The original documents are located in Box 7, folder: "National Energy Outlook - 1976" of the Frank Zarb Papers at the Gerald R. Ford Presidential Library.

Chapter IV

COAL

COAL THROUGH 1975 AND SHORT-TERM OUTLOOK

Coal is our most abundant domestic energy resource. At current consumption levels, we have enough coal reserves to last at least 300 years. At projected 1985 consumption levels, we have enough reserves to last at least 200 years. Coal accounts for about 85 percent of our fossil-fuel resources. However, coal has accounted for a declining portion of U.S. energy consumption over the last 80 years.

The purpose of the following section of the coal chapter is to provide a perspective concerning the role coal has played and is now playing in the Nation's energy economy. The long-term outlook for the industry is discussed in the second and third major sections of this chapter.

Historical Perspective (through 1972)

The Nation's coal industry began in the 18th century with bituminous coal mined in Virginia and anthracite in Pennsylvania. Coal production increased steadily throughout the 19th century. Its uses included space heating, coal gas, steam generation, and as coke in steel production. By the turn of this century, coal supplied 90 percent of the U.S. energy consumption.

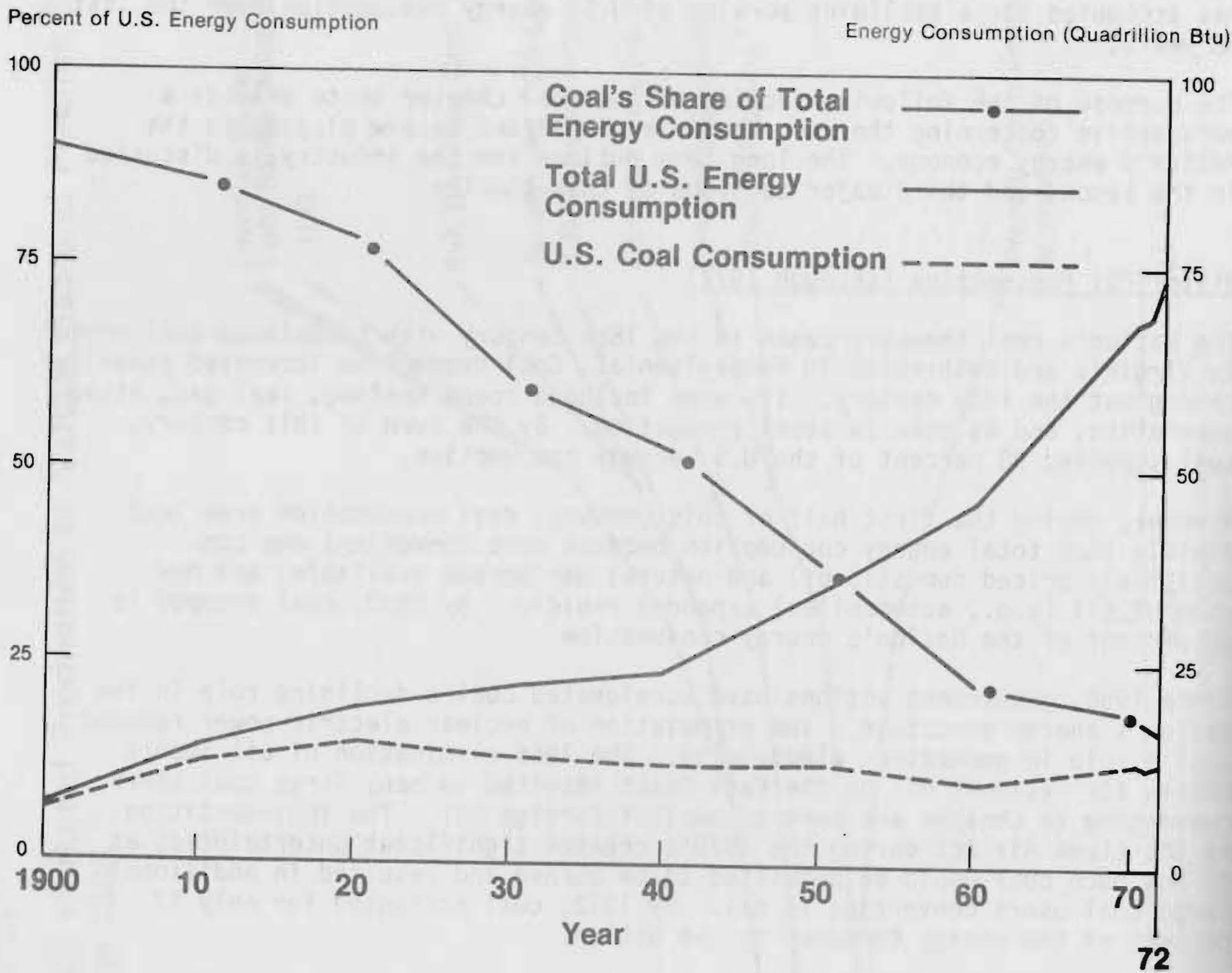
However, during the first half of this century, coal consumption grew less rapidly than total energy consumption because more convenient and competitively priced domestic oil and natural gas became available, and new uses of oil (e.g., automobiles) expanded rapidly. By 1950, coal dropped to 38 percent of the Nation's energy consumption.

Since 1950, government actions have accelerated coal's declining role in the Nation's energy structure. The stimulation of nuclear electric power reduced coal's role in generating electricity. The 1966 elimination of oil import quotas for residual oil on the East Coast resulted in many large coal users converting to cheaper and more convenient foreign oil. The implementation of the Clean Air Act during the 1970's created significant uncertainties as to how much coal would be permitted to be burned and resulted in additional large coal users converting to oil. By 1972, coal accounted for only 17 percent of the energy consumed by the Nation.

Thus, while coal production has remained almost constant, the percentage of total national energy consumption supplied by coal has declined dramatically (see Figure IV-1).

Figure IV-1

Coal's Declining Share of Total United States Energy Consumption



Although total coal consumption in 1972 was roughly the same as in 1945, the breakdown of consumption by sector has changed. In 1945, the largest consuming sector was Class 1 railroads, burning 125 million tons. By 1972, railroad consumption of coal had dropped so far that the Bureau of Mines no longer tracks it. Retail consumption totalled 119 million tons in 1945, but only nine million tons in 1972. The other category, which includes industrial uses, also dropped from 148 million tons to 72 million tons during the 1945-1972 period. The electric utilities sector was the only sector to grow throughout the period, increasing from 72 million tons in 1945 to 349 million tons in 1972 (see Figure IV-2).

During the 1950's the growth in utility coal consumption was less than the decline in consumption by the other sectors. By 1960, total coal consumption had dropped to 4.7 million tons from the 588 million tons consumed in 1945. During the 1960's, total coal consumption increased until it hit 586 million tons in 1970. During the early 1970's, coal consumption grew at a reduced rate.

The major reason for the slowdown in the growth of coal consumption was competition from oil and nuclear power. The percentage of total kilowatt hours generated with coal has been declining since 1965 (see Figure IV-3). The elimination of oil import quotas along the East Coast and the sulfur dioxide emission limitation of the Clean Air Act pushed utilities away from coal. In addition, nuclear power has increased its share of total power generation from 0.4 percent in 1965 to 4.5 percent in 1973, largely at the expense of coal. Thus, in the early 1970's, coal's only growing market--electric utilities--was being threatened. Oil and nuclear plants could produce power more cheaply than could coal in many areas of the country.

Coal production also has undergone significant shifts since 1945. In general, coal production has shifted from East to West and from deep to surface mines. In 1945, close to 75 percent of U.S. production came from the Appalachian basin. The Interior basin produced 20 percent and the remaining 5 percent came from the Far West. By 1972, Appalachian production dropped to 65 percent, with interior and western production growing to 26 and 8 percent, respectively. In 1945, only 19 percent of U.S. production was mined using surface methods. By 1972, 49 percent of production was surfaced mined. This trend towards surface mines has occurred in every region of the country. Although the total amount of coal mined increased by 15 million tons between 1945 and 1972, the amount that came from deep mines declined by 164 million tons (see Table IV-1).

Recent Events (1973-75)

The Arab embargo at the end of 1973 together with a corresponding dramatic oil price increase had a substantial impact on the coal industry. Oil consumers began to explore ways to substitute coal for oil. Further, emerging natural gas shortages and the policy of the Federal Power Commission to allocate natural gas away from electric utility boilers resulted in gas consumers exploring ways to substitute coal for natural gas.

Figure IV-2
Coal Consumption By Sector, 1935–72

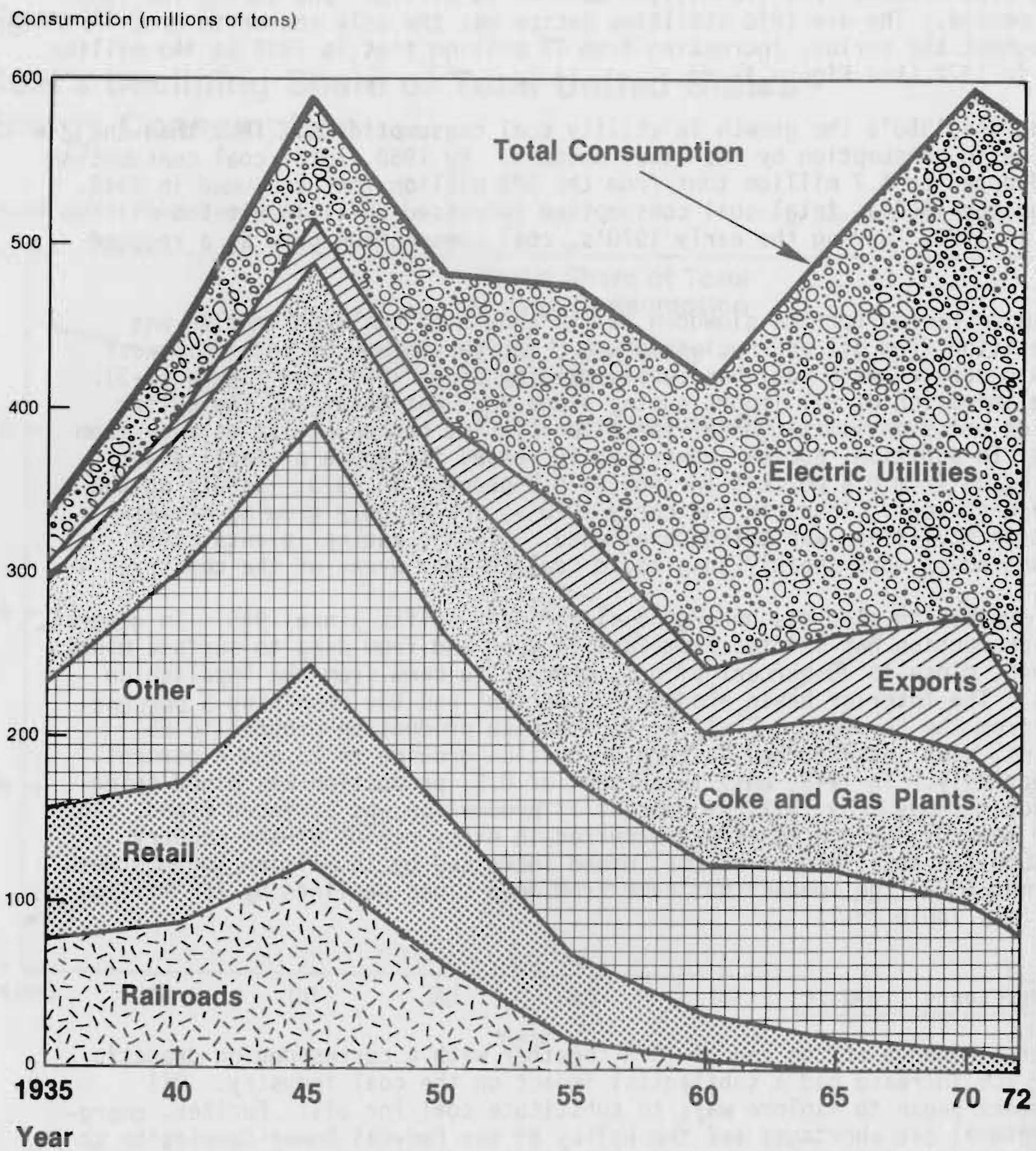


Figure IV-3
Electrical Generation By Fuel, 1955–73

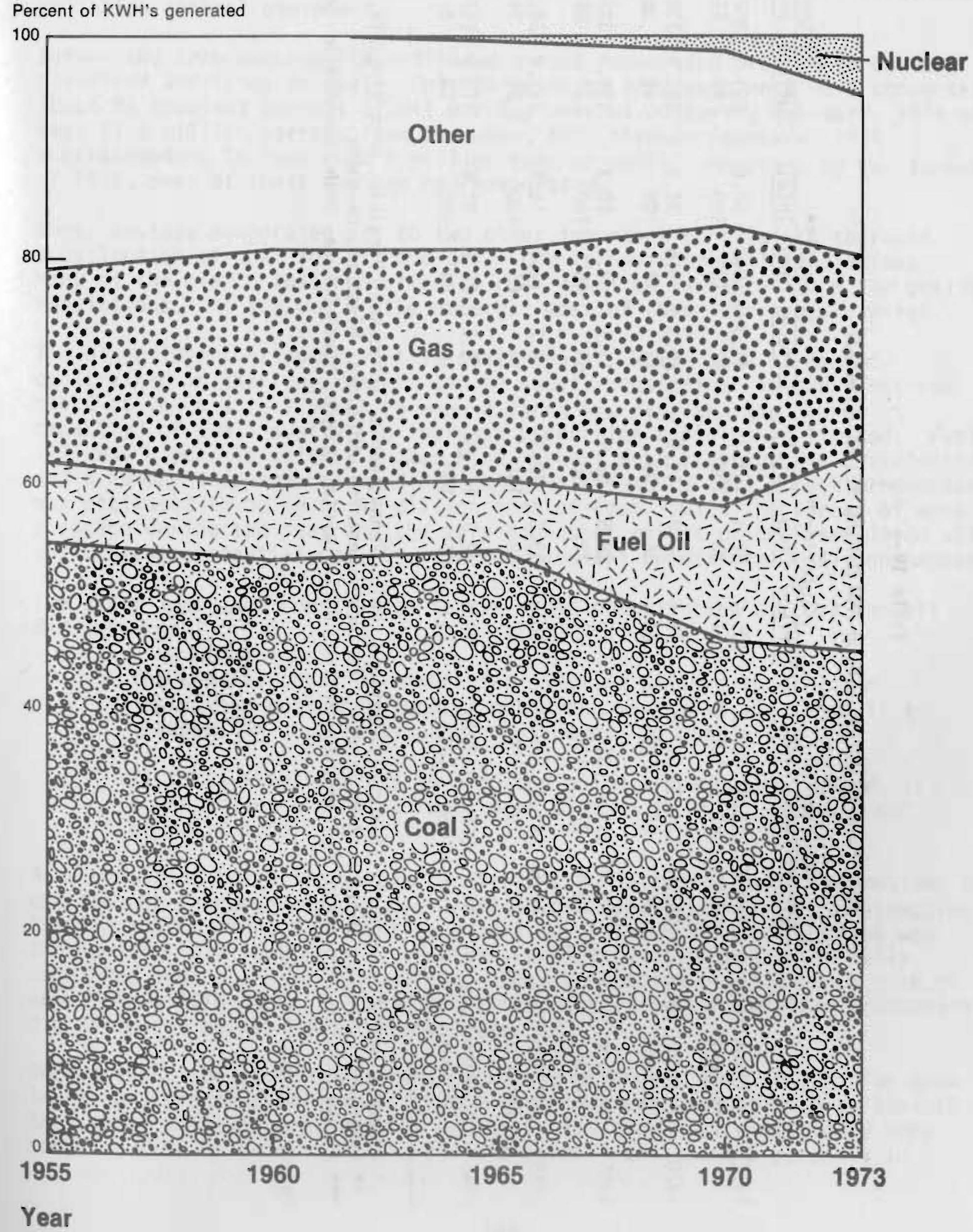


Table IV-1

COAL PRODUCTION BY REGION AND MINING METHOD, 1945-72

Year		Appalachia* Surface	Appalachia* Deep	Appalachia* Total	Interior** Surface	Interior** Deep	Interior** Total	Far West*** Surface	Far West*** Deep	Far West*** Total	National Surface	National Deep	National Total
1972	Million Tons	144.6	242.6	387.2	105.2	52.1	157.3	41.3	9.3	50.6	291.1	304.0	595.1
	Percent	37	63	100	67	33	100	82	18	100	49	51	100
1970	Million Tons	143.0	274.8	417.8	95.6	54.3	149.9	25.3	9.6	34.9	263.9	338.7	602.6
	Percent	34	66	100	64	36	100	72	28	100	44	56	100
1965	Million Tons	89.8	295.1	384.9	78.4	28.5	106.9	11.1	9.2	20.3	179.3	332.8	512.1
	Percent	23	77	100	73	27	100	55	45	100	35	65	100
1955	Million Tons	78.5	297.3	375.8	36.5	33.8	70.3	6.2	12.3	18.5	121.2	343.4	464.6
	Percent	21	79	100	52	48	100	34	66	100	26	74	100
1945	Million Tons	64.7	366.1	430.8	39.8	72.7	112.5	5.7	28.9	34.6	110.2	467.7	577.9
	Percent	15	85	100	35	65	100	16	84	100	19	81	100

* Alabama, Georgia, Kentucky (Eastern), Maryland, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia.
** Arkansas, Illinois, Indiana, Iowa, Kansas, Kentucky (Western), Michigan, Missouri, Oklahoma.
*** Alaska, Arizona, Colorado, Montana, New Mexico, North Dakota, Oregon, South Dakota, Utah, Washington, Wyoming.

Source: Bureau of Mines

However, there were several factors that limited this substitution over the 1973-75 period. One was that very few users had the physical capability to convert to coal in the short-run, where the physical constraints included lack of boilers that could burn coal, coal and ash handling facilities, and pollution control equipment.

During the Arab embargo FEA initiated a coal conversion program to convert oil-fired utilities to coal. Only 22 units at 11 powerplants were converted. About 86 thousand barrels of oil per day were saved during February, 1974 and over five million barrels from December, 1973 through February, 1974 (corresponding to less than 2 million tons of coal). However, by the summer of 1974, most of these savings had evaporated.

These savings evaporated due to two other important constraints to rapid substitution of coal for oil and gas. One is environmental regulations. Many of the plants that converted to coal required variances from air quality regulations. At the end of the embargo, most of these variances expired.

The other important constraint is coal supply. While coal is demand-constrained in the long-run, it can be supply-constrained in the short-run since it takes 4 to 7 years to open a large new mine and the "surge capacity" of the industry (to increase production rapidly) is limited. Further, 1974 was a year in which a United Mine Workers work stoppage was anticipated, and a 28-day stoppage occurred beginning in November, 1974. Lost production was estimated to be up to 41 million tons of coal. With the threat of work stoppage during the year and the very high spot market prices associated with this threat, potential coal users were reluctant to maximize coal consumption.

Two other important constraints to the rapid substitution of coal for oil and gas are:

- The capital costs of converting existing boilers to coal and installing pollution control equipment may be so high that it is cheaper for a user (all cost considered) to burn oil.

- It takes about 5 years to plan and build a new boiler; hence, if a new boiler had not already been planned in 1973, it could not be built before about 1978.

As a result of these short-term constraints to increased coal consumption, coal use did not increase rapidly over 1972 levels (see Table IV-2). Consumption in 1973 increased about 6 percent over 1972 levels, but 1974 consumption was the same as 1973 consumption. Further, coal production was essentially unchanged over the 1972-1974 period. Coal production built up to a rate of about 640 million tons in 1974, but about 40 million tons of this production did not occur due to UMW work stoppages.

During 1975, the coal market came back into balance. Coal consumption grew less rapidly than anticipated. Short-term constraints continued to inhibit the substitution of coal for oil and gas. The growth of electricity consumption (for which most of the coal is burned) was about 2 percent, in

Table IV-2

COAL CONSUMPTION AND PRODUCTION
(Million Tons)

	Consumption	Production	Stock Change
1970	587	603	+16
1971	551	552*	+ 1
1972	573	595	+22
1973	609	592	-17
1974	611	603*	- 6**
1975	624***	639***	+15

* UMW work stoppage.
** Imports increased to two million tons.
*** Estimate.

Source: Bureau of Mines

contrast to expected growth of 5 to 7 percent for the same period. The demand for metallurgical coal fell off, as steel production dropped. On the other hand, coal production stayed at about 640 million tons--its 1974 rate prior to the UMW work stoppage. As a result, coal users were able to rebuild inventories (drawn down during the UMW work stoppage) to about normal levels.

Coal prices reflected the state of the market over the 1973-75 period. Starting at the end of 1973, coal prices began to rise. Spot prices reached record levels in November, 1974, during the UMW work stoppage. Long-term contract prices were also negotiated (and renegotiated) at higher levels due to the tightness of the market and cost increases associated with inflation (see Table IV-3). Starting at the beginning of 1975, spot prices began to drop until they almost reached average long-term contract levels during the summer, where they remained for the rest of the year. This drop reflects the easing of the market during 1975.

That coal prices increased at the same time as oil prices during 1974 led some analysts to conclude that coal would be priced at the Btu-equivalent of oil, with an adjustment for pollution control costs. However, this conclusion was inconsistent with the observations that coal reserves are vast and the industry is composed of enough firms that market forces will push long-term prices to a level reflecting costs plus a fair return on capital; and that even in the short-run (when coal supply is constrained by the time it takes to open new mines), not enough energy consumers have the capacity to burn coal to bid spot prices up to the Btu-equivalent price of oil.

These observations are consistent with actual price behavior. Long-term contract prices were bid up to levels reflecting mining costs with a fair return. (Average contract prices include contracts that were negotiated several years ago and are probably lower than the average of contracts signed in the last year. However,

Table IV-3

NATIONAL AVERAGE PRICES OF DELIVERED COAL AND
RESIDUAL OIL TO ELECTRIC UTILITIES
($/Million Btu, Current Dollars)

	Coal		Residual Oil (No. 6)
	Average Spot Price	Average Contract Price	Average Contract Price
April 1973	.44	.38	.68
July 1973	.44	.39	.71
October 1973	.48	.40	.87
January 1974	.76	.45	1.54
April 1974	1.04	.52	1.86
July 1974	1.25	.56	1.95
October 1974	1.39	.62	2.00
November 1974*	1.47	.67	2.00
January 1975	1.26	.68	1.98
April 1975	1.08	.74	2.12
July 1975	.98	.76	2.00
August 1975**	.98	.78	2.02

* Spot coal prices reached their peak.
** Last month for which data is available.

Source: Federal Power Commission Form 423.

there are no indications that new contracts are being signed at a Btu-equivalence with oil.) They are essentially equivalent to the cost-based prices estimated by FEA (e.g., FEA estimates the 1985 delivered cost of utility coal to the Middle Atlantic region at about $30 a ton and the FPC reports that the average contract price for the same region was $25 a ton in August, 1975). Spot prices were bid up to levels in excess of long-term contract prices, but never to the Btu-equivalent of oil. Most significantly, these spot prices fell as the coal market loosened in 1975, an event totally inconsistent with the argument that coal will be priced equivalent to oil, for which prices did not fall (see Table IV-3).

At the end of 1975, the electric utility sector was still the largest consumer of coal and was the only sector that was showing substantial growth (see Table IV-4).

Table IV-4

COAL* CONSUMPTION BY SECTOR
(Million Tons)

	Electric Utilities	Metallurgical Use	Industry	Residential/ Commercial	Exports
1970	319	96	88	12	71
1971	326	93	74	11	57
1972	349	87	72	9	56
1973	387	94	67	8	53
1974	388	90	64	9	60
1975**	406	83	64	7	64

* Excludes anthracite.
** Estimated.

Source: Bureau of Mines

At the end of 1974, more than 80 percent of coal production was in the East and about half of total production was from surface mines. Surface production continues to grow faster than deep production, and western production continues to grow faster than eastern production (see Table IV-5).

Table IV-5

COAL PRODUCTION*
(Million Tons)

Year	East** Surface	East** Deep	East** Total	West Surface	West Deep	West Total	National Total
1970	221	328	549	34	10	54	603
1971	235	266	501	41	10	51	552
1972	236	294	530	55	10	65	595
1973	227	289	516	66	10	76	592
1974	245	267	512	80	11	91	603
1975***	-	-	531	97	11	108	639

* Excludes anthracite.
** East of the Mississippi River.
*** Estimated.

Source: Bureau of Mines.

Short Term Outlook (1976-78)

The short-term outlook for coal is growth, but the rate of growth depends on a number of key uncertainties.

On the consumption side, a key uncertainty is the rate of growth of electricity consumption. If electricity continues to grow slowly, growth in coal consumption would be modest. If electricity resumes growth at historical levels (i.e., 7 percent), growth in coal consumption would be substantial. Similar uncertainties, though of smaller impact, exist in the other sectors as well. Further, FEA's coal conversion program could increase consumption by more than 15 million tons per year by 1978.

On the production side, the key uncertainties are the number of mine openings and closings. The data that exists is somewhat incomplete and difficult to interpret.

FEA has made a short-term estimate that indicates that the coal market is likely to continue to grow in balance over the 1976-78 period, with consumption growing at a rate of about 5.1 percent (see Table IV-6).

Table IV-6

SHORT-TERM FORECAST
(Million Tons)

	Production Total	Production East	Production West	Consumption Total	Consumption East	Consumption West
1974	603	512	91	611	513	98
1975	639	531	108	624	522	102
1976	671	543	128	668	550	118
1977	715	566	149	702	564	138
1978	745	582	172	745	583	162

The key assumptions associated with this forecast are:

- Production will build up as indicated by various surveys of mine openings.
- Electricity will grow at an annual compound rate of about 5.5 percent from 1975.
- Utilities will add new capacity as indicated by the National Electric Reliability Council.
- FEA's coal conversion program will result in increased annual coal consumption in 1976, 1977, and 1978 of 5, 10 and 15 million tons, respectively.
- EPA will continue its Clean Fuels Policy of encouraging states to relax sulfur emission limitations that are more stringent than required to protect public health and/or of granting compliance delays to those coal burners

unable to comply with sulfur emission limitations due to the lack of adequate supplies of low sulfur coal and/or stack gas scrubbers.

The majority of the increased consumption and production is expected to occur in the West (see Table IV-6). Eastern production is expected to increase by 51 million tons or by 10 percent between 1975 and 1978. However, western production is projected to increase by 64 million tons or by 60 percent during the same period. This is because eastern utilities have scheduled large increases in nuclear capacity, while western utilities are shifting out of oil and gas into coal. On the production side, this reflects large new mines in the low sulfur coal fields of the West.

It should be noted that this short-term forecast does not (and need not) reflect two important determinants of coal consumption and production in the long-run. One is the type of new capacity utilities and other large users decide to build (i.e., coal, nuclear or oil). Since it takes at least 5 years to build a powerplant, capacity through 1978 can be estimated from published sources on planned capacity additions. However, as discussed below, decisions made (and to be made) since the Arab embargo to build new coal boilers rather than oil and gas boilers will have a substantial impact on coal consumption during the 1980's. The other is the leasing of the western coal lands. Coal production in the West could be adversely affected in the period beyond 1980, if the problems surrounding the leasing of these lands are not solved soon.

Further, it should be noted that neither this short-term forecast, nor the long-term FEA forecast (discussed below) account for the impact on coal production and consumption of the uncertainties associated with how certain government policy issues will be resolved (e.g., stripmining legislation, western leasing, the clean fuels deficit, and significant deterioration). These uncertainties may have a substantial adverse effect on coal production and consumption, since they render investments in coal capacity risky and hence less attractive.

Finally, in both forecasts transportation is assumed to be available to move the coal from producer to consumer. Miner productivity, both in terms of days worked and output per manday, is not projected to change by mining method. However, as the mix of mines changes with more large western mines in operation the national average productivity should improve. Similarly, problems of labor availability and attracting of capital investment were assumed not to be binding constraints. These assumptions may be over-simplifications of the situation, particularly if Federal policies relating to coal remain unresolved.

CONSUMPTION FORECASTS

This section is organized into five subsections. The first discusses the 1985 Reference Scenario forecast assuming $13 per barrel imports. This scenario is employed as a benchmark, from which to measure differences. Its use as such does not mean it is considered a "best guess" at what will happen. The

second subsection discusses the forecasted changes in consumption over time, i.e., 1980, 1985, and 1990. The third discusses the effects of different oil import prices on 1985 consumption. The fourth discusses the effects of different scenarios on 1985 consumption. The fifth discusses the policy implications of these findings.

Reference Scenario

The FEA Reference Scenario forecast at $13 imports indicates that consumption will be 1,040 million tons in 1985 and that the bulk of this increase will occur in the electric utility sector (see Table IV-7).

Table IV-7

1985 COAL CONSUMPTION
REFERENCE SCENARIO, $13 OIL IMPORTS
(Million Tons)

Sector	1974	1985	Absolute Increase	Compound Annual Percent Growth Rate
Electric Utilities	388	715	+327	5.7
Household/Commercial	9	5	- 4	-5.5
Industrial	64	124	+ 60	6.2
Coke and Gas	90	100	+ 10	1.0
Synthetics	-	16	+ 16	-
Exports	60	80*	+ 20	2.6
Total	611	1,040	+429	5.0

* Assumed values; not estimated endogenously by model.

This forecast indicates a 5.0 percent growth rate over the 1974-85 period.

The FEA analysis indicates that the best way to increase the consumption of our abundant domestic resource is through electricity, where coal consumption in this sector is limited by electricity growth rates, oil prices, nuclear capacity, and environmental regulations (each of which is discussed below). The potential for increased consumption of coal in other sectors appears to be limited. Given existing environmental regulations and the large scale required to handle coal economically, no large absolute increase in coal consumption is anticipated in the industrial sector. Further, synthetic fuels from coal do not yet compete economically with natural gas and oil, even at the equivalent of $16 oil imports, and lead times for this new technology limit the market to about 16 million tons by 1985.

Within the electric utility sector, the majority of the coal consumption is forecast to be in the current major coal-burning regions, although the percentage growth in the current minor coal-burning regions is forecast to be higher (see Table IV-8).

Table IV-8

1985 UTILITY COAL* CONSUMPTION BY CENSUS REGIONS**
REFERENCE SCENARIO, $13 OIL IMPORTS
(Million Tons)

Region	1974	1985	Absolute Increase	Compounded Annual Percent Growth Rate
Northeast	2	15	+ 13	20.1
Middle Atlantic	42	105	+ 63	8.7
South Atlantic	78	136	+ 58	5.2
East North Central	133	194	+ 61	3.5
East South Central	61	77	+ 16	2.1
West North Central	37	90	+ 53	8.4
West South Central	5	42	+ 37	21.3
Mountain	27	46	+ 19	5.0
Pacific	3	10	+ 7	11.6
National	388	715	+327	5.7

* Excludes anthracite.
** Figure IV-4 gives a map of the census regions.

This indicates that: the trend to oil on the East Coast would be reversed; utilities in the Southwest would be shifting out of natural gas; and utilities in the Pacific Coast would be shifting from both oil and gas to coal. The low growth rates in the central regions reflect high current coal consumption and substantial increases in nuclear capacity.

The forecast indicates that the utilities on a national basis will rely about evenly on low sulfur coal and high sulfur coal with scrubbers to comply with sulfur emission regulations on new plants. However, this mix varies widely by region (see Table IV-9).

Figure IV-4
CENSUS REGIONS

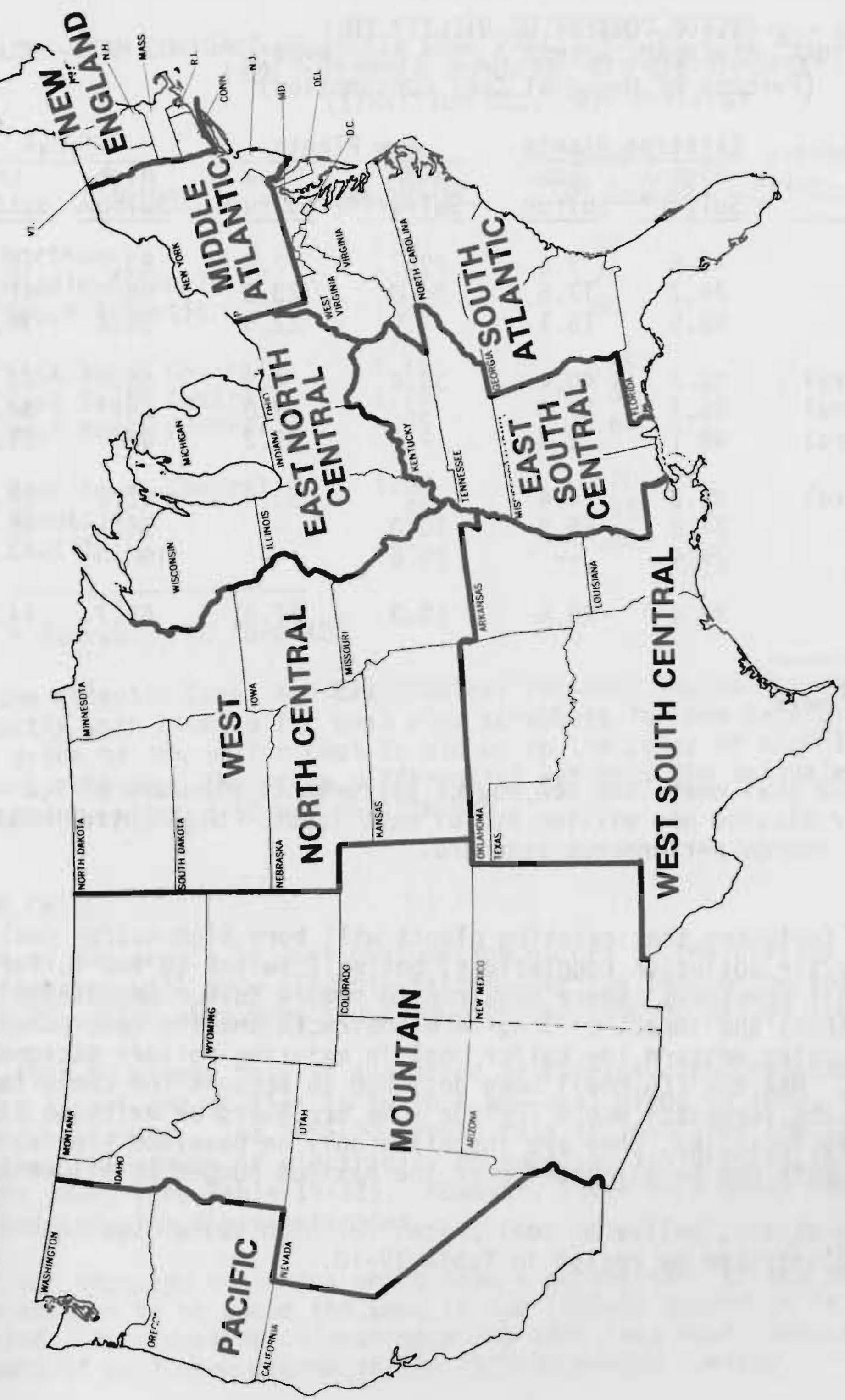


Table IV-9

SULFUR CONTENT OF UTILITY COAL
1985 REFERENCE SCENARIO, $13 OIL IMPORTS
(Percent of Regional Coal Consumption)

Region	Existing Plants		New Plants		Total	
	High Sulfur*	Low Sulfur	High Sulfur**	Low Sulfur	High Sulfur	Low Sulfur
Northeast	3.5	9.6	79.7	7.2	83.2	16.8
Middle Atlantic	24.7	17.5	34.0	23.8	58.7	41.3
South Atlantic	59.5	16.1	1.9	22.5	61.4	38.6
East North Central	21.7	40.4	33.4	4.5	55.1	44.9
East South Central	55.7	27.3	--	17.0	55.7	44.3
West North Central	48.1	22.8	--	29.2	48.1	51.9
West South Central	42.2	4.4	--	53.4	42.2	57.8
Mountain	24.1	65.9	10.0	--	34.1	65.9
Pacific	24.4	--	75.6	--	100.0	--
National	37.4	26.8	18.3	17.5	55.7	44.3

* Without scrubbers
** With scrubbers

Note: Low sulfur coal meets the new source performance standard of 1.2 pounds of sulfur dioxide per million Btu of heat input. High sulfur coal exceeds the new source performance standard.

The forecast also indicates that existing plants will burn high sulfur coal where permitted by air pollution regulations, but will switch to low sulfur (rather than install scrubbers) where required to reduce sulfur emissions. (This finding neglects the impact of long-term contracts and the cost penalties associated with burning western low sulfur coal in existing boilers designed for eastern coals. Had the FEA model been designed to account for these factors, it is likely that the forecasts would include some scrubbers on existing plants.) Where scrubbers are installed, they are installed only on baseload plants, where the high capital costs can be allocated over the maximum number of kilowatt-hours.

Within the utility sector, delivered coal prices for high sulfur coal and low sulfur coal are illustrated by region in Table IV-10.

Table IV-10

LONG-TERM CONTRACT DELIVERED COAL PRICES TO THE ELECTRIC UTILITY SECTOR
1985 REFERENCE SCENARIO, $13 OIL IMPORTS
($/Million Btu, 1975 Dollars)

Regions	1985 Low Sulfur	1985 High Sulfur	Average Contract Price, August 1975*
Northeast	1.40	.90	1.21
Middle Atlantic	1.25	.75	1.05
South Atlantic	1.25	.80	1.01
East North Central	1.15	.65	.80
East South Central	1.15	.60	.77
West North Central	.95	.65	.57
West South Central	1.00	.70	.24
Mountain	.55	.45	.32
Pacific	--	.80	.59

* Source: FPC Form 423.

On the Atlantic Coast and East Central regions, low sulfur coal competes directly with high sulfur coal plus scrubbers for new baseload powerplants. The price of low sulfur coal is bid up to the price of high sulfur coal plus scrubbing. The price differential reflects the estimated cost of scrubbing--about $.50 per million Btu.

Time Path

Most of the growth in coal consumption occurs in the utility sector. Coal consumption will grow slightly faster over the 1980-85 period than over the 1975-80 period, but more slowly during the 1985-90 period (see Table IV-11).

The 1974-80 growth rate is inhibited by current plant construction plans. There is not enough time to build a new coal plant by 1980, if it is not already planned. The 1985-90 growth rate is less than the 1980-85 rate because the growth of electricity consumption is forecast to be lower in the later years (see Table IV-12). However, there is a great deal of uncertainty associated with these estimates.

Nuclear capacity additions which have a substantial effect on coal consumption, are assumed to be about the same in the 1985-90 period as in the 1980-85 period. Accelerating nuclear capacity additions would reduce the rate of growth of coal consumption in the 1985-90 period further.

Table IV-11

COAL CONSUMPTION
REFERENCE SCENARIO, $13 OIL IMPORTS
(Million Tons)

	1974	1980	1985	1990
Electric Utilities	388	528	715	932
Household/Commercial	9	7	5	4
Industrial*	154	184	224	272
Synthetics	-	-	16	21
Exports	60	80	80	80
Total	611	799	1,040	1,309

Period	Annual Percent Growth Rate
1974-80	4.6
1980-85	5.4
1985-90	4.7

* Includes metallurgical coal consumption.

Table IV-12

ELECTRICITY CONSUMPTION GROWTH RATES
REFERENCE SCENARIO, $13 OIL IMPORTS

	Compound Annual Percent Growth Rate
1974-80	5.1
1980-85	5.7
1985-90	5.0

Most of the increased coal consumption in the low-coal consuming regions occurs during the 1980's. This again is because little or no coal capacity additions are currently planned for these regions, and there is not adequate time to plan and build coal plants by 1980. In some regions, such as the West South Central area where gas will be phased out, utility coal consumption could grow substantially by 1990 (increase from 5 to 89 million tons).

Throughout the 1975-90 period, the rate of growth of low sulfur coal consumption is substantial (see Table IV-13).

Table IV-13

UTILITY COAL CONSUMPTION BY SULFUR CONTENT
REFERENCE SCENARIO, $13 OIL IMPORTS
(Quadrillion Btu)

	1980		1985		1990	
Region	High Sulfur	Low Sulfur	High Sulfur	Low Sulfur	High Sulfur	Low Sulfur
East	4.9	4.1	7.0	5.0	6.8	7.6
West	1.4	1.1	1.6	1.9	1.8	3.3
National	6.3	5.2	8.6	6.9	8.6	10.9

In the West, low sulfur coal consumption grows steadily over the period. This is because the supply of low sulfur coal is enormous in the West, and production costs are not expected to increase much as production is expanded. Western low sulfur coal production prices are not expected to increase enough to make western high sulfur coal plus scrubbers competitive. However, in the East, the supply of low sulfur coal is limited, and the costs of producing it are expected to increase rapidly as production is expanded. This has the effect of stimulating eastern high sulfur production (by making high sulfur coal plus scrubbers competitive with low sulfur coal); and stimulating western low sulfur production by making western coal more competitive in midwestern markets. By 1990, new technologies such as fluidized bed combustion may be in commercial operation. If so, the FEA forecast (which assumes no such technology) probably overstates low sulfur coal consumption in that year.

Importantly, coal prices (in 1975 dollars) are not expected to increase substantially over the period because the national supply curve is relatively flat. As discussed above, the supply of low sulfur coal in the East is limited and has a relatively steep supply curve. However, western low sulfur coal and eastern high sulfur caol are extremely abundant and have relatively flat supply curves. Hence, increased consumption does not result in significantly higher prices. In the West, more low sulfur coal is mined without substantial price increases. In the East, low sulfur coal is mined unitl its price is equivalent to the price of eastern high sulfur coal plus scrubbers and/or the delivered price of western coal, then more high sulfur coal and more western low sulfur coal are mined without substantial price increases.

Effect of Oil Prices

The consumption of coal, and conversely of oil, in the electric utility sector is very sensitive to the price of oil. In the absence of regulation and if the price of oil is low enough, electric utilities will:

- Build new oil plants rather than new coal plants.

- Employ their existing oil plants more than their existing coal plants (i.e., baseload* coal plants and move oil plants to intermediate** load to the extent possible).

On the other hand, if the price of oil is high enough, electric utilities will build new coal plants and rely on existing coal plants as much as possible.

The specific oil prices where utilities will shift from one fuel to another depends importantly on the price of coal and powerplant capital and operating costs. These in turn vary by region, particularly the price of coal. Hence, it is difficult to generalize for the Nation as a whole. However, a specific region can be used to illustrate how the price of oil affects coal consumption.

The Middle Atlantic region serves as a useful illustrative region because both oil and coal are being consumed by electric utilities in large quantities. For this region, as all other regions, there are five specific oil prices that are relevant:

- Baseloading existing plants. Above about $8 per barrel, a utility will baseload existing coal palnts rather than existing oil plants to the extent possible; this means operating them to generate as much electricity as possible given load requirements and maintenance schedules. Below about $8 per barrel, a utility will baseload existing oil plants rather than existing coal plants to the extent possible.

- Building new plants for baseload. Above about $9.00 per barrel, a utility will build a new coal plant rather than a new oil plant if additional baseload capacity is required. Below about $9.00 per barrel, a utility will build a new oil plant rather than a new coal plant.

- Building new plants for intermediate load. Above about $10.50 per barrel, a utility will build a new coal plant rather than a new oil plant if additional intermediate load capacity is required. Below about $10.50 per barrel, a utility will build a new oil plant rather than a new coal plant.

- Substituting new coal plants for existing oil plants in baseload. Above about $13.00 per barrel, a utility will build a new coal plant to be substituted for an existing oil plant in baseload. The existing oil plant would then be used as a seasonal peaking unit (with a very low capacity factor), if at all.

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* Baseload plants assumed to have capacity factors of 70 percent (i.e., operate at 70 percent of capacity over a year).

** Intermediate load plants are assumed to have capacity factors of about 35 percent.

- Substituting new coal plants for existing oil plants in intermediate-load. Above $19 per barrel, a utility will build a new coal plant to be substituted for an existing oil plant at intermediate-load. The existing oil plant would then be used as a seasonal peaking unit, if at all.

All of these "breakpoint" prices assume that utilities will build and operate plants in a manner that will minimize total costs and consumer rates. It is possible that financial constraints (i.e., fuel adjustment clauses, regulatory lags), and load growth uncertainties (e.g., failing to forecast rapid growth so that oil plants must be built due to inadequate time for building a coal plant) could render this assumption somewhat invalid.

All of these "breakpoint" estimates were based on the assumption that the coal plants would meet new source performance standards with low sulfur coal; assuming high sulfur coal plus scrubbers would not change the estimates substantially since the price of low sulfur coal is forecast to be bid up to the equivalent of high sulfur coal plus scrubbers, particularly in the eastern demand regions. As discussed elsewhere, the price of coal does not change substantially with different production levels. Hence, a single point estimate for coal is not misleading. Further, powerplant capital and operating costs are not expected to change substantially with different coal consumption levels.

The effects of these "breakpoints" are illustrated well by the model forecasts at different oil prices (see Table IV-14).

Table IV-14

ELECTRIC UTILITY SECTOR FOSSIL FUEL CONSUMPTION
1985 REFERENCE SCENARIO (Quadrillion Btu)

	Oil Imports Price ($ per barrel) $8	$13	$16
Coal	12.5	15.4	16.3
Oil & Gas*	8.9	5.7	5.2
Total	21.4	21.1	21.5

* Oil and gas are combined because they are generally fungible in the utility sector and their prices in a deregulated market are forecasted to equilibrate on a Btu basis.

At $8 imported oil, the utility sector will consume about 12.5 quads of coal (579 million tons) and about 8.9 quads of oil and gas (the equivalent of about 4.0 million barrels per day). At $13 imported oil, the total quads of fossil fuel consumed change slightly, but coal consumption increases by 2.9 quads (to 715 million tons) and oil and gas consumption decreases by a similar amount (to the equivalent of 2.6 million barrels per day). This change results from the oil price passing through three breakpoints. At $8 imports, the delivered price of oil, after refining, to utilities generally exceeds $8; hence, existing coal plants are being operated at baseload. However the delivered price generally is less than $9; hence, new oil plants are built instead of coal plants for both base and intermediate load and no new coal plants are substituted for existing oil plants. On the other hand, at $13 imports, the delivered price of oil after refining to utilities generally exceeds $14. Hence, only new coal plants are built for base and intermediate loads and some new coal plants are build to substitute for existing oil plants in baseload. The net effect of these changes is that an additional 136 million tons of coal is consumed, and less oil and gas is consumed by the equivalent of 1.4 million barrels per day.

The difference between $13 and $16 imports is less substantial because there are essentially no additional breakpoints between $13 and $16. Coal consumption increases because total fossil fuel consumption increases (with increased electricity consumption) and because some additional new coal plants are substituted for oil and gas plants in those regions where the breakpoint around about $14 per barrel was not exceeded at $13 imports. Correspondingly, oil and gas consumption goes down slightly because some additional new coal plants are substituted for existing oil and gas plants. Hence, it is clear that the price of oil has a substantial effect on coal consumption and on oil imports.

In addition, the FEA forecasts also indicate that the price of coal does not change significantly with the price of oil (see Table IV-15).

Table IV-15

DELIVERED FUEL PRICES IN 1985 TO UTILITY SECTOR IN MID-ATLANTIC REGION ($/Million Btu, 1975 Dollars)

Oil Import Prices	Residual Oil	Low Sulfur Coal
$8/barrel	1.65	1.15
$13/barrel	2.30	1.25
$16/barrel	2.70	1.25

This is because coal prices have been modeled to be cost-based since reserve ownership is generally widespread, mining technology is widely understood, and current production is not highly concentrated in a few companies. Hence, no producer can require more than a price covering costs plus a fair return on capital, because another producer could then produce coal at a lower price. In addition, coal prices do not move much with oil prices because the supply curves for coal are relatively flat. Substantial increases in coal production are possible without corresponding price increases.

Table IV-16

COAL CONSUMPTION UNDER VARIOUS SCENARIOS 1985, $13 OIL IMPORTS (Million Tons)

Sector	Reference	$9.00 Regulation	Regional Limitation	BAU Supply With Conservation	Accelerated Supply With Conservation	Electrification
Household/Commercial	5	5	5	5	5	5
Industrial	224	218	219	217	208	284
Electrical Generation	715	679	640	655	673	841
Synthetics	16	16	16	16	53	53
Exports	80	80	80	80	80	80
Total	1,040	998	960	973	1,019	1,263

Effect of Different Policy Scenarios

The effects of the various scenarios on 1985 coal consumption with $13 oil imports are illustrated in Table IV-16. These scenarios are defined in Appendix E.

Two important observations should be noted. The first is that the total coal consumption forecasts change very little--slightly less than 10 percent below and approximately 25 percent above the Reference Scenario. However, as developed below, this is because several of the scenarios had offsetting effects specified into them.

The second important observation is that nearly all the changes in total coal consumption are due to changes within the electric sector. The only other sectors that change substantially are:

- The industrial sector where coal consumption is assumed to substitute for natural gas (by about 60 million tons) under the Electrification Scenario.
- The synthetics sector where coal consumption is assumed to increase by about 35 million tons under both the Accelerated Supply and Electrification Scenarios.

Both of these increases are due to policy assumptions used in specifying the scenarios.

The changes in the electric utility sector result from four factors: oil prices, nuclear capacity, electricity demand, and environmental regulations.

The effects of oil prices were discussed above. Under the $9.00 Regulation Scenario oil prices are reduced. This increases oil consumption and reduces coal consumption in the utility sector (see Table IV-17).

Table IV-17

ELECTRIC UTILITY FUEL CONSUMPTION
1985, $13 OIL IMPORTS

	Reference	Regulation ($9.00)
Coal (Quadrillion Btu)	15.4	14.6
Oil and Gas (Quadrillion Btu)	5.7	6.2
Total	21.1	20.8
Average Residual Oil Price ($/Million Btu)	2.25	1.92

The reduction in coal consumption is amplified slightly by a reduction in electricity consumption, resulting from the lower oil prices which make oil and gas more competitive with electricity.

The effect of nuclear capacity is apparent in the various scenarios. Coal consumption is inversely related to nuclear capacity. This is because at high oil prices, nucelar powerplants and coal powerplants generating electricity in baseload (about 65 percent of all generation) are cheaper than all other types of powerplants (see Table IV-18).

Table IV-18

ILLUSTRATIVE BASELOAD ELECTRICITY GENERATION COSTS*
(mills/kWh, 1975 Dollars)

	Nuclear	Coal	Oil Steam
Capital	13.45	9.30	7.58
Fuel	1.80	10.11	20.70
Other	3.00	2.00	1.88
Total	18.25	21.41	30.16

* Assumes a delivered price of $1.10 per million Btu for low sulfur coal and $2.25 per million Btu for residual oil. Capital costs in 1975 dollars are $550 per kw for nuclear, $380 per kW for coal and $310 per kW for oil. A fixed charge rate of 15 percent and a capacity factor of 0.7 were assumed.

Nuclear and coal generation costs are close. The delivered price of coal varies over a wide enough range that in some regions coal plants may generate electricity for less cost than do nuclear plants. Indeed, coal and nuclear plant costs are close enough that they might be considered the same, given the uncertainty associated with the estimates. However, because of the apparent cost advantages of nuclear plants in some regions, FEA's forecasting model employs them to their maximum capacity (specified as an input constraint). Once the nuclear capacity constraint is reached in those regions, the model employs coal plants until no additional capacity is required. Hence, increased nuclear capacity results in reduced coal capacity and vice versa.

At baseload generation, each thousand MWe of coal capacity consumes about 2.8 million tons of coal per year.* Thus, each thousand MWe change in nuclear capacity changes coal consumption about 2.8 million tons. In the Regional Limitation Scenario, nuclear capacity is reduced about 45,000 MWe from the Reference Scenario. This reduction acts to increase coal consumption by 126.4 million tons or 2.5 quadrillion Btu (see Table IV-19). This increase, however, is more than offset by environmental and electricity demand

* Assumes a capacity factor of 70 percent, a heat rate of 9,200 Btu per kWh, and a coal heat content of 20.0 million Btu per ton.

Table IV-19

EFFECTS OF CHANGES IN KEY FACTORS AFFECTING UTILITY COAL CONSUMPTION--1985, $13 OIL IMPORTS
(Quadrillion Btu)

	Scenario				
	$9.00 Regulation	Regional Limitation	BAU Supply With Conservation	Accelerated Supply With Conservation	Electrification
Impact of Change in Oil Prices	-0.5	-	-	-	-
Impact of Change in Nuclear Capacity	-0.1	+2.5	+0.2	-0.1	-1.2
Impact of Change in Electricity Consumption	0.4	-0.5	-1.2	-0.3	+3.1
Impact of Change in Environmental Regulations	-	-4.1	-	-	-
Other*	+0.2	+0.5	-0.2	-0.5	+0.6
Net Change in Utility Coal Consumption	-0.8	-1.6	-1.2	-0.9	+2.5

* Accounts for changes in generation efficiencies associated with changes in scrubber capacity, synthetics fuels, and load curves.

considerations discussed below. In the Electrification Scenario, nuclear capacity is increased about 20,000 MWe. This increase acts to reduce coal consumption by about 56.2 million tons or 1.1 quadrillion Btu (see Table IV-19). This reduction, however, is more than offset by increased electricity demand as discussed below.

Coal consumption is directly related to electricity consumption. This is because at high oil prices, coal capacity is employed to satisfy all additional generating capacity requirements, after the nuclear capacity constraints are reached (in those regions where nuclear generation costs are less than coal generation costs), except for some oil-or gas-fired turbines employed for peak load, which is estimated to account for about 2 percent of total load. For each billion kilowatt hours that electricity consumption changes, coal consumption changes by about 9.3 trillion Btu or about 0.4 million tons. The effect is well illustrated by the Electrification Scenario (see Table IV-20). The large increase in electricity consumption has the effect of increasing coal consumption by 3.1 quadrillion Btu. However, this is offset somewhat by an increase of nuclear capacity which reduces coal consumption by 1.2 quadrillion Btu. The net change in utility coal consumption, therefore, is 1.9 quadrillion Btu or about 96 million tons. The remaining 0.6 quadrillion Btu or 30 million ton increase in coal consumption results from other changes as described in the latter footnote to Table IV-20.

Table IV-20

EFFECT OF ELECTRIFICATION ON UTILITY COAL CONSUMPTION
1985, $13 OIL IMPORTS

	Scenario		Resulting Change in Coal Consumption	
	Reference	Electrification	Million Tons*	Quadrillion Btu
Nuclear Capacity (Thousand MWe)	141	162	- 61	-1.2
Electricity Consumption (Billion kWh)	3,022	3,351	+157	+3.1
Other**	-	-	+ 30	+0.6
Utility Coal Consumption	715	841	+126	+2.5

* An average heat content of 19.8 million Btu per ton was implicit in the model output.

** Accounts for changes in generation efficiencies associated with changes in scrubber capacity, synthetic fuels and load curves.

The effect of hypothetical environmental regulations (more stringent than currently proposed) is illustrated by the Regional Limitation Scenario with business as usual demand, where environmental regulations are specified to be (1) the requirement that all new plants burn low sulfur coal plus install scrubbers, (2) reclamation costs associated with hypothetical stripmining legislation (requiring back to original contour), and (3) a 30 percent severance tax on all western coal (see Table IV-21).

Table IV-21

EFFECT OF HYPOTHETICAL ENVIRONMENTAL REGULATIONS
ON UTILITY COAL CONSUMPTION
1985, $13 OIL IMPORTS

	Scenario		Resulting Change in Coal Consumption	
	Reference	Regional Limitation	Million Tons*	Quadrillion Btu
Nuclear Capacity (Thousand MW)	141	96	+117	+2.5
Electricity Consumption (Billion kWh)	3,022	2,967	- 23	-0.5
Environmental Regulations	-	-	-192	-4.1
Other**	-	-	+ 23	+0.5
Utility Coal Consumption	715	640	- 75	-1.6

* An average heat content of 21.3 million Btu per ton was implicit in the model output.

** Accounts for changes in generation efficiencies associated with changes in scrubber capacity, synthetic fuels and load curves.

As illustrated above, the impact of hypothetical environmental regulations (together with a slight decrease in electricity consumption resulting from electricity price increases which, in turn, are due to the increased fuel and generation costs caused by the hypothetical environmental regulations) more than offset the increase in coal consumption resulting from reduced nuclear capacity.

The hypothetical surface mining legislation assumed in the Regional Limitation Scenario is specified to require:

- An increase of deep mining prices of $.25 associated with an abondoned mine reclamation fee.
- An increase of surface mining costs of about $.50, $.75 and $1.50 in the West, Midwest, and East, respectively (estimates in each region include a $.35 per ton reclamation tax).

In summary, the severance tax and the reclamation costs increase coal prices as illustrated in Table IV-22. These price increases affect the regional distribution of production (discussed below under production) but have minimum impacts on coal consumption. This is because they increase the "breakpoints" discussed above under "Impact of Oil Prices" only slightly--less than 5 percent. Since the price of oil at $13 oil imports is generally well above these breakpoints, these coal price increases do not result in substantial shifts from coal to oil in the utility sector.

Table IV-22

COAL PRICES (FOB Mine)
1985, $13 OIL IMPORTS
($/Ton-1975 Dollars)

	Reference Scenario	Reclamation Costs	Severance Tax	Regional Limitation Scenario	Percent Increase
Central Appalachia (low sulfur)	24.10	1.50	-	25.6	6.2
Midwest (high sulfur)	10.80	.75	-	11.55	6.9
Western Northern Great Plains (low sulfur)	4.90	.50	1.62	7.20	43.3

The major impact caused by the hypothetical environmental regulations is thus associated with the requirement that all new coal-fired plants must burn low sulfur coal and install scrubbers (rather than burn low sulfur coal or high sulfur coal plus scrubbers). These requirements increases the costs of generating electricity with coal substantially (see Table IV-23).

Table IV-23

ILLUSTRATIVE COSTS OF GENERATING ELECTRICITY WITH COAL*
(Mills/kWh-1975 Dollars)

	Reference w/o Scrubber	Reference w/Scrubber	Regional Limitation Provisions
Capital	9.30	11.74	11.74
Fuel	10.11	6.85	10.97
Other	2.00	3.50	3.50
Total	21.41	22.09	26.21

* In the Reference Scenario low and high sulfur coal prices were $1.10 per million Btu delivered and $0.71 per million Btu delivered, respectively. In the Regional Limitation Scenario the price of low sulfur coal rose to $1.14 per million Btu.

These large cost increases cause the "breakpoints" discussed above to increase substantially (see Table IV-24).

Table IV-24

SHIFT IN OIL PRICE BREAKPOINTS--MID-ATLANTIC REGION*
($/Barrel Of Residual Oil, 1975 Dollars)

	Reference	Regional Limitation
From Existing Oil in Baseload to Existing Coal	8.00	8.00
From New Oil in Base-load to New Coal	9.00	12.00
From New Oil in Inter-mediate Load to New Coal	10.50	14.50
From Existing Oil in Baseload to New Coal	13.00	16.25

* Assumes delivered coal prices to be $0.77 per million Btu for high sulfur coal and $1.25 per million Btu for low sulfur coal in the Reference Scenario, and $1.27 for low sulfur coal in the Regional Limitation Scenario.

Thus, a great deal more oil and less coal is employed in the utility sector (see Table IV-25).

Table IV-25

COAL AND OIL CONSUMPTION IN UTILITY SECTOR
1985, $13 OIL IMPORTS
(Quadrillion Btu)

	Reference	Regional Limitation	Difference		
Coal	15.4	13.8	-1.6	-80	million tons* per year
Oil & Gas	5.7	9.8	+4.1	+1.9	million barrels per day
Total	21.1	23.6	+2.5		

* Assumes heat contents of 20 million Btu per ton for coal and six million Btu per barrel for oil.

However, the specified requirement that all new plants burn low sulfur coal and install scrubbers is very stringent, and has not been seriously proposed as an air pollution control strategy. It is shown for illustrative purposes only as an attempt to place a lower bound on the effect of government regulations on coal consumption and should be used to understand trends, rather than to support policy conclusions.

In summary, FEA forecasts that utility coal consumption is sensitive to: (a) oil prices (as they go up, coal consumption goes up); (b) nuclear capacity (as it goes up, coal consumption goes down); (c) electricity consumption (as it goes up, coal consumption goes up); and (d) environmental regulations (as they are made more stringent, coal consumption goes down).

The effects of each of these four factors on coal consumption in the various scenarios is summarized in Table IV-9. As is evident, the four key factors have a substantial impact on coal consumption. However, total consumption does not vary substantially between the scenarios, because the scenarios were defined such that the various factors offset each other to a large extent.

Policy Implications

The various coal consumption forecasts described above have several important policy implications.

The electric utility sector represents the greatest potential for substituting coal for oil and gas between now and 1990. This is because synthetic fuels do not yet compete economically with natural gas and oil, even at $16 per barrel. Further, it is because increased coal consumption in the industrial sector is limited by the large scale required to employ coal economically.

Coal consumption in the utility sector is extremely sensitive to oil prices. Should the price of oil (through international political events or domestic regulation) fall closer to $8 than $13 per barrel, utility oil consumption could increase substantially, to the detriment of increased coal consumption. Significantly, the potential oil savings associated with ensuring new coal rather than new oil plants are built and ensuring utilities shift loads from oil to coal to the extent practicable are greater than the potential savings from the direct conversions of oil and gas plants by an order of magnitude (e.g., about 200 million tons versus 20 million tons).

Coal consumption in the electric utility sector is very sensitive to electricity growth rates. Thus, a way of stimulating the substitution of domestic coal for oil and gas is to stimulate the substitution of electricity for oil and gas. However, the economic and environmental costs of such a strategy warrant careful consideration.

Coal consumption substitutes directly for nuclear power. Hence, the effect of increasing the use of nuclear power is generally to reduce coal consumption and vice versa. The effect of nuclear capacity on oil consumption is not significant except at low oil prices. Further, the costs of nuclear and coal electric power generation are close enough and uncertain enough that they might be considered essentially the same. Thus, it appears that there is a nuclear/coal tradeoff where the economic criteria may make little difference and where the decision between the two or the proper mix of the two may depend, therefore, on an assessment of the environmental and social costs and risks associated with them.

The effect of new and very stringent air pollution regulations could be to inhibit coal consumption and stimulate oil consumption. Although the policies examined were extreme and not currently being proposed, the analysis yields an important insight: the consideration of air pollution control strategies should include their effect on coal and oil consumption.

The FEA forecasts, together with recent market behavior, indicates that goal prices do not and will not follow oil prices.

PRODUCTION FORECASTS

This section discusses coal reserves and supply curves, the $13 Import Reference Scenario for 1985, the time path of the $13 Reference Scenario from 1975 through 1990, the effects of different oil prices, the effects of different strategies, and the policy implications of these production forecasts.

Reserves and Supply Curves

Most of the Nation's coal reserves on a tonnage basis are found west of the Mississippi River. However, on a Btu basis, most are found east of the Mississippi since western coal generally has a lower Btu content than eastern coal (see Table IV-26).

Table IV-26

DEMONSTRATED COAL RESERVE BASE*

	Billion Tons	Percent	Quadrillion Btu	Percent
East	202.3	46.3	5,000	52.1
West	234.4	53.7	4,600	47.9
National	436.7	100.0	9,600	100.0

* Includes anthractie.

Source: Based upon Bureau of Mines data.

Approximately 46 percent of the Nation's coal reserves contain 1 percent sulfur or less by weight, and most of this is in the West. However, slightly more than one-third of the reserve base can meet new source performance standards (0.6 pounds of sulfur per million Btu). Importantly, a substantial portion of the eastern low sulfur coal is high-priced premium-grade metallurgical coal. Since coking coals are essential to the making of steel and in scarce supply worldwide, utility users are typically priced out of the market for these coals. This means that about 32 percent of the Nation's coal reserves can meet new source performance standards and are available for steam purposes (see Table IV-27).

These reserve statistics indicate that there are enormous reserves of low sulfur coal in the West and of high sulfur coal in the East. However, the supply of low sulfur coal in the East is limited.

Table IV-27

LOW SULFUR COAL RESERVES
(Billion Tons)

	One Percent or Less	Steam-Coal Reserves Meeting Sulfur Dioxide New Source Performance Standard*
East	32.9	7.3
West	167.3	130.3
National	200.2	137.6

* Excludes high quality metallurgical coal some of which also meets EPA's new source performance standard.

Source: Based upon Bureau of Mines data.

In economic terms, this means that the supply curves for western low sulfur coal and eastern high sulfur coal are relatively flat, whereas the supply curve for eastern low sulfur coal is relatively steep (see Figure IV-5). The implications of these curves are that western low sulfur coal and eastern high sulfur coal production can be expanded a great deal without substantial cost increases, but that eastern low sulfur coal production cannot be expanded without substantial price increases.

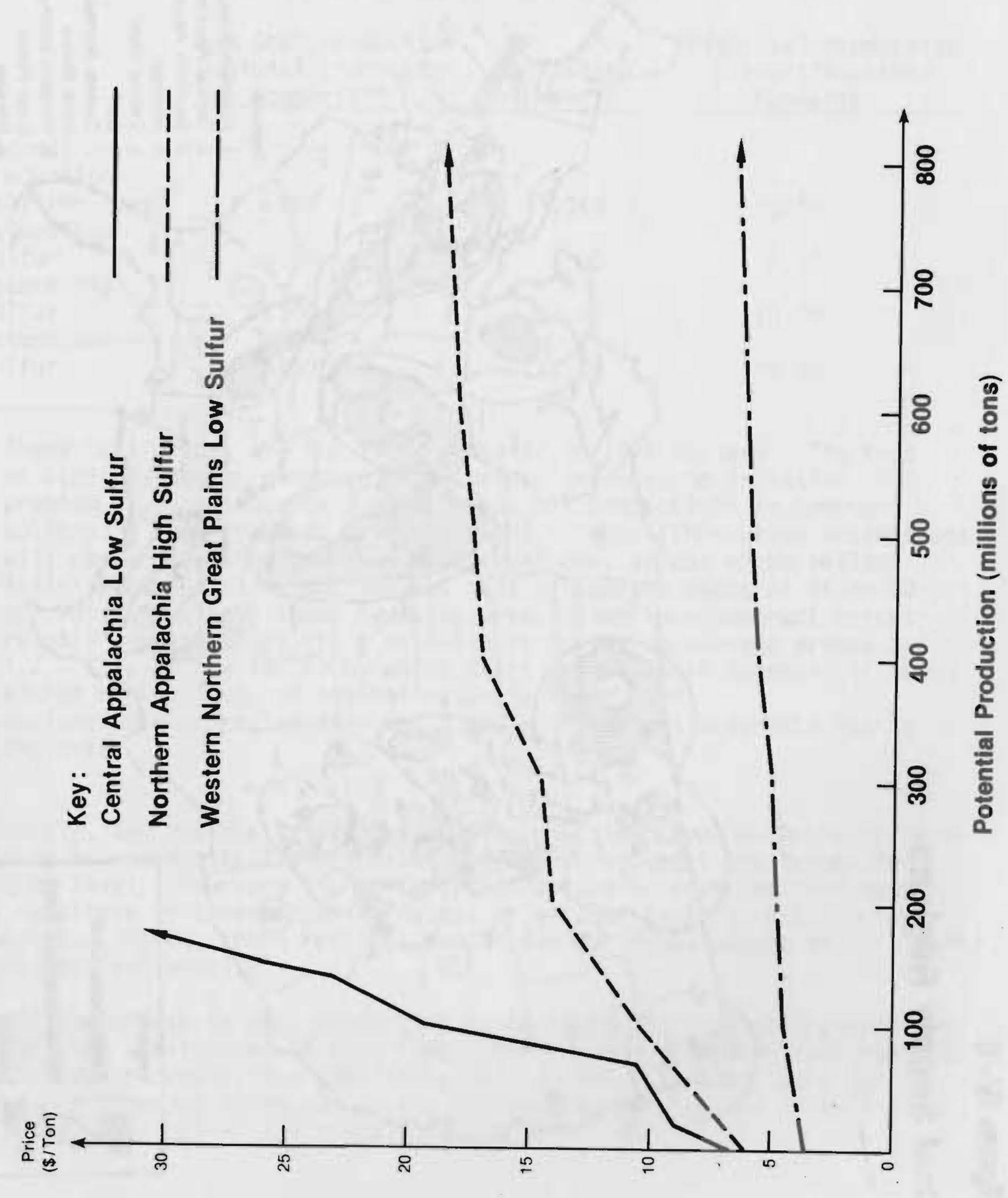
As discussed below, the results of these curves in the FEA forecasts are (a) that eastern low sulfur coal is bid up to the price of eastern high sulfur coal plus scrubbing, and (b) that prices of western low sulfur coal, eastern high sulfur coal, and eastern low sulfur coal (after it is bid up initially) do not change much over different levels of production (see Table IV-28).

Reference Scenario

The Reference Scenario forecast at $13 oil imports indicates that production will be 1,040 million tons in 1985. This represents a compound annual growth rate over 1974 levels of about 5.1 percent. The bulk of this increase occurs in the West. Further, over half is forecast to occur in one region--the Western Northern Great Plains (see Figure IV-6 for a map of coal supply regions)--with an additional 25 percent occurring in one other region--Central Appalachia (see Table IV-29).

The growth is concentrated in these regions because Central Appalachia is the only producing area in the East with substantial low sulfur reserves and the Western Northern Great Plains has vast amounts of relatively inexpensive-to-mine (on a per Btu basis) low sulfur coal reserves.

Figure IV-5
Representative Coal Supply Curves



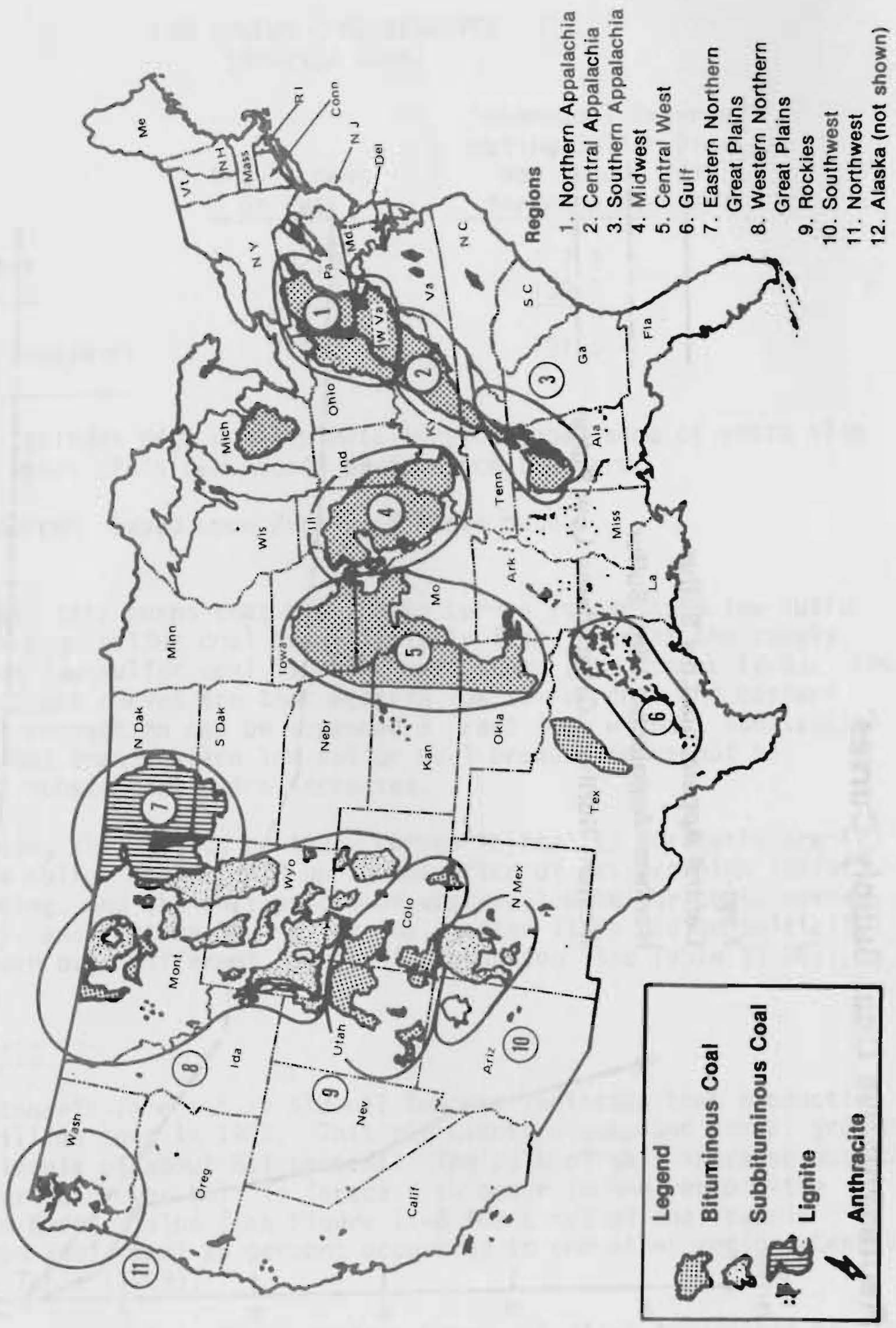


Figure IV-6
Coal Supply Regions

Table IV-28

COAL PRICES* AT DIFFERENT PRODUCTION LEVELS--1985, $13 OIL IMPORTS
($/Ton-FOB Mine, 1975 Dollars)

	Low Coal Production Regional Limitation Scenario**	Reference Scenario	High Coal Production Electrification Scenario
National Production (Million Tons)	958	1,040	1,258
Western Low Sulfur	6.50	4.90	5.50
Eastern High Sulfur	12.80	12.90	13.70
Eastern Low Sulfur	24.30	24.10	25.30

* These coal prices are for 1985, deflated to 1975 dollars. The cost of capital used to generate these prices included no inflation premium (i.e., since FEA's model makes all projections in constant dollars, a real interest rate was used). Thus, FEA's price projections will appear low when compared to current coal prices which reflect anticiapted inflation and nominal cost of capital rates of 15 to 20 percent. A rule of thumb to make current long term contract prices roughly comparable to FEA's estimate is to divide current prices by 1.2. This is the factor by which FEA's prices would increase if the higher nominal cost of capital rates had been used.

** Includes higher reclamation costs and a 30 percent severance tax in the West.

Significantly, the regional distribution of production shown in Table IV-29 is believed to be representative of what is likely to occur at the forecasted consumption level. However, the split of production between East and West is very sensitive to transportation rates, as well as factors, all of which are uncertain. Hence, these regional production estimates should be considered indicative but not precise.

Nearly all the growth in coal production is in low sulfur coal because of the sulfur emission limitations of the Clean Air Act. Many existing coal-burning facilities must reduce sulfur emissions, and all new facilities must meet new source performance standards (i.e., burn low sulfur coal or install scrubbers on high sulfur coal) (see Table IV-30).

Table IV-29

COAL PRODUCTION BY REGION—1985 REFERENCE SCENARIO, $13 OIL IMPORTS
(Million Tons)

Regions	1974	1985	Increase	Compound Annual Percent Growth Rate
Northern Appalachia	171	183	12	0.6
Central Appalachia	184	297	113	4.4
Southern Appalachia	20	25	5	2.0
Midwest	135	156	21	1.3
Total East	510	661	151	2.4
Central West	9	9	0	0.0
Gulf	8	21	13	9.2
Eastern Northern Great Plains	8	31	23	13.1
Western Northern Great Plains	35	274	239	20.6
Rockies	14	19	5	2.8
Southwest	14	21	7	3.8
Northwest	4	4	0	0.0
Alaska	1	*	-	-
Total West	93	379	286	13.6
National	603	1,040	437	5.1

* Less than 500,000 tons.

Table IV-30

SULFUR DISTRIBUTION OF COAL PRODUCTION
1985 REFERENCE SCENARIO, $13 OIL IMPORTS
(Million Tons)

	1974	1985	Increase	Compound Annual Percent Growth Rate
Metallurgical Coal*	111	138	26	2.0
Low-Sulfur Steam Coal	90	476	386	16.3
High-Sulfur Steam Coal	402	426	25	0.5
Total	603	1,040	436	5.1

* This is the premium quality coal used for coking and for export. It accounts for about 70 percent of domestic coking coal consumption and 85 percent of exports. The remainder of coking coal and exports comes from the low and high sulfur steam coal categories.

The forecast indicates the most coal users will opt for low sulfur coal rather than high sulfur coal with flue gas desulfurization, because low sulfur coal can be mined and delivered cheaper than high sulfur coal plus scrubbing. Scrubbers are installed on facilities burning about 110 million tons of high sulfur coal.* Without these scrubbers, high sulfur coal production would have decreased (i.e., 1985 production of 426 million tons minus 110 million tons of scrubbed coal equals 316 million tons, which is less than 1974 production 402 million tons. Further, it is important to note that high sulfur coal in the model is anything that doesn't meet new source performance standards. Many sulfur emission limitations for existing facilities provide for coal that just slightly exceeds these standards. Hence, the average sulfur content of "high sulfur coal" will be reduced by 1985 if compliance with current sulfur emission limitations is achieved.

Just as the regional production estimates should be viewed as approximate, so should the sulfur distribution estimates. They are very sensitive to such uncertain factors as transportation rates, scrubber costs and availability, and specific regional supply curves.

The forecast also indicates that the ratio of surface production to total production will increase from about 54 to 63 percent. This is because nearly all western production, which is forecast to grow rapidly, is surface mined.

* This estimate is probably low because the model does not account for the existence of long-term contracts or the cost penalties of burning western coals in existing boilers designed for eastern coals.

However, the ratio in the East is forecasted to drop slightly, indicating an exhaustion of inexpensive-to-mine strippable reserves in the East (see Table IV-31). Total eastern production is projected to increase by 150 million tons from 1974 to 1985 with about 100 million tons of the increase coming from deep mines.

Table IV-31

PRODUCTION BY TYPE OF MINING--1985 REFERENCE SCENARIO, $13 OIL IMPORTS
(Million Tons)

	Surface	Deep	Total	Surface as Percent Of Total
1974				
East	244.8	266.7	511.5	47.9
West	81.3	10.6	91.9	88.5
National	326.1	277.3	603.4	54.0
1985				
East	292.8	368.2	661.0	44.3
West	362.2	16.3	378.5	95.7
National	655.0	384.5	1,039.5	63.0

Again, the distribution of production by mine-type, particularly in the East, should be considered very approximate.

In the East, where low sulfur coal competes directly with high sulfur coal plus scrubbers, the FOB mine price differential reflects the cost of scrubbing to the marginal coal user (see Table IV-32).

Time Path

Coal production will grow faster between 1980-85 than over the 1975-80 period, where this growth is driven up by the consumption considerations discussed above (see Table IV-33). As noted, most of the production increases over the period are concentrated in Central Appalachia and the Western Northern Great Plains. Further, most of the production increases over the 1975-80 period are forecast to be in the West. Eastern production is not forecast to increase substantially until after 1980. However, as discussed above, these regional production estimates should be considered approximate.

Table IV-32

PRICES BY REGION AND COAL TYPE--1985 REFERENCE SCENARIO, $13 OIL IMPORTS
($/Ton FOB Mine, 1975 Dollars)

Region	Low Sulfur Coal	High Sulfur Coal
Northern Appalachia	24.90	12.90
Central Appalachia	24.10	12.60
Southern Appalachia	26.00	14.50
Midwest	22.80	10.80
Central West	-	11.35
Gulf	-	4.80
Eastern Northern Great Plains	6.30	4.40
Western Northern Great Plains	4.90	3.80
Rockies	10.00	-
Southwest	8.00	4.40
Northwest	-	5.40
Alaska	6.60	-

Table IV-33

COAL PRODUCTION BY REGION--REFERENCE SCENARIO, $13 OIL IMPORTS
(Million Tons)

	1974	1980	1985	1990
Northern Appalachia	171	163	183	199
Central Appalachia	184	269	297	322
Southern Appalachia	20	24	25	24
Midwest	135	96	156	176
Total East	510	552	661	721
Central West	9	9	9	10
Gulf	8	17	21	21
Eastern Northern Great Plains	8	14	31	45
Western Northern Great Plains	35	185	274	464
Rockies	14	16	19	21
Southwest	14	5	21	21
Northwest	4	1	4	4
Alaska	1	*	*	*
Total West	93	247	379	586
National	603	799	1,040	1,307

* Less than 500,000 tons.

For example, the 1980 forecast contains some anomalies. Midwestern production is projected to decrease in 1980 and then grow by 1985. Eastern production in 1980 is less than the short-term forecast production for 1978. These anomalies are due primarily to the way the sulfur emission limitations are handled. The 1980 forecast satisfies these limitations in the least costly manner using low sulfur coal, although it involved shutting down about 100 million tons of high sulfur production, much of which would be in the Midwest.

This should not be interpreted as indicating that such mine closings will occur, but only that given the costs specified in the model, the most cost-effective way of complying with existing sulfur emission limitations by 1980 is to substitute low sulfur coal for high sulfur coal in many boilers. It appears that EPA through its program of compliance date extensions and state implementation plan revisions will not let this happen. Further, the forecast probably overstates the impact of high sulfur coal production because the model does not account for the effects of long-term contracts or the costs of burning western coal in existing boilers designed for eastern coals. However, this anomaly is instructive in indicating the kinds of impacts that might occur from certain Clean Air Act implementation strategies.

The price paths in the various regions indicate stable prices. Western low sulfur coal remains very constant, as does eastern high sulfur coal. Eastern low sulfur coal is bid up to the equivalent of high sulfur coal plus scrubbers prior to 1980, and then remains fairly constant (see Table IV-34). Importantly, these prices are all in 1975 dollars, and hence reflect only real cost increases over the period. All factor prices were assumed to inflate at the same rate. Competition between equipment manufacturers and between coal producing regions should keep factor prices from escalating faster than the general level of inflation in the long run. However, in the short-run market imperfections may exist and enable some of the factor prices to increase faster.

Table IV-34

PRICES IN SELECTED REGIONS--REFERENCE SCENARIO, $13 OIL IMPORTS
($/Ton FOB Mine, 1975 Dollars)

Region	Coal Type	1980	1985	1990
Northern Appalachia	Low Sulfur	24.40	24.90	26.20
	High Sulfur	10.70	12.90	14.20
Central Appalachia	Low Sulfur	21.20	24.10	25.80
	High Sulfur	10.40	12.60	13.80
Midwest	Low Sulfur	21.70	22.80	23.80
	High Sulfur	10.00	10.80	11.70
Western Northern Great Plains	Low Sulfur	4.50	4.90	5.80
	High Sulfur	3.80	3.80	4.50

Effect of Oil Prices

Since the effect of different oil prices on total consumption is substantial, it is similarly substantial on total production. The fluctuations in production appear to concentrate in three regions (i.e., Northern Appalachia, Midwest, Western Northern Great Plains) (see Table IV-35).

Table IV-35

COAL PRODUCTION BY REGION--1985 REFERENCE SCENARIO
(Million Tons)

Regions	Oil Import Price $8	$13	$16
Northern Appalachia	159	183	183
Central Appalachia	285	297	298
Southern Appalachia	22	25	25
Midwest	130	156	175
East	596	661	681
Western Northern Great Plains	219	274	293
Central West	9	9	9
Gulf	20	21	21
Eastern Northern Great Plains	14	31	32
Rockies	19	19	19
Southwest	16	21	24
Northwest	1	4	6
Alaska	*	*	*
Other Western Areas	79	105	111
National	894	1,040	1,085

* Less than 500,000 tons.

As indicated above, coal prices do not change substantially with oil prices (see Table IV-36). These slight changes are due to changes in the level of production resulting from the impact of oil prices on coal consumption.

Table IV-36

REGIONAL VARIATION OF COAL PRICES WITH OIL PRICES
1985 REFERENCE SCENARIO
($/Ton FOB Mine, 1975 Dollars)

Region	Coal Type	Oil Import Prices $8	$13	$16
Northern Appalachia	Low Sulfur	24.70	24.90	25.30
	High Sulfur	11.20	12.90	13.30
Central Appalachia	Low Sulfur	21.60	24.10	24.50
	High Sulfur	10.90	12.60	12.90
Southern Appalachia	Low Sulfur	23.50	26.00	26.30
	High Sulfur	12.75	14.50	14.80
Midwest	Low Sulfur	22.00	22.80	23.10
	High Sulfur	10.10	10.80	11.10
Western Northern Great Plains	Low Sulfur	4.80	4.90	5.20
	High Sulfur	3.80	3.80	3.80

Effect of Different Scenarios

Since the effects of the various scenarios on total consumption are not great, neither are the effects on total production (see Table IV-37). Production effects tend to be concentrated in the same three regions: low sulfur coal from the Western Northern Great Plains, high sulfur coal from Northern Appalachia and high sulfur coal from the Midwest. The sensitivity of production levels results from the flatness of the supply curves in these regions. Small changes in the equilibrium price of coal lead to large changes in production for these regions.

The slight drops in production associated with the Regulation Scenario is concentrated in these regions, which together account for 75 percent of the decreases. The same is true for the Accelerated Scenario after adjustments are made for the assumed increases in synthetic fuels. Similarly, over 80 percent of the production increase associated with the Electrification Scenario is in these regions.

On the other hand, the production shifts assoicated with the Regional Limitation Scenario are more difficult to interpret. Low sulfur coal production from the Northern Great Plains drops substantially, but high sulfur production in the Midwest actually increases. Further, other regions are affected in unusual ways. There is a distinct shift in the percentage of total production from West to East.(see Table IV-38).

This shift is caused principally by the 30 percent severance tax assumed to be applied to all western production in the Regional Limitation Scenario. It renders western coals less competitive with midwestern coals in the midwestern markets.

Table IV-37

COAL PRODUCTION UNDER VARIOUS SCENARIOS
1985, $13 OIL IMPORTS
(Million Tons)

Regions	Coal Type	1974*	Reference	$9.00 Regulation	Regional Limitation	BAU Supply With Conservation	Accelerated Supply With Conservation	Electrification
Northern Appalachia	Metallurgical	12.9	20.3	20.3	20.3	20.3	20.3	20.3
	Low Sulfur	6.1	15.2	15.2	15.5	15.2	15.2	15.5
	High Sulfur	155.6	147.1	139.1	139.1	139.1	147.1	166.1
Central Appalachia	Metallurgical	87.8	100.7	100.7	100.7	100.7	100.7	100.7
	Low Sulfur	60.0	141.1	141.1	141.1	141.1	138.5	145.6
	High Sulfur	30.7	55.5	55.5	45.2	55.5	55.5	59.6
Southern Appalachia	Metallurgical	3.9	11.2	11.2	11.2	11.2	11.2	11.2
	Low Sulfur	5.8	8.5	8.5	8.5	8.5	8.1	9.0
	High Sulfur	9.8	5.6	5.6	5.6	5.6	5.6	5.6
Midwest	Low Sulfur	5.5	14.2	14.2	14.5	14.2	13.7	14.8
	High Sulfur	133.0	141.6	132.6	160.7	132.6	147.4	175.6
Central West	Metallurgical	0.9	-	-	-	-	-	-
	High Sulfur	7.9	9.3	9.3	5.8	9.3	10.9	11.8
Gulf	High Sulfur	7.7	20.6	20.6	16.8	20.6	25.3	25.3
Eastern Northern Great Plains	Low Sulfur	1.7	25.2	20.0	14.0	20.0	20.0	25.8
	High Sulfur	6.1	6.1	6.1	-	6.1	9.3	9.3
Western Northern Great Plains	Low Sulfur	2.1	251.2	237.8	213.3	213.8	220.4	376.8
	High Sulfur	32.2	22.6	22.2	21.6	21.9	25.1	25.8
Rockies	Metallurgical	6.1	6.1	6.1	6.1	6.1	6.1	6.1
	Low Sulfur	6.9	12.7	12.7	1.9	12.7	12.7	14.7
Southwest	Low Sulfur	1.2	7.7	7.7	6.7	7.7	7.7	8.7
	High Sulfur	14.8	12.9	8.3	8.3	8.3	10.8	20.2
Northwest	High Sulfur	4.0	4.0	1.0	1.0	1.0	2.6	8.9
Alaska	Low Sulfur	0.7	0.1	0.1	0.1	0.1	0.1	0.8
National	Metallurgical	111.6	138.3	138.3	138.3	138.3	138.3	138.3
	Low Sulfur	90.0	475.9	457.3	415.6	433.3	436.4	611.7
	High Sulfur	401.8	425.3	400.3	404.1	400.0	439.6	508.2
Total		603.4	1,039.5	995.9	958.0	971.6	1,014.3	1,258.2

* Regional production by coal type estimated.

Table IV-38

COAL PRODUCTION 1985, $13 OIL IMPORTS
[Million Tons (Percent)]

	Reference	Regional Limitation
East	661 (64)	662 (69)
West	379 (36)	296 (31)
National	1,040 (100)	958 (100)

The effect of the severance tax in the Regional Limitation Scenario is somewhat offset by the reclamation costs which are higher in the East than in the West. Without the reclamation costs, the severance tax would have shifted even more production out of the West. Conversely, without the severance tax, the reclamation costs would have shifted production from East to West.

Finally, the forecast indicates that high sulfur production does not fall much under the Regional Limitation Scenario and indeed increases as a percentage of total production (see Table IV-39).

Table IV-39

SULFUR CONTENT OF STEAM COAL PRODUCTION*--1985, $13 OIL IMPORTS
[Million Tons (Percent of Total)]

	Reference	Regional Limitation With BAU Demand	Change
High Sulfur	425 (47)	404 (49)	-21
Low Sulfur	476 (53)	416 (51)	-60
Total	901 (100)	820 (100)	-81

* Excludes metallurgical coal.

This may appear surprising considering that a specification of the Regional Limitation Scenario was that all new plants burn low sulfur coal with scrubbers, whereas the relevant specifications of the Reference Scenario were that new plants meet new source performance standards, either with low sulfur coal or with high sulfur coal plus scrubbers. However, it occurs because the requirement to scrub low sulfur coal in new plants would render new plant generation costs so expensive that utilities in some parts of the Nation would maximize the use of existing plants (even though they are generally less efficient and some would require scrubbers) because they could burn less expensive high sulfur coal.

This effect can be illustrated by utilities in the East North Central region, a predominantly coal burning region. Under the Reference Scenario, the forecast indicates that utilities would use those existing plants that are permitted by current air pollution regulations to burn high sulfur coal in baseload--i.e., to maximize the use of these plants. Further, existing plants required by current air pollution regulations to burn low sulfur coal or install scrubbers, would burn low sulfur coal and operate in intermediate load--i.e., to use these plants about half as much as baseload plants to minimize fuel costs. Finally, it indicates that new base load coal plants would burn high sulfur coal and install scrubbers to meet new source performance standards, while new coal intermediate load plants would burn low sulfur coal.

However, under the Regional Limitation Scenario, the new plants are not permitted to burn high sulfur coal or low sulfur coal without scrubbers. This makes generation costs from new plants very expensive. Hence, the utilities act to minimize costs by using all of the existing plants in baseload to the extent possible, installing scrubbers on those where required by air pollution regulations, because these plants are permitted to burn less expensive high sulfur coal. New plants, where expensive low sulfur coal is required, are operated only at intermediate load in order to minimize fuel costs.

The reasons for this change in coal consumption are economic. The FEA model simulates "economic dispatch"--i.e., that utilities will build and operate plants to minimize total costs. The effect of requiring new plants to burn low sulfur coal and install scrubbers is to change the relative economics of plant types, because the price of low sulfur coal is bid higher (see Table IV-40).

Note that the least expensive baseload generation (after existing plants burning higher sulfur coal without scrubbers which is always cheapest) shifts from new plants burning high sulfur coal with scrubbers in the Reference Scenario to existing plants burning high sulfur coal with scrubbers in the Regional Limitation Scenario. New plants burning low sulfur coal with scrubbers are most expensive, by a large margin.

The national average price of electricity increases from 29.73 mills per kilowatt hour in the Reference Scenario to 31.12 mills per kilowatt hour in the Regional Limitation Scenario--a 4.7 percent increase. The regional increases vary from less than 1 percent to over 10 percent (see Table IV-41). The greatest impacts occur in the Northeast, West North Central and West South Central regions where there is very little existing coal-fired generating capacity to baseload. The impact in the Mountain and Pacific regions is small since scrubbers were already required in the Reference Scenario.

Table IV-40

RELATIVE ECONOMICS OF BASELOAD COAL PLANT TYPES
EAST NORTH CENTRAL UTILITY REGION
1985, $13 OIL IMPORTS

	Reference	Regional Limitation with BAU Demand
Price of low sulfur coal ($/Million Btu)	1.11	1.21
Price of high sulfur coal ($/Million Btu)	0.63	0.68
Existing Plants Incremental Generation Costs (mills/kWh)		
- High sulfur without scrubber	8.21	8.70
- High sulfur with scrubber	13.31	13.83
- Low sulfur without scrubber	12.93	13.92
New Plant Incremental Generation Costs (mills/kWh)		
High sulfur with scrubber	12.03	-
Low sulfur without scrubber	12.21	-
Low sulfur with scrubber	16.66	17.63

Table IV-41

REGIONAL ELECTRICITY PRICES IN 1985
(Mills/kWh, 1975 Dollars)

Region	Reference	Regional Limitation with BAU Demand	Percentage Increase
Northeast	33.21	36.56	10.1
Middle Atlantic	33.43	34.90	4.4
South Atlantic	29.77	30.79	3.4
East North Central	29.79	30.91	3.8
East South Central	26.89	28.22	4.9
West North Central	28.91	31.02	7.3
West South Central	31.21	34.26	9.8
Mountain	29.26	30.15	3.0
Pacific	25.11	25.25	0.6
National	29.73	31.12	4.7

Policy Implications

There are several important policy implications in these production forecasts.

First, in 1975 dollars, the price of coal is unlikely to increase rapidly, even with large increases in production, becasue the supply curve for coal facing any particular consuming region is relatively flat.

Second, it appears that substantial increases in low sulfur coal production from the Western Northern Great Plains will occur since it appears to be the most economical means to meet coal demand. This has implications for the rate of development in the West and for Federal western leasing policy, although coal demand could be satisfied from other regions at higher costs. However, forecast production levels in the West are very sensitive to:

- Transportation rates (which if lowered mean more production and vice versa);
- Severance taxes (which if applied mean less production);
- Reclamation requirements (where if applied uniformly across the Nation mean relatively lower cost increases in the West and more production);
- Air pollution requirements (where the specific interpretations of the Clean Air Act will determine whether western production is stimulated or inhibited).

Third, it appears that the effect of reclamation provisions associated with the hypothetical stripmining legislation specified for the FEA forecast would not have substantial effects on total coal production, but would probably shift some production from East to West.

SUMMARY

Much has been done in the past year to refine and improve FEA's coal forecasting model. This work included substantial refinements of the coal supply curves and of the algorithms forecasting the demand for coal in each sector. Accordingly, much of the forecasting error associated with the forecasts has been reduced. For a discussion of these refinements, see Appendix A.

Significantly, however, the major findings this year are essentially the same as last year:

- In the long-run (although not necessarily in the short-run), coal production will be constrained by the demand for coal. The FEA Reference Scenario forecast for 1985 at $13 per barrel imported oil prices indicates that more than 1 billion tons of coal will be produced (including exports). Considerably more coal could be produced without substantial price increases, but this coal would not be consumed, because coal-using sectors are not expected to grow quickly enough to absorb it.

° The major growth in coal consumption is expected to occur in the electric utility sector. In this sector, coal consumption depends importantly on:
  - Oil Prices: The Reference Scenario forecast at $8 oil imports indicates that this sector will consume about 579 million tons in 1985, whereas, at $16 oil imports, 760 million tons are forecasted to be consumed--a difference of nearly 200 million tons.
  - Electricity Growth Rates: The Reference Scenario forecast at $13 oil imports indicates that electricity will grow at a compound annual rate of 5.4 percent between 1974-85. However, there is uncertainty associated with this estimate, and coal consumption estimates are very sensitive to electricity growth rate estimates. For each percentage point change in the compound annual electricity growth rate over the 1974 to 1985 period, forecasted coal consumption in the utility sector changes by about 150 million tons in 1985.
  - Nuclear Capacity: The Reference Scenario forecast at $13 oil imports indicates that nuclear capacity will be about 141 thousand megawatts in 1985. However, there is substantial uncertainty associated with this estimate as well, because the economic advantages of nuclear plants over coal plants may not be realized, nuclear plants are undergoing increasing attacks by public interest groups, and delays in nuclear construction schedules are difficult to predict. For each 10 percent change in the nuclear capacity estimate, estimated 1985 coal consumption changes by about 40 million tons.

° There is no reason to expect coal prices to equilibrate on a Btu basis with oil or gas prices, even after adjustments for pollution control costs. This is because:
  - Coal reserves are vast and reserve ownership is generally widespread enough that long-term contract coal prices are and will be cost-based.
  - The costs of producing coal do not increase rapidly as coal production is expanded.
  - The opportunities for expanding coal consumption including substituting coal for oil and gas (even through electricity) are limited.

° Environmental regulations could significantly inhibit coal consumption. Changes in current air pollution control regulations and/or deviations from current enforcement strategies could result in some substitution of oil for coal, particularly in the utility sector. Stripmining legislation could result in some mine-closings, and failure to proceed with Federal leasing of western low sulfur coal reserves could inhibit

the development of coal production capacity. However, none of these environmental matters need inhibit increased reliance on coal and conversely, increased coal usage need not result in substantial adverse environmental effects. Compromises, which balance the revelant conflicting social welfare concerns, are clearly possible.