved in reducing potential SO_2 emission and the potential savings to be expected in burning cleaned coal will be discussed in the following chapters.

A number of electricity generating units are smaller than 73 MW capacity. Also, most industrial and retail users of coal are small users. The new source performance standards released in June 1979 do not apply

TABLE 8. Number of utilities in the 14-state market area burning coal with an average of more than 3 percent sulfur content in 1978

State	No. of utilities	Tons of coal burned	Average Btu/lb	Average (% S)	Lbs $SO_2/10^6$ Btu potential emission
Alabama	1	2,182,000	11,647	3.4	5.83
Illinois	4	5,119,000	10,077	3.4	6.75
Indiana	6	7,583,000	10,675	3.6	6.75
Iowa	3	679,000	10,406	3.3	6.34
Kentucky	5	9,966,000	10,636	3.8	7.14
Michigan	1	1,474,000	11,285	3.2	5.67
Missouri	9	7,333,000	10,475	4.1	7.83
Ohio	12	17,160,000	11,170	4.0	7.16
Pennsylvania	1	2,734,000	11,645	3.1	5.32
Tennessee	2	7,921,000	10,868	3.5	6.44
West Virginia	1	1,393,000	11,804	4.4	7.45
Wisconsin	6	3,017,000	11,584	3.3	5.70
Total	51	66,561,000	10,899	3.7	6.84

Source: Steam Electric Plant Factors, 1979: National Coal Association, Washington, DC.

to these small users. Regulations for these small users are yet to be released, so that their potential effects cannot be assessed at this time. Another set of environmental regulations are the Surface Mining Control and Reclamation Act and the requirements of the regulations for waste disposal from mines. They affect the total cost of coal and are commonly applicable to all coal mined in the United States; thus there is little relative disadvantage to Illinois Basin coal.

COAL BENEFICIATION

Beneficiation of coal prior to burning as a means of reducing SO_2 and particulate emissions to the atmosphere is gaining favor because of the high cost of compliance with environmental regulations in electricity generation.

Nationwide, a declining percentage of coal production is being mechanically cleaned by wet processes. In 1969, 56 percent or 316 million tons of coal were cleaned by wet processes as compared with 225 million tons or 34 percent of total in 1978. Increasing production of coal from surface mines in the western states accounted for much of the relative decline in the share of washed coal in the United States; Western coal deposits are lower in ash and sulfur content. There also has been an absolute decline in tonnage of washed coal. This decline in washed coal is noted in both underground- and surface-mined coal. In 1969 about 69 percent of underground-mined coal and 36 percent of surface-mined coal were mechanically cleaned. In 1978 the share of cleaned coal had fallen to 61 percent of underground- and 18 percent of surface-mined coal.

In Illinois the percentage of mechanically cleaned coal has been well above the United States average in the last two decades, although some fluctuations have taken place. In 1961 about 90 percent of Illinois coal was washed. The percentage declined to nearly 79 percent by 1970 but rose to about 80 percent in 1978. The potential for a significant improvement in coal quality by washing has been extensively used in Illinois. Further gains will be more difficult to attain unless improvements in washing techniques are introduced.

A somewhat lower percentage of coal produced in Indiana is being washed. Latest available data from 1978 show 65 percent of Indiana coal production being cleaned. Coal cleaning in West Kentucky averaged about 36 percent in 1978, slightly above the national figure of 34 percent for that year. These differences are reflected to a certain extent in the average sulfur content of coal shipped from the three states. In 1977, the sulfur content of coal shipments from Illinois, Indiana, and West Kentucky averaged 3.1, 3.0, and 3.7 percent respectively.

Overall in the United States, the technique of coal cleaning has not changed significantly since 1969. Jigs have accounted for nearly one-half of all coal cleaned, the actual percentage varying between 45 and 50 (table 9). Dense-medium processes have been responsible for about one-third of washed coal, whereas flotation varied between 3 and 5 percent. Jigs dominate in production of steam coal, and dense-medium processes are used predominantly for production of metallurgical coal. Dense-medium processes are more efficient than jigs in producing clean coal, but they are also more expensive. The higher market value of metallurgical coal permits the use of dense-medium processes. In recent years the market situation for steam coal has changed favorably because of rising prices of other fossil fuels. The higher prices of steam coal plus the environmental limitations on burning high-sulfur, high-ash coals are incentives for the use

TABLE 9. Percentage of coal cleaned in the United States, by method of cleaning

	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	Change from 1969 to 1978
Wet methods:											
Jigs	49.1	45.9	44.9	46.4	47.6	50.2	47.8	46.7	45.2	46.6	- 2.5
Concentration table	14.4	14.4	13.9	13.6	12.6	11.2	11.0	11.2	12.0	10.5	- 3.9
Dense medium processes	30.9	33.2	34.9	32.4	31.7	31.9	33.4	32.1	32.4	33.1	+ 2.2
Flotation	3.0	3.6	3.5	4.6	5.1	4.2	4.4	4.3	5.3	4.5	+ 1.5
All other	2.6	2.9	2.8	3.0	3.0	2.5	3.4	5.7	5.1	5.3	+ 2.7
Total tons (millions) cleaned	316	306	257	281	278	258	260	269	254	225	- 91

Source: U.S. Bureau of Mines, Minerals Year Book and Bituminous Coal and Lignite Production and Mine Operations, 1977 [DOE/EIA-0018(77)] and 1978 [DOE/EIA-0118(78)].

of better coal-cleaning techniques.

Following are the average Btu and sulfur contents of utility coals from the Illinois Basin in 1978:

	Btu/lb	Sulfur content (%)
Illinois	10,755	2.85
Indiana	10,805	2.90
West Kentucky	10,800	3.50
Average	10,780	3.1

These average values were attained from data resulting from coal cleaned in the three states. The cost of coal cleaning cannot be easily determined, and a generalization for the entire Basin is even more difficult. Some economic data are expected from a study by the Electric Power Research Institute (EPRI) to be published in the Spring of 1981. However, it is useful to discuss some general aspects of the economics of coal cleaning on the basis of available information.

The requirements under the New Source Performance Standards (NSPS) of June 1979 mandate the installation of sulfur-removal equipment on new power plants and a 90-percent reduction in potential SO_2 emissions based on the sulfur content of the raw coal, so long as the maximum limit of 1.2 lb $SO_2/10^6$ Btu is not exceeded. Any economic comparison must therefore consider the benefits and costs involved in the cleaning and burning of coal. A simple illustration may help clarify the issues involved: a coal with 5-percent sulfur and 15-percent ash before cleaning can be cleaned to about 3.5-percent sulfur and 8-percent ash by present methods of coal cleaning without froth flotation. In order to comply with existing regulations, about 83-percent scrubbing of flue gases would be needed when coal with 3.5-percent sulfur is burned. On the other hand, if uncleaned coal with 5-percent sulfur is burned, about 88-percent scrubbing of flue gases would be required to comply with the 1.2 lb $SO_2/10^6$ Btu limit on emission. Thus the first alternative lies between coal cleaning and an additional 5-percent scrubbing. Because many other cost factors are involved, only a thorough analysis on a case-by-case basis can lead to an economic comparison. Similarly, any decision to subject more coal tonnage to coal cleaning and/or to increase the level of coal cleaning will have to be weighed in terms of costs and benefits involved. The following chart gives the items involved in such a cost-benefit analysis:

Costs	Benefits
Coal cleaning	Savings in transportation costs
Waste disposal	Improved boiler efficiency due to higher Btu/lb
Water pollution	Reduced boiler outages due to lower ash contents
	Savings in particulate removal
	Less scrubbing of flue gases
	Cost reduction in sludge disposal
	Savings in capital cost for construction of boiler plant due to smaller sizes of coal handling, emission control, and other equipment and land used

The cost of coal cleaning varies from mine to mine and depends on the washability of coal. A survey of various reports on the cost of cleaning coal indicates that costs can vary from as low as \$2 to as high as \$10 per ton. The benefits of coal cleaning are more diverse and are even harder to assess in terms of dollars per ton. Although, comprehensive data on economic benefits of coal cleaning are not yet available, a review of available literature indicates that the benefits may be large enough to pay for the cost of coal cleaning as it is practiced today in the United States (Zimmerman, 1978; Peng and Newcomb, 1979; Buder et al., 1980; Phillips and Cole, 1980; and EPA, 1979).

Whether the costs of cleaning coal for all production could be offset by the benefits is uncertain. At this stage we assume that more thorough coal cleaning will have a positive effect on the future of Illinois. We do not attempt to quantify the magnitude in terms of dollars per ton.

FLUE-GAS DESULFURIZATION (FGD)

As of March 31, 1980, there were 65 operational FGD systems in the United States with a total installed capacity of 23,887 MW brought into compliance with existing requirements. This represents 10.4 percent of the total coal-fired generating capacity of the nation. The existing emission limits vary depending upon age and location of the plants. In addition, 42 FGD units with a total of 19,583 MW capacity are under construction and 74 units with 42,201 MW capacity are in various stages of planning.

In the 14-state market area for Illinois Basin coal there were 29 operating FGD Systems, 13 of which were using Illinois Basin coal as of 1978. This corresponds to about 45 percent of all operating FGD systems in the United States. Eighteen more FGD systems are under construction, 10 are contracted, and letters of intent have been signed for two. Eighteen more units are being planned. The category of compliance and status of operation of these units are given in table 10.

None of the operating FGD systems in the Illinois Basin market area complies with the Federal NSPS of June 1979. However, five (or six) FGD systems under construction or in contract and scheduled to be operable in 1982/83 will satisfy or exceed the standards of the Federal NSPS. Sixteen of the eighteen planned FGD systems will comply with the NSPS. Most of

TABLE 10. Category of compliance and status of operation of FGD systems in the 14-state market area (March 1980)

Class	Operational units	Units under construction	Planned units[1]	Planned units[2]	Planned units[3]	Planned units[4]
A	–	2	3(4)	2	2	11(12)
B	10	7	3	–	–	–
C	–	–	1	–	–	–
D	13	3	1	–	–	2
E	6	6	1	–	–	–

Key to table

[1] Contract awarded [2] Letter of intent signed [3] Requesting/evaluating bids [4] Considering only FGD systems
(A) Federal NSPS(6/79) (B) Federal NSPS(12/71) (C) Standard(s) more stringent than NSPS(6/79) (D) Standard(s) more stringent than NSPS(12/71) but not more stringent than NSPS(6/79) (E) Standard(s) equal to or less stringent than NSPS(12/71)

Source: EPA Utility FGD Survey: January-March 1980; EPA–600/7-80-029b May 1980.

them will be operable in the latter half of the 1980s and the first half of the 1990s.

Table 11 compares reported and adjusted capital and annual costs for operational FGD systems. Adjustments are made for different ages and types of systems. Costs are adjusted for better comparability of systems. Depending upon system used and whether a system is new or a retrofit, adjusted total annual costs vary between 2.8 mills/kwh to 13.00 mills/kwh, averaging 5.7 mills/kwh for all plants. New systems averaged 5.2 mills and retrofits 6.1 mills per kwh (1 mill = $0.001).

The heat input (heat rate) required for the generation of 1 kwh of electricity varies from plant to plant but can be assumed to average about 9,500 Btu/kwh. Therefore, the average total costs of 5.7 mills/kwh mentioned above, translate into 60 cents per million Btu heat input and the cost range varies from about 30 cents to $1.40 per million Btu. These costs do not differentiate between similar systems using coals with different sulfur contents. However, model investigations by EPA (1979a) indicate that costs differ considerably between FGD systems operating on low- or high-sulfur coal burning units. According to this study the total costs of an FGD system for feed coal with 5-percent sulfur could be up to 50 percent higher than a system for feed coal with 1-percent sulfur. As a result, there could be a scrubbing cost disadvantage of 30 to 40 cents per million Btu for Illinois Basin coal versus low-sulfur western or other coals.

Reliability of equipment in FGD systems has been cited as an unresolved problem by many utilities. FGD systems have to be technically in a position to scrub flue gases of high-sulfur coals effectively and function without breakdowns over long periods of operation. In actual practice, however, the viability of FGD systems is very difficult to define. Four different indices are used simultaneously to assess the viability but none alone is sufficient nor is it possible to derive a combined single viability index from these four individual indices; thus there is no real way to determine just how viable a particular FGD system is. The most reliable measure is the analysis of the scrubbed flue gases over a long period of time. Even that method may be affected by managerial and technical problems. An EPA (1980) survey of 74 operational FGD systems in January-March 1980 demonstrates the difficulties in assessing the viability of the systems. In the best response to the questionnaire only 36 out of 74 utilities reported the index values; in one survey only 11 responded. The poorest response came in reporting the reliability of the FGD systems.

Although arithmetic averages of the indices cannot be representative of the performance, the ranges of index values are worth attention:

$$\text{Availability} = \frac{\text{Hrs FGD available for use}}{\text{Total hrs in period}} = 74 \text{ to } 83\%$$

$$\text{Operability} = \frac{\text{Hrs FGD operated}}{\text{Boiler operating hrs in period}} = 78 \text{ to } 80\%$$

$$\text{Reliability} = \frac{\text{Hrs FGD operated}}{\text{Hrs FGD called upon to operate}} = 65 \text{ to } 78\%$$

$$\text{Utilization} = \frac{\text{Hrs FGD operated}}{\text{Total hrs in period}} = 54 \text{ to } 60\%$$

The range of indices indicates that utilization of the FGD systems is much lower than its availability, operability, and reliability. The values of availability, operability, and reliability need improvement; however, the utilization factor is also influenced by factors outside the systems. These may be technical, managerial, economical, or a combination of all three factors.

Mechanical cleaning of Illinois Basin coal reduces sulfur content of coal, and thus the cost difference between scrubbing the high- and the low-sulfur coals falls as near to the lower end of the range as possible.

TABLE 11. Categorical results of the reported and adjusted capital and annual costs for operational FGD Systems

	Reported						Adjusted					
	Capital, $/KW			Annual, Mills/KWH			Capital, $/KW			Annual, Mills/KWH		
Category	Range	Avg	Dev	Range	Avg	Dev	Range	Avg	Dev	Range	Avg	Dev
All	29.2-189.0	80.9	40.2	.1-14.9	4.4	4.4	56.0-233.2	93.2	35.4	2.6-13.0	5.7	2.7
New	31.8-189.0	80.4	39.6	.1-14.3	3.3	3.9	66.4-117.6	86.1	17.8	2.8- 8.7	5.2	2.0
Retrofit	29.2-156.9	82.0	41.3	2.0-14.9	6.1	4.5	56.0-233.2	100.2	45.8	2.6-13.0	6.1	3.2
Throwaway product	29.2-189.0	75.6	37.2	.1-14.3	4.2	4.1	56.0-140.6	86.2	21.9	2.6- 8.7	5.1	2.0
Saleable product	127.9-156.9	142.3	14.5	2.0-14.9	8.4	6.5	134.8-233.2	184.0	49.2	12.4-13.0	12.7	.3
Limestone	31.8-168.0	74.0	37.9	1.3- 3.3	2.1	.6	56.0-117.6	88.6	25.5	2.6- 6.6	4.6	1.6
Lime	29.2-128.3	74.9	32.2	.1-14.3	6.9	4.8	67.5-140.6	90.8	22.2	2.7- 8.7	6.4	2.0
Dual alkali	43.2-189.0	96.7	65.5	3.2- 3.2	3.2	.0	Data not available			Data not available		
Lime/alkaline flyash	77.1- 85.9	80.0	4.1	.3- .3	.3	.0	77.2- 93.0	82.5	7.4	4.1- 5.2	4.5	.5
Sodium carbonate	42.9-120.0	79.8	37.0	2.1- 2.1	2.1	.0	60.9-107.9	76.6	22.2	3.2- 4.4	3.6	.6
Wellman Lord	127.9-156.9	137.6	13.7	14.9-14.9	14.9	.0	134.8-134.8	134.8	.0	12.4-12.4	12.4	.0
Limestone/alkaline flyash	47.9- 47.9	47.9	.0	2.0- 2.0	2.0	.0	71.2- 71.2	71.2	.0	2.8- 2.8	2.8	.0
Magnesium oxide	156.7-156.7	156.7	.0	2.0- 2.0	2.0	.0	233.2-233.2	233.2	.0	13.0-13.0	13.0	.0

Source: EPA Utility FGD Survey, January-March 1980;
EPA-600/7-80-029b, May 1980

Installation of FGD systems mandated by the June 1979 NSPS thus makes it environmentally possible to use high-sulfur Illinois Basin coal, but at a greater additional cost as compared with low-sulfur coals. This will have the effect of eroding the cost advantage enjoyed by Illinois Basin coal in some market areas and increasing the disadvantage in other areas where Illinois Basin coal already is more expensive than Western coal. Better market position for Illinois Basin coal therefore will depend upon the delivered price of Illinois Basin coal in comparison with other coals. Observations to date indicate that this difference will have to be about 40 to 50 cents per million Btu or 9 to 11 dollars per ton. In those market areas where this difference cannot be maintained, Illinois Basin coal will continue losing customers.

The delivered prices of coal to utilities in 1978 are compared in table 12. If 30 cents/10^6 Btu are added to the delivered cost of coal from West Virginia, East Kentucky, Pennsylvania, and Ohio, and 40 cents/10^6 Btu to those of Illinois, West Kentucky, and Indiana, the resulting hypothetical price levels would be an indication of the changes in competitive positions attributable to differential scrubbing costs. The new price levels render Illinois Basin coal incompetitive in comparison with Western coals in the entire 14-state market area. This includes the Illinois Basin itself, within which the domestic coal presently enjoys a price advantage. The prices in the remaining states east of the Mississippi River compare similarly with Western coals after adding the FGD price differential. Overall, the states within the Illinois Basin appear to compete against each other for markets rather than competing against Western coals or coals from other states east of the Mississippi River.

TRANSPORTATION OF COAL

Transportation costs constitute a significant portion of the total delivered cost of coal. Depending upon the terms of contract, the distance involved, and the mode of transportation, the cost of transportation of Illinois Basin coal to the consumer within the traditional 14-state market may vary between about 15 percent and 35 percent of the total delivered price of coal. As for Western coal, an inventory of contracts compiled by the Geological Survey of Wyoming (Glass, 1980) indicates that transportation costs could account for 30 to 90 percent of the delivered price of Wyoming coal. In 1978 within the 14-state area, the percentage of delivered costs equalling average transportation costs was about 17 percent for Illinois Basin coal, 5 percent for other coals east of the Mississippi, and 54 percent for Western coals. Railroads and barges are the main modes of long-distance coal transportation in the United States. In the Illinois Basin market area, barge transport is slightly more prevalent than on a nationwide basis.

Rail transport

Through the 1970s railroads carried from 60 to 65 percent of all coal shipments in the United States. Most coal shipped by rail was of steam grade—77 percent overall in the United States and 86 percent in Illinois, Indiana, and West Kentucky.

Annual shipments of steam coal to utilities in the 14-state Illinois Basin market increased from 1975 to 1979. This movement, spurred by improvements in the steam coal market, led to a 7.2 million ton increase in shipments by rail. Although the railroads' share of total shipments fell from 61 percent to 58 percent, hauling coal developed into a growth market for the railroad industry. This market helped improve the railroads' productivity and also provided an infusion of much needed capital.

In the early seventies, questions were raised about the ability of the railroads to move the quantity of coal that experts predicted would be consumed in 1980 and beyond. The major fear was that the switch from oil to coal would be hindered by poor road beds and inadequate rolling stock. However, from 1975 to 1979 no major structural problems in the railroad industry materialized. One reason the railroads were able to meet the demand for coal transportation was that actual increases in coal consumption fell short of the prediction. A second reason was that revenues from increased coal shipments helped railroads finance the upgrading of their capital stock. Increased coal traffic also made some railroads more attractive to investors, who provided capital for improving the capacity to haul coal.

Railroad revenues were bolstered not only by increased quantities shipped but also by higher freight rates for coal. Averages of rail rates in figure 3 show a steady climb in ton-mile costs of rail shipment. Unit train freight rates for long distance transportation (750 to 1,000 miles) showed an average 24.3 percent annual increase over the 1977-1979 period, compared with an average of 10.2 percent for the 250 to 500 miles range. Single or multiple car rate increases varied between 9.5 percent and 13.8 percent annually. The magnitude of these rail rate hikes has been subject to much criticism. Utilities in the South and Midwest have complained that the Interstate Commerce Commission is allowing the railroads to cross-subsidize other traffic with the increased coal rates. The result, utilities argue, is a much higher delivered coal cost—especially low-sulfur coal from the western states—and an ultimately higher cost of electricity.

TABLE 12. Weighted average of delivered coal prices to utilities in 1978

Destination/ Origin	Illinois (1000 tons)	Illinois $/10^6 Btu	West Kentucky (1000 tons)	West Kentucky $/10^6 Btu	Indiana (1000 tons)	Indiana $/10^6 Btu	Montana (1000 tons)	Montana $/10^6 Btu	Wyoming (1000 tons)	Wyoming $/10^6 Btu
Alabama	5.3	1.259	3,409.1	1.206	60.3	1.286	–	–	–	–
Florida	1,016.4	1.386	2,617.6	1.376	249.3	1.711	–	–	–	–
Georgia	1,590.9	1.178	3,054.0	1.157	820.9	0.93	–	–	–	–
Illinois	17,303.9	1.024	621.6	1.282	903.7	1.229	5,688.2	1.418	5,256.7	1.538
Indiana	3,242.8	1.147	4,078.7	1.033	16,824.5	0.915	1,202.0	1.347	2,464.7	1.49
Iowa	1,766.4	1.314	186.1	1.375	5.9	1.334	223.6	1.071	4,627.3	0.989
Kentucky	662.4	1.092	11,040.5	0.908	1,788.1	0.868	–	–	445.9	1.400
Michigan	745.7	1.376	413.4	1.012	–	–	3,309.0	1.057	–	–
Minnesota	636.2	1.250	16.0	1.763	–	–	10,007.1	0.763	–	–
Mississippi	353.2	0.885	–	–	–	–	–	–	–	–
Missouri	9,955.3	0.807	298.7	1.293	–	–	–	–	2,095.3	1.218
Ohio	118.3	0.963	1,001.6	0.939	–	–	–	–	4,380.1	1.385
Tennessee	29.5	1.028	7,160.1	1.188	475.2	1.181	–	–	–	–
Wisconsin	329.6	1.262	1,205.0	1.462	852.8	1.283	2,435.2	0.830	1,755.8	1.044

Destination/ Origin	Colorado (1000 tons)	Colorado $/10^6 Btu	West Virginia (1000 tons)	West Virginia $/10^6 Btu	East Kentucky (1000 tons)	East Kentucky $/10^6 Btu	Pennsylvania (1000 tons)	Pennsylvania $/10^6 Btu	Ohio (1000 tons)	Ohio $/10^6 Btu
Alabama	–	–	76.6	1.411	853.3	1.635	80.0	1.257	51.1	1.014
Florida	–	–	–	–	855.8	1.750	–	–	–	–
Georgia	–	–	64.8	1.560	8,034.9	1.251	–	–	145.0	1.644
Illinois	1,764.8	1.610	54.0	1.386	1,376.8	1.760	–	–	–	–
Indiana	450.2	1.783	8.5	1.386	1,033.0	1.358	2.8	1.656	7.1	0.943
Iowa	591.1	1.759	–	–	24.6	1.259	2.7	1.542	–	–
Kentucky	–	–	14.2	1.518	9,209.4	1.331	–	–	159.0	1.085
Michigan	–	–	3,117.0	1.090	4,958.4	1.458	1,261.0	1.399	5,311.5	1.280
Minnesota	–	–	–	–	4.3	2.180	1.4	1.608	9.0	1.956
Mississippi	273.3	2.042	–	–	237.4	1.533	–	–	–	–
Missouri	627.7	1.763	76.0	1.773	74.0	1.531	41.6	1.256	–	–
Ohio	–	–	4,849.8	1.117	8,124.4	1.361	2,044.6	1.089	21,789.1	1.219
Tennessee	–	–	38.3	1.445	5,685.0	1.221	100.9	1.191	1,999.7	1.113
Wisconsin	–	–	61.7	1.758	76.6	1.713	987.7	1.281	175.1	1.284

Source: Steam Electric Plant Factors, 1979: National Coal Association, Washington, DC.

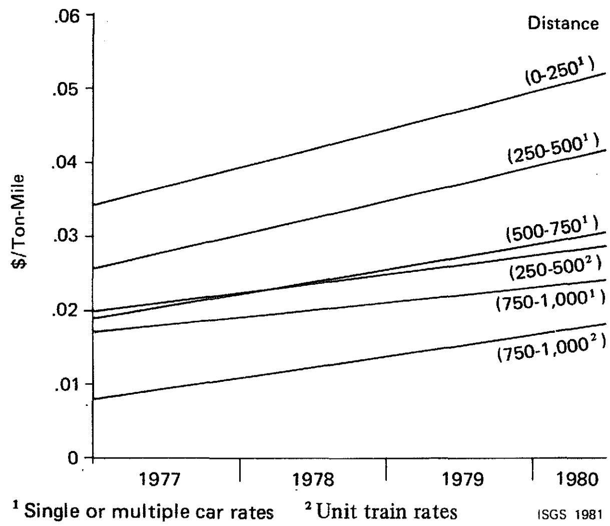

Figure 3. Average rail freights in the United States, 1977 to 1980. (Source: Data adapted from *Coal Week.*)

Increased rates have led to a shift away from railroads to other forms of coal transport. The percentage of coal consumption shipped by rail dropped in 9 of 14 states in the Illinois Basin market area (table 13). In 1979, these nine states represented 71 percent of consumption in the market area.

Modal competition has in no way threatened the position of the railroads as the primary hauler of steam coal. In both the Illinois Basin market area and the United States as a whole, railroad shipments account for well over half of the total shipments.

Barge transport

Illinois Basin coal-producing areas are close to the nation's largest waterways, including the Mississippi, Illinois, Ohio, and Tennessee Rivers (fig. 4). In addition, the Gulf Intercoastal Waterway gives Illinois Basin an access to the southern and southeastern states and to the export markets. By comparison, the waterways in the eastern United States are small. In the Illinois Basin market area, water transportation has accounted for a large share of coal transport. Water transportation—seemingly the most likely mode to benefit from growth in steam coal market and shifts away from rail shipments—has not gained; in fact, steam coal shipments by river have declined nationwide from 19 percent of total in 1975 to 17 percent in 1979. In the Illinois Basin market area, barge traffic slipped from 23 percent to 22 percent of total tonnage shipped.

Analysis of individual states shows that six states shipped a smaller percentage of their total by barge in 1979 than in 1975. Three states shipped the same percentage, and four states shipped a greater percentage. Only in Ohio and Kentucky was the switch from rail to barge appreciable.

Nationwide figures show a small but steady increase from 1974 to 1977 and a drop in 1978 (attributable to the mine workers strike) in total barge traffic of coal. Revenues during this time also increased, except in 1978 (table 14).

In contrast to the railroads, the barge industry has been free of rate controls. As a result barge freight rates have not been monitored in the past; hence, it

TABLE 13. Changes in modes of coal transportation in the 14-state market area

	1975					1979				
Destination	Rail (%)	River and ex-river (%)	Truck (%)	Great Lakes (%)	Tram and private RR (%)	Rail (%)	River and ex-river (%)	Truck (%)	Great Lakes (%)	Tram and private RR (%)
Illinois	70	19	11			66	18	10	< 1	6
Indiana	67	23	10			62	22	16		
Kentucky	49	16	35			40	24	36		
Tennessee	40	48	12			50	44	6		
Ohio	34	38	14	< 1	13	24	44	18		15
Michigan	72			28		58			42	
Wisconsin	74	15		11		72	9		19	
Minnesota	84	16				80	8		12	
Iowa	76	13	11			82	14		4	
Missouri	70	16	14			69	16	10		5
Florida and Georgia	80	20				77	23			
North Carolina	100					100				
South Carolina	100					100				
Alabama and Mississippi	36	40	13		11	42	24	34		
MARKET AREA TOTAL	61	23	11	3	3	58	22	12	4	4

Sources: Department of Energy, *Bituminous and Subbituminous Coal and Lignite Distribution*, January-September 1979. Last quarter projected; U.S. Bureau of Mines, *Bituminous Coal and Lignite Distribution*, 1975.

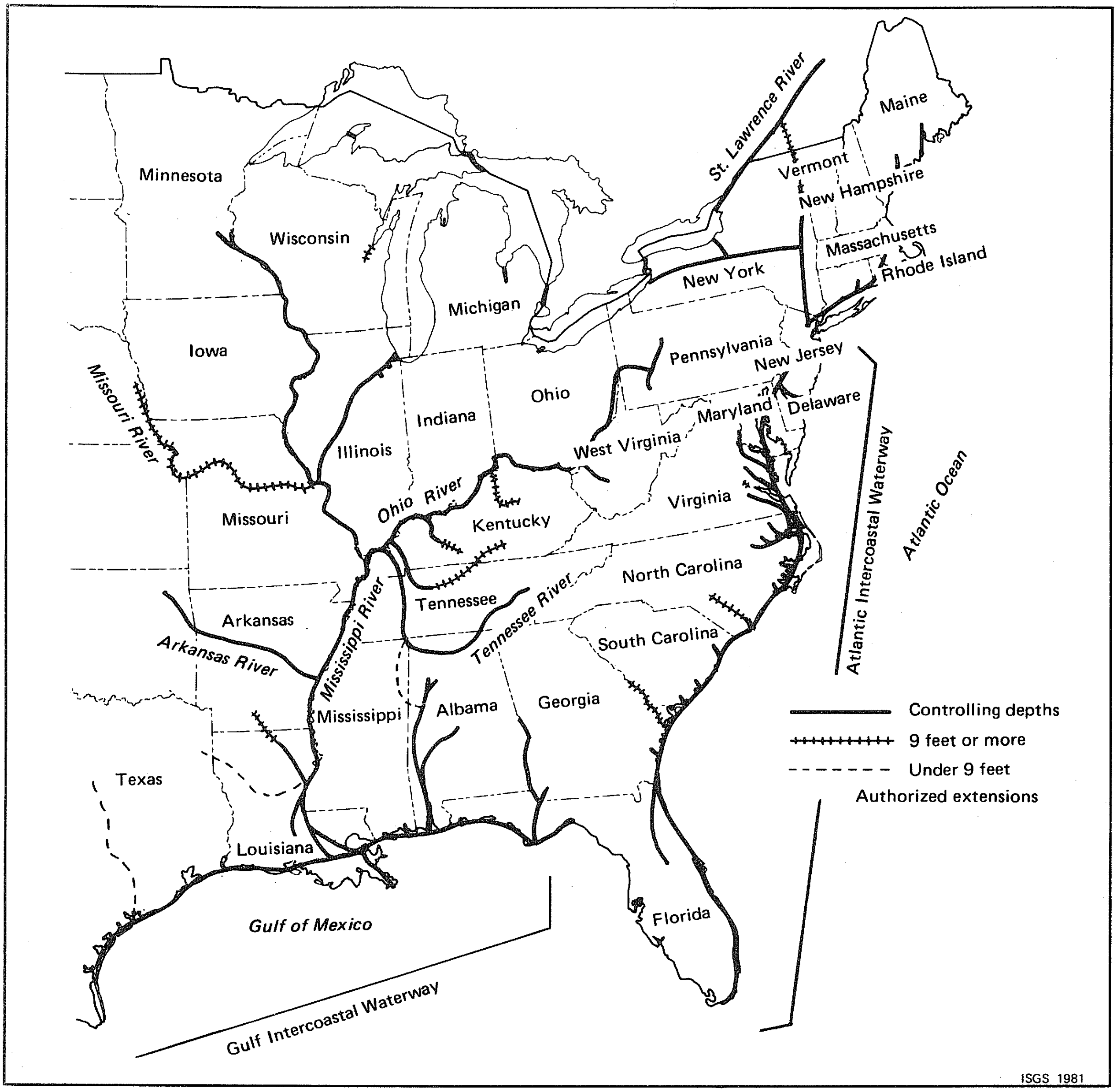

Figure 4. Major waterways of the United States.

is not possible to determine the freight rates nor the relationship between distances traveled and rates paid. However, data from table 14 show that from 1974 to 1978 average revenue per ton increased at an annual rate of about 10.5 percent in overall barge traffic. In comparison, revenues in joint rail-barge traffic increased at an average annual rate of 26.7 percent. Because of a lack of data on ton-miles transported by barge, a comparison between rail and barge is not possible.

Possible effects of railroad deregulation

The nation's railroads historically have enjoyed eminent domain and right of way. They have also been permitted to set the rail freight rates in consultation with other railroads. To protect the railroad customer and the ultimate consumers of commodities, the rate making by railroads has been subject to public scrutiny. Any changes in freight rates have to be approved by the Interstate Commerce Commission on the basis of cost increases. In October 1980 a railroad deregulation bill was approved by the House and Senate and signed into law by the President. The deregulation bill permits rates to be 160 percent of variable cost in the first year and an increase by 5 percent in the following 4 years. After 5 years the Interstate Commerce Commission will not intervene if rail freights are equal to or less than 180 percent of variable costs. This also provides captive shippers protection against unreasonably

TABLE 14. Volumes and revenues in coal barge traffic

	Joint rail and water traffic (tons)	All other traffic (tons)	Total (tons)	Joint rail and water freight revenue, gross ($)	All other traffic revenue, gross ($)	Total ($)
Bituminous and lignite						
1974	384,440	52,008,777	52,393,217	705,346	79,619,651	80,324,997
1975	335,953	51,353,033	51,689,086	740,460	89,727,310	90,469,451
1976	192,639	54,857,214	55,049,853	467,992	106,665,680	107,133,672
1977	311,666	55,179,464	55,491,130	723,020	116,527,251	117,250,271
1978	1,165,436	41,081,635	42,247,071	5,492,368	93,835,597	99,327,865
Bituminous only						
1974	384,640	50,957,083	51,341,723	705,346	79,619,527	80,164,873
1975	335,953	50,912,005	51,247,958	740,460	88,489,743	89,230,203
1976	192,639	51,909,700	52,102,339	467,992	105,435,540	105,903,532
1977	311,666	52,763,597	53,075,263	723,020	116,115,923	116,838,943
1978	398,716	39,432,793	39,822,509	1,083,726	93,465,834	94,549,560
Summary						
	1974 ($/ton)	1975 ($/ton)	1976 ($/ton)	1977 ($/ton)	1978 ($/ton)	
Joint rail and water traffic	1.83	2.20	2.42	2.32	4.71	
All other traffic	1.53	1.74	1.94	2.11	2.28	
Total	1.53	1.75	1.94	2.11	2.35	

Source: U.S. Interstate Commerce Commission, Report on Transport Statistics (1974-78), Part 5, Table 5.

high rates. Rail freight rates are expected to generally rise when deregulation becomes effective because railroads have been complaining about exceptionally low rates of return. The Citibank has compiled the returns to share holders in different industries during the 1973 to 1978 period (table 15).

During the same period, prices of coal at the mine have risen faster than the rail freight rates, thereby reducing the share of rail freight in total delivered cost of coal. As table 16 demonstrates, this has been primarily the result of drastic increases of coal prices in 1974. Since 1974, however, the rise in rail freight has generally been slightly higher than the rise in mine head price of coal. A generally rising demand for coal both domestically as well as internationally and the deregulation of rail rates will tend to increase the cost of coal and the rail rates. As stated earlier, the share of transportation in total delivered cost of Illinois Basin coal is generally lower than for Western coal. Western coal, therefore, may face greater adverse effects of deregulation of railroads than Illinois Basin coal.

In Illinois and in some other states this advantage to the Illinois Basin coal may not be realized, because existing electricity pricing regulations permit utilities

TABLE 15. Returns to shareholders in the railroad and other industries

	Railroads (%)	Electric and gas utilities (%)	Petroleum products and refining (%)	Chemical products (%)
1973	3.5	10.8	15.6	15.0
1974	4.3	10.4	19.9	19.0
1975	0.8	11.6	14.1	14.6
1976	1.8	11.8	15.1	15.7
1977	1.9	11.7	14.2	14.5
1978	1.3	11.3	14.3	15.0

Source: Dempsey, William H., President, Association of American Railroads, Statement before the Surface Transportation Subcommittee of the Senate Committee on Commerce, Science, and Transportation, February 22, 1980.

TABLE 16. Share of rail freights in total delivered cost of coal in the United States

	Mine price ($/ton)	Rail rate ($/ton)	Total ($/ton)	Share of rail freight in total (%)
1973	8.53	3.73	12.31	30.7
1974	15.75	4.71	20.46	23.0
1975	19.23	5.25	24.48	21.4
1976	19.43	5.86	25.29	23.2
1977	20.50	6.48	26.98	24.0
1978	22.40	7.32	29.72	24.6

Source: Dempsey, William H., President, Association of American Railroads, Statements before the Surface Transportation Subcommittee of the Senate Committee on Commerce, Science, and Transportation, February 22, 1980.

to directly pass on to the customer the higher cost of transporting Western coal. By comparison, recovery of long-term investments in FGD systems or other methods of emission control offer no incentive to utilities economically. In some states of the Illinois Basin market area, especially in the southern and southeastern states, rising transportation costs of Western coal may offer an opportunity to Illinois Basin coal.

Coal slurry pipelines

About 58 percent of all coal in the United States is presently being hauled by rail, about 18 percent by barge, and 14 percent by truck. Slurry pipelines, as a single product transportation mode, represent a change in transportation trends. A number of coal slurry pipelines are in the planning stage. Supporters of pipelines are convinced that they offer viable and economical alternatives to rail and barge (Souder and Burt, 1979). The pipelines, with more than 65 percent of the cost fixed as compared with 35 percent fixed costs for rail, are less vulnerable to inflation than railroads. However, only one coal slurry pipeline exists thus far in the United States, and all economic calculations are estimates. As a result definite freight rate comparisons are impossible.

A pipeline approximately 1,500 miles long has been proposed by Continental Resources Co. of Winter Park, Florida, to transport 40 to 50 million tons of Illinois Basin and Appalachian coal annually to Georgia and Florida (fig. 5). Model studies indicate that the cost of transporting coal by slurry pipeline to Florida may be substantially lower than the cost by railroads; one estimate shows about half as expensive. Savings in transportation costs to the southeastern United States may be essential for Illinois Basin coal. As demonstrated earlier in this investigation, Illinois Basin coal has not maintained its share of the growing southeastern utility markets.

A controversy exists in the field of federal transportation policy regarding railroad deregulation and free market competition. Since 1978 the Federal government has acted to deregulate the transportation industry beginning with airlines and trucking and concluding with railroads. The barge industry has never been subject to rate regulations. Because almost 75 percent of coal shippers served by the railroads are captive, i.e., they do not have an alternative to railroad transportation, they will face a freight rate increase although the legislators have acted to limit the rate increases. Pipelines would be the only alternative available to many coal shippers in order to keep the coal freight rates competitive. Presently, the pipelines do not enjoy the same rights in comparison with railroads. Questions about eminent domain and right of way are left to the discretion of the states and the railroads are doing everything they can to stop the pipelines from being competitive. A logical consequence of the deregulation policy and the principles of free market economy would be to facilitate, at State and Federal levels, the development of competitive modes of transportation by a suitable solution to the problems of eminent domain and right of way. Such a competition is in the interest of both the consumers and the coal producers from the Illinois Basin.

To summarize the transportation situation, several conclusions are pertinent: (1) Illinois Basin coal may expect an overall favorable rate situation in comparison

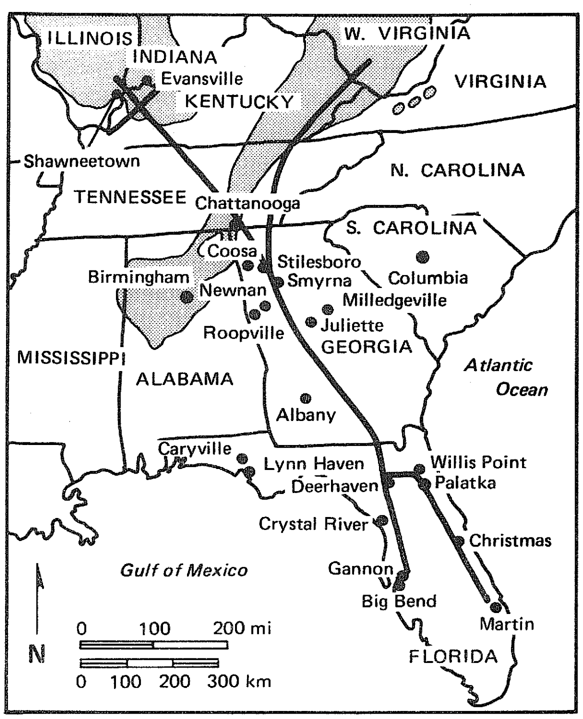

Figure 5. Location of coal fields, utility plants, and a proposed coal slurry pipeline. (Source: Wiley M. Cauthen Continental Resources Co., Illinois Mining Institute, 1979.)

with Western or Appalachian coals because of the past low rates of return on investment, high rate of freight increases for long-distance unit-train transport (about 70 percent of Western coal is transported over long distances by unit trains), and the railroad deregulation bill. All these factors are likely to lead to larger increases in the rail-freight rates for Western and Appalachian coals than for the Illinois Basin coals in the 14-state area. (2) The barge industry, which has never been subject to rate regulations, has shown lower rate increases in the past than the railroads and has contributed to the advantage of Illinois Basin coal. (3) Coal slurry pipelines, if facilitated by legislative actions of the states, may help keep freight rates competitive in all modes of transportation.

TAXATION

Taxation of the coal mining industry takes several forms: ad valorem property tax; severance tax; gross production tax; net production tax; and coal use tax.

Most states have the ad valorem property tax applied to the coal and other minerals; the tax is based upon evaluation of the property, which includes the mineral deposit and the mining and processing plants. The tax rates vary and no averages can be stated (table 17). The most common forms of taxation are the severance and the gross production taxes, which are levied as percentage of the mine head value of coal or on a dollar per ton basis. Gross production tax is normally in percentage of the gross value of production. Some states levy a coal use tax, which is the sales tax for locally produced and consumed coal, and a use tax for coal produced outside the state but consumed in the state.

Severance tax is a compensation paid to the State for depriving it of its natural wealth. The tax is most common in western states. The highest percentage of severance tax is paid in Montana (30 percent). The severance tax of 85 cents per ton in North Dakota on surface-mined coal may amount to about 15 to 20 percent of the value of coal mined. Ohio also has a severance tax of 4 cents per ton.

Illinois Basin states do not impose a severance tax although Illinois and West Kentucky collect 5 and 4.5 percent tax respectively on gross production. The Appalachian states—West Virginia and East Kentucky—are comparable to Illinois Basin states. No severance taxes are levied in Indiana and Pennsylvania. The severance taxes of Colorado are \$.60/ton, 50 percent credit for underground mines, and 50 percent credit for lignite. Montana taxes are shown in the following schedule:

Btu/lb	Surface mine	Underground mine
≤7000	\$.12/ton or 20% of value	\$.05/ton or 3% of value
7000-8000	\$.22/ton or 30% of value	\$.08/ton or 4% of value
8000-9000	\$.34/ton or 30% of value	\$.10/ton or 4% of value
>9000	\$.40/ton or 30% of value	\$.12/ton or 4% of value

A 17-percent tax in Wyoming consists of 10.5 percent gross production tax and 6.5 percent ad valorem property tax collected by the counties.

Because of large differences in the mine head values of coal produced in the Illinois Basin and in western states, the actual difference in dollars per ton is minimized. Based upon the latest available data on value of coal produced by states, the tax rates in 1977 compared as follows:

TABLE 17. Taxes on underground and surface mined coal

	Severance	Property (Ad valorem)	Gross production (%)	Percentage
Illinois	–	Applicable	5 (sales)	5.00
Indiana	–	Applicable		–
West Kentucky	–	Applicable	4.25	4.25
Montana	30%	Applicable	–	30.00
Wyoming	–	6.5% (county)	10.50	17.00
Colorado	\$.60/ton	Applicable	–	–
North Dakota	\$.85/ton	Applicable	–	–
Pennsylvania	–	Applicable	–	–
Ohio	\$.04/ton	Applicable	–	–
East Kentucky	–	Applicable	4.25	4.25
West Virginia	–	Applicable	3.85	3.85

Source: Department of Agriculture, State Taxation of Mineral Deposits and Production, September 1978; Coal Week, 4-17-78 to 5-1-78.

	Tax ($/ton)
Illinois	0.86
West Kentucky	0.77
Montana	1.80
Wyoming	1.40
East Kentucky	0.98
West Virginia	1.19

Consumers of Western coal therefore paid up to $1/ton more in 1977 in terms of taxes to those states and 20 to 30 cents/ton more to the eastern states as compared with Illinois Basin coal.

Certain individuals are working to limit the severance tax by law to 12.5 percent to protect the consumer from a tax thought to be hindering the interstate commerce. For the Illinois Basin coal industry, a reduced severance tax in other states may result in increased price competition.

Funds collected through severance taxes are allocated to various tasks at local and state levels including schools, highways, and local organizations. In some cases counties not producing coal also receive a share. Generally, the money has been used to deal with the impact of coal mining on the community. The funds could also be used for promoting coal mining, coal utilization, or coal research.

At the present rate of coal production and value, each 1-percent severance tax may result in 35 to 40 million dollars in revenue in the Illinois Basin every year. This amount is equivalent to 1.4 to 1.6 million tons of coal at the present level of coal prices or about 1 percent of the Illinois Basin coal production. Any gains hoped for by investing the severance tax money to promote use of Illinois Basin coal must therefore be carefully weighed against possible market losses due to increased price of coal, especially at a time when efforts are being made in other states to lower coal taxation.

COST OF COAL PRODUCTION

The cost of producing coal is influenced by various factors including: labor productivity; material and energy; and capital (depreciation and interest).

The single most important cost factor is labor. In the Illinois Basin, labor accounts for about 45 percent of the f.o.b. mine price of coal and thus an even higher percentage of the actual cost of mining coal. Labor productivity, in turn, is dependent on various other factors such as mechanization, mine size, and stripping ratio in strip mines. These factors were dealt with extensively in previous publications of the Illinois State Geological Survey (Malhotra, 1976a and b) and are valid to date.

Table 18 summarizes the productivity and mine mouth values of coal during the 1968 to 1977 period. Estimates for 1979 are based on average rates of increase from 1968 to 1978. The data show that productivity of coal mines in the Illinois Basin has declined in comparable amounts with that in the eastern states. Illinois Basin coal, however, remains, in general, lower in value than coal of the eastern states. In 1968, the value of Illinois Basin coal averaged 15 to 28 percent below national average as compared with only 6 to 17 percent below in 1979. The western states, especially Montana and Wyoming, have substantially increased productivity. The Colorado, Montana, and Wyoming coals now enjoy a sizable advantage in mine head values. In 1968 the western states ranged from 42 percent below to 2 percent above national average in coal value, but in 1979 were 24 to 68 percent below. The three Appalachian states (table 18) averaged from 15 percent below to 15 percent above national average in value in 1968; in 1979, the same states ranged from 2 to 57 percent above.

Illinois Basin coal thus faces a different problem than the Western coals. Whereas the larger portion of the delivered price of Western coal consists of transportation costs, in the Illinois Basin it is the mining cost. Improving mining productivity therefore has a greater significance in the future of Illinois Basin coal than for Western coal mines. If only the mine-head value of coal is considered, the Illinois Basin coal has apparently improved its competitiveness in comparison with Appalachian coal, although as seen before, the overall competitive position has deteriorated.

The task of improving the productivity of coal mines in the Illinois Basin is rendered difficult. Illinois Basin mines, with an average 1977 productivity of 18.4 tons per man-day, were already more productive than the United States national average of 14.8 tons per man-day. The average revenues of Illinois Basin coal ($16.50/ton) were nearly 17 percent lower than the United States average of $19.80/ton.

Underground coal mines in Illinois and West Kentucky are the largest in the nation, producing an average 1.2 and 0.8 million tons respectively in 1977 (table 19). Surface mines in the Illinois Basin averaged 267,000 tons per year in 1977, as compared with the United States average of about 120,000 tons/year. By comparison, surface mines in Montana and Wyoming averaged 3.4 and 2.8 million tons in 1977. Nearly 60 percent of Illinois Basin coal production comes from surface mines. The economies of scale therefore are in favor of western surface mines, although considerable success has also been achieved in the Illinois Basin.

An investigation of changes in labor productivity of coal mines by Oak Ridge Associated Universities (1979) shows significant consistencies between Illinois mines and national averages. However, there are also some important differences. The investigation, based

TABLE 18. Summary of productivity and mine mouth values of coal

	Coal mines productivity				Value of coal			
	1968 (ton/ man-day)	1977 (ton/ man-day)	Annual change (%)	1979* (ton/ man-day)	1968 ($/ton)	1977 ($/ton)	Annual change (%)	1979* ($/ton)
United States total	19.4	14.8	– 2.9	14.0	4.7	19.8	+ 17.4	25.4
Illinois	29.7	15.1	– 7.2	n.a.	4.0	17.3	+ 17.6	24.0
Indiana	33.8	26.4	– 2.7	n.a.	3.9	13.8	+ 15.2	21.2
West Kentucky	n.a.	17.8	n.a.	n.a.	3.4	17.1	+ 19.6	24.3
Colorado	18.2	16.9	– 0.8	n.a.	4.8	16.8	+ 14.9	19.4
Montana†	50.3	125.2	+ 10.7	n.a.	2.7	5.9	+ 9.2	8.1
Wyoming	50.6	68.5	+ 3.4	n.a.	3.3	8.2	+ 10.6	10.1
Ohio	25.4	13.7	– 6.6	n.a.	4.0	17.1	+ 17.6	25.8
Pennsylvania	15.4	11.5	– 3.2	n.a.	5.4	25.6	+ 18.9	32.8
West Virginia	15.8	8.2	– 7.0	n.a.	5.3	31.0	+ 21.6	39.8

* Estimated on the basis of average annual rate of increase between 1968 and 1978.
† Includes lignite

Source: U.S. Bureau of Mines, Minerals Yearbook, 1976;
Department of Energy, Bituminous Coal and Lignite Production and Mine Operations (1977).

on regression analyses involving various factors affecting productivity, indicates that the loss of productivity in underground coal mines in the United States since 1969 has been largely due to the Coal Mines Health and Safety Act (CMHSA) and especially due to increasingly stricter enforcement of some of its provisions concerning withdrawal orders. This reflects clearly in the largely increased negative effect of CMHSA on productivity since 1972 - 73 about 3 to 4 tons per man-day. There are other factors involved in productivity decline. The 1975 changes in coal market conditions—increased production and prices—enabled previously marginal operations to remain in production, which caused a productivity decline of about 1.7 tons per man-day. Also, the increasing number of wildcat work stoppages between 1970 and 1975 caused a loss in productivity of 1.1 tons per man-day. Increasing average production per mine accounted for some compensation of lost productivity until 1974 but this effect lessened in 1975 and thereafter.

In Illinois, the regression analysis showed that initially the CMHSA almost solely accounted for the productivity losses in the underground mines in the 1970s. A slightly greater impact on productivity of Illinois underground coal mines has been attributed to the improved coal market conditions in 1975, which prevented closing the marginally economic mines. The increased size of the average mine offset some of the losses in Illinois too.

The investigation differentiates between Appalachian and non-Appalachian surface mines. The Appalachian surface mines essentially show the same causes and pattern of productivity decline. The implementation of reclamation laws resulted in only a slight decline in productivity until 1972 but a rapidly increasing effect thereafter. On the other hand, increasing average size of mines until 1972 offset the productivity losses partially. After 1972 the number of small mines increased dramatically and resulted in declining average mine size and falling productivity. The rise in number of small operators was facilitated by a doubling coal price between 1973 and 1975.

TABLE 19. Average sizes of mines in 1977

	Underground (ton/yr)	Surface (ton/yr)
Illinois	1,180,000	512,000
Indiana	168,000	276,000
West Kentucky	779,000	187,000
Colorado	138,000	385,000
Montana	–	3,400,000
Wyoming	325,000	2,836,000
Ohio	430,000	121,000
Pennsylvania	274,000	65,000
West Virginia	97,000	65,000
United States	106,000	119,000

Source: Bituminous Coal and Lignite Production and Mine Operations, 1977: U.S. Department of Energy DOE/EIA-0118(77), December 21, 1979.

In the non-Appalachian states, reclamation acts resulted in increasing loss of labor productivity, especially in 1972 and thereafter. A structural change taking place in the surface mining industry shifted the production to large western mines and until 1973 more than compensated for the losses in average productivity. As a result, overall productivity increased from 37.3 tons to 43.8 tons per man-day between 1965 and 1973. In the 1973 - 1975 period the number of non-Appalachian surface mines increased by 34 percent, the average mine size declined, the coal price more than doubled, and reclamation laws continued to affect productivity, thus resulting in productivity decline to the 1965 levels.

In Illinois, nearly two-thirds of productivity losses between 1972, when state reclamation laws first showed effects, and 1976 can be attributed to the State Land Conservation and Reclamation Act of 1971. Further productivity losses were caused by the declining size of mines and the aging of mines (older than 7 years). The overall productivity of surface mines in Illinois increased from 38 to 40 tons per man-day between 1969 and 1972 but declined to 25 tons per man-day in 1976 and to an estimated 15 tons per man-day in 1980.

Absenteeism and wildcat strikes accounted for an increasing number of man-days lost since 1968, reaching more than 2.25 million man-days lost in 1977. Preliminary statistics for 1978 and estimates for 1979 show that man-days lost may have reached the lowest figures since 1968 as a result of the labor contract signed between the United Mine Workers of America and the Coal Mines Operators Association in 1978.

The reasons for declining productivity can thus be traced back to changing geologic conditions, government regulations, a changing price situation, and labor behavior. Some positive steps are required to meet the challenge: a review of government regulations; negotiation of labor contracts considering labor needs as well as productivity aspects; an investigation of new technologies such as the longwall mining for greater resource utilization and higher labor productivity; and introduction of production incentives.

SUMMARY

- The rising demand for coal in the United States has not prevented substantial market losses for Illinois Basin coal nor is it likely to do so in the future.
- More extensive coal cleaning may pay for itself because of savings realized in boiler plants, waste disposal, and handling areas.
- The mandatory installation of scrubbers may permit use of high-sulfur coal, but added costs of scrubbing high-sulfur coal will have a negative impact and will result in continued loss of markets even in the long term. Efforts to minimize scrubbing costs must therefore be undertaken.
- Illinois Basin coal may have increased advantage in transportation costs especially over Western coals. The positive effects of railroad deregulation may not fully compensate for disadvantages elsewhere.
- The moderate tax advantage presently enjoyed by Illinois Basin coal vs. Western coal does not significantly improve its market chances. Introduction of a severance tax in Illinois and reduction of severance taxes in western states are being considered. Both these actions could affect the competitiveness of Illinois Basin coal in the future.
- Because coal mining costs account for the single largest cost factor, future efforts in improving marketability of Illinois Basin coal must aim at reducing mining costs. The most significant factors will be to minimize the adverse effects of regulations and to improve labor relations in order to increase productivity.
- Table 20 summarizes the quantifiable and non-quantifiable effects of the factors analyzed on future competitive positions of Illinois Basin coal.

TABLE 20. Summary of the effects of various factors on the future prospects of Illinois Basin Coal

Factors	Illinois Basin Coal	Western Coal[a]	Eastern Coal[b]
Demand for coal vs other fuels	+	+	+
Competition from other United States coal fields	–	+	+
Environmental regulations	–	–	–
Coal beneficiation	+	+	+
	($/ton)	($/ton)	($/ton)
Flue gas desulfurization cost[c]	8.70 –	+	6.60 –
Transportation cost	5.00 +	16.50 –	1.75 +
Taxation	0.80 +	2.00 –	0.80 +
Value of coal f.o.b. mine	23.00 –	12.00 +	32.00 –
Subtotal[d]	37.50	30.50	41.15

[a] Western coal refers to Colorado, Montana, and Wyoming.
[b] Eastern coal refers to West Virginia, East Kentucky, Pennsylvania, and Ohio.
[c] Relative costs of FGD.
[d] Cost relation is significant, absolute figures will vary (see c).

Note: The nonquantifiable aspects of the factors have been judged with a + or – sign depending upon their overall future effects. The quantifiable factors are based on 1979 values.

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