The original documents are located in Box 4, folder "Coal (4)" of the Loen and Leppert Files at the Gerald R. Ford Presidential Library.

3-16-76

Neta:

Send a copy of the attached with a short note from me to:

Rep. Joe Skubitz
Rep. Jim Haley
Rep. Sam Steiger
Rep. Phil Ruppe

& keep copy for our files.

Thanks.

DIRECTOR
COUNCIL ON WAGE AND PRICE STABILITY

March 16, 1976

Charles Leppert:

Per our discussion at lunch last week.

Michael Moskow

March 17, 1976

Dear Joe:

I am enclosing herewith, the March 1976 Staff Report of the Council on Wage and Price Stability, "A Study of Coal Prices."

This is a review of the coal price changes from 1948 to 1975.

Sincerely,

Charles Leppert, Jr.
Special Assistant
for Legislative Affairs

Honorable Joe Skubitz
House of Representatives
Washington, D. C. 20515

Enclosure

March 17, 1976

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Honorable James A. Haley
House of Representatives
Washington, D.C. 20515

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Special Assistant
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Honorable Philip E. Ruppe
House of Representatives
Washington, D. C. 20515

Enclosure

FOR RELEASE IN AM'S

WED., MARCH 17, 1976

Executive Office of the President
Council on
Wage and Price Stability

Staff Report

March 1976

A Study of Coal Prices

EXECUTIVE OFFICE OF THE PRESIDENT
COUNCIL ON WAGE AND PRICE STABILITY
726 JACKSON PLACE, N.W.
WASHINGTON, D.C. 20506

ERRATA:

Page 69, lines 23-24. Change to read: "are now estimated to be about 4 trillion tons."

Page 69, line 30. Change 434 to 437.

Page 69, line 36. Change 217 to 211.

Page 70. "Total Recoverable Resources" should read "Total Recoverable Reserves."

EXECUTIVE OFFICE OF THE PRESIDENT
COUNCIL ON WAGE AND PRICE STABILITY
726 JACKSON PLACE, N.W.
WASHINGTON, D.C. 20506

March 16, 1976

TO THE MEMBERS AND ADVISER MEMBERS OF THE COUNCIL ON WAGE AND PRICE STABILITY

This report was undertaken in response to the remarkable tripling of coal prices in recent years. This increase was all the more unusual because coal prices have historically (1948-1969) been quite stable. The study was undertaken in accordance with the Council's statutory mandate to review and analyze price behavior in individual industries which exhibit strong inflationary pressures.

The report concludes that the sharp increase in coal prices between September 1973 and November 1974 reflected an abnormal surge in demand for a product whose immediate supply cannot be expanded rapidly. The surge was caused by a quadrupling of the price of imported oil, which to some extent is a substitute fuel, and by near-panic buying in anticipation of the coal miners strike of November 1974. The behavior of coal prices was precisely that which one might expect in a competitive natural resource market where short-run supply is relatively fixed and unable to accommodate rapid increases in demand. These sharp increases in price led to sharp increases in coal company profits in 1974 and 1975. The report found the degree of economic concentration in the coal industry to be less than in the average manufacturing industry in the United States.

The report also points out that as coal demand has receded from its peak level in November 1974, coal prices also have declined from their historic highs.

The outlook for coal prices in the next decade is favorable, the report concludes, with good prospects for stable prices (1975 dollars) and in some parts of the country declining prices. The key here is western coal. Any sizeable development of the nation's western coal reserves will place substantial downward pressure upon coal prices. The report analyzes the reasons western coal enjoys an advantage as an energy source over eastern coal, OPEC oil, uranium and natural gas:

-- Its supply is vast.

-- It is relatively inexpensive to mine.

-- It is low in sulfur and therefore less expensive to burn cleanly.

But the report cautions that the actual price level for coal at any time in the next decade will depend on what happens with several critical factors currently constraining the development of new western mines. It concludes that major development is hampered by considerable uncertainty surrounding:

- the outcome of Federal environmental policies regarding sulfur oxides emissions, strip-mining reclamation and coal leasing;

- future growth rates in demand for generation of electrical power by utilities which currently accounts for 70 percent of coal consumption.

A word about the report itself. Section I is an executive summary; section II analyzes the development and structure of the industry; sections III and IV describe and analyze coal price changes from 1948 to 1975; and section V analyzes prospects for coal prices over the next decade. A critique of coal price statistics is contained in Appendix A, and the twenty largest domestic coal companies and their 1974 production are listed in Appendix B.

The report was prepared under the direction of Robert W. Crandall, Assistant Director of the Office of Wage and Price Monitoring. Assisting in parts of the study were Rush Greenslade, consultant to the Council staff, and research assistants Christopher Roberts and Robert Zoellick.

Michael H. Moskow
Director

TABLE OF CONTENTS

I. EXECUTIVE SUMMARY

In 1969, the average price per ton of coal sold in the United States was $4.99, exactly what it had been in 1948. Though there had been some price fluctuation in the intervening years, it had been slight. During that period, only once (1957) had the price edged up over $5; only once (1963) had it fallen below $4.40.

The Price Rise

When average prices per ton jumped 25 percent in 1970, another 36 percent between 1971 and 1973, and 93.4 percent in 1974, it was obvious that something out of the ordinary was occurring in the United States coal industry. Moreover, these average price data actually understated the trend for new sales of coal because they aggregated current sales with sales made under agreements struck in earlier years. Approximately 80 percent of all coal sold in the U.S. market is sold under long-term contracts, and prices of coal delivered under these contracts naturally change far more slowly than and lag behind prices in the remaining 20 percent of the market, the so-called "spot market." (See Figure I)

In the fifteen-month period from September 1973 to November 1974, the average delivered price to electric power plants of steam coal purchased in the spot market rose from $10.67 per ton to $31.95 per ton. In the same period, the price of export coal rose from $17.64 per ton to $63.27 per ton, and the Wholesale Price Index (1967=100) for domestic sizes of coal (for household and commercial use) rose from 188 to 552.

Because of these unusual developments, the Council staff began an analysis of the behavior of prices in the coal industry in July 1975. This study was undertaken in accordance with the Council's statutory mandate to review and analyze price behavior in individual industries which exhibit strong inflationary pressures. The following pages summarize the findings of the study and offer an analysis of future price and consumption trends in the industry.

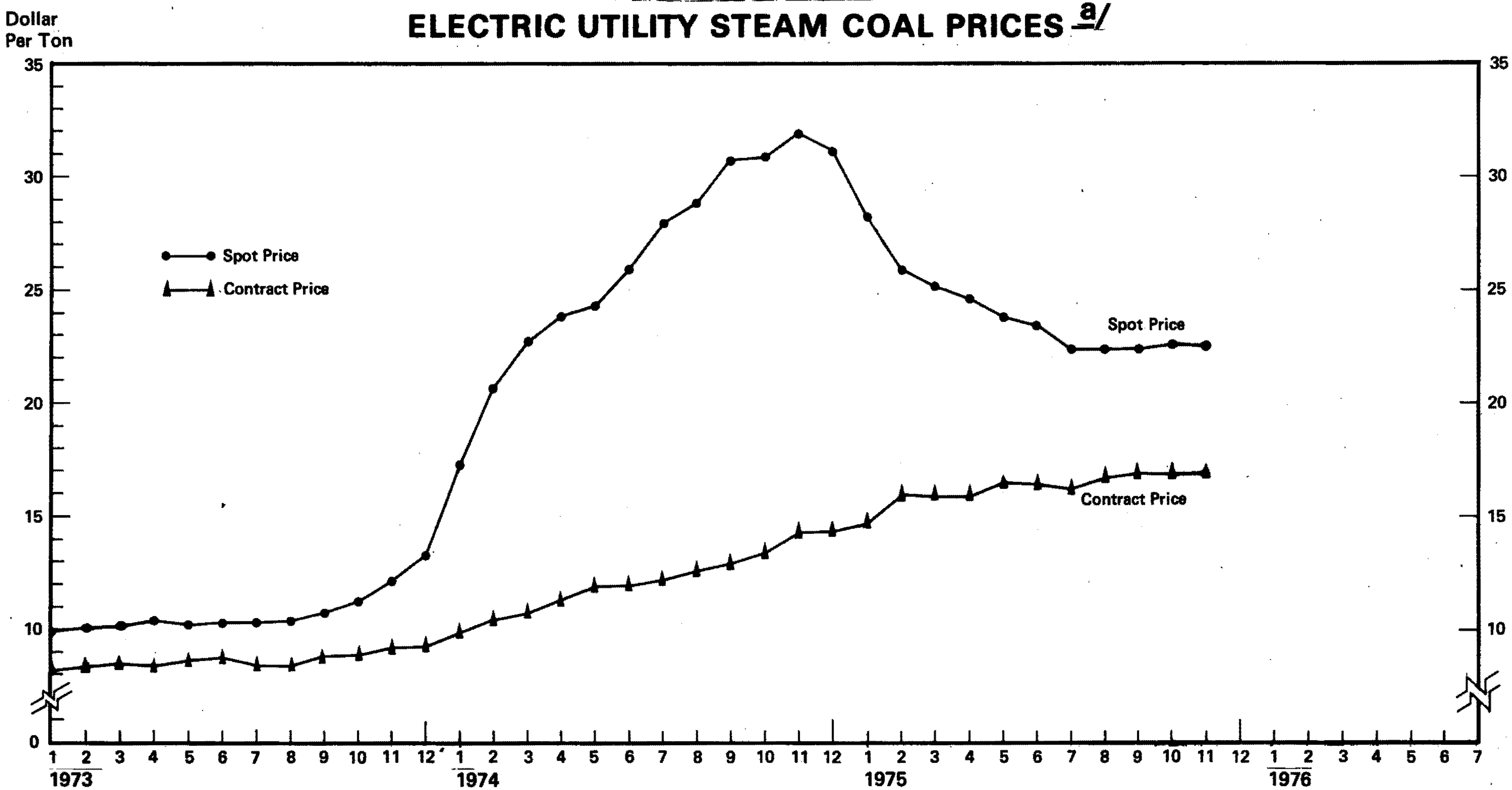
Why Prices Rose

The study focuses upon several factors which explain the rapid rise in prices through 1974.

- OPEC Actions. The rapid rise in coal prices which began in November 1973, illustrated in Figure I, was in large part the result of dramatically higher prices for imported oil. The unanticipated strength of the oil embargo and subsequent OPEC cartel pricing which drove up the price of oil to electrical utilities by 180 percent in the year ending June 1974 created an abnormal increase in the demand

FIGURE I

ELECTRIC UTILITY STEAM COAL PRICES a/



a/ F.P.C., Monthly Fuel Cost and Quality Information, news releases; based on Form 423 reports.

for coal. Substitution of coal for oil by a small number of users combined with inflexible demands from coal-dependent utilities placed sharp upward pressure on prices. During this period, delivered spot prices rose by 148 percent and average delivered contract prices by 38 percent.

- UMW Strike. Anticipation of the United Mine Workers' strike was a major factor putting upward pressure on spot coal prices during the second half of 1974. This pressure intensified as the expiration date (November 12, 1974) of the contract approached and it became clear that contract negotiations were proving unsuccessful. Strenuous efforts in the second half of 1974 by the steel industry, electric utilities and foreign purchasers to build stockpiles reached near-panic proportions.

These two unusual forces in the face of a relatively fixed short-term supply of coal drove its price up steeply.

A somewhat less important factor contributing to the upward trend in prices during this period was the continuing increase in labor costs, a trend which had begun in 1970. Average labor costs per ton of coal, which represent about one quarter of the price of a ton of coal, have risen significantly since 1970. Labor, which had cost an average of $2.38 per ton in 1970, was costing $3.65 per ton by 1974 and would rise to $4.45 by 1975. Much of this increase was due to a significant reduction in output per manhour during this period. Implementation of the Federal Coal Mine Health and Safety Act of 1969 may have contributed to this reduction in productivity.*

It is noteworthy that, while the spot price of coal rose rapidly relative to costs, it did not rise as much as the price of oil, nor did it behave differently from the prices of other competing fuels. Between September 1973 and July 1975, the price paid by utilities in Texas for intrastate natural gas increased by 246 percent and the price of uranium more than tripled.

The fact that 1974 price increases in the coal industry were largely demand-induced was evidenced by the experience of the last year, illustrated in Figure I. The strike, which had created much of the abnormal demand, began on November 12, 1974, and union mines were shut down for

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* The study examines only some of the costs associated with this Act, and does not attempt a definitive analysis of its overall costs or the countervailing benefits flowing from improved mine worker safety.

nearly one month. By mid-December, however, the industry had returned to three-quarters normal production, and by January 1975 to full production. Spot prices promptly began to decline. Six months later in May, average contract prices leveled off. Recent spot prices have dropped to half the level they had reached one year ago (February 1975), according to representative quotes by brokers reported in the trade press. Moreover, these prices are now less than one-half the cost of the equivalent energy obtained from residual oil.

While it was true that both spot and contract prices have remained above their mid-1973 levels, there are reasons for this:

- The world price of oil has remained high due to the OPEC actions of 1973-1974. Prices of imported oil have continued to rise since the 1973 embargo, raising the price of one of the most important substitutes for coal to more than $13 per barrel.

- Insufficient time has elapsed for many major new capital investments to have become fully operational in the coal industry. New mines require several years to become productive. Moreover, Government policy remains uncertain in a number of areas, serving to inhibit major expansion. These policy areas include, among others, coal leasing, sulfur oxides emissions, and strip-mining reclamation.

Competition and Supply in the Coal Industry

The report finds that the recent price behavior in this industry was consistent with what would be expected in a competitive natural resource market that had experienced sudden increases in demand.

In 1974, the top four U.S. coal companies produced slightly more than a quarter of total domestic coal output. The eight largest firms produced about a third, and the twenty largest companies controlled a bit more than half of total production. By comparison, in the average manufacturing industry, the largest four firms accounted for approximately 39 percent of industry sales in 1966. Not only is the coal industry less concentrated than the average manufacturing industry, but the trend in the coal industry since 1970 has been toward reduced concentration.

Concentration is greater in some areas than in others, the greatest occurring in states such as Illinois, Indiana, Kansas and Missouri where there are large tracts of coal which may be strip-mined. But there is little evidence that price behavior is different in those areas than in West Virginia, Pennsylvania and Eastern Kentucky where ownership is much more fragmented.

In a natural-resource market where short-run supply elasticity is low, it is reasonable to expect sudden increases in demand to produce rapid increases in price. The expansion of output requires major new investments. Transportation facilities must be adapted to the new facilities. Output can be expanded quickly in existing mines only if the mines are operating at less than full capacity and if men and machines can be quickly added.

Because of the suddenness of the embargo, most of the 1974 supply expansion was limited to existing mines. Nevertheless, employment grew ten percent from October 1973 to October 1974. At the same time production increased from 54.4 million tons for the month to 60.3 million tons, again a ten percent expansion. If the UMW strike had not intervened, there would have been additional production of about 36 million tons, or a total increase of 47 million tons over the 1973 production level. The study concludes that output did not expand more in 1974 largely because of technological and practical barriers to rapid expansion.

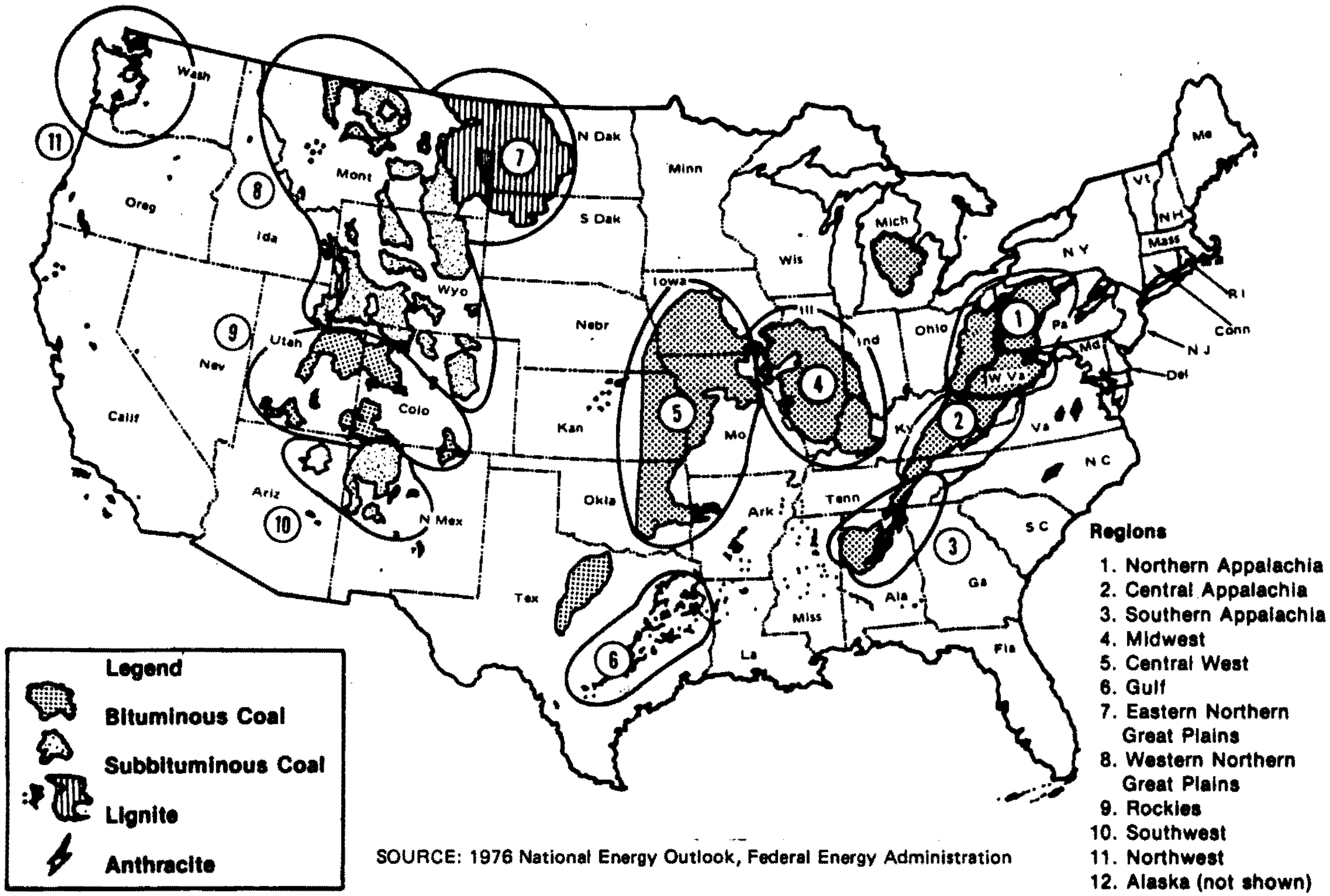
The fact that the coal industry was not poised to spring for rapid capital expansion in 1974 is explained by financial conditions in the industry in the years just previous. Profits in 1971-1973 had not been conducive to high levels of investment. Moreover, the prospects for increased coal demand were clouded by uncertainties regarding: (a) competition from nuclear power generation; (b) competition from relatively cheap low sulfur oil before 1974; and (c) Clean Air Act limitations on sulfur oxides emissions.

Profits for the coal industry in 1974 and 1975 contrast sharply with profit levels in the early 1970s. Available data on profits, although limited, show that the average rate of return on investment fell from 15.6% in 1970 to 10.6% in 1973, while the average return for 425 industrial firms for the same period rose from 10.3% to 14.1%. In 1974, the average rate of return for coal companies rose to 25.2%, while the average rate for industrial firms remained almost constant at 14.2%. Preliminary data for 1975 indicate that coal company profits continued to rise as contract prices maintained their upward movement through 1975. These sharp increases in profits flowed from the higher coal prices stimulated by the higher levels of demand described above.

Fuel Adjustment Clauses

Concern has been expressed that the automatic fuel adjustment clauses permitting regulated utilities to pass through their fuel cost increases eliminate all incentive for utilities to resist coal price increases. The report concludes that utilities committed to

Coal Supply Regions



SOURCE: 1976 National Energy Outlook, Federal Energy Administration burning coal by past investment decisions had little alternative in 1974 but to purchase coal in a market in which the price was soaring, regardless of whether they had a fuel adjustment clause. In the short run, utilities could neither substitute other fuels for coal nor curtail output because of their public utility status. Furthermore, an analysis of the consumption-inventory patterns for electric utilities suggested that they did not behave differently from nonutility firms which had no automatic fuel adjustment clauses by which they could pass on coal price increases.

The Next Decade: The Importance of Western Coal

What happens to coal prices in the next decade depends importantly on factors which are currently constraining its supply. The 1976 National Energy Outlook recently released by the Federal Energy Administration, predicts that coal output will be 799 million tons in 1980 and 1039 million tons in 1985, of which 31 percent and 36 percent will be derived from the West in 1980 and 1985, compared to only 17 percent in 1975. The projections are based upon an assumption of continuing high prices of imported oil and little new nuclear power. A critical component of the long-term forecast is the development of the subbituminous and lignite deposits of Wyoming, Montana, and North Dakota, which are estimated to contain 48 percent of U.S. coal reserves. There are a number of advantages to this western coal.

- It is often low enough in sulfur content to meet air quality standards required by the Clean Air Act without additional sulfur emission controls -- whereas only a small fraction of coal from the mid-West and Appalachia is low in sulfur.

- Western coal seams are generally easier to mine than seams east of the Mississippi. They are close to the surface, often quite thick and are concentrated in a few areas. Western surface mining operations are therefore cheaper than in the East where seams are deeper, thinner, and distributed more sporadically. Production from western mines would be more responsive to any increase in price than production from eastern mines.

Given these advantages, the development of western coal reserves will place substantial downward pressure upon coal prices. Eastern movement of this coal should place an upward limit upon coal prices in most consuming locations west of the Appalachians if supply constraints discussed later are eased. The output of eastern coal will exceed western output for more than another decade, but the prices realized from this coal will be constrained increasingly by the availability of western coal. The delivered price of coal in midwestern and eastern locations will be less than the price of equivalent energy from oil unless there is a sharp break in the OPEC price of oil. These delivered coal prices will induce utilities to invest in new coal-fired capacity and to convert some older oil-fired capacity to coal. The precise prices and rates of consumption at each consuming location are difficult to predict due to the long list of uncertainties facing coal producers and consumers:

- Oil Prices. The strength of demand for coal depends importantly on the cost and availability of substitute fuels -- notably oil. At present OPEC oil prices, coal is more attractive than oil to electrical utilities, but this situation could change if the price of imported oil should fall substantially (by one-third or more).

- Nuclear Power. The nuclear power industry -- a major potential competitor -- has an increasingly unclear future. Unanswered questions include: (1) the level of operating costs; (2) availability of enriched uranium supplies; (3) the extent of private sector assumption of costs for uranium fuel enrichment technology; (4) the extent of environmental and safety hazards at every point in the nuclear fuel cycle; (5) the potential costs of regulatory safeguards.

- The Rate of Electrical Energy Demand and Growth. Because the electric power industry consumes about 70 percent of U.S. bituminous coal, growth in demand for electricity will have a major effect on demand for coal. Current demand has fallen substantially below previous estimates, and there is now a considerable difference of opinion as to future rates of growth. Current estimates of annual growth in electricity output range all the way from 3 to 7.2 percent, a difference which could mean as much as 600 million tons more or less of coal consumption in 1985.

- Sulfur Oxides Policy. A major obstacle blocking expansion of long-term coal demand is uncertainty regarding Federal legislation for sulfur oxides control. Coal users have been reluctant to make long-term commitments until questions on possible revisions of the Clean Air Act of 1970 are resolved.

- Strip-Mining Regulations. The future of strip mining in both the East and the West remains cloudy. While strip-mining legislation exists in all major coal-producing states, these laws could be strengthened, increasing the cost of surface mining. Moreover, federal strip-mining reclamation legislation continues to be a possibility. The future supply price of coal is intimately tied to the cost of exploiting surface deposits and, therefore, to the cost of reclamation required by law.

- Coal Leasing Policy. Resolution by the Supreme Court of *Sierra Club v. Kleppe* should serve to clear up some of the environmental policy issues involved in the leasing of federal coal lands, but until these issues are resolved coal production from existing or new federal leases could be constrained. This case concerns the Interior Department's compliance with the National Environmental Policy Act of 1969 in its leasing of federal coal lands in the Powder River Basin.

- Transportation. Major new investments are required to move coal from the West to eastern and midwestern consuming points. Whether this investment should take the form of expanded (unit-coal train) railroad capacity, investments in coal-slurry pipelines, or expanded inland waterways is still very much under debate.

- State Severance Taxes. There may be additional western state taxes on production from their low-cost coal deposits. These taxes would increase western coal producers' costs and drive up coal prices throughout the country.

- Labor Costs. Continuing labor difficulties and rising coal miner wages coupled with declining productivity in eastern deep mines, could drive up prices in eastern regions thus increasing the penetration of western coal in eastern markets.

The problem, in sum, is that despite the vast reserves of domestic coal and the Federal Government's stated intent of encouraging development of those reserves as part of the effort to achieve energy independence, a great deal of uncertainty exists regarding future coal demand and the resolution of federal policies pertaining to coal burning and coal production. In recent months, few long-term coal contracts for new mines have been signed. Until there is an assured market, coal producers may not be able to justify nor finance the major investments needed to construct and operate large new mines east of the Mississippi. At the same time, development of planned western mines has been delayed in areas where environmental issues are unresolved. Until some of these uncertainties are clarified, short-term coal demand will have to be met by production from existing mines and from exploitation of lands currently under lease. Moreover, even if some of the present uncertainty is resolved, several years will be required to get large new mines into production since constructing a new underground mine requires from three to five years and a large surface mine needs two to three years.

Recognizing all these uncertainties, the report made several observations about the outlook for coal prices in the next decade.

- The increase in the production of western coal will act as a brake on the upward movement of coal prices throughout the United States in the next decade if legal and policy issues are resolved. The outlook is therefore favorable with good prospects for stable prices (1975 dollars). Midwestern prices of low sulfur coal may decline from current levels and eastern seaboard prices should also be constrained near current levels as western coal moves eastward.

- Assuming western development takes place, the long-term equilibrium price of coal in most locations west of the Appalachians will be relatively independent of the long-term rate of growth in demand. In other words, the reserves of western coal are so large and accessible that small increases in price will generate substantial increases in supply. If adequate transportation facilities are constructed, western coal, because of the great responsiveness of its supply to changes in price, should be available from FOB mine prices of $5 to $6 per ton (1975 prices) regardless of how much demand increases for the next decade.

- At present, imported oil and nuclear power are so costly that most electrical utility new investment decisions throughout the country are in coal-fired capacity. If the cost of these substitute sources of energy were to fall, their greatest impact would be felt on the eastern seaboard. Major declines in oil prices and nuclear costs would be required to have a noticeable effect upon midwestern and western coal prices.

- Possible innovations in west-east transportation, such as the coal-slurry pipeline, will not be a major force in the next decade. Investments in railroad capacity and the level of railroad rates will have a major effect, however, in determining the transportation cost of western coal and, thus, the price of both western and eastern coal in the United States.

- If Congress were to tighten current law governing sulfur oxides emissions, many coal-burning utilities would be forced either to invest in scrubbers or to use very low sulfur coal. At present there are unresolved questions as to the cost of using scrubbers. Once these questions are resolved, the difference in cost between low and high sulfur coal will be equal to the cost of operating and amortizing scrubbers.

II. COAL INDUSTRY TRENDS

1. Post-War Decline

The United States is rich in coal reserves. But the fuel is dirty, dangerous to mine underground, environmentally damaging to mine above-ground, difficult to handle and expensive to transport. Because of all these problems post-World War II coal markets declined as the largest coal consumers turned to oil and natural gas, which were cleaner, more convenient, and cheaper. Coal production sank from 630 million tons in 1947 to a nadir of 403 million tons in 1961 (Table II-1). Coal, which had supplied 43.5 percent of U.S. energy needs in 1947, declined to 21.5 percent of the nation's fuel supply in 1961 chiefly because the demand from domestic heating and railroad markets shifted to other sources.1/

2. Industry Growth in the 1960's

Coal production began to revive gradually but steadily during the 1960's, primarily due to the number of large coal-fired power plants built to meet the rapidly increasing demand for electrical energy. Technological advances enabled boilers in these power plants to use coal more efficiently, so that production increased to 603 million tons in 1970. Although coal still represented only 24 percent of the nation's

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1/ The uses and value of coal are determined by its physical and chemical characteristics: heat content (Btu), ash content (non-combustibles), water content, and sulfur content. Certain gaseous, smoking and coking characteristics are important for specific industrial applications, particularly for steel manufacturing. Metallurgical -- or coking -- coal, used for steel production, must have low sulfur and ash content, and it must coke (remain solid and release its gases) instead of crumbling when heated in an airless coke oven. Low volatile coal is superior to high volatile coal because it has a lower percentage of stored gases (less than 22 percent by weight), and it produces greater amounts of stronger coke. Low volatile coal is scarcer than high volatile and commands a somewhat higher ($3-$6 per ton) price. Normally, the two types of coal are blended to make coke.

Steam coal, used primarily for electric power generation, is more common and less expensive (averaging half the price of metallurgical coal). Steam coal can be higher in sulfur and ash content, but the most desirable forms have low sulfur content, low ash content, and high Btu value.

TABLE II-1

Growth of the Bituminous Coal Mining Industry in the United States

Year	Production (net tons)	Value		Men Employed	Number of Mines	Average Number of Days Worked	Net Tons Per Man		Percent of Total Production Strip Mined
		Total (thousands)	Average per ton				Per Day	Per Year	
1945	577,617,327	1,768,204	3.06	383,100	7,033	261	5.78	1,508	19.0
1946	533,922,068	1,835,539	3.44	396,434	7,333	214	6.30	1,347	21.1
1947	630,623,722	2,622,635	4.16	419,182	8,700	234	6.42	1,504	22.1
1948	599,318,229	2,993,267	4.99	441,631	9,079	217	6.26	1,358	23.3
1949	437,868,036	2,136,871	4.88	433,698	8,559	157	6.43	1,010	24.2
1950	516,311,053	2,500,374	4.84	415,582	9,429	183	6.77	1,239	23.9
1951	533,664,732	2,626,030	4.92	372,897	8,009	203	7.04	1,429	22.0
1952	466,840,782	2,289,180	4.90	335,217	7,275	186	7.47	1,389	23.3
1953	457,290,449	2,247,942	4.92	293,106	6,671	191	8.17	1,560	23.1
1954	391,706,300	1,769,620	4.52	227,397	6,130	182	9.47	1,724	25.1
1955	464,633,408	2,092,383	4.50	225,093	7,856	210	9.84	2,064	24.8
1956	500,874,077	2,412,004	4.82	228,163	8,520	214	10.28	2,195	25.4
1957	492,703,916	2,504,406	5.08	228,635	8,539	203	10.59	2,155	25.2
1958	410,445,547	1,996,281	4.86	197,402	8,264	184	11.33	2,079	28.3
1959	412,027,502	1,965,607	4.77	179,636	7,719	188	12.22	2,294	29.4
1960	415,512,347	1,950,425	4.69	169,400	7,865	191	12.83	2,493	29.5
1961	402,976,802	1,844,563	4.58	150,474	7,648	193	13.87	2,678	30.3
1962	422,149,325	1,891,554	4.48	143,822	7,740	199	14.72	2,935	30.9
1963	458,928,175	2,013,309	4.39	141,646	7,940	205	15.83	3,240	31.4
1964	486,997,952	2,165,582	4.45	128,698	7,630	225	16.84	3,784	31.2
1965	512,088,263	2,276,022	4.44	133,732	7,228	219	17.52	3,829	32.3
1966	533,881,210	2,421,293	4.54	131,752	6,749	219	18.52	4,052	33.7
1967	552,626,000	2,555,378	4.62	131,523	5,873	219	19.17	4,198	33.9
1968	543,245,000	2,546,340	4.67	127,894	5,327	220	19.37	4,263	34.1
1969	560,505,000	2,795,509	4.99	124,532	5,118	226	19.90	4,497	35.2

TABLE II-1 (Cont'd)

Growth of the Bituminous Coal Mining Industry in the United States

Year	Production (net tons)	Value Total (thousands)	Value Average per ton	Men Employed	Number of Mines	Average Number of Days Worked	Net Tons Per Man Per Day	Net Tons Per Man Per Year	Percent of Total Production Strip Mined
1970	602,932,000	3,772,662	6.26	140,140	5,601	228	18.84	4,296	40.5
1971	552,192,000	3,904,562	7.07	145,664	5,149	210	18.02	3,784	46.9
1972	595,386,000	4,561,983	7.65	149,265	4,879	225	17.74	3,992	46.3
1973	591,738,000	5,049,612	8.53	148,121	4,744	227	17.58	3,991	46.8
1974	603,406,000	9,503,644	15.75	166,701	5,247	206	18.68	3,820	45.6
1975*	640,000,000	12,000,000	18.75	170,000	5,275	225	18.0	4,230	NA

NA = Not Available

* = Estimated. Some of these preliminary statistics may not be consistent with one another.

SOURCE: Bureau of Mines

total energy supply (compared with 32 percent for oil and 32 percent for gas),2/ the significant development was the new and steadily-growing demand for coal by electric utilities.

As indicated by Table II-2, the major market loss occurred as the railroads switched from coal to diesel fuel. Retail dealer delivery of coal to consumers also dropped sharply as did the demand by mining and manufacturing industries (other than steel and cement). By the 1960's the railroad market had disappeared and was being replaced by the electric utility demand for coal, which was growing at an annual rate of 6.4 percent. Utility use of coal has grown from less than 20 percent of the total coal market in 1950 to 70 percent in 1975. In addition, a significant amount of coal is purchased by industry in order to generate electricity for their private use.

3. Prices

The price of coal also has reflected demand trends. The average price per ton dropped from $4.99 in 1948 to $4.39 in 1963. But as electric utility and export demand for coal increased in the 1964-70 period, the price rose to $6.26 in 1970. It continued to rise gradually during the early 1970's. In 1974, however, the average price surged to $15.75 per ton -- almost twice that of the previous year -- and to $18.75 in 1975, according to preliminary estimates. There appear to be three reasons for this startling price increase:

- The Arab oil embargo of September 1973 and the subsequent Organization of Petroleum Exporting Countries (OPEC) price increases made domestic coal immediately attractive because of the relative certainty of supply and its lower cost.

- The United Mine Workers' (UMW) contract was about to expire in November 1974, and fears of a strike led some coal consumers to try to stockpile an adequate supply of coal.

- Price controls ended on most coal production in August 1973, and on the rest of the industry in March 1974.

2/ National Coal Association, Coal Data, 1974.

TABLE II-2

Yearly Consumption, by Consumer Class, of Bituminous Coal

Year	Electric Power Utilities	Bunker Foreign Trade	Beehive Coke Plants	Oven Coke Plants	Steel & Rolling Mills	Railroads and Other Manufacturing and Mining Industries	Retail Dealer Deliveries	Total Domestic Consumption	Exports	Total Consumption
1935	30,936	2,683	1,469	49,046	16,585	175,163	80,444	356,326	9,742	366,068
1940	49,126	2,989	4,803	76,583	14,169	198,553	84,687	430,910	16,466	447,376
1945	71,603	3,192	8,135	87,214	14,241	255,885	119,297	559,567	27,956	587,523
1950	88,262	2,042	9,088	94,757	10,877	164,754	84,422	454,202	25,468	479,670
1955	140,550	1,499	2,869	104,508	7,353	113,613	53,020	423,412	51,277	474,689
1960	173,882	945	1,640	79,375	7,378	86,804	30,405	380,429	36,541	416,970
1961	179,629	770	1,496	72,385	7,495	84,895	27,735	374,405	34,970	409,375
1962	190,833	687	1,339	72,923	7,319	86,485	28,188	387,774	38,413	426,187
1963	209,038	670	1,613	76,020	7,401	90,935	23,548	409,225	47,078	456,303
1964	223,032	711	2,025	86,732	7,394	91,607	19,615	431,116	47,969	479,085
1965	242,729	655	2,693	92,086	7,466	94,487	19,048	459,164	50,181	509,345
1966	264,202	609	2,369	93,523	7,117	98,481	19,965	486,266	49,302	535,568
1967	271,784	467	1,372	90,900	6,330	92,464	17,099	480,416	49,528	529,944
1968	294,739	417	1,268	89,497	5,657	92,028	15,224	498,830	50,637	549,467
1969	308,461	313	1,158	91,743	5,560	85,374	12,666	507,275	56,234	563,509
1970	318,921	298	1,428	94,581	5,410	82,909	12,072	515,619	70,944	586,563
1971	326,280	207	1,278	81,531	5,560	68,655	11,351	494,862	56,633	551,495
1972	348,612	163	1,059	86,213	4,850	67,131	8,748	516,776	55,960	572,736
1973	386,879	116	1,310	92,324	6,356	60,837	8,200	556,022	52,870	608,892
1974	390,068	80	1,337	88,410	6,155	57,819	8,840	552,709	59,926	612,635
1975*	332,799	21	941	69,178	2,245	48,694	5,034	458,912	53,542	512,454

* Through October

SOURCE: Bureau of Mines

4. Employment and Productivity

Productivity trends in the coal industry have developed in two ways: (1) improved productivity for surface mining contrasted with (2) a simultaneous decline in productivity for underground mining.

When coal demand picked up in the early 1960's, it was met increasingly by surface mining methods requiring far less labor than underground mining. By 1974, 54 percent of all U.S. coal was surface mined. The shift from deep to strip mining meant that overall industry productivity improved while overall employment remained low. For example, in 1973 output per man-day was 36 tons for surface mining, whereas deep mining output per man-day was less than 12 tons.

Underground mining productivity improved significantly until 1969, however, since then productivity has dropped from 15.6 tons per man-day in 1969 to 10.85 in 1974. Several factors seem to be responsible for this decline in productivity:

- The Coal Mine Health and Safety Act of 1969 which, in the interest of improved mine worker health and safety, provided for stricter mine safety requirements and for expanded health benefits for miners, has lowered output per man-day and increased labor and other operating costs.*

- The lack of trained manpower (foremen, supervisors, etc.). The last generation of experienced miners from the coal industry's pre-World War II boom days are retiring, and the current generation has frequently abandoned mining because it has been considered a dying industry. In the last few years, there has been an influx of new miners due to the resurgence in coal demand, but adequate training can take as long as three to five years.

5. Western Expansion

The newest and potentially most important trend is, of course, the post-oil embargo attention that has focused on coal development as a means of achieving U.S. energy independence from foreign suppliers. The emphasis on development of the nation's enormous coal reserves generated interest in expansion of the huge resources of the West (particularly the subbituminous and lignite deposits of Wyoming, Montana, and North Dakota: Northern Great Plains), which is estimated to contain 48 percent of U.S. coal reserves. There are a number of reasons for the attractiveness of western coal compared with Appalachian and midwestern reserves. Although these reasons will be discussed in detail in Chapter V, the most important ones are noted below:

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* This study examines only some of the costs associated with this Act, and does not attempt a definitive analysis of its overall costs or of the countervailing benefits flowing from improved mine safety.

- Western coal is often low enough in sulfur content to meet air quality standards required by the Clean Air Act without additional pollution controls.

- Western coal seams are often much easier to mine than seams east of the Mississippi. The seams are close to the surface, are often quite thick, and large quantities of the coal are concentrated in a few areas. Because most western coal can be surface mined, and because of the higher productivity levels of that mining method, operators have found it more attractive to move to a more mechanized, less labor-dependent mining method.

- The structure of the coal industry changed as a number of coal companies were bought by integrated energy companies. The new ownership was interested primarily in developing the huge tracts of low sulfur western coal from strip mines to be used by large electric utilities. Some of the western coal tracts were bought in the hope of converting the coal to synthetic fuels (gasified and liquefied coal).

Western production[3/] was 107 million tons in 1975 and is expected to grow to approximately 250 million tons by 1980. However, a number of environmental, legal and federal policy decisions halted coal expansion in the West for the last few years. Many of those particular constraints on western development are expected to be resolved within the next year. Despite that, a number of imponderables continue to cloud the outlook for expanded demand for U.S. coal (see Chapter V).

6. Current Situation

The present problem is that despite the vast reserves of domestic coal and the federal government's stated intent of encouraging development of those reserves as part of the effort to achieve energy independence, a great deal of uncertainty exists regarding future coal demand and federal and state policies affecting coal expansion. Since the embargo, very few new long-term coal contracts have been signed. One dilemma is that until there is an assured market for medium-to-high sulfur coal, coal industry executives say that they cannot justify nor finance the major investments needed to construct and operate large new mines east of the Mississippi. At the same time, development of planned, low-sulfur western mines has been slowed and uncertainty

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3/ Northern Great Plains, Rocky Mountain States, Pacific States and Texas.

remains not only about the resolution of the legal impediments, but also about other major constraints which may curtail expansion of western coal mining. Until some of these issues are resolved, short-term coal demand will have to be met by production from existing mines. Even if there were some resolution of the present uncertainty, several years would be required to get large new mines into production. Industry estimates for construction of a new underground mine range from three to five years and for a large surface mine two to three years.

Given the short-term inelasticity of coal supply, spot prices are subject to rather sharp fluctuations in response to variations in demand. In November 1974, demand was intense, and spot prices surged. Within the last year, however, short-term demand has flagged for a number of reasons -- relaxed buying subsequent to the panic induced by the embargo and the UMW strike, sufficient coal stockpiles, slackened steel industry demand for metallurgical coal, warm weather, very few coal conversions under the Federal Energy Administration's program, and minimal growth of electrical energy demand -- so that average spot prices in February 1976 -- chiefly reflecting midwestern and eastern coal prices -- are about half their previous year's levels.

III. RECENT HISTORY OF COAL PRICES -- 1973-1975

1. The Surge in Spot Prices

Coal prices increased moderately in the early 1970's, but the oil embargo of September 1973 initiated a dramatic acceleration. Prices began to climb in late 1973, accelerated throughout 1974, and peaked in November 1974 just before the settlement of the United Mine Workers' strike. During the fifteen-month period from the month prior to the embargo (September 1973) to resolution of the UMW strike (December 1974), the following increases in spot prices were recorded (Table III-1):

- The delivered spot prices of steam coal for use by electric power plants rose from \$10.67/ton to \$31.05/ton as reported by the Federal Power Commission.

- The price of exported coal (primarily metallurgical) rose from \$17.64/ton to \$63.27/ton according to U.S. Bureau of Mines and Tariff Commission data.

- The Bureau of Labor Statistics (BLS) Wholesale Price Index (1967 = 100) for domestic sizes of coal -- for household and commercial use -- rose from 188 to 552. For high volatile and low-to-medium volatile (which is more desirable because it is burned more efficiently) metallurgical coal used mainly for industrial purposes other than fuel, the index rose from 222 and 236 to 576 and 616, respectively.

  Prices began to decline after the UMW strike ended but at a much slower pace than they had risen. The price of steam coal for power plants dropped steadily to \$22.52/ton by October 1975. Export prices dropped more erratically with a \$46.22/ton price in October 1975. Spot steam prices continued to drop as demand slackened. Mid-February 1976 reports from producing regions indicate prices ranging from \$12.50-\$16/ton for both low and high sulfur steam coal. Export prices for the same period range from about \$46-\$51/ton.[1/]

1/ Wall Street Journal, February 16, 1976.

TABLE III-1

Representative Spot Coal Prices

Month	Year	1967 = 100 Wholesale Price Indexes a/ Metallurgical Low and Med. Volatile	High Volatile	Domestic d/	$/Ton Elec. Utility Spot b/ (Delivered)	$/Ton Export c/ (FOB Port)
	1970	149.9	150.9	141.9	-	13.40
	1971	184.2	185.3	166.1	-	15.74
	1972	204.8	198.4	176.2	-	17.38
	1973	227.9	216.5	192.0	-	18.96
	1974	443.2	424.4	367.4	26.55	40.39
Janaury	1973	216.1	208.2	189.3	-	19.81
Feburary		216.1	298.2	189.3	-	20.15
March		217.1	298.6	187.6	-	19.79
April		221.8	214.6	188.4	10.44	18.18
May		222.1	214.8	188.8	10.24	17.45
June		225.1	215.2	189.3	10.43	17.60
July		226.5	215.2	185.5	10.40	18.64
August		226.5	215.2	185.5	10.44	19.00
September		236.1	222.2	188.0	10.67	17.64
October		236.1	225.1	189.1	11.24	19.56
November		244.3	225.1	211.4	12.05	19.54
December		247.0	225.1	211.4	13.34	20.81
January	1974	254.4	232.8	219.7	17.02	22.77
February		257.6	235.9	219.7	20.57	24.54
March		288.8	248.3	232.5	22.54	26.48
April		422.2	422.6	326.4	23.70	28.11
May		422.4	422.6	340.0	24.21	31.28
June		441.6	422.8	362.3	25.84	34.79
July		494.6	482.1	384.8	27.99	39.83
August		519.0	505.6	390.4	28.87	48.26
September		534.2	505.6	403.5	30.64	51.86
October		534.0	252.4	488.6	30.67	48.79
November		534.0	525.4	488.6	31.95	55.86
December		615.8	576.5	552.2	31.05	63.27

(MORE)

TABLE III-1 (Cont'd)

Representative Spot Coal Prices

		1967 = 100 Wholesale Price Indexes a/			$/Ton Elec. Utility Spot b/ (Delivered)	$/Ton Export c/ (FOB Port)
		Metallurgical				
Month	Year	Low and Med. Volatile	High Volatile	Domestic d/		
January	1975	640.2	624.2	566.0	28.12	60.60
February		631.0	624.2	566.0	25.92	55.10
March		631.6	603.4	545.0	24.02	50.60
pril		640.7	618.7	545.0	24.52	46.70
May		653.7	619.1	552.7	23.78	47.20
June		653.7	619.1	538.8	23.36	47.60
July		654.1	619.7	538.8	22.35	44.70
August		631.5	620.2	530.6	22.39	48.10
September		631.5	620.2	521.9	22.46	48.79
October		631.5	620.2	521.9	22.52	46.22
November		619.8	619.8	510.6	NA	49.40
December		643.2	656.2	518.4	NA	49.24
January	1976	643.2	656.2	504.4	NA	NA

a/ BLS
b/ FPC, Monthly News Releases
c/ Bureau of Mines and National Coal Association
d/ Household and Commercial
NA = Not Available

2. Price Reporting

Strangely, the BLS indexes do not reflect these drops in price. Instead, all three BLS indexes exhibit an early 1975 increase followed by only moderate declines. However, there is reason to suspect that BLS sampling problems for coal may be responsible for a lag in reflecting actual increases and an understatement of the peak price.2/ Note the divergence in movements in the BLS, Tariff Commission, and Federal Power Commission spot-price series in Figure III-1. The trend in domestic metallurgical coal prices follows export coal because the latter is used primarily for metallurgical purposes. One major reason for the price surge is to be found in the steel industry's dependence upon metallurgical coal for coking operations. (Blast furnace ovens must stay hot continuously since so much time is needed to reheat the ovens to adequate levels). Because industry buyers felt they could not risk running out of metallurgical -- or coking -- coal, the prospect of a miners' strike loomed forebodingly over coal buying trends during 1974.

Federal Power Commission reports on spot coal prices in Table III-1 which indicates a smaller rise in utility prices than in metallurgical prices from June 1973 to June 1975. However, it must be noted that the FPC price reports include transportation charges for utility coal. With some rough calculations of freight charges for all coal3/, spot prices can be approximated as shown:

	(FPC) $/Ton Delivered	Index Delivered	$/Ton RR Charges	$/Ton Excluding RR Charge	Index Excl. RR (FPC)	Index Low Volume BLS
June 1973	10.43	100	3.71a/	6.72a/	100	100
June 1975	23.36	224	5.18b/	18.18b/	270	290

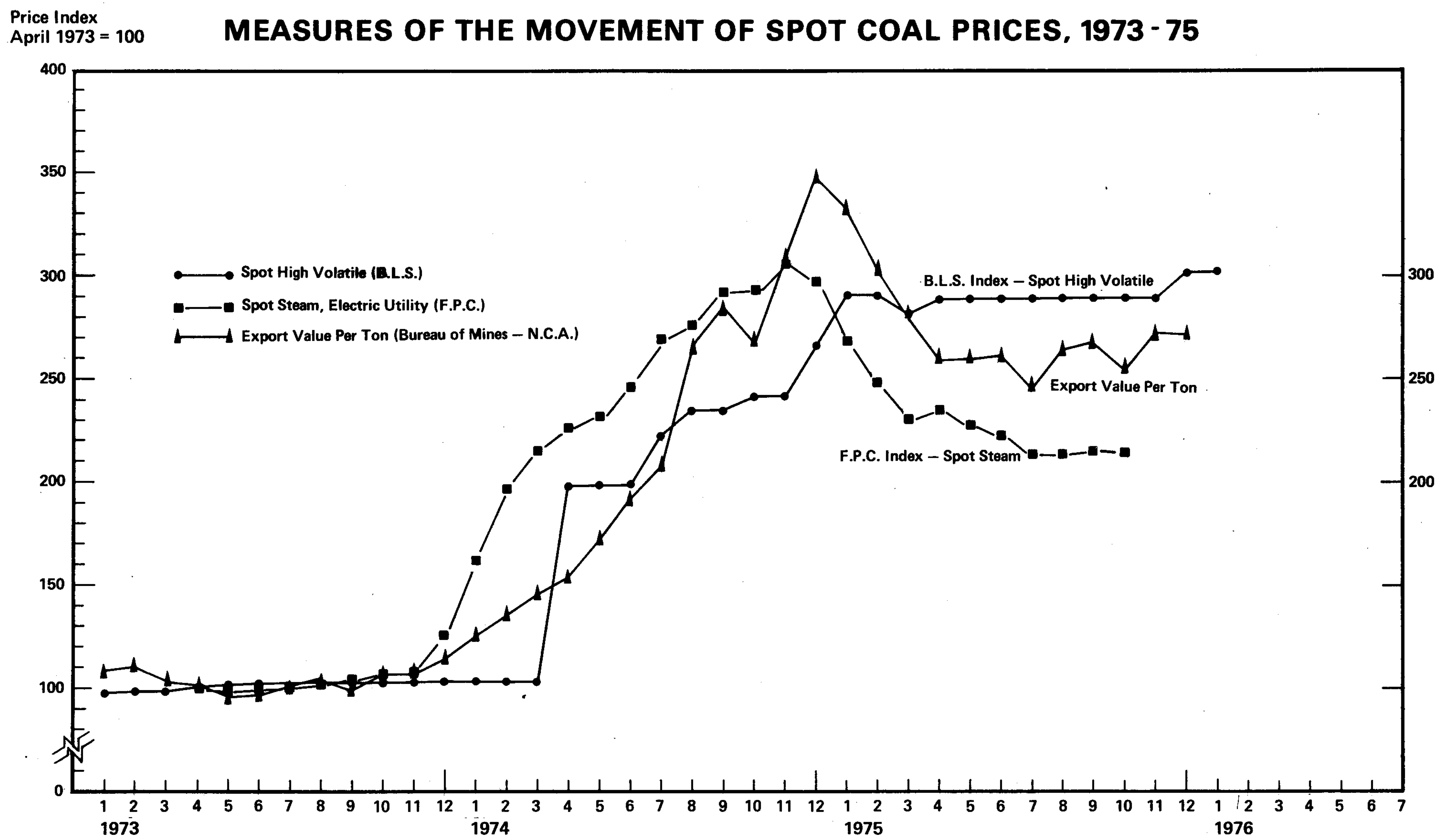
a/ Source: Bureau of Mines.
b/ Estimated from RR rate increases.

2/ This same sample deficiency is strongly suggested by comparing BLS steam coal spot prices for the Wholesale Price Index with steam coal spot prices reported by utilities to the FPC. (See Appendix A.)

3/ Since actual transportation charges for spot market purchases are not reported, a rough approximation of these charges can be made using average freight charges for all coal, as reported by the Bureau of Mines. Charges were $3.71 per ton in 1973 and $4.71 in 1974. Railroad rates were raised 10 percent on June 20, 1974. They rose again by 7 percent on April 16, 1975. Thus, freight charges were 10 percent higher in the first half of 1975 or $5.18 per ton higher than the 1974 average.

FIGURE III-1

MEASURES OF THE MOVEMENT OF SPOT COAL PRICES, 1973 - 75



This suggests that the increase in the price of steam coal, F.O.B. mine, over the two-year period was nearly the same as that of metallurgical coal, 170 percent versus 190 percent (although, as noted earlier, the BLS index may be somewhat understated).

The above discussion focuses solely upon the movement of spot prices, but only 20 percent of coal purchases are made in the spot market. The other 80 percent are purchased on long-term contracts. This includes most metallurgical and steam coal for power generation and a large part of export coal. The price of coal delivered on these long-term contracts rose at a slower and steadier rate than in the spot market.

Unfortunately, the only contract price data available are for utility steam coal reported to the Federal Power Commission as of the date of delivery. Table III-2 compares contract steam coal prices since January 1973 with spot prices and with the average price of all coal. The average price follows the contract price more closely than it does the spot prices, since 80 percent of total sales is by long-term contract purchases. It is evident that contract prices rose slowly starting immediately after the onset of the embargo. The rate of increase was modest throughout 1973. But during 1974, these contract prices rose by more than 50 percent (see Figure III-2 for a comparison of the behavior of spot and contract prices during this period). The rise in contract prices cannot be accounted for by typical contract escalation clauses, which are tied to labor costs.4/ Information on other costs is not available, but it does seem likely that many contracts were renegotiated.

3. Regional Price Variation

The national averages in Tables III-1 and III-2 mask a great deal of regional variation. For example, in July 1975, in the South Atlantic region, which depends on Appalachian coal, the average spot price for utility coal was $24.84 per ton and the contract price was $23.78 per ton. In the western mountain region, the spot price was $5.08 and the contract price was $6.47. The national difference between spot and contract price is much larger than the difference in most states because cheap western coal is sold almost entirely on long-term contracts.

4/ See Table IV-2.

TABLE III-2

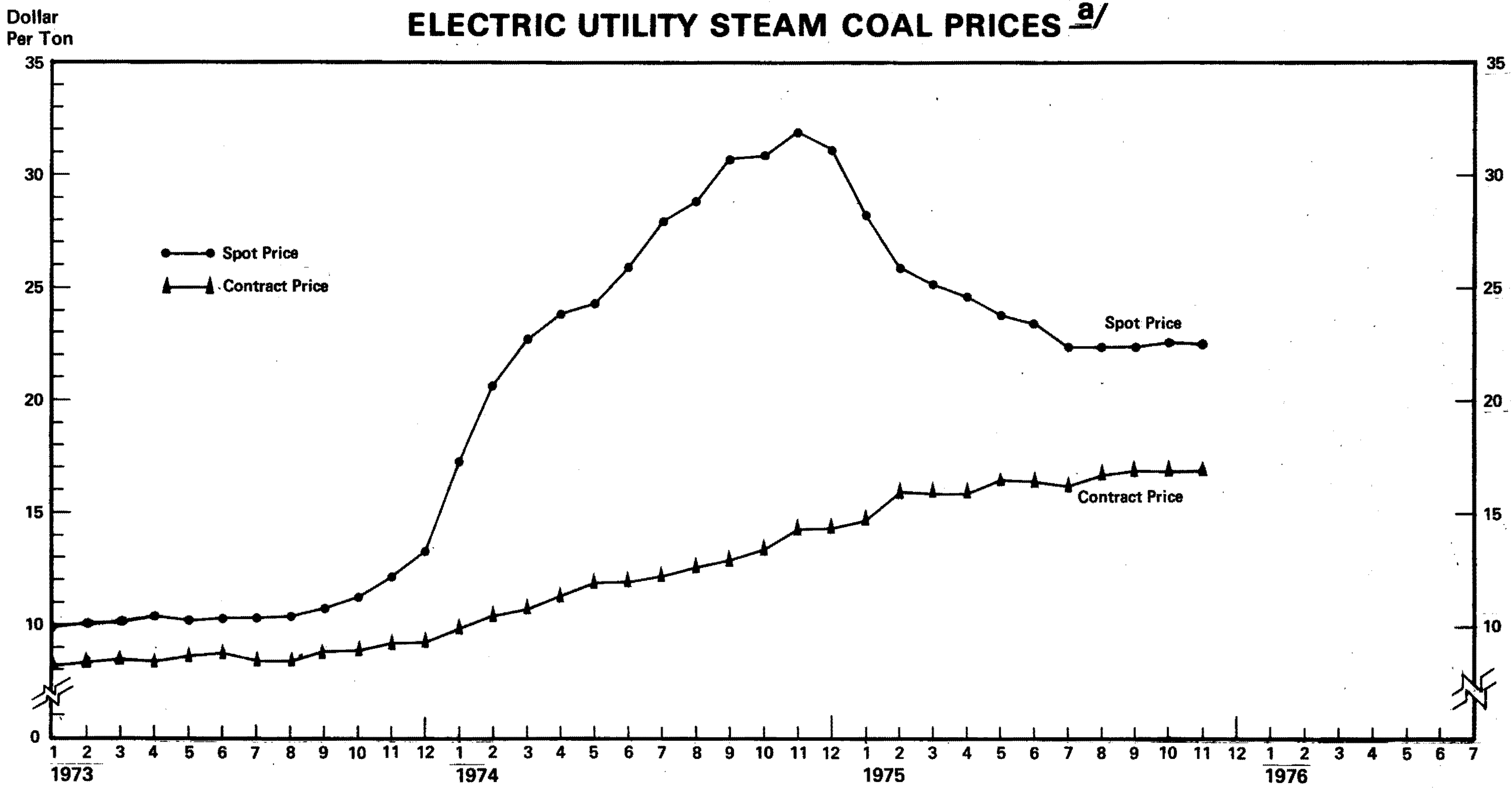
Electric Utility Steam Coal Prices[a/]
(Dollars Per Ton)

Month	Year	Spot Price[b/]	Contract Price[b/]	Average Price
June	1972	$ -	$ -	$ 8.17
August		-	-	8.17
September		-	-	8.17
October		-	-	8.25
November		-	-	8.27
December				8.23
January	1973	9.91	8.09	8.41
February		10.01	8.31	8.53
March		10.07	8.42	8.70
April		10.44	8.43	8.80
May		10.24	8.51	8.80
June		10.43	8.62	8.94
July		10.40	8.44	8.82
August		10.44	8.45	8.84
September		10.67	8.71	9.10
October		11.24	8.86	9.35
November		12.05	9.13	9.74
December		13.34	9.18	10.00
January	1974	17.02	9.83	11.32
February		20.54	10.40	12.53
March		22.54	10.63	13.37
April		23.70	11.28	13.84
May		24.21	11.80	14.46
June		25.84	11.87	15.17
July		27.99	12.05	15.88
August		28.87	12.50	16.74
September		30.64	12.89	17.15
October		30.67	13.30	17.58
November		31.95	14.16	19.23
December		31.05	14.20	18.78
January	1975	28.12	14.57	17.41
February		25.93	15.71	17.71
March		25.02	15.68	17.50
April		24.52	15.88	17.52
May		23.78	16.45	17.78
June		23.36	16.40	17.65
July		22.35	16.06	17.28
August		22.39	16.65	17.73
September		22.46	16.76	17.81
October		22.52	16.72	17.73
November		22.50	16.79	17.67

a/FPC, Monthly Fuel Cost and Quality Information, news releases, Form 423 reports.

b/Separate data on spot and contract price are not available before January 1973.

FIGURE III-2
ELECTRIC UTILITY STEAM COAL PRICES a/



a/ F.P.C., Monthly Fuel Cost and Quality Information, news releases; based on Form 423 reports.

4. 1975 Coal Demand

Coal consumption in 1975 rose only 2.5 percent above 1974 levels. Production, on the other hand, increased 6.1 percent over 1975. (See Table III-3).

TABLE III-3

Coal Production and Consumption in 1975, Cumulative
(000 Tons)

	1975[1/]	1974	Percent Change
Production	640,000	603,406	6.1%
Consumption			
Electric Utilities	404,000	390,068	3.6
Coking Coal	85,000	89,747	-5.3
All Other Mfg.	65,000	64,054	1.5
Retail	8,000	8,840	-9.5
Total	562,000	552,709	1.7%
Exports	66,000	59,926	10.1%
Total	628,000	612,635	2.5%

1/ Estimates -- published in Commodities Data Summary Statements (January, 1976 -- U.S. Bureau of Mines)

The weakness in coal demand may be attributed to the following factors:

- The output of electrical energy was only 1.7 percent higher in October 1975[5/] than in 1974 due to the recession and to the effect of energy conservation measures. The historical growth rate of electrical energy demand had averaged between 5 and 7 percent per year during the late 1960's and early 1970's. That growth rate has slowed for many reasons, and growth for the remainder of the decade is likely to proceed at a slower rate.

- Electric utilities have not increased coal stockpiles above normal levels because of the slowdown in demand.

5/ Edison Electric Institute, December 12, 1975.

• The steel industry and other industrial users of coal have reduced coal purchases 4 to 6 percent below 1974 levels due chiefly to the recession.

Only coal exports -- principally to Japan -- have increased significantly above 1974 levels. However, there are recent indications that the 16 percent increase in export price levels from 1974 to 1975 are slowing down due to the worldwide recession. The Japanese steel industry, the principal importer of U.S. metallurgical coal, has suffered a reduction in production levels, and there have been reports that it will try to hold down prices for 1976.6/

The slowdown in growth has most affected spot prices; contract prices continued to rise through late 1975 -- although much more gradually than during 1974. The tripling of coal spot prices in 15 months had caused great concern, especially to small buyers. Although large electric utilities and large steel companies had been subjected to slow deliveries, cutbacks in supply, deteriorations in coal quality, and higher prices, these problems had been cushioned by long-term contracts. In some cases, a few large coal consumers were able to rely on production from their own captive mines.

Small industrial, commercial and household users, on the other hand, were often completely dependent on the spot market or short-term contracts and could not shift easily to other fuels. These customers shouldered the burden of spot increases or rapid changes in contract prices and also, in many cases, experienced disruption of coal supplies. Complaints about spot prices came from these coal consumers as well as from householders whose electricity rates rose quickly because of automatic fuel adjustment clauses.

5. Summary of the Recent History of Coal Prices

Following the oil embargo in November 1973, the prices of all kinds of coal began to increase rapidly. Spot coal prices (about 20 percent of the market) rose much faster and to a higher level than contract prices (the other 80 percent).

6/ Coal Week, McGraw-Hill, November 24, 1975, p. 1. See also Wall Street Journal, February 19, 1976, referring to a two percent cut by Consolidation Coal in prices of highest quality coking coal to Japanese steelmakers.

Spot prices paid by electric utilities, as reported by the FPC, almost tripled from June 1973 to November 1974, during the UMW strike. The Wholesale Price Indexes of metallurgical coals, reported by the BLS, were slightly more than 2-1/2 times greater in December 1964 than in June 1973. A more accurate measure of price change, however, may be provided by the average value of metallurgical coal, which rose 3-1/2 times during the same period.

Since the settlement of the coal miners' strike in December 1974, spot prices have declined steadily. Although the FPC's official figures are available only through 1975, recent quotes of representative spot prices reported in the trade press indicate a range of $12.50 - $16/ton for spot prices for both high and low sulfur eastern coal. Though still higher than the September 1973 average of $10.67/ton, spot prices have dropped to about half the level of one year ago.

The price of contract coal for electric utilities increased more slowly -- to about 90 percent above mid-1973 by August 1975. The latest reports indicate that contract prices have flattened out and have fluctuated mildly from month to month.

IV. REASONS FOR THE INCREASE IN COAL PRICES

1. The Effect of Oil Prices and the United Mine Workers' Strike

The two largest surges in coal prices can be pinpointed in time: soon after the onset of the OPEC oil embargo in September 1973 and as the impending United Mine Workers' strike threatened to become a reality when the union's contract expired on November 12, 1974. Prices finally peaked during the three weeks in November when the strike actually occurred. Since the settlement of the strike, spot prices have declined, but long-term contract prices have continued to grow at a moderate pace.

At the time of the embargo, residual and distillate fuel oil were direct competitors with coal as a boiler fuel. Oil accounted for 15 percent of electric utility fuel; coal accounted for 44 percent, but the mix was more evenly divided along the East Coast, where imported residual oil was easily delivered and directly competitive with Appalachian coal. A large number of eastern power plants had shifted from coal to residual oil beginning in 1966 when import controls were effectively removed. They switched even more eagerly when enactment of the Clean Air Act of 1970 restricted the use of high-sulfur fuels such as most eastern coal.

Thus, the impact of the embargo was quickly felt on the oil-dependent northeastern utility market. As indicated in Table IV-1, spot prices for residual fuels jumped 37 percent from October to November 1973.1/ Coal prices soon followed. Spot coal prices rose 11 percent in December 1973 and then soared 28 percent in January. It is evident that residual oil price rises led the enormous increases, but the prices of fuels climbed in its wake. According to the BLS Wholesale Price Index (Table IV-1), the price of residual fuel oil, by March 1975, had risen 282 percent over June 1973. During the same month, the spot coal index registered a rise of 216 percent over June 1973 price levels.

Coal was not the only fuel, of course, whose prices were responsive to the surge in oil prices. The average price of intrastate natural gas paid by Texas utilities rose from $.30 per million cubic feet (MCF) in September 1973 to $.80 per MCF in July 19752/ -- an increase of 246 percent. Another example is the price of uranium (U_3O_8), which increased from an average of $8 per pound in 1973 to a mid-1975 level of more than $30 per pound for forward contracts.3/

1/ BLS Wholesale Price Index

2/ FPC monthly news release. Most of this gas is sold under long-term contract. The spot price of intrastate gas has reportedly risen to between $1.50 and $1.90 per MCF.

3/ Nuclear Exchange Corporation, 8/25/75

TABLE IV-1

Fuel Oil vs. Coal Prices

Month	Year	WPI (BLS) Residual Fuels[a/] (1967=100)	WPI (BLS) Residual Fuels[a/] June (1973=100)	FPC Fuel Oil[b/] Average Price $ per bbl	FPC Fuel Oil[b/] Average Price June (1973=100)	FPC Spot Coal Price[c/] June (1973=100)	FPC Contract Coal Price June (1973=100)
January	1973	161.8	87.5	-	-	95.0	93.9
February		168.0	90.9	-	-	96.0	96.4
March		177.8	95.7	-	-	96.6	97.7
April		185.3	100.2	4.22	99.1	100.1	97.8
May		181.0	97.9	4.31	101.2	93.2	98.7
June		184.9	100.0	4.26	100.0	100.0	100.0
July		176.6	95.5	4.42	103.8	99.7	97.9
August		183.5	99.2	4.61	108.2	100.1	98.0
September		201.6	109.0	4.89	114.8	102.3	101.0
October		206.0	111.4	5.32	124.9	107.8	102.8
November		281.4	152.2	6.29	147.7	115.5	105.9
December		319.4	172.7	7.34	172.3	127.9	106.5
January	1974	417.2	225.6	9.77	229.3	163.2	114.0
February		505.9	273.2	11.42	268.1	197.2	120.6
March		522.0	282.3	11.58	271.8	216.1	123.3
April		561.8	303.8	11.49	269.7	227.7	130.9
May		497.6	269.1	11.56	271.4	232.1	136.9
June		476.2	257.5	11.96	280.8	247.7	137.7
July		533.8	288.7	11.92	279.8	268.4	139.8
August		449.4	242.8	11.93	280.0	276.8	145.0
September		519.5	281.0	11.94	280.3	293.8	149.5
October		506.6	274.0	12.17	285.7	294.1	154.3
November		514.8	278.4	12.26	287.8	306.3	164.3
December		604.4	326.7	12.54	294.4	297.7	164.7

(MORE)

TABLE IV-1 (Cont'd)

January	1975	515.8	279.0	12.19	286.2	269.6	169.0
February		528.2	285.7	12.44	292.0	248.6	182.3
March		534.6	289.1	12.58	295.3	239.9	181.9
April		491.3	265.7	12.79	300.2	235.1	184.2
May		489.3	264.6	12.61	296.0	228.0	190.8
June		479.9	259.5	12.31	289.0	224.0	190.3
July		473.3	256.0	12.25	287.6	214.3	186.3
August		458.1	247.8	12.38	290.6	214.7	193.2
September		461.8	249.8	12.39	290.6	215.3	194.4
October		450.4	243.6	12.19	286.2	215.9	194.0
November		459.3	248.4				
December		451.8	244.6				

a/ BLS. As reported, residual fuel index is lagged one month beginning 3/73. In this table the data has been moved back one month. Price data excludes fuel oil for electric power through 8/75.

b/ FPC fuel oil for electric power production.

c/ From Table III-2.

Anticipation of the United Mine Workers' strike created more upward pressure on coal prices. This pressure intensified as the expiration date of current contract approached (November 12, 1974), and it became clear that contract negotiations were proving unsuccessful. The strenuous efforts in the second half of 1974 by the steel industry, electric utilities, and foreign purchasers to build stockpiles developed into a near panic, which was reflected in utility and export prices, as production approached capacity. The BLS/WPI for metallurgical coal does not fully reflect the peak prices paid at this time. Responses to a survey of steel companies by the Council on Wage and Price Stability indicated that spot prices for metallurgical coal ranged as high as $100 or more per ton in late 1974. (Compare that to a September 1973 export price -- mainly for metallurgical coal -- of $17.64/ton and a peak average export price of $63 per ton in December 1974.)

The strike had a relatively short duration. It began on November 12, and union mines were completely shut down for three weeks. By mid-December, however, the industry returned to three-quarters normal production and by January to full production. Spot prices began their gradual decline at that time, but long-term contract prices continued to rise -- although more slowly than during 1974.

The 1975 decline in coal prices has been so pronounced that electrical utilities and other coal consumers are now able to purchase coal at less than one-half of the cost of equivalent energy obtained from residual oil. Thus, in most geographical markets in the United States, the price of coal is not presently sensitive to changes in the price of oil.

2. Costs and Profits

During most of the 1960's and 1970's, the coal industry was under severe competitive pressure from other fuels, and profit margins were low. An exception was 1970, when production grew from 560 million tons in 1969 to 603 million tons, and exports jumped from 56 million tons to 71 millions tons. No comprehensive data on overall costs are available but labor cost trends per ton can be approximated from wages and output per man-day shown in Table IV-2.

The index of price (average value F.O.B. mine) moved somewhat faster than the index of average labor costs from 1970 to 1973. This divergence widened sharply in 1974, as the average value of coal rose 84 percent while labor costs increased 4.0 percent. Increased labor costs through 1974 are due largely to increased wages and welfare fund payments, but part of the rise is due to reductions in output per man-day since 1969, due primarily to progressive implementation of the Coal Mine Health and

TABLE IV-2

Bituminous Coal Mining.
Labor Cost and Value Per Ton

Year	Average Daily Earnings a/ $	Tons Per Manday b/	Wage Supplements c/ $	Labor Costs per Ton d/ $	Index of Labor Costs 1968=100	Average Value Per ton b/ $	Index of Value 1968=100	Annual Output Million Tons
1968	30.88	19.37	.40	1.994	100	4.67	100	454
1969	33.92	19.90	.43	2.135	107.1	4.99	106.9	561
1970	36.64	18.84	.43	2.375	119.1	6.26	134.0	603
1971	38.88	18.02	.46	2.618	131.3	7.07	151.4	552
1972	42.48	17.74	.64	3.035	152.2	7.66	164.0	595
1973	45.76	17.58	.72	3.323	166.6	8.53	182.7	592
1974	50.08	18.68	.77	3.451	173.1	15.72	336.6	603
1975 e/	57.45	18.0	1.19	4.382	219.7	18.75	401.5	640

a/ BLS average hourly earnings, times 8.

b/ Bureau of Mines.

c/ These include: welfare fund payments per ton plus an allowance for Christmas bonus beginning 1969 and additional days of paid vacation in 1973 and 1974. In addition to payments per ton, a payment of the welfare fund of $.90 per hour was begun in December 1974 and $1.40 per hour in December 1975. The estimates of wage supplements are still incomplete. Employers' contributions to Social Security, workmen's compensation and unemployment compensation are omitted. These might not affect the trend of labor costs seriously. However, black lung insurance payments or accruals, (also omitted), which began in 1974 would raise 1974 and 1975 labor costs significantly. Unfortunately no national average is available. For some underground mines, black lung related might add $1.00 per ton.

d/ Column (1) ÷ column (2) plus column (3).

e/ 11 months, preliminary.

Safety Act of 1969. The 1975 estimate is preliminary, but contract utility prices alone have risen about 35 percent above the 1974 average while estimated labor costs per ton increased 27 percent

Because comprehensive cost figures are unavailable, the above comparisons may be somewhat misleading since they cover only labor costs. Moreover, as in any natural resource industry, costs vary substantially across mines. At best, the above trends give a rough indication of relative direction of labor costs and price nationally. Most underground mining is done in Appalachia; hence, the eastern region would show significantly higher and perhaps more rapidly-growing labor costs. Nationally, however, the average value per ton of coal rose much more rapidly than labor costs in 1974 and 1975. Unless all other costs have grown more quickly than labor costs (which appears doubtful), the average price has also outpaced total costs.

In a competitive industry which has increasing costs, prices should tend to equal the average costs of operation in new mines and the incremental cost of operation in established mines. Given that the lowest-cost deposits are developed first, it should not be surprising that profits in established mines rise when demand increases. Conversely, one would expect profits to fall considerably during periods of declining demand.

These observations are supported by the fragmentary reports from coal firms. (Many of the largest coal producing firms are conglomerates or captive subsidiaries of steel companies. These companies are not required to report profits from coal operations separately.) Table IV-3 presents the profits of a sample of companies or subsidiaries, which account for 22.6 percent of 1974 production. From 1970 through 1973 profits fell sharply for these firms due to declining demand. The average net income in 1973 was only about $0.20 per ton. In part, these low returns were due to price controls. In 1974, after the price of oil soared and induced the rise in coal prices, net profits rose to $2.80 per ton or 18 percent of the average value per ton.

Because there are relatively few large coal companies whose principal output is coal, data on rates of return on investment for the industry are only fragmentary. Standard and Poor's index of coal companies is based upon only four firms at present. These four firms' experience follows the gross profit experience detailed in Table IV-3. Their average rate of return on investment (after taxes) was 15.58 percent in 1970, but it fell to 12.78 percent in 1971, and 10.01 in 1972. These returns compare with an average for all industrials of 10.28 percent in 1970, 10.80 percent in 1971, and 11.64 percent in 1972. In 1973 the average return for all industrials rose to 14.14 percent after taxes while coal remained at 10.61 percent. With the sharp rise in

TABLE IV-3

Coal Mining Companies
Net Profits After Taxes
($000)

Company	1975 1st Half	1974 1st Half	1974	1973	1972	1971	1970
Amax Coal a/	-	-	28,443	15,280	16,572	-	-
Appalachian			1,489	138	(257)	433	(293)
Rapoca			6,762	(492)	(1,438)	471	3,373
Westrans		2,685	7,226	752	1,334	688	816
Carbon Industries	13,091	6,554	14,348	2,399	2,850	2,836	3,170
Consolidation Coal f/	60,700 b/	8,700	43,800	(12,800)	16,600	7,600	21,300
Diamond	311	1,524	2,888	1,240	554	291	393
Eastern Associated	25,764	11,876	27,734	(315)	4,864	9,946	16,980
Falcon Seaboard	6,410	3,877	11,234	2,196	1,224	(5,588)	222
General Energy	3,560	8,012	16,860	1,512	12	(793)	(2,273)
General Exploration	1,164	574	1,789	(836)	(2,742)	(1,452) e/	(1,695)
Island Creek	95,500	44,100	101,495	10,610	8,700 c/	4,900 c/	29,700 c/
North American	3,706	2,849	4,929	3,986	2,831	1,248	1,894
Pittston	109,693	39,054	113,636	25,416	24,097	35,325	84,495
Rochester and Pittsburgh	3,460	2,919	7,127	2,173	2,074	771	2,771
Valley Camp	4,906 d/	2,577	4,909	2,402	1,662	(117)	2,912
Westmoreland	37,033	13,923	36,153	4,702	5,193	4,433	8,910
Total Profits (Excluding Consolidation, Island Creek, and Pittston)			143,448	19,857	18,161	13,167	37,180
Index (1970=100)			385.82	53.41	48.85	35.41	100.00
Grand Total			402,379	43,083	67,558	60,992	122,675
Index (1970=100)			328.00	35.12	55.07	49.72	100.00

a/ Included for comparison purposes only; excluded from totals and indexes.
b/ Includes extraordinary gain of appx. $12.0 mil from property sales.
c/ Island Creek's gross contribution to Occidental's earnings before taxes and interest charges.
d/ Includes extraordinary gain of $2,143,089 in 1975 and $374,491 in 1974 from sales of assets.
e/ Includes 495,260 loss on discontinued operations.
f/ Consolidation's net contribution to Continental's earnings before interest charges.

SOURCE: SEC Forms: 10K and 10Q, and Annual Reports: Moody's Industrials and Over the Counter.

coal prices throughout 1974, the rate of return for the S&P coal companies soared to 25.23 percent while the industrial average remained virtually constant at 14.18 percent. But this sudden increase in profitability is not sufficient evidence upon which to base a judgment on the competitiveness of the industry. The owners of the coal-producing facilities would have realized considerable profits from the sudden surge in demand regardless of the degree of competition in the industry.

3. Concentration in the Coal Industry

The price and profit increases of 1970-71 and the period since the oil embargo have brought charges of concentration and lack of competition in the coal industry. The validity of such charges can be assessed by examining the structural characteristics of the industry.

Historically, the bituminous coal industry has consisted of thousands of firms. Entry has been open to any landowner with coal reserves on his property. That situation is still true; indeed, during coal's most bullish year to date -- 1974 -- many small new surface mining operations were reported in Appalachia. However, despite their large number, the aggregate effect of small mines is relatively small. Instead, it is the large corporations able to finance mines capable of producing half a million tons of coal per year which have been the focus of concern about industry concentration. Opening such a large mine requires a significant investment, and at least two years of development before production can begin.

As Table IV-4 shows, the top four U.S. Coal companies produced slightly more than a quarter of total production in 1974. The eight largest firms produced about a third, and the twenty largest companies controlled a bit more than half of total production. By comparison, the four largest firms in the average manufacturing industry accounted for approximately 39 percent of their industry's output in 1966[4/] Not only does it appear that the coal industry is not heavily concentrated, and thus that market prices of coal are not easily manipulated, but Table IV-4 shows a trend away from the degree of concentration that existed in 1970. From 1955 to 1970, there was a significant increase in the production controlled by large companies, that movement peaked in 1970 and dropped noticeably in 1971 and 1974. The decline may be attributed in part to these factors:

- 1971 and 1974 were years in which strikes closed down the unionized portion of the industry for six and four weeks, respectively.

4/ Frederick M. Scherer, Industrial Market Structure and Economic Performance, 1970, p.63.

TABLE IV-4

Bituminous Coal Industry Concentration Ratios:
Shares of Total Production
(Percent)[a/]

Number of Firms	1955	1960	1965	1970	1971	1972	1973	1974
Top 4	17.8	21.4	26.6	30.2	27.8	30.2	29.1	26.6
Top 8	25.4	30.5	36.3	40.7	37.6	40.0	39.1	36.7
Top 20	39.5	44.5	50.1	56.5	52.2	55.8	54.9	51.2

a/ A list of the top 20 coal producers and their parent companies is given in Appendix B.

SOURCES: FTC - Concentration in the U.S. Energy Industry, 1974.

Keystone Coal Manual, and McGraw-Hill, for various years.

- Large companies are generally more unionized than smaller producers.

- These larger firms work more days per year than the smaller companies because their production is more likely to be committed to serving long-term contracts.

- In the months immediately preceding the strikes, it is likely that the smaller firms expanded output more than the larger companies since the smaller mines generally have more excess capacity.

Concentration in some areas is much greater than for the country as a whole. The greatest concentration occurs in Midwestern states such as Illinois, Indiana, Kansas and Missouri, where there are more large tracts of strippable coal reserves, and in western Kentucky. One study has found that prices in those regions rose less from 1968 to 1970 -- despite greater concentration -- than they did in West Virginia, Pennsylvania and eastern Kentucky where ownership is much more fragmented.5/

Regional concentration may be of limited importance, however, given that many companies have mines in several regions. Most companies of moderate size are technically and managerially qualified to open a new mine in regions other than those in which they are currently operating. Most reserves are relatively accessible and barriers to entry are low, except those legal barriers recently raised in the West. Large coal consumers may also open new mines if high prices and the need for a steady supply warrant. Most large steel firms and many utilities have captive mines. In fact, most of the large new mines of the western states have been opened by independent mining companies under contract to or in joint ownership with electric utilities (e.g., the large Decker mine in Montana owned jointly by Peter Kiewit Co. & Pacific Power and Light).

It is worth noting that two recently published studies of the coal industry concluded that there is no plausible evidence of significant market power nor of price manipulation by either the largest coal companies or by the oil and other non-coal parent companies as of 1972.6/

5/ Reed Moyer, "Price and Output Behavior in the Coal Industry" in Competition in the U.S. Energy Industry, Ballinger, 1975, Thomas D. Suchesneau.

6/ Moyer, op. cit. and Richard L. Gordon, U.S. Coal and Electric Power Industry, Johns Hopkins Press for Resources for the Future, 1975, pp. 67-88.

4. Charges of Lack of Competition:

After coal demand prices began to rise in 1970, charges of lack of competition in the coal industry were made to the Justice Department by the American Public Power Association (APPA) and some of its members. The evidence cited was the rapid increase in the price of coal in 1970 (from an average value per ton of $4.99 in 1969 to $6.26 in 1970), the existence of supply shortages in 1970, and the failure of some suppliers to deliver on long-term contracts. These conditions were all in evidence again in 1974. The Justice Department found insufficient evidence to take action. The rapid rise in prices in 1974, as in 1970-71 is clearly consistent with sharp increases in demand in an industry with short-run supply inelasticity.

A third study on competition in the coal industry cited the 1973 and 1974 price rises as evidence of a lack of competition.7/ The report, prepared for APPA, assumes that the elasticity of coal supply is fairly high in the short run, but this assumption appears to be unjustified.

Competitive industries often experience great price swings in the face of changes in demand, particularly in natural resource markets. A surge in demand coupled with an inelastic short-term supply results in a large price surge. Once sufficient time elapses and major new investments are made, a new equilibrium is reached. At that point, overall prices may be higher or lower than the original level depending on long-term supply conditions.

Short-run supply elasticity is generally low in natural-resource markets because expansion of output requires major new capital investments. Moreover, transportation facilities must be adapted to the new facilities. In the coal industry, output cannot be expanded readily in existing mines without some new investments unless the mines are operating with excess capacity. Increasing output even in these mines requires the purchase of new equipment or extensive use of overtime. Given the delays associated with the purchase of additional equipment and the existence of labor contracts which limit overtime, output simply cannot expand measurably in the short run in response to rising prices. Thus, one would not expect rapid increases in output in response to a sudden rise in demand.

7/ Barth and Bennett. An Economic Analysis of Price Changes in the U.S. Coal Industry, October 1974. A study for the American Public Power Association.

As long as new mines can be opened in areas in which deposits are of comparable quality and accessibility to those being exploited by existing mines, the long-term supply elasticity will be fairly high. This means that it requires only a minor rise in the long-term equilibrium price to induce major new investments in mining capacity. For long-term expansion under current conditions, however, substantial financing and a two-to-five-year development period are required.

The 1974 supply expansion was limited primarily to existing mines in the face of the unexpected oil embargo and subsequent oil price increases. Given the sudden increase in demand and the 1974 strike, the response in terms of increased employment and production was not as sluggish as some of the APPA's report's charges might imply. Employment grew from 148,100 in 1973 to an estimated 166,700 in 1974 (Bureau of Mines, see Table II-1). BLS data indicate that average monthly employment grew ten percent from October 1973 to October 1974. At the same time production increased from 54.4 million tons to 60.3 million tons, again a ten percent expansion. If the UMW strike had not intervened and production had proceeded at the October rate until the end of 1974, there would have been additional production of about 36 million tons. This additional output would have yielded an increase in total 1974 production of 47 million tons over the 1973 level. If this had occurred, mine production would have been near capacity at 230 days worked for the year. (The largest number of days worked since World War II was 234 in 1947, the peak production year -- See Table II-1.) Further substantial expansion would have required the opening of new mines. Thus, the lack of expansion of coal output in 1974 is not indicative of lack of competition but rather of the technological and market constraints.

The paucity of investment in new coal mining capacity in recent years may be explained by the financial conditions in the industry prior to 1974. Profits in 1971-1973 were not conducive to high levels of investment. Indeed, the number of mines declined steadily from 1970 to 1973 (see Table II-1). Basically, new mines were developed prior to 1974 only if firm long-term sales contracts were signed with customers. The prospects for increased coal demand were clouded then by uncertainties regarding: (a) competition from nuclear power generation, (b) relatively cheap low sulfur oil before 1974, and (c) Clean Air Act limitations of sulfur emissions. Fundamental uncertainties regarding future long-term coal demand were a major reason for the low level of new mine openings prior to the oil embargo. Those uncertainties have grown in the last two years, and others -- such as the prospects for western coal development and rates of electrical energy demand growth-- have been added to the list. (See Chapter V.)

5. <u>The Effect of Fuel Adjustment Clauses</u>

Most electric utilities have automatic fuel adjustment clauses in the regulation governing them. These clauses permit the utilities to pass fuel cost increases to consumers without prior regulatory approval. It has been alleged that such clauses weaken the resistance of utilities to fuel cost increases. Thus, spot price increases were supposedly larger and renegotiations of long-term contracts more numerous than they otherwise might have been in the period of rapidly rising prices. But it must be granted that the utilities have a long-run interest in holding costs down in order to maximize profits for a given regulatory constraint.8/ Thus, one must examine the magnitude of the short-run increases in prices because of fuel adjustment clauses, and whether the increase is likely to be permanent.

A public utility may respond to a rise in the price of a given fuel by either substituting another fuel or by reducing output. Given its charter to serve the public necessity and convenience, the latter strategy is not practicable. Even without fuel adjustment clauses, the utility cannot reduce output to consumers in response to a sudden increase in costs. Substituting, for example, oil for coal as the price of coal rises requires considerable time in order to replace equipment and install new unloading and storage capacity. Thus, few utilities are in a position to respond to a rise in the price of coal by reducing their purchases of it. Nor does a utility company have sufficient buying power to affect the price of coal as given and adjust its long-term fuel plans in response to changing perceptions of the cost of using various fuels.

It is interesting to compare the electric utility industry's response to rising coal prices in late 1974 with the responses of the steel industry and other manufacturing and mining firms. Total consumption in each sector depends upon the trend in demand for its final products and the ease of substituting among fuels. Firms may reduce stocks in response to a price increase, either hoping for a subsequent decline in spot and new contract prices or as the first step of a plan to switch to a new fuel. Thus, we might expect to see some reduction in stocks relative to consumption if firms were able to reduce or switch fuels as the price of coal rose. In fact, as

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8/ See Baumol and Klevorich, Input Choices and Rate of Return Regulation: An Overview of the Discussion, Bell, J. of Economics, Spring 1971 for a discussion of this point. They demonstrate that a regulated utility may not choose the most efficient production technique, but otherwise it is a cost minimizer in the pursuit of profit maximization.

Table IV-5 shows, steel companies, electric utilities, and other sectors generally increased stocks through October 1974, but they then reduced these inventories after the strike ended in December. The steel companies subsequently built up their inventories as the result of a 15 percent decline in steel production between October and February, but the electric utility and other sectors maintained inventories in early 1975 which were much closer to their early 1974 levels. In short, there is little in the consumption-inventory patterns for electrical utilities which would suggest that they behaved differently in the short run from nonutility firms which had no automatic fuel adjustment clauses with which to pass on coal price increases.

Finally, it should be recalled that export prices rose even more than other coal prices. Yet foreign buyers continued to accept shipments at an increasing rate; exports for October and November 1974 were well above the 11.1 million tons of October and November of 1973 (Table IV-6). Export prices rose spectacularly, relaxing in December at three and one-half times the mid-1973 level.

The evidence, although limited, points to the conclusion that all major coal consumers, including foreign importers, were helpless in the face of a coal strike of unpredictable duration. This limited evidence is consistent with the theory that fuel adjustment clauses had no measurable effect upon the price of coal.

6. Conclusion

The rapid rise in coal prices which began in November 1973 can be explained in part as a response to the rising price of world oil brought about by OPEC. Given the unanticipated strength of the oil embargo and subsequent OPEC cartel pricing, the coal industry was faced with a sharp, unexpected increase in demand in late 1973. This increase in demand drove up the spot price of coal by nearly 200 percent in one year and the average contract price paid by utilities by over 50 percent.

Coal mining costs have increased substantially since 1969. Prices rose only moderately faster than costs until 1974, when they experienced a sudden upswing. As a result, profits increased greatly in 1974 for a sample of coal companies. There is no evidence, however, of excessive concentration which would permit producers to exert power over the price of coal. Rather, the large profits are the predictable consequence of a sharp increase in demand in an industry in which supply is highly inelastic in the short run.

TABLE IV-5

Bituminous Coal Stocks and Consumption
(Million Tons)

1974	Steel Companies (Oven Coke Use) Stocks	Consumption	Electric Utilities Stocks	Consumption	Other Manufacturing and Mining Stocks	Consumption
January	6.3	7.9	81.9	34.4	8.9	5.8
February	6.1	7.2	79.8	30.4	9.1	5.5
March	6.3	7.6	84.9	31.5	9.4	5.3
April	6.7	7.7	90.1	29.7	9.5	4.9
May	7.5	7.8	95.2	31.5	9.3	4.4
June	7.4	7.6	95.4	31.6	8.3	4.1
July	6.5	7.7	90.4	36.0	8.4	4.0
August	6.7	7.6	88.5	35.4	9.4	4.5
September	7.1	7.4	91.5	30.8	9.5	4.3
October	8.3	7.6	99.4	31.9	9.8	5.0
November	7.2	6.5	93.3	32.0	7.9	4.8
December	6.0	6.0	82.6	35.0	6.2	5.1
1975						
January	7.1	7.2	81.2	35.7	6.6	5.3
February	8.0	6.9	80.0	32.0	8.5	5.7
March	8.7	7.8	80.9	32.7	7.8	5.7
April	9.0	7.3	85.7	30.1	7.5	5.3
May	9.6	7.2	92.1	30.1	7.6	4.8
June	10.0	7.0	96.8	33.1	7.5	4.2
July	8.1	6.5	93.0	36.2	7.5	4.1
August	7.3	6.5	93.1	37.8	7.6	4.3
September	7.0	6.2	96.6	32.4	7.8	4.7
October	7.7	6.6	102.5	32.7	7.9	4.7

SOURCE: Bureau of Mines
End of Month

TABLE IV-6

U.S. Bituminous Coal Exports (1000 tons)

Month	1973	1974	1975
January	2,954	2,813	4,254
February	2,669	4,627	4,470
March	3,377	3,179	5,653
April	5,063	4,944	6,159
May	5,140	6,032	7,011
June	4,969	6,369	6,269
July	4,164	5,307	4,691
August	5,125	5,088	5,859
September	3,424	4,893	4,529
October	5,882	7,342	4,647
November	5,215	6,744	7,593
December	4,889	2,587	4,534
Year Total	52,870	59,926	65,669

SOURCE: Bureau of Mines

Spot and contract prices remain above their mid-1973 levels for a number of reasons:

- The world price of oil has remained high since the oil embargo of late 1974. Royalties on foreign oil have continued to rise since the embargo, raising the price of one of the most important substitutes for coal.

- Insufficient time has elapsed for major new investments to be launched in the coal industry. New mines require several years to become operational. Moreover, a number of economic and institutional constraints on major expansion exist. (See Chapter V).

- The demand for coal with low-sulfur content has risen since 1973 because of air quality regulations imposed upon major coal consumers.

- Export demand for metallurgical coal remained strong throughout the recession, declining only gradually in early 1975 and then rising once more in the fall. (Only recently have there been signs that export demand may decline.)

As of February 1976, spot activity was at a relative standstill and some spot quotes reported earlier were low enough to stimulate at least limited new contract negotiations.9/ There appear to be several reasons for the rapid decline in spot trading:

- Except for January, the winter weather -- particularly in the East -- was much warmer than normal;

- The effects of the recession upon the demand for steel and electricity had a major impact upon the derived demand for coal.

- Natural gas curtailments did not produce as severe an effect as was anticipated, and

- Few coal conversions occurred.

10/ Coal Week. McGraw-Hill, December 8, 1975, p. 5.

Spot price increases in particular, along with disruptions in supply and contracts renegotiated under duress, created a hardship for many consumers. Among these was the steel industry, which was facing a slowdown in demand and rising prices. The surge in spot prices has ended, however, and they have declined by 50 percent from their 1974 highs. Shortages have disappeared. If the spot price of coal appears high relative to mining costs (excluding royalties and economic rent), it has not risen as much as oil. Contract prices for utilities may be near equilibrium, given the cost of expanding existing mines and rising labor costs.

It appears, then, that the spot price for coal, which is extremely sensitive to shifts in demand, is in decline because the conditions that existed one year ago have changed. Short-term demand has waned because the speculation and anxiety created by the oil embargo and the threat of the UMW strike have abated. Recent demand for coal has been so low that wide spot price movements have halted. At the same time, the problem of insufficient increases in long-term coal contracts to warrant major coal expansion still exists. Uncertainties regarding government policies for coal expansion and environmental protection are greater than ever. These uncertainties, described in the next chapter, may affect the long-run price of coal as severely as the events of the past few years.

V. COAL PRICES FOR THE NEXT DECADE

The previous chapters detailed the sharp rise in coal prices in 1974 and the subsequent moderate decline in 1975 and provided an explanation for this pattern. Given that coal prices remain above their mid-1973 level, the period directly preceding the Arab oil embargo, it is reasonable to ask whether future conditions will allow coal prices to recede or if there will be continuing upward pressures upon them in the years ahead. It is impossible to predict the future pattern of coal prices and consumption with precision, but one can at least detail the myriad of forces which will operate to determine the level of coal prices in the long run -- for at least the next ten years.

It is convenient to divide the forces impinging upon coal prices during the next decade into two categories: those related to demand and those pertaining to supply. In the former category are the following:

- The future course of prices for substitute energy sources such as oil and nuclear power.
- The rate of future growth in the demand for coal-using industries, particularly for electric utilities.
- The choices facing energy-intensive industries in meeting air quality standards -- especially those pertaining to sulfur emissions.

Supply considerations which will have an important influence upon future coal prices include:

- The size and accessibility of coal reserves in the eastern and western sections of the United States.
- Resolution of the debate between those concerned about the ecological and social effects of rapid coal development in the western states and those who argue that this development is essential to foster a low-cost domestic alternative to high-priced foreign oil.
- The development of transportation facilities from the western coal deposits.

Although this chapter cannot provide a detailed price/output scenario for U.S. coal in the next decade, it serves as a preliminary introduction to the prospects for future coal prices. Moreover, it highlights the importance of a few key public policy decisions which will significantly affect the course of domestic coal prices and consumption.

It was assumed that new technologies which would increase coal demand -- such as fluidized bed combustion, coal gasification and liquefaction -- will not be available for widespread commercial use until the late 1980's and beyond. In addition, increased demand due to the Federal Energy Administration's coal conversion program is considered negligible because so few actual conversions have taken place.

A. Demand Considerations

1. Oil Prices

The prospects for long-term coal supply and demand cannot be adequately addressed without considering the possibility that the now high price of Middle Eastern oil could be lowered sufficiently to erase the competitive promise that both domestic coal and nuclear energy offer. The policies of the Organization of Petroleum Exporting Countries (OPEC) have raised oil prices far above their immediate opportunity costs. It has been argued that the Middle East can produce adequate supplies of oil to meet worldwide demand at a production cost of $0.20 a barrel through at least 1985.[1] Calculating transportation costs of about $0.50 a barrel and desulfurization costs of $1.00 a barrel, it is conceivable that the marginal price for desulfurized crude oil in the northeast United States could be as low as $1.70 a barrel.[2] That figure, of course, is highly speculative and is not reflected in the current price of imported crude, which averaged $14.25 a barrel in August 1975.[3]

A conventional measure of the equivalence between the price of oil and the price of coal is that one barrel of oil is worth one quarter of a ton of coal. This is based upon a yield of 6 million Btu's per barrel of oil and 24 million Btu's per ton of coal. However, the costs of handling and burning coal require it to sell at a discount from oil for equivalent heat content. This discount is probably in the range of 25 to 33 percent; hence, if the price of world oil were

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1/ M.A. Adelman. The World Petroleum Market. Baltimore: Johns Hopkins University Press for Resources for the Future, Inc., 1972.

2/ Richard L. Gordon, U.S. Coal and the Electric Power Industry. Baltimore: Johns Hopkins University Press for Resources for the Future, March 1975.

3/ Monthly Energy Review, Federal Energy Administration, November 1975.

to fall to its production and transportation costs, the price of coal would have to fall to about $5 per ton to be competitive.

All projections of the future prices of coal, therefore, depend upon the continuing ability of the OPEC cartel to keep the world price of oil high.[4/] The most recent FEA Energy Outlook utilizes a $13 per barrel price for oil as its "benchmark" estimate for 1985.[5/]

Although the world price of oil will have a major impact upon the future course of coal prices, it should be pointed out that regional coal prices may be determined independently of those for oil. In some parts of the country, such as the West and Midwest, the supply price of coal may be so low that oil cannot compete for stationary uses. In these areas, the price of coal will be set by its long-run supply function and transportation costs. Given the possibility that western coal may be price-elastic in supply, the price of coal in these regions may not be sensitive to demand in the long run either. In other areas, such as the East, coal supply may be much less price-elastic and western coal too inaccessible to compete with oil. In these, the price of oil or of other energy sources, such as nuclear, may determine the long-run equilibrium price of coal. For these regions, competitive fuel prices would affect not only the price of coal but the share of total energy derived from coal.

At current prices, however, oil cannot compete with coal even in the East. Imported oil now costs more than $2.30 per million Btu's while low-sulfur coal delivered to eastern consumption points costs utilities much less -- from $1.00 to $1.50 per million Btu's (see Table V-10). Oil prices would have to fall by at least 33 percent to begin to compete with coal for new electric utility plants.

2. The Coal/Nuclear Mix

Even if it were possible to clear up some of the uncertainty about the world price of oil and U.S. policy on imports and domestic energy resource development, a basic question remains regarding the mix of coal and nuclear energy in the future. Nuclear power, once heralded as the most promising energy source, has recently appeared

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4/ See Adelman, op. cit., for a discussion of OPEC stability.

5/ Federal Energy Administration, 1976 National Energy Outlook, February 1976.

increasingly uncertain for a number of reasons. The effect has been more uncertainty regarding prospects for overall long-term coal demand, with the possibility that demand could increase significantly if facilities originally designated as nuclear are now set for coal.

During the one-year period from August 1974 to August 1975, more than half of the 180 planned nuclear plants were cancelled (8) or deferred (85).6/ The 56 currently operating nuclear plants comprise about 8 percent of the nation's total power base, but earlier expectations for nuclear power's share of the domestic energy base had been much more optimistic, even for its share in the late 1970's.

Economics of Nuclear Power. Although one of the major incentives for nuclear development has been the financial attraction of long-run operating efficiency and of a cheap, clean fuel supply, capital expenditures are very high. Recent estimates put capital costs for a nuclear plant beginning operation in 1985-1987 at $1,005 per kilowatt in 1980's prices. Comparative costs for new coal-fired plants have been estimated at $690 per kilowatt (midwestern plant burning low-sulfur western coal) and $910 per kilowatt (eastern plant burning high-sulfur eastern coal, with SO_2 removal facilities calculated at $220 per kilowatt).7/ It has been generally assumed that low annual operating and fuel costs would make nuclear energy cheaper than coal (or oil) over the long run. However, even these assumptions are now subject to question.

Assuming that a nuclear plant operates at a 75 percent capacity factor8/ (the proportion of normally-available time during which a plant is actually in operation), one may estimate that the operating costs for nuclear power would average 2 mills per kwh less than coal.9/ That close cost differential alone is enough to create

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6/ Leonard F. C. Reichle, "Economics of Nuclear Power." EBASCO, Inc. Paper delivered to the New York Society of Security Analysts, August 27, 1975.

7/ Reichle, Ibid. The following assumptions were made in determining the costs: (1) plants would become operative in 1985-1987. (2) Because of economies of scale, these plants are assumed to be clustered into two, 1,200 MW nuclear units and three, 800 MW coal-fired units with each plant totalling 2,400 MW. (3) The coal-fired plants are separated into a midwestern station using high-sulfur eastern coal with sulfur oxide removal facilities costing $220 per kilowatt (more than twice the average assumption -- see Section 4, on Sulfur Oxides Policy).

8/ Richard L. Gordon, U.S. Coal and the Electric Power Industry, Baltimore: Johns Hopkins University Press for Resources for the Future, Inc., March 1975.

9/ EBASCO Report, Op. cit.

uncertainty about the economic competitiveness of coal versus n'clear power. In addition, the 75 percent capacity factor assumption may be optimistic. Existing plants have been operating at an average of 55 to 58 percent of capacity in recent months.10/ Although it is possible that lower-than-anticipated capacity levels are a function of start-up problems common to any new technology, it is also possible that the regulatory safeguards which will be required for adequate environmental and safety precautions will become standard. Since a plant's performance rate has a large impact on operating costs, it has been argued that the costs of such regulatory safeguards should be a standard component of annual operating costs.11/

Fuel Availability. Naturally occurring uranium ore must be enriched from 0.7 percent to 2.3 percent uranium content to be a commercially usable fuel. There are now only three such enrichment plants in the United States, and uncertainty exists regarding sufficient availability of enriched uranium in the future. Since 1971, the federal government has been trying to induce private industry to take over its formerly exclusive role in the enrichment process. However, enormous capital investments are needed. The companies interested initially in the enrichment program, which is estimated to cost up to $30 billion in the next 15 years, are reluctant to undertake it without large federal guarantees for enrichment technology. A major study of coal and nuclear energy costs contends that nuclear costs include some subsidies (such as this type of guarantee, which may be required in order to induce firms to proceed with an expensive and risky enrichment program), and that previous nuclear cost estimates have thus been understated. 12/

Regulatory Delays. Due to the environmental and safety questions enmeshed in every aspect of the nuclear fuel cycle -- from mining uranium ore to disposal of the spent radioactive fuel -- regulatory proceedings have delayed construction of nuclear plants up to ten years from the time prior to announcement of planned construction to the date at which operation begins. One major effect of the siting, planning and construction delays is that utilities, which are uncertain about future electricity demand, have been postponing nuclear plant construction to determine how much electrical energy will be needed.

10/ Monthly Energy Review. Federal Energy Administration, monthly issues. November 1975-February 1976.

11/ Michael Rieber. "Nuclear Power Fuel Cycle Costs." The Coal Future: Economic and Technological Analysis of Initiatives and Innovations to Secure Fuel Supply Independence. Urbana, Illinois: University of Illinois for National Science Foundation (RANN). May 1975, p. II-2.

12/ Rieber, op. cit.

Breeder Reactor. Additional doubts revolve around the future of the demonstration liquid metal fast breeder reactor program, which produces more fuel than it consumes and had been viewed at one point as the most promising nuclear technology of the future. The breeder program has been delayed due to its escalating costs[13/] and due to the safety risks created by highly toxic plutonium needed for fuel instead of the uranium required in conventional light water reactors.

In summary, the combination of rising operating costs, long regulatory delays, uncertainty concerning fuel availability, and continued problems with breeder development does not bode well for the growth of nuclear power in the next decade. Given the greater certainty of the economics of coal-fired plants, utilities are likely to choose coal over nuclear power in all areas of the country, except those far removed from coal deposits.

3. Electrical Energy Demand Growth

An important determinant of coal demand through the next decade is the assumed rate of growth in demand for electrical energy. Because the electric power industry now consumes about 70 percent of U.S. bituminous coal, projections of demand growth have a major effect on the outlook for adequate supplies and the price of coal. The rate of growth of total electric power output averaged 7.0 percent per year in 1970-73 and peak output grew even more rapidly, but demand plummeted subsequent to the embargo and growth was essentially negative in 1974. Despite some indications that the economy began to recover from the recession as early as April 1975, the annual rate of growth for electricity consumption in 1975 was only 1.8 percent as of November 22.[14/]

Estimates of anticipated growth through 1980 vary widely, although it is widely assumed that a general economic recovery will be accompanied by a rapid resurgence in electrical energy demand followed by a dip as demand levels off. Actual projections of demand growth through 1980 encompass a range of from 3.5-7.2 percent per annum (see Table V-1).

13/ Cost estimates for TVA's Clinch River Breeder Demonstration Program have increased from a 1972 projection of $700 million to at least $1.7 billion today, and cost estimates are still climbing.

14/ Edison Electric Institute, November 22, 1975.

TABLE V-1

Projected Electrical Energy Demand
Growth Rates Through 1980

Source	Percent Growth Per Year
National Economic Research Associates, Inc. (NERA), for the Edison Electric Institute 1/	5 - 7.2
Environmental Protection Agency 2/	3.5 - 5.9
Federal Energy Administration 3/	5.1
Federal Power Commission 4/	5.4
Energy Research and Development Administration 5/	6
Bureau of Mines 6/	5

1/ Based upon ranges presented in two recent studies for Edison Electric Institute: (1) National Economic Research Associates, Inc., "The Costs of Reducing SO_2 Emissions from Electric Generating Plants. A Report for the Electric Utility Industry Clean Air Coordinating Committee." June 1975. (2) NERA, INc., "An Analysis of the Costs to the Electric Utility Industry of House and Senate Significant Deterioration Proposals." December 3, 1975.

2/ Based upon two reports: (1) EPA, Office of Planning and Evaluation, "Implications of Alternative Policies for the Use of Permanent Controls and Supplemental Control Systems (SCS)," July 7, 1976. (2) EPA, Office of Planning and Evaluation, "An Analysis of the Economic Impact on the Electric Utility Industry and the Environmental Benefits of Alternative Approaches to Significant Deterioration," Draft. December 2, 1975.

3/ 1976 National Energy Outlook, February 1976

4/ Federal Power Commission. Communication with Bureau of Power, June 27, 1975.

5/ Energy Research and Development Administration. Office of Planning and Analysis, November, 1975.

6/ Bureau of Mines, Energy Through the Year 2000 (Revised), December 1975.

In order to understand the effect of what might appear to be a relatively narrow range, it is useful to note that FEA's National Energy Outlook model projects that each additional one percent increase in the growth rate for electrical energy translates into 150 million tons of coal consumption per year by 1985 -- or approximately 15 percent of annual output. For the present, however, many analysts have noted the following phenomena which could yield an overall decline from the historic rate of 7.0 percent demand growth:

- Energy conservation measures, due to improved building and industrial processes and to alterations in individual energy consumption patterns, may create long-lasting changes in demand for electrical energy. The impetus for such long-lasting changes in consumption may simply be a response to the higher relative price of energy.

- Rate reform measures, which are now being considered by many state regulatory commissions and are implemented by a few ,could reduce the need for increases in peak generating capacity. It is not yet clear how measures such as peak-load pricing and/or elimination of declining block rates may affect demand. While awaiting such findings, however, the industry may feel constrained by what could be substantial demand modification due to pricing changes.

Countering the possible reasons for continuation of the decline from historic electrical demand-growth levels is the possibility that a rapid and/or strong economic recovery will lead to a demand surge.

Clearly then, uncertainty exists regarding demand growth rates for electrical energy. The cloudiness of the projections add to the questions surrounding long-term coal demand, both in terms of the mix of coal and nuclear development and in terms of coal consumption alone.

4. Sulfur Oxides Policy

A major obstacle blocking expansion of long-term coal demand has been uncertainty regarding federal policy for sulfur oxides control. Coal customers have been reluctant to make long-term commitments until questions on possible revisions to the Clean Air Act of 1970 -- currently being debated in Congress -- and about EPA implementation and enforcement are resolved. As long as there has appeared to be a possibility that Congress might make major changes in the law, utilities have been reluctant to authorize large expenditures for technology to clean up sulfur emissions from coal-fired power plants -- which might later prove legally unnecessary. On the other hand, if it appeared that flue gas desulfurization (FGD) systems (stack gas scrubbers) would be required as the alternative to (in some cases, in addition to) low-sulfur ($\leq$ one percent) coal, the demand for medium-to-high sulfur coal in certain regions of the country would rise and the demand for low-sulfur coal would be reduced. The Clean Air Act required that national health protective ambient air quality standards were to be attained by June 30, 1975. As of the attainment date, however, more than half of the coal-fired power plants (170 out of 335) were in violation of the law,15/ and it has been estimated that more than 100 million of the approximately 400 million tons of coal consumed annually by power plants are not in compliance with SO_2 emission limitations.16/ For existing coal-fired power plants to meet the requisite emission limitations imposed by the states, either low-sulfur coal, stack gas scrubbers, and/or other control techniques (such as coal cleaning) must be employed.

The Clean Air Act also requires that all new coal-fired power plants that began construction or signed a construction contract after August 17, 1971, must meet federal New Source Performance Standards (NSPS) for sulfur dioxide emissions.17/ As the law is now interpreted, these plants must sign contracts for either long-term low-sulfur coal supplies or stack gas scrubbers in order to meet NSPS. In addition, a recent advisory study recommended use of coal washing, or -- if necessary to meet emission standards -- coal washing plus scrubbing, as the most economic and environmentally efficient means of meeting SO_2 emission standards for power plants in the northeastern quadrant of the United States.18/

The crux of the sulfur oxides problem is that there is a short-term scarcity of low-sulfur coal to meet emission limitations. The utility industry has been reluctant to employ stack gas scrubbers which

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15/ EPA, Office of Planning and Evaluation, Memorandum, December 12, 1975.

16/ Coal Week, McGraw Hill, November 10, 1975, p. 5.

17/ NSPS requires sulfur dioxide emissions of no more than 1.2 pounds per million Btu in a coal-burning steam generating plant using more than 250 million Btu per hour. This is equivalent to about 0.76 percent sulfur by weight for 12,000 Btu/pound coal. However, the equivalency drops to 0.51 percent for 8,000 Btu/pound coal. The significance of the sulfur value relative to heat value is that low Btu western coal must be lower in sulfur to meet NSPS.

18/ "Report on Sulfur Oxide Control Technology," Commerce Technical Advisory Board (CTAB), September 1975.

would allow use of medium-to-high sulfur coal. EPA enforcement has been constrained because of limitations in the current law,19/ and most utilities have been unwilling to commit themselves to scrubbers while in doubt about whether Congress might amend the law.

5. The Costs of Sulfur Emission Controls

The cost of continuous sulfur emission controls required by the Clean Air Act is subject to significant regional variations, and it appears that different control methods may be more or less economic depending upon the region of the country where the coal is burned. Three principal methods are currently used for meeting sulfur emission standards:

a. Low-sulfur coal.

b. Coal beneficiation techniques -- crushing, separating, washing, and drying to remove as much sulfur prior to combustion as possible. Medium-sulfur coals, in particular, are expected to be good candidates for advanced beneficiation methods to achieve NSPS or SIP standards. (About 40 percent of the coal used for power plants at present is washed but primarily to remove dust and grit from the mine.)

c. Flue gas desulfurization systems -- or stack gas scrubbers, which treat gases created during coal combustion with a reagent to remove the sulfur. There are two types of FGD systems: (1) nonregenerable systems, which produce a sludge-like waste product, and (2) regenerable systems, which produce a potentially marketable byproduct of elemental sulfur or sulfuric acid.

Low Sulfur Coal. The overall costs of burning low-sulfur coal are comprised of the following:

- The transportation cost of the coal, which varies with the distance between the consumer and the mine and with the choice of transportation modes.

- Capital costs associated with use of low-sulfur coal in power plants designed for medium or high-sulfur coal, due to fuel switching. These costs include upgrading of the electrostatic precipitator (ESP) used for particulate removal. Additionally, use of low-sulfur, low-Btu western coal with high ash and water content will lead to derating of boilers designed for eastern coals with resulting capital charges for boiler modifications and/or loss of generating capacity.

- Costs associated with disposal of greater amounts of ash wastes which are generated by low-sulfur, low-Btu western coal with high ash and water content.

19/ EPA's current enforcement authority is limited to issuing injunctions and imposing only criminal penalties. The Administration has proposed an amendment authorizing EPA to impose civil penalties, which would give it greater enforcement capability.

Coal Beneficiation. Capital costs for coal cleaning or beneficiation plants vary according to the sophistication of the process to be used and the characteristics of the coal to be treated. Costs are estimated at a range of \$4-\$9 per ton of coal treated per year (mid-1974 dollars). Thus, a plant treating 3 million tons a year would cost from \$11.2-\$25.2 million.20/

Operating costs again vary with the degree of processing, ranging from \$0.30 to \$1.60 per ton of clean coal at the mine. Applicable depreciation costs can increase total operating costs to a range of \$1.23-\$4.83 per ton of clean coal at the mine.21/ However, beneficiation significantly lowers all post-cleaning transport and handling costs to the extent that in many situations the use of cleaned coal is comparable to the cost of direct combustion of raw coal.

Flue Gas Desulfurization Systems. Costs for FGD, or stack gas scrubber, systems include capital costs for the scrubber, operating costs, raw materials, and sludge disposal systems. Although scrubber system costs have been fairly well established, site-specific factors and market conditions influence total system costs so greatly that there exists a wide range of estimates. The results of several major analyses of FGD costs are summarized in Table V-2. Capital and operating costs for scrubber installation on both new and existing plants (retrofit) are presented. The typical base case is a 500 MW plant using 3-3.5 percent sulfur coal. Information on costs relating to lime/limestone nonregenerable scrubbers, which produce a slurry sludge requiring disposal and/or treatment, is considered the most reliable since all operational systems to date are this type.

Much of the utility industry has resisted installation of stack gas scrubbers, citing high costs and poor reliability as reasons for its reluctance to use the technology. Although a number of technical problems remain unresolved, FGD development progressed during 1975. Four full-scale scrubbers have begun operation during the past year, bringing the number of currently operating systems to 22 (3,394 MW).22/

20/ CTAB report, op. cit. p. 33.

21/ Ibid., p. 35. Range varies with the sophistication of the technology.

22/ "Status of Flue Gas Desulfurization Industry, September 15, 1975." PEDCO-Environmental Specialists, Inc. Prepared for EPA, Office of Research and Development.

TABLE V-2

Range of Costs Reported For Flue Gas Desulfurization Systems

	CAPITAL COSTS ($/KW)				TOTOAL ANNUALIZED COSTS (Including Capital Charges) MILLS/kWh			
	Nonregenerable		Regenerable		Nonregenerable		Regenerable	
	New	Retrofit	New	Retrofit	New	Retrofit	New	Retrofit
TVA[1/]	61 (Lime)	70	72 (Magnesia)	70	3.7 (Lime)	4.2	4.0 (Magnesia)	4.0
	68 (Limestone)	62	85 (Sodium)	87	3.4 (Limestone)	3.4	5.4 (Sodium)	6.3
			110 (Catox)	98			3.7 (Catox)	5.0
PEDCO[2/]	52-66	64-81	64-95	80-122	3.9	4.3	4.7	5.8
NERA[3/]	50-81	59-87	95	115-205				
IGCI[4/]	37-74	42-78			3.8	3.7		
CTAB[5/]	64-119							

1/ G.G. McGlamery, R.T. Torstrick, H.L. Faucett, L.J. Henson "Flue Gas Desulfurization Economics." Tennessee Valley Authority. Prepared for EPA, Office of Research and Development. March 1976. System costs are for 90 percent SO_2 removal and onsite solids disposal.

2/ T.W. Devitt and R.S. Amick. PEDCO-Environmental Specialists, Inc. "Flue Gas Desulfurization Process Cost Assessment." Prepared for EPA, Office of Planning and Evaluation. May 6, 1975. Calculated in January 1975 dollars. Costs for sludge disposal (nonregenerable systems) and by-product regeneration/ recovery are included, as are any costs of replacement power of "capacity penalty" resulting from the scrubber' estimated 3-8 energy penalty.

(Footnotes -- Table V-2 Cont'd)

3/ National Economic Research Associates, for Edison Electric Institute's Clean Air Coordinating Committee. Submitted as an appendix to the PEDCO report. May 6, 1975. NERA's original range of costs was 33-197 $/KW. Lime/limestone nonregenerable systems ranged from 34-116 $/KW. PEDCO made the following adjustments to fit its model: (1) Costs were adjusted to January 1975 dollars. NERA's dollar values had ranged from 1970 to 1980; (2) Particulate control costs were deducted since the purpose of the study was to estimate only the incremental SO_2 control costs; (3) Indirect costs were adjusted, usually upward, to provide adequate funds for engineering, field expenses, overhead, interest during construction, startup and contingency; (4) Replacement power costs were deducted since only a few utilities reported such costs -- all using different methods; (5) Sludge disposal costs were adjusted to reflect the costs of only SO_2 scrubber sludge disposal rather than fly ash or other coal combustion wastes. Costs were adjusted to anticipate sludge disposal for the lifetime of the FGD system, rather than for a brief demonstration period; (6) Regeneration facility costs were added for applicable systems not reporting such costs. The upper range and average adjusted costs were high because of an exceptionally high cost reported by the New England Power Company (NEPC) for a prototype FGD system. The utility stated that its reported costs should be considered "upper limits." Excluding the NEPC costs, NERA's estimates range form 50-137 $/KW with an average value of $85/KW. Nonregenerable system costs range from 50-88 $/KW.

4/ Industrial Gas Cleaning Institute. Submitted as an appendix to the PEDCO report. May 6, 1975. Variations in the manufacturer estimates for retrofit costs is primarily due to differences in assumed retrofit difficulty.

5/ Commerce Technical Advisory Board Panel on Sulfur Oxide Control Technology. "Report on Sulfur Oxide Control Technology." U.S. Department of Commerce. September 10, 1975. Costs of particulate removal by electrostatic precipitators, which adds an average of $5/KW to capital costs, are included. The CTAB figures, calculated for a 1000 MW plant, also include permanent sludge disposal costs.

Note: The cost of scrubbing can be translated into an equivalent cost per million Btu's of energy input by multiplying the above annualized costs by 111. Thus, a cost of 4 mills per kWh is roughly equivalent to another 44¢ per million Btu's of coal input.

An additional 23 units are under construction and 73 are in the planning stages.23/

Recent analyses of the status of FGD technology indicate that many of the past problems associated with scrubbers can be attributed to poor understanding of the chemistry involved. Some of these technical problems are being resolved as the chemical engineers operating the scrubbers at the various utilities develop expertise and experience.24/

Another question that arises is the ability of the scrubber manufacturing industry to meet demand. EPA estimates that 69,000 MW of scrubber capacity will be required by 1980 in order to meet air quality standards.25/ Because of the long lead time for installing a scrubber and the costs of breaking long-term contracts for low-sulfur coal, changes in scrubber demand for new coal-fired plants coming on line before 1980 are not likely.26/ If post-1980 demand increases significantly beyond current expectations -- due to stronger environmental requirements in the Clean Air Act -- the industry may be able to respond adequately if contracts are signed which allows it sufficient lead time (4-5 years).27/

A final consideration regarding scrubber capacity is the advantage incurred by those utilities which have chosen to delay making a scrubber commitment. Because the technology has improved over time and continues to do so, and because enforcement of the Clean Air Act has been weak, it has been advantageous for a utility to postpone

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23/ Ibid. 11 contracts awarded, 11 letters of intent signed, 6 requesting or evaluating bids, 46 considering only FGD systems.

24/ CTAB Report. Op. Cit., p. 27

25/ "Impact of Alternative Policies for Sulfur Dioxide Control on the Clean Fuels Deficit." Sobotka & Company. Report prepared for EPA, Office of Planning and Evaluation, July 1975.

26/ "Critique by the Environmental Protection Agency of Supplementary Materials Submitted for the Record by the Clean Air Coordinating Committee of the Electric Utility Industry." EPA, Office of Planning and Evaluation, July 29, 1975.

27/ Industrial Gas Cleaning Institute. Testimony presented before the Senate Public Works Subcommittee on Environmental Pollution, May 1975.

the investment even if it intends to install a scrubber eventually.

The Alternatives Compared. A comparison of the cost estimates for sulfur control alternatives is presented in Table V-3. The figures were prepared by EPA's Office of Research and Development, using November 1974 dollars. Although individual values cannot be stated definitively, the relative cost considerations are representative. These cost estimates indicate that use of regional coal is the cheapest compliance method for the West. East of the Mississippi, however, the range of overall effective costs varies tremendously. In some cases, it may be cheaper to use low-sulfur, high volatile eastern coal if steel industry demand is slack. In other cases, it may be cheaper to clean or scrub higher sulfur local coals than to pay high transportation costs moving coal West to East, especially if early indications that low-sulfur western coal use reduces efficiency and raises costs of particulate-removing electrostatic precipitators.[28/] The estimates in Table V-2 for the costs of scrubbing translate into an added cost of utilizing high-sulfur coal of from 40¢ to 64¢; hence, it is reasonable to expect utilities to bid low-sulfur coal up to a premium of this magnitude over the cost of higher-sulfur coal.

B. Long-Run Supply.

1. U.S. Coal Reserves and Resources

Any discussion of the long-term supply of any natural resource generally begins with an estimate of the total stock of the resource potentially available for economic use. These estimates often vary widely, depending upon the recoverability assumed. For instance, the estimates of total U.S. coal reserves vary from 137 to 3,968 billion tons, the former reflecting an estimate of those coal deposits which may be recovered economically through strip mining with the latter indicating a gross estimate of both identified and hypothetical coal deposits found within 6,000 feet of the surface.

Regional Coal Characteristics. Although estimates of reserves provide no direct evidence on the intermediate or long-term supply price of coal, they provide at least a hint of the potential for exploiting coal resources in various parts of the country. Since coal is

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28/ Conversation with James Abbott, EPA, Office of Research and Development, February 12, 1976.

TABLE V-3

Fuel and Control
Cost Estimates For SO_2 Control Alternatives[1]

SO_2 Control Alternative	Fuel Costs (Mills/KWH)	Capital Costs	Annualized Control Costs (Mills/KWH)	Effective Costs (Fuel and Annualized Control Costs)
Low-Sulfur Coal				
Western Coal[2]	4.0 - 6.0	\$50/KW[5]		4.0 - 6.0
Eastern Coal[2]	4.5 - 9.0	NA[6]		4.5 - 9.0
Coal Cleaning				
Physical	3.1 - 6.7[4]	\$10/KW	0.8 - 1.5	3.9 - 8.2
Chemical (Inorganic Sulfur Removal)[3]	3.1 - 6.7[4]	\$26/KW	1.55	4.7 - 8.3
Flue Gas Desulfurization				
Lime/Limestone (Nonregenerable)	3.1 - 6.7[4]	\$45 - 50/KW	2.9	6.0 - 9.6
Regenerable	3.1 - 6.7[4]	\$60 - 85KW	3.07 -3.80	6.2 -10.5

1/ November 1974 dollars

2/ Costs are for western coal delivered in the West and for eastern coal delivered in the East; additional costs for West to East transportation are approximately \$7.50 per ton per 1,000 miles (see Table V-8).

3/ Availability expected in 1978.

4/ Coal cost is for high-sulfur (3.0 - 4.0%) eastern coal

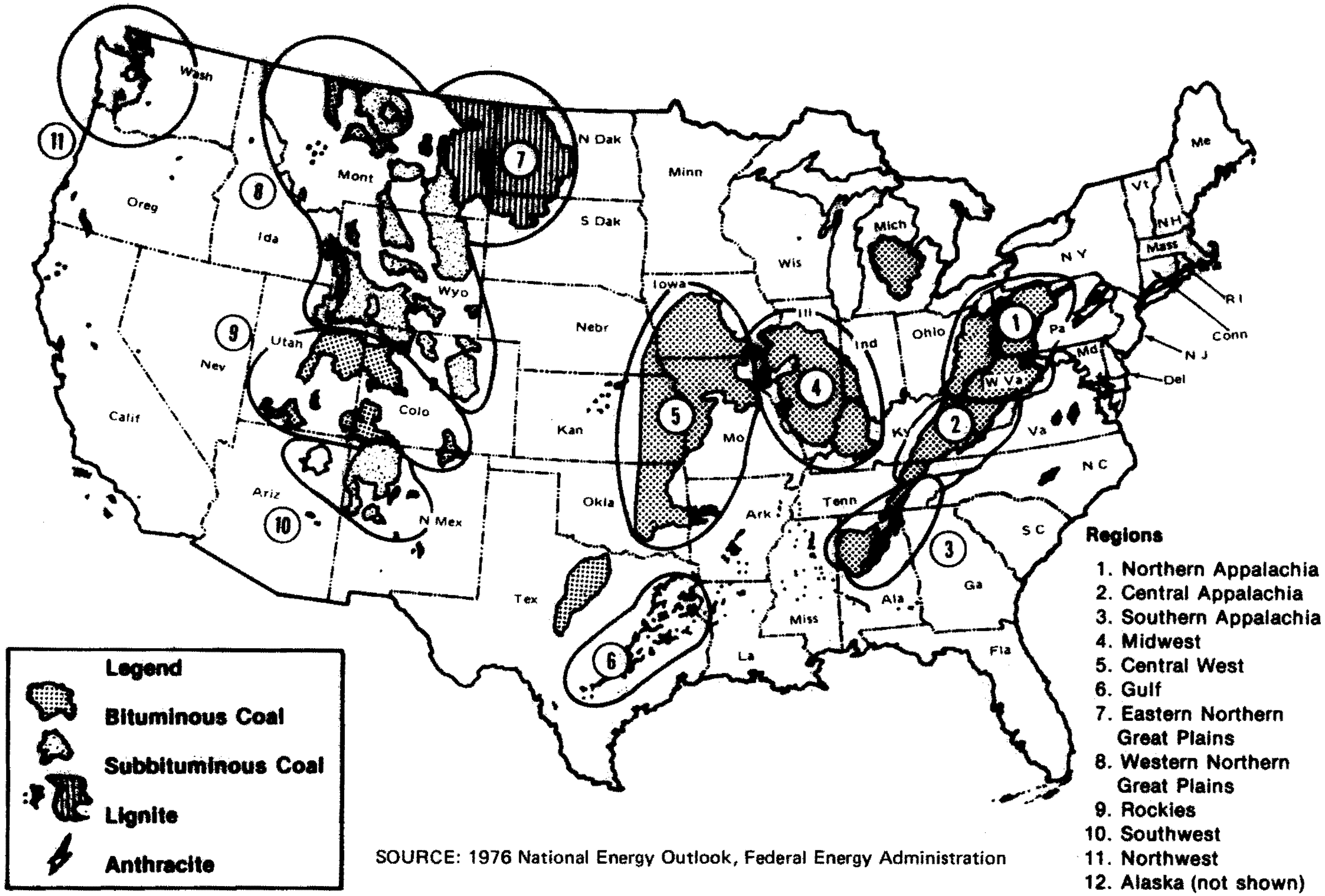
5/ EPA estimates that electrostatic precipitator (ESP) costs may increase significantly when low-sulfur western coal is burned because decreased resistivity diminishes ESP operating efficiency.

6/ NA = Not applicable.

Source: Sulfur oxide throwaway sludge evaluation panel (SOTSEP). EPA, Office of Research and Development, 1975.

Figure V-I

Coal Supply Regions



SOURCE: 1976 National Energy Outlook, Federal Energy Administration far from a homogeneous substance, it might be useful to describe the deposits in various sections of the country before presenting estimates of total reserves, projected 1980-85 supply, or factors affecting the long-run supply price of coal in various regions. Figure V-1 outlines coal reserves across the nation.

The ideal steam coal is one low in sulfur and ash content, high in heat (Btu) value, close to major use centers, and easily and cheaply mined. However, each regional class of coal is characterized by varying combinations of these qualities.

Northern Great Plains and Rocky Mountain Provinces contain large quantities of cheaply minable, low-sulfur coal. The Northern Great Plains area consists of two regions -- one underlain by lignite and the other by subbituminous coal. Their heating value ranges from 6,000 Btu/lb. for the lowest lignite grade to 9,800 Btu/lb. for the highest grade subbituminous coal. Sulfur content ranges from 0.2-1.0 percent.29/ Large quantities of coal are considered recoverable by efficient strip mining methods, but shipment to major use centers in the East may be restricted by high transportation costs. Lignite in particular is expensive to transport long distances because of its high water content and low Btu value, so the major markets for this grade coal are expected to be either regional power plants or gasification plants.30/

The Rocky Mountain area contains coal with higher Btu value (9,700-11,300 Btu/lb.) than the Powder River Basin.31/ Sulfur content is generally low. Transportation has been facilitated by access to a major East-West rail line (Union Pacific) even though distances to midwest markets are great. However, reserves in this area are smaller than in the Powder River Basin and mining costs are higher because some underground mining is needed.32/

29/ "Strippable Reserves of Bituminous Coal and Lignite in the U.S." U.S. Bureau of Mines Information Circular 8531 (1971).

30/ J. G. Asbury and K. W. Costello. "Price and Availability of Western Coal in the Midwestern Electric Utility Market, 1974-1982." Argonne National Laboratory. Report prepared for the National Science Foundation and EPA. October 1974, p. 16.

31/ The Powder River Basin is located in Wyoming.

32/ *Ibid.*, p. 22.

Western Interior Province (including Arkansas, Iowa, Kansas, Missouri and Oklahoma) contains coal with a high degree of inorganic sulfur which can be easily removed by cleaning methods. The coal has high Btu value, but its mining costs are high -- in part because reserves are deposited in thin veins. 33/

Midwestern Region (including Illinois, Indiana and western Kentucky) has coal with medium to high sulfur content and high Btu value, and mines close to markets.

Appalachian Region coals vary in sulfur content. Eastern Kentucky and West Virginia have large quantities of low to medium sulfur coal. The remaining coal is chiefly medium to high sulfur. Btu value is high. The mines are close to major markets, but mining costs have been high. Many existing surface mines have been depleted, and underground mining costs have risen.

Estimates of Coal Reserves. Table V-4 contains a summary of recent estimates of coal resources and reserves by degree of certainty, recoverability, region, sulfur content and heat content. The term "resource" refers to coal that can be currently or potentially extracted "Reserve," however, applies only to the coal which may be recovered with existing technology at prices reasonably close to current prices.

Total coal resources -- the total stock of coal within the United States which could be mined in the absence of any economic constraints -- are estimated to be in the range of 2.9 trillion to 3.2 trillion tons. These estimates include both identified and hypothetical deposits and differ in large part due to techniques of extrapolating from measurable deposits.

Identified resources -- specific coal deposits whose quantities are known from geologic evidence but which are not currently minable -- are estimated at about 1.6 trillion tons.

Demonstrated reserves, estimated at 434 billion tons, refer to deposits at depths and in seam thickness similar to those from which coal is now being extracted. This category, while part of the identified resources base, is determined by a higher degree of geologic identification and engineering analysis.

The most meaningful reserve estimate refers to what is called "recoverable" reserves which is calculated to be in the range of 217-258 billion tons. This category refers to that quantity of the demonstrated

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33/ Patrick A. Hamilton, D. H. White, Jr., and Thomas K. Matson, "The Reserve Base of U.S. Coals by Sulfur Content." U. S. Bureau of Mines, 1975.

TABLE V-4

Estimates of U.S. Coal Reserves and U.S. Coal Resources
(billion tons)

Total Recoverable Resources 1/	211-258
Total Demonstrated Strippable Reserves 1/	137
Low Sulfur (≤1%) Strippable Demonstrated Reserves 1/	73.3
Low Sulfur (≤ 1%) Underground Demonstrated Reserves	126.9
Total Low Sulfur (≤1%) Demonstrated Reserves 1/	200.2
Total Demonstrated Reserves 1/	437
Low Sulfur (≤1%) Identified Resources 2/	1000
Total Identified Resources 3/	1581
Total Resources 4/	3968

1/ U.S. Bureau of Mines (1974)

2/ U.S. Bureau of Mines (1966) and U.S. Geological Survey (1973)

3/ U.S. Geological Survey (1973)

4/ U.S. Geological Survey (1974)

reserve base which can presumably be produced using present technology at current prices. Recoverability varies from one deposit to another, with surface coal considered 80 percent recoverable (Bureau of Mines) and deep-mined coal only 50 percent recoverable. However, economists generally believe that estimates of recoverable reserves provided by the Bureau of Mines are somewhat optimistic.

Of even greater significance in terms of coal demand are those demonstrated reserves containing low-sulfur coal, which are estimated at 200.2 billion tons by the Bureau of Mines, of which those amounts considered recoverable would be significantly smaller. Only 73.3 billion tons of demonstrated low-sulfur reserves are estimated to be in strip-minable deposits compared with 126.9 billion tons located in underground deposits. If 80 percent of the demonstrated strip-minable reserve base is considered recoverable, then only about 59 billion tons of low-sulfur strippable stock might be considered reserves in an economic sense.

Nonetheless, even with substantially reduced calculations of recoverable reserves, most recoverable reserves of low-sulfur strippable coal lie west of the Mississippi (Table V-5). The Bureau of Mines estimated in 1974 that 92.6 percent of the nation's low-sulfur strippable demonstrated reserves, which are attractive because they are likely to meet air quality requirements at the lowest production cost, are located in the West.

Finally, it should be noted that evaluation of reserves of low-sulfur coal on a Btu basis significantly reduces U.S. low-sulfur coal estimates. An analysis of the draft environmental impact statement for the federal coal leasing program has suggested that 55 percent of western reserves are not low enough in sulfur to meet air quality standards.34/ Others, while still cautious, are less pessimistic about the future low-sulfur coal supply and simply point out that available data are sufficient to determine whether western coals adequate to meet air quality standards are economically minable.35/ Atlantic Richfield Company reports that analysis of the 102 cores taken from its Black Thunder property (Eastern Powder River Basin - Wyoming)

34/ Environmental Impact Assessment Project. "A Scientific and Policy Review of the Draft Environmental Impact Statement for the Proposed Federal Coal Leasing Program of the Bureau of Land Management." December 20, 1974.

35/ "Task Force Report on Fuel Availability for the National Power Survey." Federal Power Commission, July 1973.

TABLE V-5

Location of U.S. Reserves of Coal*
(billion tons)

	East of Mississippi			West of Mississippi		
Total Identified Resources						
U.S. Geological Survey (1973)	487			1,094		
Demonstrated Reserves						
U.S. Bureau of Mines (1975)	202			232		
Strippable Demonstrated Reserves						
U.S. Bureau of Mines (1975)	34			103		
Underground Demonstrated Reserves						
U.S. Bureau of Mines (1975)	169			131		
	Low	Med.	High	Low	Med.	High
Identified Resources by Sulfur Content	≤ 1%	1-3%	3%	≤ 1%	1-3%	3%
U.S. Bureau of Mines (1966) & U.S. Geological Survey (1973)	97	180	209	919	66	109
Demonstrated Reserves by Sulfur Content						
U.S. Bureau of Mines (1975)	33	55	81	167	38	11
Strippable Demonstrated Reserves by Sulfur Content						
U.S. Bureau of Mines (1975)	5	7	15	68	27	4
Underground Demonstrated Reserves by Sulfur Content						
U.S. Bureau of Mines (1975)	27	49	67	99	10	8

*The figures for reserves by sulfur content will not sum to the totals given for underground and strippable demonstrated reserves because the sulfur content of some reserves is unknown. Similarly, the total strippable and underground figures will not equal demonstrated reserves, because the latter includes an unknown category.

indicates a mean sulfur content of 0.77 pounds SO_2 per million Btu, well below the NSPS of 1.2 pounds per million Btu.36/

The importance of the western low-sulfur deposits which are deemed strippable is obvious. Although the Bureau of Mines estimate of 68 billion tons of these reserves and, therefore, 54 billion in recoverable reserves may be somewhat optimistic, these magnitudes loom large in comparison with projected coal consumption of one billion tons per year in 1980. A continuing concern for air quality, high oil prices, and limited low-sulfur deposits which can be easily mined in the East point to the obvious conclusion that western low-sulfur coal will be central in U.S. energy plans for the next few decades.

2. Supply in 1980 and 1985

The previous section suggests that demand for coal over the next ten years will have to be met by greatly increased western production. To highlight the growth of the estimated contribution of western reserves to the nation's coal supply during this period, Table V-6 summarizes various supply projections by region. Although there are obvious disagreements about the rate and extent of expansion, there is no doubt that western production will grow significantly above its 1975 level of slightly more than 100 million tons. By 1985, production from the West could exceed 350 million tons if various impediments to development are eased.

3. Long-Run Supply Price

The estimates in Table V-6 are supply projections without an appropriate context. Surely, supply is somehow related to market price. At what price will the projected supplies be forthcoming? How price-sensitive is supply?

Most of the estimates of western supply assume that strippable coal can be removed at a price of $4.50 to $6.00 per ton, and that supply is extremely price-elastic in that range. Table V-7 contains a range of supply price estimates for both the East and the West but no precise estimates of supply elasticities for coal production in the 1980's. The FEA estimate is based upon a supply study which posits an extremely price-elastic supply schedule for low-sulfur western coal in the range of $5 per ton at the mine (1975 dollars). Eastern supply is

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36/ "Development of Western Coal -- A Producer's View." Atlantic Richfield Company, April 14, 1975. The report also estimates that the Roland seam in the Wyoming Powder River Basin is believed to contain at least 50 percent (8.5 billion tons) recoverable reserves adequate to meet NSPS.

TABLE V-6

Estimated Coal Output for 1980 and 1985 by Region
(Millions of tons)

Year	East and Central (Appalachia & Midwest)	West (Northern Plains & Rocky Mt. States)
1975	533	107
1980		
FEA 1/	552	247
Sobotka & Company 2/	623	276
NERA	679	160
1985		
FEA 1/	661	378
Sobotka & Company 3/	639	460

1/ Federal Energy Administration, 1976 National Energy Outlook. February 1976. These estimates assume a $13/bbl price of imported oil.

2/ Sobotka & Company. For EPA, Office of Planning and Evaluation, December 1975.

3/ "Impact of Increased Coal Use on the Clean Fuels Deficit." Sobotka & Company. EPA Contract No. 68-01-2407. February 14, 1975. Total figures are lower than 1980 projections because estimates are only for steam domestic use rather than for coke, gas, or export.

TABLE V-7

Estimates of Long-Run (1980's)
Supply Price of Coal (F.O.B. Mine)
(Cents per Million Btu, 1975 dollars)

	Type of Coal				
	Low Sulfur	Low Sulfur	Medium Sulfur	High Sulfur	
Source	Western	Eastern	Eastern	Eastern	Central
Sobotka (1975)	23		77	65	65
Gordon (1975)	26-32		52-65		
Searl (1973)	33-37		44-47		
ICF-FEA (1976)	26	100-108		52-60	49

	Western	
	Surface	Deep
Asbury and Costello (1975)	22-25	64

Low Sulfur = 0-1% sulfur content

Medium Sulfur = 1-3% sulfur content

High Sulfur = 3%+ sulfur content

far less price-elastic; hence, estimates of "supply price" require a precise determination of equilibrium quantities to be mined.

From Table V-7,it is possible to conclude that western coal will be much cheaper than any eastern output. Eastern low-sulfur coal, for example, is approximately four times as expensive to extract as its western equivalent. Therefore, eastern coal will be used only in those areas in which it enjoys a large transportation advantage over western output, once an equilibrium is established. Moreover, high- or medium-sulfur coal will sell at a discount from low-sulfur coal which should approach the cost of cleaning and scrubbing required for compliance with environmental regulations.

Given the relative long-run costs of coal production, it seems clear that western coal will increasingly displace eastern output in the West and Midwest. Moreover, its price at any consumption point should be largely independent of the extent of demand, given the elasticity of western supply. As long as institutional or legal restraints do not impede western development, western coal should be transported east to a point at which its long-run supply price plus transportation costs are equal to the price of either eastern low-sulfur coal, the price of higher-sulfur eastern coal plus allowances for the cost of cleaning and/or scrubbing, or the equivalent cost of competing energy sources such as nuclear or imported oil. This equilibrium will be approached as power plants make the appropriate changes in boiler design or invest in requisite scrubbers or, finally, as new investments in generating capacity assume quantitative importance.

The above scenario depends, of course, upon the assumption that western coal deposits will be available to meet prospective demand in the next decade or two. If legal restrictions slow its development, eastern coal will sell at higher prices in most eastern and midwestern locations, and coal mine operators in those regions will reap considerable scarcity rents. If western states attempt to capture some of the available rents through sizable severance taxes, coal prices in most consuming locations will be affected in a similar fashion with like effects upon eastern coal producers' economic rents. On the other hand, cost-increasing developments in the East, such as large increases in wages and benefits for miners or stricter and better-enforced Appalachian strip-mining regulations, will simply lead to greater western coal penetration at the social cost of greater resource use in transportation, but without creating rents for western coal producers.

4. Environmental and Legal Constraints on Western Coal Development

A massive switch from eastern to western coal development will have tremendous impacts in every relevant sector. Accordingly, a number of legal and environmental constraints have been imposed on western development:

- Sierra Club v. Kleppe (Formerly Sierra Club v. Morton), has been expected to delay development in the coal rich Northern Great Plains area. A June 16, 1975 decision by the U.S. Court of Appeals for the District of Columbia ruled that no mining development could proceed in the Northern Great Plains until the Interior Department issued a regional environmental impact statement on coal development. In the interim, an injunction halted four companies from proceeding with preliminary mining operations. The Department of Interior appealed to the Supreme Court which granted certiorari on January 12, 1976 and simultaneously lifted the injunction limiting initial work by the affected companies. A court decision is expected before summer 1976.

- Production from existing leases on federal lands has been slowed by delays in obtaining the necessary approval of mining plans and environmental impact statements. This procedure has been clouded with uncertainty in part because of the issues unresolved in Sierra Club v. Kleppe.

- New leasing of federal coal lands in the West had been halted since 1971 by the Department of the Interior because the environmental impact statement for the entire coal leasing program had been found to be inadequate. The moratorium was lifted in January 1976, and Interior anticipates being able to call for nominations of lease tracts during 1976, with actual leasing beginning in 1977.

Despite charges that a program for rapid new coal leasing is unnecessary since production from existing leases (estimated at 16 billion tons)37/ has been almost negligible,38/

37/ Because of the inadequacy of most existing data regarding federal coal lands and current leases, and because of the importance of determining the quantities and characteristics of recoverable reserves, it would be useful for the Department of the Interior to compile and make public a detailed inventory of all federal leases, preference right lease applications and prospecting permits. This is necessary in order to determine lease history and status, economic factors which would affect the lease development, coal characteristics such as sulfur and ash content determined on a Btu basis, and environmental factors such as reclamation potential for surface mined land. Specifically, lease history and status should include name of the leaseholder, location, acreage, production status, rental and royalty provisions, special lease stipulations, and ownership of surface overlaying the lease. Economic factors affecting development of the lease should include the estimated quantity of recoverable reserves, location

Interior argues that new leasing must begin now for the post-1985 period because 5-10 years are required to bring a lease into production.

To counter speculation[39/] and to promote greater competition and more production, Interior has proposed regulations requiring "diligent development" of existing leases. Moreover, the Congress is expected to complete action soon on coal leasing legislation, which would preempt Interior's regulations with even stricter requirements for competitive bidding, production levels, and environmental reclamation.

Consequently, despite the possibility that coal leasing reform legislation could be delayed or that other roadblocks (such as further lawsuits) might threaten progress towards resumption of coal leasing, it is reasonable to assume that within the next year, the federal leasing program will be renewed or sufficiently clarified to end that particular uncertainty.

- Surface mining reclamation requirements are now imposed by almost all states with mining operations and may be extended

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with respect to transportation routes, and relationship to contiguous non-federal leases. Coal characterization information should include sulfur, ash, and trace element content--adjusted to a uniform Btu value. Environmental considerations should include potential for rehabilitation and reclamation, and other relevant environmental information.

38/ (i) General Accounting Office report, March 1976. (ii) Environmental Advisory Committee to the Federal Energy Administration, Effects of Coal Development in the Northern Great Plains. (iii) Northern Great Plains Resources Program Report to the Department of the Interior, April 1975. The report estimated that federal coal reserves already under lease in Montana, Wyoming and the Dakotas were about 9.8 billion tons. Interior's environmental impact statement on the leasing program stated that in the last few years, coal production from those federal leases amounted to less than 10 million tons/year, less than 0.1 percent of the coal under lease.

39/ The Department of the Interior has determined that 50 percent of all existing leases can be categorized as having no past production and no stated plans for future production. 237 leases, most only 5-10 years old, are so categorized, according to Coal Week, McGraw-Hill, July 21, 1975.

by federal legislation under consideration in Congress. Costs vary considerably, but a few estimates have been made. These find that reclamation costs for eastern and midwestern surface-mined coal are much higher than western costs. Typical estimates range from 20 cents per ton for western coal to $1-$2 per ton for eastern coal,40/ with a significant increase of from $3.45-$4.85 per ton for coal on steep slopes in the Appalachian region.41/ However, a related problem -- the large quantities of water needed for revegetation of arid and semi-arid lands in the West -- could increase western strip mining reclamation costs considerably above the estimate of 20 cents if revegetation is required. The key question is the extent and type of reclamation required and its incremental cost above estimates for average reclamation procedures.

- A growing number of western states have imposed not only strict environmental restrictions but also various taxes on coal-related activities. Montana, which leads this movement, has enacted a severance tax of 30 percent of the value of all coal mined within the state, and one of the toughest strip-mining reclamation laws in the country. Other states, particularly the other Northern Great Plains states, are following suit.

At this juncture, it is very difficult to predict the future outcome of legal disputes and policy debates involving western leasing and land reclamation. Moreover, it is unclear to what extent the western states will tax the economic rents deriving from their low-cost coal deposits. It does seem clear, however, that western coal production will increase in the next decade, placing downward pressure upon coal prices in the Midwest and in the East. But the

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40/ "Final Task Force Report on Coal." FEA Project Independence Blueprint, U.S. Department of Interior, November 1974.

41/ "Coal Surface Mining and Reclamation: An Environmental and Economic Assessment of Alternatives." Council on Environmental Quality, Comm. Print., 93rd Congress, first session. Senate Committee on Interior and Insular Affairs, March 1973.

magnitude of this increase in production cannot be forecast with precision.

5. Transportation Costs. Transportation costs will not only determine the future price of coal but will also help to locate the geographic equilibrium point between the use of western and eastern coal.

There are three primary methods of moving coal from the mine mouth to the consumer: water (either river or Atlantic Coast barges or Great Lakes collier), rail (usually unit trains, which move directly back and forth on a prearranged run from a mine to a specific power plant), and slurry pipelines.

Water is presently the cheapest form of coal transport (see Table V-8). In part, this may be due to the low user costs through inland waterways which result from the U.S. Army Corps of Engineers providing maintenance and improvements without direct charges to the shipper. Barge costs for coal hauling are estimated to be 50 percent less than rail, although costs of getting the coal to the water could raise the total estimate of the cost per ton mile for this mode of transportation.

Water transport involves some problems. For example, the Great Lakes colliers which use the St. Lawrence Seaway are constrained by size limitations and by winter closings. In addition, the inland waterway system is congested and in need of repairs and replacement of some existing locks and dams.42/

Despite water transport's attractiveness (in part, because there are no user fees for barges), it is secondary to rail movement in the U.S. because access from the coal fields to the power plants is limited. When possible, a combination of rail and water is used, but overall the rails handled 67 percent of all the coal loaded at mines in 1975. Water accounted for about 12 percent of all coal transport.

Unit trains have been the cheapest means of rail transportation to date, with an estimated cost of less than half that of regular rail movement.

Coal slurry pipelines may offer the promise of the cheapest means of moving coal long distances for the long-term, but this is

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42/ Proposals to replace the Alton, Illinois Locks and Dam 26, which has created a bottleneck on the upper Mississippi system, have been blocked by a coalition of environmental groups and the railroads. An estimated 55-60 million tons of bulk cargo passed through the Alton facility in 1975. Compounding the delay is a court injunction against construction of a replacement project pending approval of an environmental impact statement and subsequent congressional authorization of the project.

TABLE V-8

Coal Transportation Costs

Transport Method	Cost (cents/ton mile)
Rail - Unit Train	
Northern Great Plains Resources Program (1975)	0.48 - 0.76
Sobotka & Co. (1975)	0.65 - 0.75
Congressional Research Service (1975)*	0.13 - 0.80
Coal Supply Task Force - FEA (1975)	0.5
Martinka & Ross - American Electric Power (1974)	0.7 - 1.2
Gordon (1975)	0.5 - 0.6
Slurry Pipeline	
Northern Great Plains Resources Program (1975)**	0.34 - 1.01
Rieber (1975)	0.62 - 1.72
Barge	
Martinka & Ross (1974)	0.3 - 0.4
Sobotka & Co. (1975)	0.1 - 0.4

* Based on national power survey report estimate of all rail costs ranging from 0.7-8.3 and assuming that unit trains costs are half of regular rail costs.

** Lower estimate for 15 million ton per year capacity; higher estimate for 3 million ton per year capacity.

now subject to some dispute. However, only one pipeline is now functioning in the United States, and plans to build a 1,030 mile pipeline from Wyoming to five Middle South utilities in Arkansas have been blocked because the railroads, which fear the competitive advantage of the slurry pipeline, have refused to permit rights of way over their lands in the West. Legislation granting the pipelines eminent domain currently awaits congressional action, but even if the legislation were to pass during 1976 or 1977 other problems regarding the coal slurry pipeline remain. The greatest difficulty involves the enormous amounts of water required -- an estimated 6 billion gallons of water a year would be needed from the arid Wyoming high plains to form the half coal/half water slurry. Thus, even if the rights of way issue is resolved, water demand could present sufficient difficulties so that through the early 1980's at least, few,if any slurry pipelines will be constructed between the Northern Great Plains and regions east of the Mississippi.

Table V-8 estimates transportation costs per ton mile from major coal producing areas of the country to major markets. These costs may be translated into total costs per million Btu's for major routes between producing and consuming regions. Such estimates appear in Table V-9, which clearly demonstrate the high costs of transporting western coal to the East Coast. The importance of transportation costs can be seen in the following section which draws together all of the demand-supply considerations into a set of equilibrium price projections for various consuming points.

TABLE V-9

Estimated Transportation Costs From
Producing Region to Destination
(cents per million Btu)

	Low Sulfur Northern Great Plains	Medium Sulfur East	High Sulfur East	High Sulfur Central
Sobotka (1975)				
Chicago, IL	51	25	-	17
St. Louis, MO	46	18	-	5
Cleveland, OH	54	18	4	-
Huntington, W. VA	69	5	9	-
Fall River, MA	93	40	21	-
Baltimore, MD	84	28	7	-
Columbia, SC	109	19	27	-
New Orleans, LA	58	20	-	13
Northern Great Plains Resources Program (1975)				
Minnesota	15-20			
Illinois-Indiana	49			

C. Synthesis - The Long-Run Equilibrium

As the preceding pages demonstrate, there is no easy answer to the question: What will be the price of coal in the 1980's or 1990's?" Projecting future supply and demand for coal based upon recent or current experience is difficult because:

- Coal is not a homogeneous commodity. It varies considerably as to sulfur content, heat content, ash production, and location.
- The geographical dispersion of U.S. coal supply and/or coal users precludes determination of a single future price for coal of any given sulfur or heat content. Rather, delivered prices of coal vary considerably across the country.
- Competition from oil will depend upon the world price of petroleum and the cost of transporting low-cost coal from West to East in the United States.
- The premium now commanded by low-sulfur coal will depend upon air quality standards, western coal production, stack gas scrubber technology, and the cost of nuclear or low-sulfur fossil fuel substitutes.
- The demand for coal is derived from the demand for electric power, steel, and other industrial products and services. A variety of factors will influence these final demands, including future rate regulation practices of public utility commissions, the strength of aggregate demand, and the future course of exchange rates.
- Expanded development of western coal -- low in sulfur content and easily mined -- will be affected by future state and federal environmental policies, state tax policies, court interpretations of existing statutes, and reformulated leasing policies.
- Western coal expansion will require major new investments in transportation.

These and other future influences are sufficiently uncertain at this writing to preclude any precise prediction of coal prices and consumption at various locations in the United States during the next decade or two. Nevertheless, some modest long-run predictions emerge from scenarios which have been sketched by industry experts based upon the numerous studies of coal production and consumption to which this report has referred. Although these long-run predictions must be viewed cautiously, they at least emphasize the importance of western coal and transportation costs in determining the long-run price of coal in various regions of the country and the movement of that geographic point where East-West price parity exists for coal.

1. Projected Low-Sulfur Coal Prices

The maximum price of low-sulfur coal at all U.S. consuming points should equal the cost of Northern Great Plains production, plus transportation charges to the consumer. Given the estimates of the cost of western low-sulfur coal, F.O.B. mine, in Table V-7, and the estimates for transportation costs in Table V-8, it is possible to specify a range of delivered prices for the mid-1980's. These estimates appear in Table V-10 for selected cities. Included in Table V-10 are also the current prices paid by utilities in the respective states and the prices paid in the year before the Arab oil embargo. The pre-embargo prices are stated in 1972 prices while the other two series are in 1975 prices in order to demonstrate the increase in nominal prices which has occurred in the past three years and its relationship to geographical location.

Table V-10 demonstrates that -- except for Missouri which enjoys an atypically low current price of low-sulfur coal -- midwestern consuming points should experience price moderation in the next decade. The prospective delivered price of western coal is less than late 1975 prices. Eastern seaboard prices are another matter. Given the very large costs of transporting western coal as far as Maryland or South Carolina, the prospective delivered price for the 1980's is very high and is probably above the cost of alternatives, such as higher sulfur coal which has been washed and/or scrubbed , or low-sulfur eastern coal. Nevertheless Table V-10 demonstrates that even the upper range of estimated delivered prices for the 1980's are not above the average price paid by utilities in the Midwest and East in late 1975.

The estimates in Table V-10 may be interpreted as optimistic by those who fear that transportation bottlenecks will not be overcome by the 1980's or that western development will be slowed by environmental constraints, severance taxes, or capital equipment shortages. These estimates should therefore be taken as the reflection of a potential long-run equilibrium. Prices could be much higher if any of the above bottlenecks slow western development.

A somewhat higher set of predicted prices for 1985 emerge from FEA's recent 1976 National Energy Outlook. These estimates, reproduced in Table V-11, are considerably higher for the four Central Census regions, ranging from \$0.95 per ton in the West North Central region to \$1.15 in the East North Central and East South Central regions as compared with

TABLE V-10

Delivered Low-Sulfur Coal Prices (1972 and 1980's)
(cents per million Btu)

	July 1972[a/] Federal Power Commission (by state) (1972 prices)	Current[b/] Prices (October 1975)	1980's[c/] Estimated Prices (1975 prices)
Chicago, Illinois	61	96	73 - 88
St. Louis, Missouri	41	51	68 - 83
Cleveland, Ohio	40	110	76 - 91
Huntington, W. Virginia	37	98	91 - 106
Baltimore, Maryland	54	157	106 - 121
Columbia, S. Carolina	46	95	131 - 146

a/ Gordon, (1975), Op. Cit.

b/ FPC data for states

c/ Table V-7 for estimated long-run supply prices of western coal
Table V-8 for estimated transportation costs

the range of $0.76 to $0.91 in Table V-10. Part of the difference may be accounted for by different assumptions concerning reclamation costs and severance taxes at the mine, but most is undoubtedly due to the differences in assumed transportation costs. If transportation costs are in the vicinity of one cent per ton mile in 1985 (measured in 1975 dollars) rather than 0.75¢, the estimated delivered costs in Table V-10 would be increased by from $0.13 to $0.20 in the Central Census regions, rendering them more compatible with FEA estimates. In short, the equilibrium 1985 coal prices are very sensitive to assumptions concerning the future cost of transportation.

TABLE V-11

Long-Term Contract Delivered Coal Prices
to the Electric Utility Sector
($/Million Btu, 1975 Dollars)

Regions	1985 Low Sulfur	1985 High Sulfur
Northeast	1.40	.90
Middle Atlantic	1.25	.75
South Atlantic	1.25	.80
East North Central	1.15	.65
East South Central	1.15	.60
West North Central	.95	.65
West South Central	1.00	.70
Moutain	.55	.45
Pacific	--	.80

SOURCE: FEA, 1976 National Energy Outlook

2. The Long-Run Cost of Burning Alternative Types of Coal

Clearly, not all coal consumers will burn low-sulfur coal in the 1980's. But given the trend in sulfur policy, the continuing high costs of imported oil, and the uncertainties surrounding nuclear development, it appears increasingly likely that coal consumers -- especially electric utilities -- will be faced with the choice of burning low-sulfur coal or installing flue-gas desulfurization systems in the next ten years. The tradeoffs involved in such a choice are best delineated by summarizing a detailed recent study.

A recent study for EPA provides an analysis of the projected alternative costs for meeting two sets of environmental standards -- emission standards for existing plants under the State Implementation Plans (SIP) and Federal New Source Performance Standards (NSPS) for new power plants[43/] in eight consuming points in the Midwest, South, and East. The estimates are obviously sensitive to assumptions concerning the cost of western coal at the mine, transportation charges and scrubbing costs, but a few general conclusions emerge rather boldly from Table V-12.

First, it appears that midwestern users will find low-sulfur western coal the most desirable alternative. Southwestern low-sulfur coal was deemed irrelevant for a study of east-of-Mississippi costs because it is more expensive than Northern Plains coal. Additionally, state emission standards in the West are so strict in many cases that even use of local low-sulfur coal is insufficient to meet them. Scrubbers as well as local coal will be required for most new plants. Moving south and east from the Midwest, however, medium-and-high-sulfur regional coal begin to appear more economical. Despite its high mine-mouth cost, eastern and midwestern medium-to-high sulfur coal is increasingly attractive as the distance from the inland water system increases.

It seems that geographic price parity for western versus eastern coal could be reached in the future at any point where coal can be delivered by water, which could be anywhere up and down the Mississippi River and as far east as Buffalo. Less certainty in finding a parity point exists when midwestern rail transportation has to be used because of the tendency of midwestern lines to influence rate determination in order to maintain coal revenues.[44/]

The factors likely to influence the determination of the price parity point include not only specific local determinants such as employment considerations or transportation cost anomalies, but also variations in both western and eastern production costs due to state severance taxes or property assessments, the degree of reclamation required subsequent to strip mining, and union wage and benefit increases. Other types of

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43/ NSPS of 1.2 pounds SO_2 per million Btu means that much of western low-sulfur coal is unable to meet the standard without cleaning or scrubbing. Low-grade lignite, for example, at 6,000 Btu/lb. will need a sulfur content of 0.36 percent to meet NSPS. The typical Btu value of Powder River Basin coal is 8,000 Btu/lb., requiring a sulfur content of 0.4 percent.

44/ Martin B. Zimmerman, Long Run Mineral Supply: The Case of Coal in the United States. Massachusetts Institute of Technology, September 1975.

TABLE V-12

Long-Run Costs of Coal Burning in the 1980's[a]
(Cents per Million Btu in 1975 dollars)

	Low-Sulfur Coal		Medium Sulfur	High-Sulfur Coal	
	N. Plains	Eastern	Eastern	Eastern	Central
Cost of SIP - Conforming Coal Burning in Existing Installations					
Chicago (Central Great Lakes)	95	106	-	129	
Cleveland (Eastern Great Lakes)	98	99	116	-	
St. Louis (Upper Mississippi River)	90	99	-	117	
New Orleans (Lower Mississippi River)	102	101	-	125	
Huntington (Ohio River)	113	86	121	-	
Baltimore (Atlantic Coast)	128	109	119	-	
Columbia (Southeast Inland)	153	100	139	-	
Fall River, Mass. (New England)	137	121	133	-	
Cost of NSPS - Conforming Coal Burning in New Installations					
Chicago	83	-	-	114	
Cleveland	81	-	101	-	
St. Louis	78	-	-	102	
New Orleans	90	-	-	110	
Huntington	101	-	106	-	
Baltimore	116	-	104	-	
Columbia	141	128	124	-	
Fall River	125	-	118	-	

Definitions:

SIP - State Implementation Plans (for SO_x Emission Control)
NSPS - Federal Standard for SO_2 Emissions from New Stationary Sources
Low Sulfur $<$1 percent sulfur
Medium Sulfur 1-3 percent sulfur
High Sulfur $>$ 3 percent sulfur

a/ Includes costs of delivered coal, boiler modification and flue gas desulfurization.

SOURCE: "Impact of Increased Coal Use on the Clean Fuels Deficit." Sobotka & Co., Inc. EPA Contract No. 68-01-2407, October 21, 1975.

considerations such as specific site and market conditions (other than proximity to low-sulfur coal deposits, which determine transportation costs) include local emission standards, age of electric generating facilities, relative ease of scrubber utilization, and proximity to coal deposits which can be washed sufficiently to meet air quality standards.

The estimates in Table V-12 indicate that for existing plants in the East, it is cheaper to burn medium-sulfur eastern coal (which can often be washed to meet emission standards -- a less costly alternative than scrubbing). In addition, medium-sulfur eastern coal is quite competitive with western low-sulfur coal in Cleveland and New Orleans, in particular. A minor increase in production or transportation costs for western coals could tip the balance towards eastern coal for those regions. Of course, the same point could be made alternatively: if coal production costs or scrubber costs rise in the East, western coal would obviously be more economical in Cleveland and New Orleans.

For those new plants which must meet NSPS, the estimates indicate a large future market for eastern high-sulfur coal if its market price can be held somewhat near current levels. A price increase of as little as $2 per ton, all else equal, would reduce future market prospects by one-third to one-half.45/

D. Conclusions

- Western coal will be a major force in U.S. coal consumption, but the extent of its movement to the East will depend on resolving questions regarding: (1) Clean Air Act regulations, implementation, and enforcement; (2) environmental regulations which may increase production costs, such as stricter surface mining reclamation requirements than now exist; (3) taxes imposed by western states on extracted coal; and (4) transportation costs.

- Given the cost of extracting western coal, the delivered price of low-sulfur coal in consuming areas west of the Appalachians may not rise appreciably in the next decade once a new equilibrium is established. Given sufficient time for western development and for new transportation

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45/ It must be stressed that the estimates contained in Table V-11 are based upon the assumption that coal consumers have the time to adjust to market conditions. It is possible that many years may be required before new investments in boilers can be made, scrubber technology can be established, or existing boilers can be modified to accomodate the "optimal" choice of fuels. Until that time, costs for some consumers may greatly exceed those in Table V-12 if environmental standards are enforced.

investments, western low-sulfur coal should be available at most midwestern consumption points at prices no higher than those paid by utilities for low-sulfur coal in late 1975 and perhaps at substantially lower prices.

- A geographic point of price equilibrium between low-sulfur western coal and eastern coal will ultimately be reached somewhere east of the Mississippi River. At this point, the western coal will sell at a premium dictated only by the cost of flue-gas desulfurization or cleaning the eastern and midwestern coal. East of this point, the premium will be greater; hence, utilities will move towards use of eastern high-sulfur coal and flue-gas desulfurization, if this technology proves viable.

- If estimates of price elasticity of supply for western coal are accurate, the long-run delivered price of low-sulfur coal in most consuming locations west of the Appalachians should not vary with demand.

- Oil cannot compete with coal in new power plants given its current imported price of more than $2.30 per million Btu's. Unless world oil prices fall by one-third or various constraints raise delivered coal prices by more than 50 percent above long-term equilibrium projections, oil will not compete with coal in the 1980's in the electrical utility market.

- Attainment of a new long-run equilibrium in the coal market may be delayed substantially by institutional and legal problems in leasing western federal coal lands. Resolution of Sierra Club v. Kleppe could unleash a number of these constraints.

- Resolution of sulfur oxides policy issues could have a major impact upon future coal prices, especially if flue-gas desulfurization systems are mandated. Such requirements would reduce the premium exacted for low-sulfur coal and increase the demand for regional high-sulfur coal.

- Serious economic problems in expanding western production from little more than 100 million tons per year in 1975 to 300-400 million tons per year in 1985 could develop. Supply bottlenecks in transportation equipment and capital equipment required for surface mining are possible given the necessary rate of expansion and current uncertainties deriving from environmental challenges and discussion of new sulfur-oxides legislation.

- Nuclear power will grow much more slowly than once anticipated. As a result, more new coal-fired plants will be built, increasing the demand for steam coal.

APPENDIX A

Reporting of Coal Spot Prices

Deficiencies exist in the Bureau of Labor Statistics (BLS) wholesale indexes for coal for these reasons:

- BLS price indexes are based upon reports of spot prices from producers or sales companies; they do not represent delivered prices.

- At a time when spot pricing is highly sensitive to fluctuations in demand, the sample prices may be unrepresentative if they are reported by large companies which sell only small amounts of coal on a spot basis.

For these two reasons, it is difficult to obtain adequate and complete information about spot pricing patterns. However, there is better information available for two important classes of coal (the BLS index includes all grades of coal). Coal price information is reported to the Federal Power Commission (FPC) for steam coal used to fire electric power plants and to the export price index, useful chiefly for metallurgical coal. Both of these alternative sources can be used to check the BLS indexes.

(BLS is well aware of the deficiencies contained within its indexes and has taken recent steps to improve them. Beginning this summer, a new set of WPI coal data will be released that includes contract prices, and separate listings by region as well as by method of production.)

In the case of steam coal, the FPC requires that all fossil-fuel-fired steam electric power generating stations larger than 25 MW (megawatts) capacity -- which includes more than 95 percent of all such power plants -- report the following:

- Type of coal by mining method, heat value (Btu's per pound), sulfur and ash content.

- Quantity of coal delivered (in tons).

- Terms of the sale (spot, contract with price adjustment clause, new or newly renegotiated contract, and all other contract purchases).

- Price paid per Btu and per ton.

In addition to the relevant pricing information required by the FPC, coal customers report delivered prices, which include transportation costs. Also, because the delivery time may take from a few days to a month, prices reported to the FPC lag slightly behind FOB mine prices.

To illustrate the inadequacy of BLS compared to FPC figures for providing spot coal price information, see Table A-1 which compares BLS steam electric and all bituminous coal indexes, with electric utilities coal prices as reported to the FPC. The table breaks down the FPC price for the two regions in which the greatest number of spot purchases were made in 1974. It is evident from the table that the FPC purchase price shows a dramatically higher increase than does the BLS steam electric index.

Furthermore, the BLS sample represents Appalachian coal. The index of the FPC price for the South Atlantic region, which would most closely reflect Appalachian coal prices, rose to twice that of the BLS index -- 329 in December 1974 compared to 162 -- and remained 92 points above the BLS index as of June 1975. Since the BLS F.O.B. mine price should have fluctuated even more than the delivered price due to transportation costs remaining constant in 1974, it is even more apparent that the BLS index has failed to provide accurate and useful spot price data.

In the case of metallurgical coal price increases, the BLS index can be compared to the export price index since U.S. coal exports are composed almost entirely of metallurgical coal. (Derived from Table III-1.)

	BLS Index		Export Price Index
	High Volatile	Low Volatile	
June 1973			100
December 1974	268	274	359
June 1975	288	290	270

Although it cannot be assumed that export coals have the same quality and composition -- and therefore reflect similar market changes -- as domestic coals, it is more than likely that export prices reflected some of the same uncertainty about supply being unable to meet certain demand prior to the UMW strike of November 1974. Since a steady supply of metalurgical coal used for coking is crucial to the steel industry, prices did reflect intense demand (from $17.60/ton in June 1973 to $63.27/ton in December 1974).

TABLE A-1

Bituminous Spot Coal Prices: BLS vs. FPC

Month /	Year	All Bituminous	Steam Electric	United States Total	South Atlantic	East North Central b/
July	1973	99.5	99.4	99.7	99.5	100.1
August		99.5	99.4	100.1	100.7	100.6
September		103.4	103.6	102.3	103.2	102.2
October		104.1	104.4	107.8	108.2	107.8
November		111.4	112.0	115.5	114.8	113.2
December		112.1	112.8 c/	127.9	126.2	122.4
January	1974	116.3	117.5	163.2	190.7	134.4
February		117.8	119.2	197.2	232.0	167.0
March		120.9	121.1	216.1	242.6	194.8
April		142.0	123.4	227.7	262.5	201.1
May		143.9	124.2	232.1	266.0	223.8
June		150.7	131.6	247.7	276.5	251.6
July		160.4	137.3	268.4	303.6	253.6
August		166.9	141.2	276.8	315.6	260.4
September		172.8	147.1	293.8	341.2	269.2
October		183.5	155.1	294.1	343.8	268.1
November		183.5	153.6	306.3	346.7	286.3
December		198.5	162.0	297.7	328.9	276.5
January	1975	198.7	157.3	269.6	298.9	294.3
February		189.3	143.5	248.6	255.5	243.5
March		178.6	129.4	239.9	239.7	232.0
April		178.1	126.8	235.1	229.7	227.3
May		177.6	124.3	228.0	226.9	222.0
June		173.9	122.9	224.0	214.5	227.4

a/ Includes Delaware, D.C., Florida, Georgia, Maryland, North Carolina, South Carolina, Virginia, and West Virginia.

b/ Includes Illinois, Indiana, Michigan, Ohio, and Wisconsin.

c/ The steam electric series began in December 1973. Before that the series consisted only of screenings, which included all boiler uses.

Sources: Bureau of Labor Statistics, Wholesale Prices and Price Indexes, monthly.

Federal Power Commission, Monthly Fuel Cost and Quality Information, News Releases, Monthly.

- High oil prices and continuing uncertainty about nuclear costs will strengthen the demand for eastern coal.

- If medium-to-high sulfur eastern coal cannot be washed or scrubbed at prices competitive with delivered western coal, western coal will be used more heavily in the East.

- Innovations in West-East transportation, such as the coal slurry pipeline, are not likely to be a major force in the next decade.

- Continuing delays in resolving environmental issues raised by western coal development could generate sharp increases in eastern and midwestern coal prices, given the much greater inelasticity of supply of coal in these latter areas. The beneficiaries of such a delay would be the owners of current mines in the eastern and midwestern regions.

- Labor problems, more stringent eastern and midwestern reclamation requirements, or higher eastern and midwestern severance taxes could increase production costs considerably in the East or Midwest, inducing greater importation of western coal at substantially increased social costs of transportation.

APPENDIX B

THE TWENTY LARGEST COAL MINING CORPORATIONS IN 1974

(Independent coal producers are marked with an asterisk. Where coal companies are subsidiaries of companies engaged in other activities, the parent is in parenthesis.)

	Company	Production (Ton)
1.	Peabody Coal Co. (Kennecott Copper Corp.)	68,104,076
2.	Consolidation Coal Co. (Continental Oil and Gas Corp.)	51, 753,933
3.	Island Creek Coal Co. (Occidental Petroleum Corp.)	20,848,017
4.	Amax Coal Co. (Amax Inc.) (Standard Oil of California)	19,948,871
*5.	Pittston Co.	17,381,911
6.	(United States Steel Corp.)	16,389,000
7.	Arch Mineral Corp. (Ashland Oil, Inc.)	13,878,539
8.	Bethlehem Mines Corp. (Bethlehem Steel Corp.)	13,347,625
*9.	North American Coal Corp.	9,771,563 1/
10.	Peter Kiewit Cons Mining Div.	9,697,000
11.	Old Ben Coal Co. (The Standard Oil Company of Ohio)	9,451.880
*12.	Eastern Associated Coal Corp. (Eastern Gas and Fuel)	7,697,893
*13.	Westmoreland Coal Co.	7,580,575
14.	Pittsburgh & Midway Coal Mining Co. (Gulf Oil Corp.)	7,528,174
15.	(Utah International Inc.) 2/	6,955,000
16.	(General Dynamics Corp.)	6,950,073
*17.	Texas Utility Generating Co. (Tex.) 3/	6,500,000
18.	(American Electric Power Company, Inc.)	6,378,631
*19.	Rochester & Pittsburgh Coal Co.	4,608,792
20.	A.T. Massey Coal Co., Inc. Properties (St. Joe Minerals Corp.)	4,303,357

1/ Includes production of the Decker Mine (6,786,000 tons in Montana) Operated by Peter Kiewit Construction, but is jointly owned by Kiewit & Sons and Pacific Power and Light.

2/ In addition to coal, Utah International mines copper, iron ore, uranium, oil and gas, in foreign countries as well as in the U.S. Also, it is engaged in shipbuilding, development, and construction.

3/ Is owned by Texas Utilities.

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