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MASTER

COAL COMPETITION:
PROSPECTS FOR THE 1980s

DRAFT REPORT

Technical Appendix

United States
Department of Energy

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APPENDIX I

HISTORICAL PERSPECTIVE OF COAL

HISTORICAL PERSPECTIVE OF COAL

A COAL STUDY REPORT UNDER
SECTION 742
OF THE
POWERPLANT AND INDUSTRIAL FUEL USE ACT
OF 1978

Prepared By

MILDRED KIKTA

COAL STUDY PROJECT
ENERGY INFORMATION ADMINISTRATION
DEPARTMENT OF ENERGY

WASHINGTON, D. C.
November - 1980

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HISTORICAL PERSPECTIVE OF COAL

I. INTRODUCTION

Before World War II coal was the world's dominant energy-producing fuel then steadily lost ground to other fuels. Although coal accounts for about 85 percent of the U.S. fossil-fuel reserves, it has accounted for a declining portion of U.S. energy consumption over the past 80 years due to the increased use of oil and natural gas. In recent years, however, coal began gaining in stature and importance as a major source of energy due to a continual depletion of the world's nonrenewable resources, the Arab oil embargo and passage of the Powerplant and Industrial Fuel Use Act (PIFUA) 1978*.

The development of a new energy basis for continued economic growth has therefore become an urgent necessity. In the industrialized countries coal can become the principal fuel for economic growth and the major replacement for oil in many uses. Coal may also provide the only way for many of the less developed countries to obtain the fuel needed for electric power and industrial development and to reduce their dependence upon oil.

This report consists of ten chapters presenting a historical overview of coal in past years and the part it has played as an energy source in the economic growth of the United States prior to World War II through 1978 and concludes that the outlook for increasing the share of coal's energy consumption is indeed promising.

II. DEFINITIONS OF COALS AND COAL MINING

Coal has always been available when the Nation required an inexpensive plentiful source of energy and offers a ready and reliable substitute as an alternate to imported oil.

Rich deposits of coal underlie the hills and hollows of Kentucky, Ohio, and West Virginia. Thick beds lie just below the surface of Arizona, Montana, Wyoming and other western States. Vast seams are scattered across the Illinois Basin and Pennsylvania. Coal is mined in 26 of the 31 States where bituminous, anthracite, and lignite reserves have been found.

Although one lump of coal may look very much like another, there are many different grades and qualities. Coal is ranked by its transformation from lignite through bituminous to anthracite. In this development, fixed carbon

*P.L. 95-620 (H.R. 5146), November 9, 1978, U.S. Congress.

is the only element that maintains a fairly uniform gradient, increasing from low-rank to high-rank coals. The change is caused by the dispelling of moisture and volatile matter by heat from pressure or other sources. High grades of coal have a heating value of 12,600 British thermal units per pound; lower grades have only half or a third as much. One system of classification divides coal into two broad categories: soft coal (brown and lignite) and hard coal (anthracite and the various grades of bituminous coal). The ability of different types of coal to form coke when they are heated in the absence of air also varies widely. Since coke for steelmaking is one of coal's major uses, a second important classification divides coals into metallurgical (or coking) coals and thermal (or steam) coals, which are burned to provide either heat or steam for the generation of electric power.

The principal classes of coal, in ascending order of rank, are as follows:

Lignite, a low-rank, brown-to-black coal, contains 30 to 70 percent moisture; it disintegrates rapidly in air and is liable to spontaneous combustion, even on vertical or sloping faces exposed by mining. Vast lignite deposits exist and are extensively mined in Germany, eastern Europe and Australia despite its objectionable physical properties and low heat value.

Subbituminous, a black coal, contains from 15 to 30 percent moisture when mined. It weathers and is subject to spontaneous combustion to a lesser degree than lignite.

Bituminous coal, the most abundant variety, varies from medium to high rank. It is black and banded, weathers to a lesser degree. Bituminous coal may be of coking quality. This property is independent of rank classification and depends on the ability of the coal to produce a coke when heated in a coke oven.

Anthracite, a hard coal of brilliant lustre, can be rubbed without leaving a stain on the finger, burns slowly with a pale blue flame, and requires a minimum of attention. Because of its clean burning properties, anthracite is used primarily as a domestic fuel. It is sometimes blended with bituminous coal to produce a mixture with improved coking qualities. Until the 1920's, when oil and natural gas began to take its place, anthracite was a preferred fuel for household heating.

Mining, used in a broad sense, includes the extraction of minerals occurring naturally. While liquids, such as crude petroleum; and gases, such as natural gas; fall into the mining category, this report deals primarily in the mining of coal which, along with ores, is considered a solid. The term "mining" is also used in the broad sense to include quarrying, well operation, milling (crushing, screening, washing, flotation, etc), and other preparation customarily done at the mine site, or as a part of mining activity.

Standard Industrial Definition of Bituminous and Lignite Mining and Anthracite Mining:

Major Group 12.--BITUMINOUS COAL AND LIGNITE MINING

The Major Group as a Whole

This major group includes establishments primarily engaged in producing bituminous coal or lignite. Included are mining operations and preparation plants (also known as cleaning plants and washeries) whether or not such plants are operated in conjunction with the mines served. The production of coal fuel briquettes and packaged fuel is classified in Major Group 29, and the production of manufactured gas from coal in Industry 4925.

Group	Industry
No.	No.

121	Bituminous Coal and Lignite Mining
-----	------------------------------------

1211	Establishment primarily engaged in producing bituminous coal or lignite or in developing bituminous coal or lignite mines. This industry includes underground mining, auger mining, strip mining, culm bank mining, and coal cleaning, crushing, screening, and sizing plants, whether or not operated in conjunction with the mines served.
------	--

Brown coal mining	Lignite mining
Cleaning plants, bituminous coal	Screening plants, bituminous coal
Coal mining, bituminous	Semianthracite mining
Crushing plants, bituminous coal	Semibituminous coal mining
Culm bank recovery, bituminous coal or lignite: except on a contract basis	Strip mining, bituminous coal: except on a contract basis
Hard coal mining, except Pennsylvania anthracite	Subbituminous coal mining
	Washeries, bituminous coal

1213	Bituminous Coal and Lignite Mining Services
------	---

Establishments primarily engaged in performing bituminous coal lignite mining services for others on a contract, fee, or similar basis. Establishments which have complete responsibility for operating mines for others on a contract, fee, or similar basis are classified according to the product mined rather than as bituminous coal and lignite mining services.

Auger mining services, bituminous coal or lignite: on a contract basis	Lignite strip mining: on a contract basis
--	---

Bituminous coal mining services: on a contract basis	Overburden removal for bituminous coal: on a contract basis
Culm bank recovery, bituminous coal or lignite: on a contract basis	Sinking shafts for bituminous coal and lignite mining: on a contract basis
Draining or pumping bituminous coal and lignite mines: on a contract basis	Strip mining, bituminous coal: on a contract basis
Drilling for bituminous coal and lignite mining: on a contract basis	Stripping services, bituminous coal and lignite: on a contract basis
Lignite mining services: on a contract basis	Tunneling bituminous coal and lignite mining: on a contract basis

Major Group 11.--ANTHRACITE MINING

The Major Group as a Whole

This major group includes establishments primarily engaged in producing anthracite (hard coal). Included are mining operations, dredging operations, and preparation plants (also known as cleaning plants, breakers, and washeries) whether or not such plants are operated in conjunction with the mines served. The production of coal fuel briquettes and packaged fuel is classified in Major Group 29, and the production of manufactured gas from coal in Industry 4925.

Group No.	Industry No.
--------------	-----------------

111	Anthracite Mining
-----	-------------------

1111	Establishments primarily engaged in producing anthracite or developing anthracite mines. All establishments in the United States that are classified in this industry are in Pennsylvania. This industry includes underground mines, stripping or culm bank operations by owners or lessees, dredge operations, and coal preparation plants (breakers, washeries, and screening plants) whether or not operated in conjunction with the mines served.
------	---

Anthracite mining	Recovery of anthracite from culm banks, except on a contract basis
Breakers, anthracite	Screening plants, anthracite
Coal mining, anthracite	Strip mining, anthracite: on a contract basis
Culm bank recovery, anthracite: except on a contract basis	Washeries, anthracite
Dredging, anthracite	
Preparation plants, anthracite	

1112 Anthracite Mining Services

Establishments primarily engaged in performing anthracite mining services for others, on a contract fee, or similar basis. Establishments which have complete responsibility for operating mines for others on a contract, fee, or similar basis are classified according to the product mined rather than as anthracite mining services.

Anthracite mining services performed on a contract basis	Mine tunneling, anthracite: on a contract basis
Culm bank recovery, anthracite: on a contract basis	Overburden removal for anthracite: on a contract basis
Draining or pumping of anthracite mines: on a contract basis	Sinking shafts for anthracite mining: on a contract basis
Drilling for anthracite mining: on a contract basis	Strip mining, anthracite: on a contract basis

III. TYPES OF COAL MINES

There are basically two types of coal mines, underground (alternately known as deep) mines and open-pit (more commonly called surface or stripmining) mines. To these a third might be added, underwater mine. The type of mine depends primarily upon the relationship of the coal bed to the surface. When the coal seams run deep into the earth from an outcrop on a hillside or lie deeper beneath the surface, underground mining is conducted. Stripmining, also referred to as open-pit and surface mining, can be carried on to a depth of 100 feet or slightly more. Sometimes coal beds are bound to extend far out under the sea, and if conditions are right, the coal can be recovered. Underwater mining, of little importance in the United States, is conducted by Canada, Chile, and Great Britain.

UNDERGROUND MINING

Depending upon the way in which the coal seam is approached, underground mines are either drift, slope, or shaft mines.

These three methods (or various combinations thereof), are used to gain access to coal located too deep underground for surface mining.

A drift is a horizontal, or nearly horizontal, tunnel driven from the surface that usually follows the seam. Drifts are used where the seam outcrops and is level or only slightly inclined. This is the cheapest method of access, permitting continuous transportation from the coal face to the surface by any conventional means.

A slope is an inclined opening driven to work a seam with a downward inclination, or to reach from the surface to a seam or between seams. Men and supplies frequently are moved on a track in the same slope opening in which the coal belt conveyor is located.

referred to as "blind shafts".

A shaft is a vertical opening driven from the surface to provide access to a seam or seams and to serve various levels of a mine. It is called a "blind shaft" when driven from one seam down to another. Early shafts were small multipurpose openings, lined at first with wood and later with brick. Modern shafts from the surface are normally lined with reinforced concrete, brick, or steel. Because it provides the shortest distance between two vertical points, the shaft is used almost exclusively today to reach a deep seam. In the past, belt conveyors were used on slopes, which replaced shafts when depths were limited. Today, with automatic high-speed hoisting machinery available, shafts are replacing the long slopes.

While there are many ways of removing coal in underground mining, two basic underground methods, room-and-pillar and longwall, are employed. The shortwall method--a combination of the two--is an alternative which can be implemented whenever mining conditions are workable.

Room-and-Pillar Method

In the United States, most of the underground coal mines follow a room-and-pillar plan that results in intersecting tunnels 14 to 20 feet wide. The pillars are columns of coal that are left standing to help support the roof of rooms from which coal has been removed. After the mine face has been advanced as planned, the miners work backward, or retreat, withdrawing the standing sections, which are called pillars, allowing the roof to collapse behind them.

Two main types of room-and-pillar coal mining are employed in the United States--conventional mining and continuous mining--because the coal seams, especially bituminous seams, are very thick.

The conventional method, which involves the cutting, drilling and blasting, loading, and hauling of coal out of the mine, is the oldest and most complex of the mechanized deep-mining processes. It accounts for about 32 percent of the total coal mined underground. Coal recovery with the conventional mining method, as with other room-and-pillar methods, is in general probably no more than 50 to 60 percent, although much higher recovery rates are obtained at some mines.

Continuous mining accounts for over 63 percent of the total coal mined underground in the United States. In one operation, a continuous mining machine tears the coal from the seam with its revolving teeth and loads it for transport out of the mine. The continuous miner (machine) is a great technological improvement over conventional mining because it eliminates the "bottleneck" which occurs with conventional mining when one of the steps in the mining sequence falls behind. In addition, it requires fewer men to produce an equivalent tonnage of coal. Conventional mining, however, will probably be utilized for quite some time because (1) it gives considerable protection to the miners by localizing the hazards of gas and dust, (2) it offers flexibility in responding to adverse seam conditions (poor roof rock, hard coal, and high rates of methane gas liberation), and (3) conventional mining units are more reliable and more readily available. Continuous miners actually operate intermittently, with delays attributed most often to roof control, ventilation, haulage, and maintenance and related problems.

Longwall Method

In the longwall method, almost all of the coal is removed from the working surface, or face, and the area that has been mined is filled with rock and sand. This method of mining utilizes a steel plow or rotating, cutting drum which moves back and forth across a face that is several hundred feet long to cut the coal, which then falls onto a conveyor. A series of large self-advancing hydraulic jacks that are topped with broad steel beams and set a few feet apart, supports the roof face (350--600 feet long), the support jacks momentarily release their pressure and move forward to resume their support. Coal recovery rates of 95 percent are not uncommon.

The longwall mining method accounts for only 4 percent of the total underground coal mines in the United States. By contrast, it is extensively used in European coal mines where the coal seams are thin and distorted and lie at considerable depth. These conditions favor the longwall method which is well adapted to the use of machines to perform most of the labor.

Inherent problems exist in utilizing the longwall mining method: (1) a soft top or bottom or a top too strong to cave will make the method untenable; (2) a wide variance in seam thickness cannot be tolerated because of the use of roof support jacks with a limited height range; (3) displacement faults, seam pinchouts, or the presence of gas wells offset the advantages of the system; and (4) moving the system from one working area to the next requires at least 30 shifts to accomplish and is a cost disadvantage. The advantages of the longwall system, however, appear to outweigh the disadvantages in seams where longwall mining is an alternative. Consequently, longwall mining is expected to increase its share of the total coal mined in the United States.

Shortwall Method

Still another type of mining, which is somewhat a combination of room-and-pillar and longwall mining, is shortwall mining. Shortwall mining utilizes a continuous miner to cut and load from the open end of a rectangular pillar of coal, while self-advancing roof supports provide protective cover. Overall recovery of coal with the shortwall method is about 85 percent of the coal seam, about 10 percent lower than the longwall method but still higher than the room-and-pillar methods. Shortwall mining offers some advantages over longwall mining; where seam variability is great, shortwall mining can be utilized because the length of the wall of coal to be mined is less (150-200 feet long), and movement of the equipment to a different area is less of a problem than with longwall mining because of the utilization of self-support jacks.

In choosing the best method of underground mining, a very important consideration is pressure. Because internal stresses increase with depth and density of rock, underground workings become progressively more hazardous as they go deeper. The zones of depth, therefore, are generally grouped into three areas of rock behavior according to pressure stress.

In the first zone where the exact depth varies because of different types of strata and geologic treatment, rock pressure presents no problem if mining dimensions are kept within established limits. This zone includes most of the coalfields in the Appalachian and interior areas of the United States, in New South Wales, South Africa, and the Lorraine fields in France. Room-and-pillar mining is practicable in this zone and many strata conditions permit longwall. The choice is a matter of economics.

Most of the coalfields of the United Kingdom, U.S.S.R., Ruhr Valley, The Netherlands and Belgium, which fall within the second and third zone of depth where pressures are greater, require use of the longwall method.

SURFACE, OR STRIP, MINING (OPENPIT)

While strip mining is not new to this century, modern earth-moving equipment has made it a major, and often controversial technique. However, the impact of this technique has been tempered somewhat by passage of the Surface Mining Control and Reclamation Act of 1977 (SMCRA), Public Law 95-87, enforced by the Office of Surface Mining (OSM), Department of the Interior.

Approximately one-half of U.S. coal production comes from surface mines where the coal seams lie fairly close to the earth's surface. The size and type of surface operation is greatly influenced by the size of the property, the thickness and slope of the coal, and the type of overburden. The basic unit for determining economic limitations is the ratio of overburden to thickness of coal. This varies from 1:8 in thick brown coal deposits of Australia to 30:1 in some U.S. strip mines. Surface mining techniques are used when the cost of removing the overlying rock overburden is low enough to make mining economical. Surface-mined coal is frequently too near the surface for deep mining, because shallow overburden is often too fragmented and weak to form a safe roof in an underground mine. Coal is not generally surface mined if it lies more than 150 feet below the surface. Conversely, in the Eastern coal regions of the U.S. the overburden that must be removed generally averages about 100 feet with a 4-foot seam thickness. While seams as thick as 100 feet are not uncommon in the West, seams average about 35 feet with an overburden of 35 feet.

The major methods of surface (strip) mining utilized in the United States are: (1) area mining, (2) contour mining, and (3) auger mining. Both area and contour mining utilize numerous techniques and equipment, depending on the geology and climate of the area to be mined.

Area mining techniques are utilized mainly in relatively flat terrain to gently rolling slopes (0 to 10°) in Northern Appalachia to Midwest and West. Basically, with this type of surface mining, a trench or "box cut" is made through the overburden to expose a portion of the deposit. The coal is then removed from this first cut, which may extend as far as the limits of either the deposit or the property. Succeeding parallel cuts are made, with the spoil being deposited in the cut just previously excavated.

The machines used in surface mining range in size from ordinary construction bulldozers and front-end loaders to huge power shovels and draglines that are the largest moving land machines in the world. Because of its versatility, smaller, more mobile equipment is generally used in the Eastern (Appalachian) strip mines in order to traverse the rugged terrain. In the Western and Midwestern coalfields, where strippable coal seams are fairly continuous for miles, gigantic equipment is mainly utilized.

Contour mining is practiced in areas, particularly the Appalachian, where the terrain is mountainous or rolling with medium to steep slopes (10-15° or greater), and multi-layered thin coal beds. Contour mining techniques are numerous, but basically, the method consists of removing the overburden above the coal bed to expose the coal. The coal is then removed and the operation procedure moves along into the hillside until the ratio of the overburden to strippable coal (stripping ratio) becomes so great that it is uneconomical to mine.

Auger mining is usually associated with contour strip mining, and is commonly utilized to recover additional tonnages after the stripping ratio becomes too great to be economical. Augers extract the coal by boring horizontally into the seam; some augers are as large as seven feet in diameter and can drill in excess of 200 feet into the hillside. Regulations prohibit augering in some areas of Appalachia and the Midwest.

IV. MINING WORK FORCE

American Coal Miner

In a recent study on community and living conditions in the coalfields, the President's Commission on Coal found that coal mining has long attracted workers from across a broad spectrum of American society. Many workers came from England and Europe to work in the anthracite fields of Pennsylvania during the immigration waves of the 19th and 20th centuries. Englishmen, Scots, Welshmen, Germans and Czechs--often sons of miners--were drawn to the United States by promises of higher wages, improved working conditions and a better life.

In 1922, the U.S. Coal Commission conducted a study of the 1920 Census data and determined that of the 525,152 workers in the bituminous coalfields, 59 percent were native-born white, 8 percent were native-born black, and 33 percent were born in other nations. The study found that most of the foreign-born workers were from Italy, Austria, Hungary, Poland, Russia, France, England, Yugoslavia and Germany. The lure of profits also drew men of various backgrounds into the areas of management and ownership.

Today, American coal miners are a varied group, consisting of men and women of all ethnic and racial backgrounds--white, black, Hispanic, Asian-Americans, and American Indians.

That variety--with the exception of women and indians--has long been characteristic of American miners. Years ago, however, it was also characteristic of them to be poorly paid in comparison with the rest of the industrial work force, not as well educated and generally not part of the contemporary middle class.

Many of those patterns have and are changing. Today, the work force is no longer entirely male. Of 1,281 miners recently surveyed*, 97 percent were male, 61 percent of the miners are largely married and some of their spouses (24 percent) work. The miners' average income is \$19,442 and 53 percent of them have completed at least high school.

Miners often come from mining families. Of all respondents 56 percent had a miner-father, 37 percent a miner-grandfather, and 12 percent a miner-great-grandfather.

The mining work force is also younger than it was a generation ago, partly because a slump in production in the 1960s brought few new miners into the occupation. This resulted in the so-called "missing generation" of miners. Of respondents to the survey, fully 41 percent are 29 years old or younger.

Finally, the survey concluded that miners seem to like mining and accept all the dangers, uncertainties, and plain hard work of the occupation. Miners seem to have an unspoken camaraderie and deep sense of personal satisfaction in having teamed with other miners to complete a day's work and in overcoming the adversities of nature. Of all respondents to the survey, 64 percent said they would remain in coal mining and 6 percent said that they would reconsider entering the coal mining work force given another chance to be a coal miner.

Unions

While the coal industry consists of many people--coal mine operators, miners, transporters, users--it is usually the mine owners and the union members who have dominated the public scene.

The confrontations between coal companies and coal unions has been as hard-fought, as tragic, as colorful and ultimately as successful for both sides as any in the history of American business and labor.

From about 1750 to the 1890s, the companies faced no organized demands from the miners, who were largely illiterate, poorly paid and politically powerless. Working conditions in many mines were bad. Most mine operators concentrated on profit and paid scant attention to safety or health of their men. Major disasters from explosions occurred regularly.

As coal mining grew in importance after the Civil War and mining operations increased, miner resentment against the operators also increased, spawning the beginnings of the effort to organize the coalfields and giving rise to radical groups, the most notorious of which was the Molly Maguires--a supposedly secret society of Irish miners, existing from 1850 to 1877. They objected to the living and working conditions in the anthracite fields of Pennsylvania, where they were especially strong. They contended that coal company camps were unfit for living or raising a family, that pay was too low, and that the mines were unhealthy and unsafe.

*Living Conditions Survey, President's Commission on Coal, Wash., D.C., 1980.

Using terrorism as well as political strategies, the Molly Maguires burned down coal tipples, blew up locomotives and even shot company supervisors. The coal operators eventually hired a Pinkerton agent to infiltrate the secret society. As a result of his testimony, 20 miners in 1877 were tried for violent acts, convicted, and hanged.

In those same years, the foundations were laid for what has become the major coal-mining labor union in the United States--the United Mine Workers of America (UMWA).

The union was founded in 1890 and drew its early strength from miners in the Midwest. Its active U.S. membership in January 1979 was 184,539 nationwide, but it remains particularly strong in the Midwest and the East. There were also an estimated 41,000 nonunion miners, mostly in the West but also in mines scattered throughout other coalfields.

The President's Commission on Coal in its study of the American coal miner further reported that union miners now produce about half of the coal mined in the United States--the UMWA share is about 48 percent of union coal mined--illustrating the trend in recent years toward increased production of large, nonunion surface mines in the West. The productivity per miner in surface mines exceeds that in underground mines by a substantial margin. Some miners especially in the western surface mines belong to unions other than the UMWA. These include the International Union of Operating Engineers, the Progressive Mine Workers, and the Southern Labor Union, among others.

Miners are not the only unionized group. The coal operators also have an organization--the Bituminous Coal Operators' Association (BCOA), which consists of more than 130 operators in the Nation. Both the UMWA and BCOA maintain headquarters in Washington, D. C.

V. DEVELOPMENT OF COAL

The Nation's coal industry began in the 18th century with bituminous coal mined in Virginia and anthracite in Pennsylvania. While coal had been mined commercially since 1750, importance as a fuel was not attributed to coal until the 1800s, wood was still considered a primary fuel for heating homes and fueling furnaces of the fledgling industries of the nation. Petroleum and Petroleum products had not yet entered the picture.

The development of coal as a fuel was limited. However, by the middle of the 19th century a number of small mines produced coal for local consumption. If a locality had access to coal and the mineral could be easily mined, the residents would burn coal in preference to wood although little of the fuel was transported significant distances from the source. The industry could best be characterized as having a large number of extremely small mines supplying very localized markets. Because of the widespread nature of the coal industry, it received little attention unless local labor disputes disrupted the supply of coal for home-heating purposes.

For about a century and a quarter from the first commercial coal mining in this country, about 1758 to 1885, a great industry composed of many small units, was gradually created; one that became largely important in the mineral production as well as in the national economic structure. It always supplied all the fuel the country needed when it was needed and when transport facilities were available, as had been the case also since 1885.

In the second half of the 1880s, came the rapid expansion of industry and the railroad system, and with it began the real growth of the coal industry in the United States. This availability of fuel fostered the growth of energy-consuming industries. The growth of the railroads also encouraged the expansion of the iron and steel industry, which by the 1860s abandoned charcoal in favor of coke for the reduction of iron ore to pig iron. With the advent of the coal-fired steam engine, the railroads became both the major consumers and the major transporters of coal, hauling it from rich coalfields of Appalachia and Illinois to the cities in the Midwest and East where coal soon became the principal fuel for steam-generated electricity. Coal production increased steadily throughout the 19th century. By 1918 the consumption of coal reached a peak, as a great industrial nation depended on it for nearly all energy and heat. This period was the reign of "King Coal". It uses included space heating, coal gas, steam generation and as coke in steel production. New processes permitted the rapid conversion of coal into coke that, mixed with high-grade iron ore from the Mesaba Range in Minnesota, soon turned the United States into a major steel producer.

VI. MINE OWNERSHIP

Coal production has historically been highly fragmented with small producers being an important source of coal. Most of the coal production is centered in the East-North Central part of the United States so are most mines of all size descriptions. The situation has changed dramatically, however. New coal provinces have opened in the West. The operations which have begun to work these deposits tend to be very large scale mines, in part because a large production scale is required to achieve the necessary transportation economies to bring the coal to eastern markets at competitive prices. Electric utilities are currently the sole major user of coal. Large coal producers have a distinct advantage over small coal producers in meeting demands of utilities because the large producers can offer long term supply contracts to utility buyers. In addition, small producers are unable to attain economies in transportation with the use of unit trains as do the large coal producers. As a result, small producers are restricted to dwindling spot market sales of coal. Consequently, changes in the end use pattern of coal has placed small producers at a disadvantage and has allowed large producers to capture increasingly large amounts of the market.

During World War II and immediately thereafter, the great demand for coal and the attendant high prices led to expansion in production capacity in the coal industry. At that time the industry consisted of several large mine operators, who accounted for only a small percentage of the total production, and a large number of small operators, many of them marginal, who were engaged in fierce competition. The boom reached its peak in 1920, when the average value per short ton at the mines reached \$3.75, not including the expenses of selling. Then prices

and employment began to vascillate, violent competition erupted (by 1932 the average value per ton was \$1.31, the lowest since 1916), until the recovery program of the late 1930s when the industry began a slow upward trend. However, it could never quite recover its former peak as the patterns of consumption of fuel changed due to changing technology using oil and gas which became exceedingly more popular.

Since 1960 important transformations have taken place in the coal industry in the United States. These are partly due to the continued expansion in the use of coal by electric generating stations.

The rise in coal production created great coal companies--Peabody, Consolidation, Island Creek, Pittston. They once dominated the coal industry and are still considered among the top 50 coal-producing companies in the United States today.

Changes in the ownership of coal mining companies and coal reserves have taken place over the past years. Entries into the coal mining industry, through acquisition, have been made most significantly by electric utilities and oil companies. Seventy-seven percent of the coal mining companies producing over three million tons annually are controlled by non-coal interests.

For example, during the 60s, most of the large oil companies entered the coal industry. Gulf Oil Company started the movement when it bought Pittsburgh & Midway Coal Mining in 1963. In 1966, Continental Oil Company bought Consolidation Coal Company, then the country's second largest coal producers. Sohio Petroleum Company and Occidental Petroleum Corporation bought major coal companies in 1968, and in that year Ashland Oil Corporation created an affiliate to mine western coal. Exxon Corporation entered the coal market in the late 1960s. By 1974, 17 of the largest oil companies had major interests in coal and the trend is expected to continue.

The President's Commission on Coal in its report determined that by 1976 forty-one percent of the U.S. coal reserves were owned by oil and gas companies. During the period from 1962 through 1975, annual coal production by oil companies grew from 56.4 million tons to 108.0 million tons--an increase of 91.6 percent. The trend toward fewer but larger companies, particularly in the oil and gas group, is expected to continue. These developments have sparked an interest in the subject of coal company acquisition, especially by oil companies.

There is substantial evidence to suggest that large mines have significant advantage over small size operations. The proportion of total coal output accounted for by the fifty largest mines has increased consistently each year since 1947, except for the following years: 1961, 1963, 1969, 1970, 1971, 1974, 1975, 1976 and 1978. During 1978, 785 bituminous and lignite operating companies produced 603,131,389 tons of the 654 million ton total production. Thus, about 22% of the estimated 3,600 such companies in the United States produced 92.20% of the estimated total.

During 1978, 87 bituminous coal organizational groups each produced more than one million tons. These 87 "top" organizations produced 69.28% of the total, as compared with 87 groups with a percentage of 68.88% in 1977. The output of larger operating groups (see Appendix for table of annual production of top bituminous coal operating groups) indicates they have maintained their position of overall production. While the percentage of 60.8 for 1978 is only slightly higher than 1977's, it is based on production decrease of about 37 million tons for the year. The coal strike in the first several months of the year substantially affected annual output of the top producers. Annual production of the top bituminous coal operating groups has increased consistently from 45.5 percent in 1943 to 60.8 percent in 1978.

The largest commercial organization, Peabody Coal Company produced 52,457,891 tons or 8.02 percent of the national total, as compared with 65,425,088 tons or 9.50 percent in 1977. Consolidation Coal Company ranked second with 41,821,000 tons or 6.39 percent of the total. Amax Coal ranked third with 29,787,285 tons with seven others: Island Creek, Arch Mineral, NERCO, Pittston, Western Energy, U.S. Steel and Peter Kiewit exceeding 10 million tons. This is in contrast to 1949, with a total production of 438 million, when only 2 companies exceeded 10 million tons.

The survivor technique*, when applied to coal, confirms the finding that the largest producers have cost advantages. The small operations are less able to take advantage of bulk hauling discounts, trainload unit train rates, volume barge shipment contracts and other economies of scale. Also, it is not always economically feasible for small companies to compete and secure the type of financing required to open up a new, modern, underground or surface mine in the 20th century. Consequently, changes in the end use pattern of coal and the high cost of financing new coal mines has placed small producers at a disadvantage and has allowed large producers to capture increasingly large amounts of the market.

A definite trend exists toward fewer but larger companies. In addition, to the increasing total tonnage produced by the top 50 coal-producing groups, the trend toward larger companies shows up in the various tonnage groups. In comparing 1978 (a large producer year) with 1949 (a small producer year), we find a decrease of 18 percent in the number of companies in the groups producing over 1 million tons. Companies producing over 100,000 tons, while increasing their percentage of total production from 83.15 percent to 92.20 percent declined in number from 836 to 785, or by 6.1 percent from 1949 to 1978.

Meanwhile the number of small companies, i.e., under 100,000 tons per year, continues to fluctuate, but their share of the total has declined from 17.85 percent to 7.80 percent. It should be noted, however, that the total number of companies in the 100,000 to 199,999 group in 1978 was 294, the third largest number since the 301 in 1947, and the 320 in 1977.

Numerous and substantial acquisitions of coal companies and coal reserves by large, diversified corporations have given rise to concern about possible overall, anticompetitive, effects on the coal industry. However, it appears that changing economics of coal production makes it unlikely that the traditional small coal producers will be able to remain competitive. Thus, it is likely that noncoal interests will continue to be attracted to the industry and account for much of the expansion in coal production.

* Relates to the measures taken by coal producers to protect the miners in their workplace.

VII. PRODUCTION

The bituminous coal industry is just now recovering from a slump that has lasted since the mid-40s.

From the late 40s until 1960, the coal industry was struggling to stay alive due to competition with oil and natural gas. Following World War II the use of coal for transportation and home heating was sharply reduced. Inexpensive and plentiful oil and natural gas invaded its residential, railroad, industrial and utility markets. The strategy for survival was to increase productivity through mechanization of the underground mines in the traditional coalfields of the East and Midwest.

From 1950 to 1960, coal production declined 20 percent from 516.3 million tons to 415.5 million tons in 1960. Productivity nearly doubled from 7 to 13 tons daily per miner but not without an awful fall in employment in the industry. In just 10 years time, employment declined 59 percent as 246,000 miners were displaced from the industry leaving a total of 169,400 workers. The stimulation of nuclear electric power reduced coal's role in generating electricity. In 1966 elimination of oil import quotas for residual oil on the East Coast resulted in many large coal users converting to less costly and more convenient foreign oil. The implementation of the Clean Air Act during the 1970s created significant uncertainties as to how much coal would be permitted to be burned and resulted in several large coal users converting to oil. By 1972, coal (14,500 Quadrillion Btu's of 62,805 total energy produced) accounted for about 24 percent of the energy produced by the Nation. In 1978, total energy produced decreased to 6,208 Quadrillion Btu's with coal accounting for 15,037 tons, showing an increase of approximately 1-percent over 1972, or a total of 25 percent.

With all it's problems, coal production increased during the 1960s by 244.4 million tons--a total of 4,890.8 million tons--surpassing the 1950 level of 4,646.4 million tons by mid-decade. Productivity continued to climb and employment to decline. By 1969, employment fell to 125,000 persons--the lowest level in this century. Productivity for all mines, both underground and surface, peaked in 1969 at 19.9 tons per man day. Productivity for underground mining also peaked that year at 15.61 tons per man day. Surface mining productivity, however, continued to increase after 1969 until 1973, when it reached 36.7 tons per man day and then began its decline.

Production continued to increase through the 1970s--an increase of 724.3 million tons during the 1970-1978 period over the 1960s--accompanied by growing employment and declining productivity. The 1970-1979 period was marked by a 28 percent drop in productivity reversing much of the productivity gains of the previous decade.

Coal production has undergone significant shifts since 1945. In general, coal production 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*.

*Alabama, Georgia, Kentucky (Eastern), Maryland, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia.

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 9 percent, respectively. In 1945, only 19 percent of U.S. production was mined using surface methods. By 1972, 49 percent of production was surface mined. This trend toward surface mines occurred in every region of the country. Although the total amount of coal mined increased by 17 million tons between 1945 and 1972, the amount that came from deep mines declined by 164 million tons as the surface production curve climbed. At the end of 1974, more than 80 percent of coal production was from surface mines. Surface production continued to grow faster than deep production, and western production continued to grow faster than eastern production. By 1978, Appalachian production dropped to 55 percent, with interior and western production growing to 22 percent and 23 percent, respectively, only 37 percent of U.S. production was deep mined while U.S. coal production utilizing surface methods increased to 63 percent. Although the total coal mined during the 1972-1978 period increased by 34.3 million tons, the amount that came from deep mines declined by 69.3 million tons and is expected to continue its downward trend for the more popular surface mining method which showed an increase of 103.6 million tons over 291.9 million tons mined in 1972.

In 1978, coal production totaled 660.2 million tons, 5.0 percent less than the 694.8 million tons produced in 1977. The major production loss was attributable to the strike by the United Mine Workers during nearly the entire portion of the first quarter. The 9-week strike against the Norfolk and Western Railway curtailed production during the third quarter. Coal production in the Eastern coalfields (coal-producing states east of the Mississippi River) declined from 529 million tons in 1977 to 476 million tons in 1978. The coal strike had only a slight impact on coal production in western states, output increased 18 million tons, up from 166 million tons in 1977 to 184 million tons in 1978.

In 1978, total domestic coal supply (production, plus imports, minus exports, and plus or minus changes in inventories) exceeded reported domestic consumption by approximately 10 million tons. Nearly all of the supply surplus occurred because of an unprecedented increase in coal stockpiles at minesites. Prior to 1978, mine inventories of coal seldom exceeded 3 million tons. The buildup in mine inventories in 1978 occurred in several states in the Appalachian coalfields, in anticipation of work stoppages (which never materialized) at mines supplying coal under long-term contract and at mines supplying spot market coal under depressed market conditions.

VIII CONSUMPTION

By the turn of the 20th century, coal supplied 90 percent of the U.S. energy consumption, production peaking at approximately 631 million tons in 1947. 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.

**Arkansas, Illinois, Indiana, Iowa, Kansas, Kentucky (Western), Michigan, Missouri, Oklahoma.

***Alaska, Arizona, Colorado, Montana, New Mexico, North Dakota, Oregon, South Dakota, Utah, Washington, Wyoming.

Although total coal consumption in 1972 was roughly the same in 1945, the breakdown of consumption by sector changed. In 1945, the largest consuming sector was Class I railroads, burning 125 million tons. By 1972, railroad consumption of coal dropped so far that the Bureau of Mines discontinued its tracking. Retail consumption totalled 119 million tons in 1945, but only nine million tons in 1972, increasing slightly in 1978 to 10 million or 11.5 percent. The other category, which includes industrial uses, dropped from 148 million tons to 72 million tons during the 1945-1972 period. During the 1975-78 period consumption in this area fluctuated up and down around 62 million tons. The electric utilities section was the only sector to continue its growth during this period, increasing from 72 million tons in 1945 to 394 million in 1972. In the 1975-78 period it reached a high of 480 million tons, an increase of 131 million tons over 1972.

During the 1950s 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 1975. The downward trend in coal consumption during this period reflected the substitution of petroleum and natural gas for coal by electric utilities, in the residential and commercial markets, and for railway transportation. During the 1960s, total coal consumption increased until it hit 586 million tons in 1970. During the early 1970s, coal consumption grew at a reduced rate. Coal consumed in 1972 (12,461 Quadrillion Btu's of 71,643 total energy consumed) accounted for only 17 percent of the energy consumed by the Nation. Total energy consumed increased in 1978 by 6,511 Quadrillion Btu's to 78,154 with coal accounting for 13,965 tons, showing an increase of only .74 percent over 1972, a total of 17.74 percent during the 1972-1978 period.

The percentage of total kilowatt hours generated with coal had been declining since 1965. The major reason for the slowdown in the growth of coal consumption was competition from oil and nuclear power. 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 increased in its share of total power.

The Arab embargo at the end of 1973 together with 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.

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, the Federal Energy Administration initiated a coal conversion program to convert oil-fired utilities to coal. Only 22 units at eleven 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 began to erode.

Along with the above-mentioned constraints, the savings in oil continued to evaporate due to two other important constraints to rapid substitution of coal for oil and gas. One was environmental regulations because 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 was coal supply. While coal is demand-constrained in the long-run, there is cause for concern that 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 additionally important constraints to the rapid substitution of coal for oil and gas were:

- o The capital costs of converting existing boilers to coal and installing pollution control equipment was so high that it was cheaper for a user (all costs considered) to burn oil.
- o It took 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 decreased over 1972 levels. Consumption in 1974 was substantially 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 United Mine Workers work stoppages.

During 1975, the coal market (consumption and production) 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 contrast to expected growth of 5 to 7 percent for the same period. The demand for metallurgical coal, a basic ingredient in steel manufacturing, decreased as steel production dropped. On the other hand, coal production stayed at about 640 million tons, its 1974 rate prior to the United Mine Workers (UMW) work stoppage. As a result, coal users were able to rebuild inventories (drawn down during the UMW work stoppage) to about normal levels.

The Energy Information Administration reported in its March 1979 issue of the Monthly Energy Review that the total 1978 domestic coal supply (production plus imports, minus exports, and plus or minus changes in inventories) exceeded reported consumption by approximately 10 million tons. Nearly all of the supply surplus occurred because of an unprecedented increase in coal stockpiles at minesites. Prior to 1978, mine inventories of coal seldom exceeded 3 million tons. The buildup in mine inventories in 1978 occurred in several states in the Appalachian coalfields in anticipation of work stoppages (which never materialized) at mines supplying coal under long-term contract and at mines supplying spot market coal under depressed market conditions.

Domestic consumption of coal totaled 623.5 million tons in 1978, down 2.2 million tons or 0.4 percent from the amount consumed in 1977. Electric utilities consumed* 481.2 million tons of coal in 1978, 4.1 million tons more than the amount consumed in 1977. Coke plants, the second largest coal consuming sector, used 74.4 in 1978, 6.3 million tons less than the amount consumed in 1977. Total coal consumption by general industry, including shipments to retail dealers, totaled 70.9 million tons, unchanged from demand in 1977.

Following settlement of the coal strike on March 25, 1978, consumer stock levels of coal were restored to normal levels. Total stocks of bituminous coal and lignite increased from 83.8 million tons at the end of March to 141.6 million tons at the end of December. Electric utility stockpiles* of bituminous coal and lignite increased from 74.9 million tons on March 31 to 126.0 million tons on December 31. During this period, bituminous coal stocks held by coke plants increased from 3.8 million tons to 8.2 million tons, and generally industry stockpiles of bituminous coal and lignite increased from 5.0 million tons to 7.1 million tons. Stocks of coal in retail dealer yards increased from 0.1 million tons on March 31, 1978 to 0.4 million tons on December 31.

IX. PRICES

While f.o.b. mine coal prices were relatively unchanged from 1949 to 1969, and only increased moderately from 1970 to 1973, a gradual coal price did occur between 1948 and 1968 due to increased productivity and competitive price pressures from cheap oil and gas**. Many utilities and industries switched from coal to oil and gas. In the latter part of 1973, coal prices began to rise and escalated rapidly after 1974**. Coal prices reflected the state of the market over the 1973-75 period. The Coal Mine Health and Safety Act and declining productivity forced mining costs upward as the coal market firmed in response to steadily rising utility demand. Sharp increases in prices during March-December 1974 were caused by the combined effect of a coal demand increase during the oil embargo, panic buying in anticipation of the UMW strike--in order to replenish low stockpiles exhausted during the 1973-1974 winter--and expectations of a coal boom during 1975-85 (which has yet to materialize). Spot prices reached record levels in November 1974 during the UMW work stoppage. Long-term contract prices were negotiated (and renegotiated) at higher levels due to the tightness of the market and cost increases associated with inflation.

The spot steam coal market declined during 1975-1977 as producers over-expanded during the summer, where they remained for the rest of the year. This drop reflected the easing of the market during 1975. Coal price increases since 1977 have also been tempered by the shift to Western coals which have lower-than-average mine prices; and due to long-term contract buying sometimes the electric utilities price is lower than the reported mine price.

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. This conclusion, however, was inconsistent with observations that coal reserves are vast and the industry is composed of enough

*Includes bituminous, lignite, and anthracite consumption, and excludes petroleum coke consumption. Stocks include bituminous coal and lignite only.

**See accompanying graphs and table on coal prices, pp. 20-22.

Figure 58. Prices of Bituminous Coal and Lignite and Anthracite

NATIONAL COAL PRICES, F.O.B. MINES, 1947-1977

1977\$ TON

DELIVERED PRICE OF UTILITY COAL

1977\$/TON

Source: See accompanying table.

BITUMINOUS COAL PRICES, 1947-1977

(1977 dollars per ton)*

	National Average F.O.B.**	DELIVERED PRICE TO UTILITIES		
		National Average	Contract	Spot
1947	11.85	--	--	--
1948	13.30	--	--	--
1949	13.14	--	--	--
1950	12.78	--	--	--
1951	12.17	--	--	--
1952	11.96	--	--	--
1953	11.83	--	--	--
1954	10.72	--	--	--
1955	10.45	--	--	--
1956	10.85	--	--	--
1957	11.06	--	--	--
1958	10.42	--	--	--
1959	10.00	--	--	--
1960	9.67	--	--	--
1961	9.36	--	--	--
1962	8.99	--	--	--
1963	8.68	--	--	--
1964	8.67	--	--	--
1965	8.46	--	--	--
1966	8.37	--	--	--
1967	8.30	--	--	--
1968	8.01	--	--	--
1969	8.15	--	--	--
1970	9.70	--	--	--
1971	10.43	--	--	--
1972	10.85	--	--	--
1973	11.27	12.06	11.50	14.47
1974	19.22	18.87	14.65	32.41
1975	21.42	19.63	18.10	26.52
1976	20.57	19.46	18.94	22.58
1977	20.50	20.37	19.25	24.99

* GNP implicit price deflators are used in computing the 1977 dollar prices.

** Free on Board: Price of consignment to customer with all costs paid (including cost of loading onto a transportation carrier), not including transportation expenses.

Source: Energy Information Administration.
FPC/FERC: Annual Summary of Cost and Quality of
 Fuels to Electric Plants, 1973-1977.

firms that market forces would 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 even if they have the desire.

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 recent years. However, 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 the Federal Energy Administration (FEA), now the Department of Energy, (e.g., In 1976, FEA estimated the 1985 delivered cost of utility coal to the Middle Atlantic region at about \$30 a ton and the Federal Power Commission, now FERC, reported 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 would be priced equivalent to oil, for which prices did not fall*.

At the end of 1975, the electric utility sector was still the largest consumer of coal (about 403 million tons, or 72 percent of total U.S. bituminous coal and lignite consumption); however, during the 1975-77 period demand increased at a lower-than-expected rate of 3-5% per annum rather than the earlier (1960-1973) rate of 7% per annum. In 1978, coal-fired production increased 6.3 percent above the December 1977 level. Electric utility coal consumption for December 1978 was 43.7 million tons, 5.7 percent above the 1977 rate.

X. EXPORTS/IMPORTS

The years after World War II marked the entry of the United States into the world coal trade on a large-scale permanent basis, even though it had enjoyed a bulge in shipments abroad in World War I.

The emergency of the U.S. as a major exporter of coal overseas--in fact the largest at this time--is one of the major developments of the years since World War II. The U.S. thus took over the role held by Great Britain in the years prior to 1945.

Europe at the end of World War II, with much of its mining capacity ruined and in need of even more energy, looked to the U.S. for its energy resources. The only country able to supply large quantities of coal at reasonable prices at that time was the U.S., and the reconstruction era brought a boom in our shipments abroad.

As Great Britain and the European Continent recovered from the ravages of war, Great Britain became able to step up output and mines were rebuilt on the European Continent. Starting in 1948, bituminous coal shipments from the U.S. slackened, peaked out again in 1957 at 76,446,000 tons, and entered into another expansion in 1962, and steadily increased. Currently, about 54 million tons of coal (8 percent

*See accompanying "National Average Price" table, p. 24.

NATIONAL AVERAGE PRICES OF DELIVERED COAL AND
RESIDUAL OIL TO ELECTRIC UTILITIES
(\$/Million Btu, Current Dollars)
April 1973 - August 1975

	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	.75	.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.

SOURCE: Federal Power Commission Form 423.

of production) are exported from this country. The principal receiving nations are Canada and Japan, which account for 32 percent and 30 percent, respectively, of U.S. export tonnage*.

The satisfactory pace of shipments abroad, as well as previous activity peaks, reflects the fact that the U.S. is fortunate in having ample reserves of the speciality coals--metallurgical and coal gas, for example--which were and are scarce abroad but which are essential for steel-making and for fueling other industrial expansion.

United States coal exports are a major contributor to the nation's balance of trade. In 1976, the value of coal and coke exports from the U.S. was over three billion, including rail transportation to ports of exit. This is almost all a net gain since only a nominal tonnage of coal is imported into the United States. For example, in 1977, the U.S. imported 1.8 million tons of coal. In 1978, 3.0 million tons of coal was imported, an increase of only 1.2 million tons over the amount imported in 1977. Australia and South Africa provided 72 percent of total U.S. coal imports.

In 1977, U.S. exports of bituminous coal totaled over 53 million tons. U.S. exports of anthracite in 1977 amounted to 624,908 net tons, and coke shipments were 1.3 million tons. These figures exclude tonnages going to the U.S. military forces in West Germany.

U.S. exports of coal totaled 40.7 million tons in 1978, 13.6 million below the amount exported in 1977 and 19.3 million tons below the level of exports in 1976.

However, there is evidence that coal markets may be in the process of widening their boundaries beyond the United States. The rapidly rising prices of oil are increasing exports from U.S. coal mines. Exports of metallurgical coal, always substantial, are expected to reach 60 million tons in 1980. The greatest increase in coal exports should come from steam coal, however. Exports of steam coal are expected to grow from 1 million tons in 1979, to 7.5 million tons in 1980, to as much as 80 million tons by 1990. Correspondingly, the prices U.S. users pay for coal will become more sensitive to international demand.

If these expectations materialize, markets of both metallurgical and steam coal may be international by the end of this decade.

XI. CONCLUSION

As a result of my research and discussions with numerous individuals knowledgeable on the subject of coal, it becomes more and more evident that the outlook for coal is continued growth, but the rate of growth will depend on the production and consumption as well as research and development (e.g., U.S. Synthetic Fuels Corporation) of the United States' largest fossil fuel reserves. If electricity continues to grow slowly, growth in coal consumption will be modest. If electricity continues at historical levels (i.e., 7 percent) growth consumption will be substantial. As for production, much will depend on the matter of mine openings and closings as the shift from deep to surface mines continues and the mining trends increase Westward.

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*See accompanying "Exports" graph and chart, pp. 26-27.

BITUMINOUS COAL EXPORTS

Note: Percent figures represent percent shares of total export tonnage.

Source: See accompanying table.

BITUMINOUS COAL EXPORTS, 1945-1977

(million tons)

Year	EXPORTS					Percent of Domestic Production
	Total	To Canada	To Japan	To Europe	Other	
1945	28.0	21.6	-	3.9	2.5	4.8
1950	25.5	23.0	0.2	0.8	1.5	4.9
1955	51.3	17.2	2.8	28.7	2.6	11.0
1960	36.5	11.6	5.6	16.9	2.4	8.8
1965	50.2	15.7	7.5	25.0	2.0	9.8
1966	49.3	15.8	7.8	23.0	2.7	9.2
1967	49.5	15.3	12.2	19.4	2.6	9.0
1968	50.6	16.7	15.8	15.4	2.7	9.3
1969	56.2	16.8	21.4	15.1	2.9	10.0
1970	70.9	18.7	27.6	21.5	3.1	11.6
1971	56.6	17.6	19.7	16.4	2.9	10.3
1972	56.0	18.2	18.0	16.7	3.1	9.4
1973	52.9	16.2	19.2	14.3	3.2	8.9
1974	59.9	13.7	27.3	15.9	3.0	9.9
1975	65.7	16.7	25.4	19.2	4.4	10.1
1976	59.4	16.5	18.8	19.8	4.3	8.8
1977	53.7	17.2	15.9	14.9	5.7	8.0

PROJECTED COAL EXPORTS

(million tons)

		DOE*	EEA
1985	Tonnage	74	50-55
	Percent of Total Production	7%	5%
1990	Tonnage	81	50-55
	Percent of Total Production	6%	4-5%

* DOE mid-level projection assumes medium economic growth and medium availability of energy with constant oil prices.

Source: Bureau of Mines: Minerals Yearbook, 1945-1977.

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Domestic Energy Production (Trillion Btu)

Year	Coal 1/	Crude Oil	Natural Gas Liquids	Natural Gas (Dry)	Hydro Electric 2/	Nuclear Electric	Other 3/	Total
1975	15,189	17,729	2,374	19,641	3,152	1,900	72	60,057
1976	15,853	17,262	2,327	19,480	2,976	2,111	81	60,091
1977	15,964	17,434	2,327	19,565	2,337	2,702	82	60,431
1978	15,117	18,434	2,255	19,524	2,963	2,977	68	61,317
1979	17,762	18,005	2,394	19,164	2,974	2,773	88	63,163

Percentage of Total Btu

1975	25.3	29.5	4.0	32.7	5.3	3.2	0.1	100.0
1976	26.4	28.7	3.9	32.4	5.0	3.5	0.1	100.0
1977	26.4	28.9	3.9	32.4	3.9	4.5	0.1	100.0
1978	24.7	30.1	3.7	31.8	4.8	4.9	0.1	100.0
1979	28.1	28.5	3.8	30.3	4.7	4.4	0.1	100.0

1/ Includes bituminous coal, lignite and anthracite.

2/ Includes industrial and utility production of hydropower.

3/ Includes geothermal power and electricity produced from wood and waste.

Domestic Energy Consumption (Trillion Btu)

Year	Coal 1/	Petroleum	Natural Gas (Dry)	Hydro Electric 2/	Nuclear Electric	Net Coke Imports	Other 3/	Total
1975	12,823	32,732	19,948	3,217	1,900	14	72	70,706
1976	13,733	35,178	20,345	3,065	2,111	-	81	74,513
1977	14,110	37,176	19,931	2,519	2,702	15	82	76,535
1978	14,069	38,014	20,039	3,145	2,977	131	68	78,442
1979	15,213	37,059	19,833	3,156	2,773	64	88	78,187

Percent of Total Btu

1975	18.1	46.3	28.2	4.6	2.7	0.1	0.1	100.0
1976	18.4	47.2	27.3	4.1	2.8	-	0.1	100.0
1977	18.4	48.6	26.0	3.3	3.5	-	0.1	100.0
1978	18.0	48.5	25.4	4.0	3.8	-	0.1	100.0
1979	19.3	47.4	25.4	4.0	3.6	0.2	0.1	100.0

1/ Includes bituminous coal, lignite, and anthracite.

2/ Includes industrial and utility production and net imports of electricity.

3/ Includes geothermal power and electricity produced from wood and waste.

Figure 2. Production of Energy by Type

Energy production in the United States in 1979 totaled 62.80 quadrillion Btu. This represents the fourth consecutive annual increase in U.S. energy production.

Coal production in 1979 increased 15.8 percent from the 1978 level which had been adversely affected by the miner's strike of November 1977 through March

1978. The large increase in coal production offset decreases in all other major sources of production; crude oil decreased 2.2 percent, and natural gas decreased 1.5 percent.

Table 2. Production of Energy by Type, 1949-1979

Year	Coal ¹		Natural Gas ²		Petroleum ³		Natural Gas Plant Liquids		Hydropower ⁴		Nuclear Power		Geothermal		Wood and Waste ⁵		Total Energy Production	Change from Previous Year
	Quadrillion Btu ⁶	Million Short Tons	Quadrillion Btu ⁶	Trillion Cubic Feet	Quadrillion Btu ⁶	Million Barrels	Quadrillion Btu ⁶	Million Barrels	Quadrillion Btu ⁶	Billion kWh ⁷	Quadrillion Btu ⁶	Billion kWh ⁷	Quadrillion Btu ⁶	Billion kWh ⁷	Quadrillion Btu ⁶	Billion kWh ⁷	Quadrillion Btu ⁶	Percent
1949	12.53	480.6	5.33	5.20	10.68	1,842	0.71	157	1.42	94.8	0	0	0	0	0	0	30.73	-14.6
1950	14.62	560.4	6.23	6.02	11.45	1,974	0.82	182	1.42	100.9	0	0	0	0	0	0	34.54	12.4
1951	15.04	576.3	7.42	7.16	13.04	2,248	0.92	205	1.42	104.4	0	0	0	0	0	0	37.83	9.5
1952	13.23	507.4	7.96	7.69	13.28	2,290	1.00	224	1.47	109.7	0	0	0	0	0	0	36.94	-2.4
1953	12.74	488.2	8.35	8.06	13.67	2,357	1.06	239	1.41	109.6	0	0	0	0	0	0	37.23	0.8
1954	10.95	420.8	8.69	8.39	13.43	2,315	1.11	252	1.36	111.6	0	0	0	0	0	0	35.56	-4.5
1955	12.72	480.8	9.34	9.03	14.41	2,484	1.24	281	1.36	116.2	0	0	0	0	0	0	39.08	9.9
1956	13.72	529.8	10.09	9.66	15.18	2,617	1.28	293	1.43	125.2	0	0	0	0	0	0	41.62	6.5
1957	13.42	518.0	10.61	10.25	15.18	2,617	1.29	295	1.52	133.4	0	0	0	0	0	0	42.00	0.9
1958	11.18	431.6	10.94	10.57	14.20	2,449	1.29	295	1.59	143.6	(*)	0.2	0	0	0	0	39.21	-6.7
1959	11.08	432.7	11.96	11.55	14.93	2,575	1.38	321	1.55	141.2	(*)	0.2	0	0	0	0	40.90	4.3
1960	11.12	434.3	12.05	12.23	14.98	2,575	1.46	340	1.60	149.1	0.01	0.5	0	0	(*)	0.1	41.78	2.2
1961	10.73	420.4	13.10	12.66	15.21	2,622	1.55	362	1.65	155.2	0.02	1.7	(*)	0.1	(*)	0.1	42.27	1.2
1962	11.21	439.0	13.72	13.25	15.52	2,676	1.59	373	1.81	171.7	0.03	2.3	(*)	0.1	(*)	0.1	43.88	3.8
1963	12.15	477.2	14.51	14.08	15.97	2,753	1.71	401	1.77	169.0	0.04	3.2	(*)	0.2	(*)	0.1	46.16	5.2
1964	12.83	504.2	15.30	14.82	16.16	2,787	1.80	422	1.89	180.3	0.04	3.3	(*)	0.2	(*)	0.1	48.03	4.1
1965	13.38	527.0	15.78	15.29	16.52	2,849	1.88	442	2.06	197.0	0.04	3.7	(*)	0.2	(*)	0.3	49.67	3.4
1966	13.82	546.8	17.01	16.47	17.56	3,028	2.00	469	2.06	197.9	0.06	5.5	(*)	0.2	(*)	0.3	52.52	5.7
1967	14.19	564.9	17.94	17.39	18.65	3,216	2.18	514	2.35	224.9	0.09	7.7	0.01	0.3	(*)	0.3	55.41	5.5
1968	13.93	556.7	19.07	18.49	19.31	3,329	2.32	550	2.35	225.9	0.14	12.5	0.01	0.4	(*)	0.4	57.13	3.1
1969	14.20	571.0	20.46	19.83	19.56	3,372	2.42	580	2.65	253.5	0.15	13.9	0.01	0.6	(*)	0.3	59.44	4.0
1970	15.05	612.7	21.67	21.01	20.40	3,517	2.51	606	2.63	251.0	0.24	21.8	0.01	0.5	(*)	0.4	62.51	5.2
1971	13.59	500.9	22.28	21.61	20.03	3,454	2.54	618	2.82	269.5	0.41	38.1	0.01	0.5	(*)	0.3	61.70	-1.3
1972	14.49	592.5	22.21	21.62	20.04	3,455	2.60	638	2.86	275.9	0.58	54.1	0.03	1.5	(*)	0.3	62.81	1.8
1973	14.37	598.6	22.19	21.73	19.49	3,361	2.57	634	2.86	275.4	0.51	83.5	0.04	2.0	(*)	0.3	62.43	-0.6
1974	14.47	610.0	21.21	20.71	18.57	3,203	2.47	616	3.18	304.2	1.27	114.0	0.05	2.5	(*)	0.3	61.23	-1.9
1975	15.19	654.6	19.64	19.24	17.73	3,057	2.37	596	3.15	303.2	1.90	172.5	0.07	3.2	(*)	0.2	60.06	-1.9
1976	15.85	684.9	19.48	19.10	17.26	2,976	2.33	587	2.98	286.9	2.11	191.1	0.08	3.6	(*)	0.3	60.09	0.1
1977	15.83	697.2	19.57	19.16	17.45	3,009	2.33	590	2.34	224.0	2.70	250.9	0.08	3.6	(*)	0.5	60.30	0.3
1978	15.04	670.2	19.49	19.12	18.43	3,178	2.25	572	2.96	283.8	2.98	276.4	0.06	3.0	(*)	0.3	61.21	1.5
1979*	17.41	775.8	19.19	18.83	18.02	3,108	2.38	607	2.96	283.4	2.75	255.4	0.08	3.9	0.01	0.5	62.80	2.6

¹ Bituminous coal, lignite, and anthracite.² Dry marketed natural gas.³ Crude oil and lease condensate.⁴ Electric utility and industrial generation of hydropower.⁵ Wood, refuse, and other vegetal fuels consumed by electric utilities. Converted to Btu by applying national average heat rates for fossil fuel steam electric plants. Data do not include wood derived fuel consumed by the pulp and paper industry which amounted to an estimated 1.8 quadrillion Btu in 1978. This table also excludes small quantities of other energy forms for which consistent historical data are not available, such as solar energy obtained by the use of thermal and photovoltaic collectors; wind energy; and geothermal, biomass, and waste energy other than that consumed at electric utilities.⁶ See Units of Measure, Conversion Factors, and Energy Equivalents Section for factors to convert physical unit data into Btu.⁷ See Explanatory Note 6.

* Less than 0.005 quadrillion Btu.

* Preliminary.

Note: Sum of components may not equal total due to independent rounding. All sums and percent changes are calculated from data prior to rounding.

Sources: See source listings for individual fuels on Tables 18, 38, 45, 58, and 59 of this publication.

Source: Energy Information Administration, 1979 Annual Report to Congress

Figure 3. Consumption of Energy by Type

Energy consumption in the United States increased annually from 1960 through 1973. After decreases in 1974 and 1975, consumption again increased in 1976, 1977, and 1978. Preliminary data indicated that a small decrease occurred in 1979. Petroleum has grown from 38.3 percent share of U.S. total energy consumption in 1949 to 48.7 percent in 1977; the preliminary 1979 estimate is 47.5 percent. Coal dropped from 40.6 percent of total energy consumption in 1949 to

19.3 percent in 1979. Natural gas increased its share from 16.6 percent in 1949 to 25.5 percent in 1979. Energy from other sources (hydropower, nuclear, and electricity produced from geothermal power and wood and waste, and net imports of coal coke) accounted for only 4.7 percent of total energy consumption in 1949 and 7.7 percent in 1979.

Table 3. Consumption of Energy by Type, 1949-1979

Year	Coal ¹		Natural Gas (Dry)		Petroleum ²		Hydropower ³		Nuclear Power		Geothermal		Wood and Waste ⁴		Net Imports of Coal Coke		Total Energy Consumption	Change from Previous Year
	Quadrillion Btu ⁵	Million Short Tons	Quadrillion Btu ⁵	Trillion Cubic Feet	Quadrillion Btu ⁵	Million Barrels	Quadrillion Btu ⁵	Billion Barrels	Quadrillion Btu ⁵	Billion kWh	Quadrillion Btu ⁵	Billion kWh	Quadrillion Btu ⁵	Billion kWh	Quadrillion Btu ⁵	Thousand Short Tons	Quadrillion Btu ⁵	Percent ⁶
1949	12.60	483.2	5.15	4.97	11.89	2,104	1.45	96.4	0	0	0	0	0	0	-0.01	-269	31.08	-5.7
1950	12.89	494.1	5.97	5.77	13.32	2,357	1.44	102.7	0	0	0	0	0	0	(⁷)	40	33.62	8.2
1951	13.20	505.9	7.05	6.81	14.43	2,561	1.45	106.6	0	0	0	0	0	0	-0.02	-865	36.11	7.4
1952	11.84	454.1	7.55	7.29	14.96	2,661	1.50	112.0	0	0	0	0	0	0	-0.01	-479	35.83	-0.8
1953	11.87	454.8	7.91	7.64	15.56	2,774	1.44	111.6	0	0	0	0	0	0	-0.01	-363	36.78	2.6
1954	10.17	389.9	8.33	8.05	15.85	2,831	1.39	114.0	0	0	0	0	0	0	-0.01	-272	35.73	-2.8
1955	11.52	447.0	9.00	8.69	17.26	3,086	1.41	120.3	0	0	0	0	0	0	-0.01	-405	39.18	9.6
1956	11.72	456.9	9.61	9.29	17.95	3,212	1.49	129.8	0	0	0	0	0	0	-0.01	-525	40.76	4.0
1957	11.14	434.5	10.19	9.85	17.94	3,215	1.56	137.0	0	0	0	0	0	0	-0.02	-704	40.81	0.1
1958	9.83	385.7	10.66	10.30	18.54	3,328	1.63	146.9	(⁷)	0.2	0	0	0	0	-0.01	-271	40.65	-0.4
1959	9.79	385.1	11.72	11.32	19.33	3,477	1.59	144.7	(⁷)	0.2	0	0	0	0	-0.01	-337	42.42	4.3
1960	10.12	398.0	12.39	11.97	19.92	3,586	1.65	153.7	0.01	0.5	(⁷)	0	(⁷)	0.1	-0.01	-227	44.08	3.9
1961	9.89	390.3	12.93	12.49	20.22	3,641	1.68	157.5	0.02	1.7	(⁷)	0.1	(⁷)	0.1	-0.01	-318	44.73	1.5
1962	10.17	402.2	13.73	13.27	21.05	3,796	1.82	172.2	0.03	2.3	(⁷)	0.1	(⁷)	0.1	-0.01	-222	46.80	4.6
1963	10.69	423.5	14.40	13.97	21.70	3,921	1.77	169.1	0.04	3.2	(⁷)	0.2	(⁷)	0.1	-0.01	-298	48.61	3.9
1964	11.25	445.7	15.29	14.81	22.30	4,034	1.91	182.3	0.04	3.3	(⁷)	0.2	(⁷)	0.1	-0.01	-421	50.78	4.5
1965	11.89	472.0	15.77	15.28	23.25	4,202	2.06	196.8	0.04	3.7	(⁷)	0.2	(⁷)	0.3	-0.02	-744	52.99	4.4
1966	12.48	497.7	17.00	16.45	24.40	4,411	2.07	199.0	0.06	5.5	(⁷)	0.2	(⁷)	0.3	-0.03	-1,006	55.99	5.7
1967	12.24	491.4	17.94	17.39	25.28	4,585	2.34	224.6	0.09	7.7	0.01	0.3	(⁷)	0.3	-0.02	-618	57.89	3.4
1968	12.66	509.8	19.21	18.63	26.98	4,902	2.34	225.2	0.14	12.5	0.01	0.4	(⁷)	0.4	-0.02	-698	61.32	5.9
1969	12.72	516.4	20.68	20.06	28.34	5,160	2.66	254.5	0.15	13.9	0.01	0.6	(⁷)	0.3	-0.04	-1,456	64.53	5.2
1970	12.66	523.2	21.79	21.14	29.52	5,364	2.65	252.9	0.24	21.8	0.01	0.5	(⁷)	0.4	-0.06	-2,325	66.83	3.6
1971	12.01	501.6	22.47	21.79	30.56	5,553	2.86	273.1	0.41	38.1	0.01	0.5	(⁷)	0.3	-0.03	-1,335	68.90	2.2
1972	12.45	524.3	22.70	22.10	32.95	5,990	2.94	283.6	0.58	54.1	0.03	1.5	(⁷)	0.3	-0.03	-1,047	71.63	4.9
1973	13.90	562.6	22.51	22.05	34.84	6,317	3.01	289.7	0.91	83.5	0.04	2.0	(⁷)	0.3	-0.01	-317	74.61	4.2
1974	12.88	558.4	21.73	21.22	33.45	6,078	3.31	316.9	1.27	114.0	0.05	2.5	(⁷)	0.3	0.06	2,262	72.76	-2.5
1975	12.82	562.6	19.95	19.54	32.73	5,958	3.22	309.3	1.90	172.5	0.07	3.2	(⁷)	0.2	0.01	546	70.71	-2.8
1976	13.73	603.8	20.35	19.95	35.17	6,391	3.07	295.5	2.11	191.1	0.08	3.6	(⁷)	0.3	(⁷)	-4	74.51	5.4
1977	13.96	625.3	19.93	19.52	37.18	6,727	2.52	241.4	2.70	250.9	0.08	3.6	0.01	0.5	0.02	588	76.39	2.5
1978	13.85	625.2	20.00	19.63	37.97	6,879	3.17	303.6	2.98	276.4	0.06	3.0	0	0.3	0.13	5,029	78.15	2.3
1979 ⁸	15.08	680.9	19.86	19.49	37.02	6,707	3.16	303.1	2.75	255.4	0.08	3.9	0.01	0.5	0.07	2,534	78.02	-0.2

¹ Bituminous coal, lignite, and anthracite² Refined petroleum products supplied including natural gas plant liquids and crude oil burned as fuel³ Electric utility and industrial generation of hydropower and net electricity imports⁴ Wood, refuse, and other residual fuels consumed by electric utilities. Converted to Btu by applying national average heat rates for fossil fuel steam electric plants. Data do not include wood derived fuel consumed by the pulp and paper industry which amounted to an estimated 1.0 quadrillion Btu in 1978. This table also excludes small quantities of other energy forms for which consistent historical data are not available, such as solar energy obtained by the use of thermal and photovoltaic collectors, wind energy, and geothermal, biomass, and waste energy other than that consumed at electric utilities⁵ See Units of Measure, Conversion Factors, and Energy Equivalents Section for factors to convert physical unit data into Btu⁶ Percent change calculated from data prior to rounding⁷ Less than 0.055 quadrillion Btu⁸ Preliminary

Note: Sum of components may not equal total due to independent rounding

Source: See source listings for individual fuels on Tables 18, 28, 46, 48, 56, 58, and 59 of this publication.

Source: Energy Information Administration, 1979 Annual Report to Congress.

Energy Consumption, by Major Source and Economic Sector (Quad Btu)

<u>Sector/Source</u>	<u>Coal 1/</u>	<u>Petro- leum</u>	<u>Natural Gas (Dry)</u>	<u>Non- Fossil 2/</u>	<u>Electricity</u>		<u>Total</u>
					<u>Distrib- uted</u>	<u>Loss Dist.</u>	
<u>Residential & Commercial</u>							
1975	0.248	5.870	7.581	-	3.584	8.729	25.981
1976	0.234	6.290	7.866	-	3.725	9.060	27.180
1977	0.234	6.327	7.462	-	3.932	9.589	27.545
1978	0.265	6.423	7.679	-	4.090	10.105	28.563
1979	0.242	6.663	7.991	-	4.166	10.218	29.280
<u>Industrial</u>							
1975	3.786	5.929	8.532	0.044	2.304	5.613	26.207
1976	3.773	6.682	8.768	0.033	2.525	6.144	27.924
1977	3.612	7.552	8.641	0.052	2.635	6.431	28.923
1978	3.433	7.666	8.518	0.167	2.731	6.752	29.266
1979	3.558	7.952	7.702	0.101	2.848	6.984	29.146
<u>Transportation</u>							
1975	0.001	17.872	0.595	-	0.015	0.035	18.518
1976	-	18.799	0.559	-	0.015	0.036	19.408
1977	-	19.476	0.543	-	0.014	0.035	20.068
1978	-	20.017	0.546	-	0.015	0.037	20.614
1979	-	19.180	0.529	-	0.015	0.036	19.760
<u>Total End Use</u>							
1975	4.035	29.640	16.708	0.044	5.903	14.377	70.706
1976	4.012	31.771	17.193	0.033	6.265	15.240	74.513
1977	3.846	33.355	16.646	0.052	6.581	16.055	76.536
1978	3.693	34.106	16.743	0.167	6.836	16.894	78.442
1979	3.800	33.795	16.222	0.101	7.029	17.238	78.187
<u>Utility Fuels</u>							
1975	8.788	3.092	3.241	5.159 3/	-	-	20.280
1976	9.720	3.407	3.153	5.224 3/	-	-	21.505
1977	10.264	3.821	3.285	5.266 3/	-	-	22.636
1978	10.372	3.908	3.297	6.154 3/	-	-	23.730
1979	11.412	3.264	3.611	5.892 3/	-	-	24.267
<u>Total Fuel Use</u>							
1975	12.823	32.732	19.948	5.203	-	-	70.706
1976	13.733	35.178	20.345	5.257	-	-	74.513
1977	14.110	37.176	19.931	5.318	-	-	76.536
1978	14.069	38.014	20.039	6.321	-	-	78.442
1979	15.213	37.059	19.833	6.081	-	-	78.187

1/ Includes Bituminous, Anthracite, Lignite.

2/ Includes hydro power & net coke imports.

3/ Includes nuclear power, hydro power, and others.

Source: Energy Information Administration, Department of Energy.

Energy Consumption by Major Source and Economic Sector
(Continued)
As a Percent of Total Btu

Sector and Year	Coal	Petroleum	Natural Gas (Dry)	Non-Fossil	Electricity		Total
					Distributed	Loss Dist.	
<u>Residential and Commercial:</u>							
1975	1.0	22.5	29.2	-	13.8	33.6	100.0
1976	0.9	23.2	28.9	-	13.7	33.3	100.0
1977	0.8	23.0	27.1	-	14.3	34.8	100.0
1978	0.9	22.5	26.9	-	14.3	35.4	100.0
1979	0.8	22.8	27.3		14.2	34.9	100.0
<u>Industrial:</u>							
1975	14.5	22.6	32.6	0.2	8.8	21.4	100.0
1976	13.5	23.9	31.4	0.1	9.1	22.0	100.0
1977	12.5	26.1	29.9	0.2	9.1	22.2	100.0
1978	11.7	26.2	29.1	0.6	9.3	23.1	100.0
1979	12.2	27.3	26.4	0.4	9.8	24.0	100.0
<u>Transportation:</u>							
1975	-	96.5	3.2	-	0.1	0.2	100.0
1976	-	96.9	2.9	-	0.1	0.2	100.0
1977	-	97.1	2.7	-	0.1	0.2	100.0
1978	-	97.1	2.6	-	0.1	0.2	100.0
1979	-	97.1	2.7	-	0.1	0.2	100.0

Domestic Energy Consumption by Primary Energy Type

Domestic Energy Consumption, by Economic Sector (Trillion Btu)

<u>Year</u>	<u>Residential/ Commercial</u>	<u>Industrial</u>	<u>Transportation</u>	<u>Total</u>
1975	25,981	26,207	18,518	70,706
1976	27,180	27,924	19,408	74,513
1977	27,545	28,923	20,068	76,536
1978	28,563	29,266	20,614	78,442
1979	29,280	29,146	19,760	78,186

Percent of Total

1975	36.8	37.1	26.2	100.0
1976	36.5	37.5	26.1	100.0
1977	36.0	37.8	26.2	100.0
1978	36.4	37.3	26.3	100.0
1979	37.5	37.3	25.3	100.0

Table 45. Coal Supply and Disposition, 1949-1979
(Million Short Tons)

Year	Supply					Disposition			
	Production			Imports	Change in Consumers' Stocks, Losses, and Unaccounted for ¹	Total	Exports ²	Consumption	Total
	Underground	Surface	Total						
1949	358.9	121.7	480.6	0.3	35.1	516.0	32.8	483.2	516.0
1950	421.0	139.4	560.4	0.4	-37.3	523.5	29.4	494.1	523.5
1951	442.2	134.2	576.3	0.3	-8.1	568.6	62.7	505.9	568.6
1952	381.2	126.3	507.4	0.3	-1.4	506.3	52.2	454.1	506.3
1953	367.4	120.8	488.2	0.3	2.8	491.3	36.5	454.8	491.3
1954	306.0	114.8	420.8	0.2	2.8	423.8	33.9	389.9	423.8
1955	358.0	132.9	490.8	0.3	10.3	501.4	54.4	447.0	501.4
1956	380.8	148.9	529.8	0.4	0.5	530.7	73.8	456.9	530.7
1957	373.6	144.5	518.0	0.4	-3.2	515.2	80.8	434.5	515.3
1958	297.6	134.0	431.6	0.3	6.4	438.3	52.6	385.7	438.3
1959	292.8	139.8	432.7	0.4	-9.0	424.1	39.0	385.1	424.1
1960	292.6	141.7	434.3	0.3	1.4	436.0	38.0	398.0	436.0
1961	279.6	140.9	420.4	0.2	6.1	426.7	36.4	390.3	426.7
1962	287.9	151.1	439.0	0.2	4.1	443.3	41.2	402.2	443.3
1963	309.0	168.2	477.2	0.3	-2.7	474.8	51.3	423.5	474.8
1964	327.7	176.5	504.2	0.3	-7.9	496.6	50.9	445.7	496.6
1965	338.0	189.0	527.0	0.2	-3.0	524.1	52.2	472.0	524.1
1966	342.6	204.2	546.8	0.2	1.6	548.6	50.8	497.7	548.6
1967	352.4	212.5	564.9	0.2	-22.7	542.4	51.0	491.4	542.4
1968	346.6	210.1	556.7	0.2	4.9	561.8	52.0	509.8	561.8
1969	349.2	221.7	571.0	0.1	3.2	574.3	57.9	516.4	574.3
1970	340.5	272.1	612.7	(³)	-17.0	595.7	72.4	523.2	595.7
1971	277.2	283.7	560.9	0.1	-1.4	559.6	58.0	494.2	552.3
1972	305.0	297.4	602.5	(³)	-21.1	581.5	57.2	524.3	581.5
1973	300.1	298.5	598.6	0.1	17.9	516.6	54.0	562.6	616.6
1974	278.0	332.1	610.0	2.1	7.4	519.5	61.1	558.4	619.5
1975	293.5	361.2	654.6	0.9	-26.2	529.4	66.8	562.6	629.4
1976	295.5	389.4	684.9	1.2	-21.7	564.4	60.6	603.8	664.4
1977	266.6	430.6	697.2	1.6	-18.8	580.0	54.7	625.3	680.0
1978	242.8	427.4	670.2	3.0	-7.0	566.2	41.0	625.2	666.2
1979 ⁴	302.0	473.7	775.8	2.1	-30.6	747.2	66.3	680.9	747.2

¹ Includes changes in stocks at electric utilities, coke plants, other industries, and retail dealers and the balancing item of losses and unaccounted for. Net additions to stocks are considered as negative numbers.

² Includes small quantities of anthracite shipped overseas to U.S. Armed Forces.

³ Less than 0.05 million short tons.

⁴ Preliminary.

Note: Sum of components may not equal total due to independent rounding.

Sources: • 1949 through 1975—U.S. Department of the Interior, Bureau of Mines, *Minerals Yearbook*, "Bituminous Coal and Lignite" chapter; Federal Power Commission, Form 4, *Monthly Power Plant Report*. U.S. Department of the Interior, Bureau of Mines, *Minerals Yearbook*, "Coal—Pennsylvania Anthracite" chapter. • 1975 through 1979—U.S. Department of Energy, Energy Information Administration, *Production of Coal, Bituminous and Lignite*, weekly. U.S. Department of Energy, Energy Information Administration, Federal Power Commission, Form 4, *Monthly Power Plant Report*.

Source: Energy Information Administration, *Annual Report to Congress*, Vol. II, 1979

NATIONAL SUMMARY

Supply and Demand (1,000 Net Tons) 1916-1979

<u>Year</u>	<u>Production</u>	<u>Imports</u>	<u>Total Available</u>	<u>Domestic Consumption</u>	<u>Exports</u>	<u>Total Consumption</u>
1916	502,520	1,898	504,418	493,979	21,255	515,234
1917	551,791	1,449	553,240	529,409	23,840	553,249
1918	579,386	1,480	580,866	530,593	22,351	552,944
1919	465,860	1,024	466,884	481,658	20,114	501,772
1920	568,667	1,262	569,929	508,595	38,517	547,112
1921	415,922	1,285	417,207	391,849	23,131	414,980
1922	422,268	5,089	427,357	426,915	12,413	439,328
1923	564,565	1,882	566,447	518,993	21,454	540,447
1924	483,687	417	484,104	484,004	17,100	501,104
1925	520,053	602	520,655	499,193	17,462	516,655
1926	573,367	534	573,901	532,581	35,272	567,853
1927	517,763	550	518,313	499,801	18,012	517,813
1928	500,745	559	501,304	498,828	16,164	514,992
1929	534,989	495	535,484	519,555	17,429	536,984
1930	467,527	241	467,768	454,990	15,877	470,867
1931	382,089	206	382,295	371,869	12,126	383,995
1932	309,710	193	309,903	306,917	8,814	315,731
1933	333,631	249	333,880	317,685	9,037	326,722
1934	359,368	180	359,548	343,814	10,869	354,683
1935	372,373	202	372,575	356,326	9,742	366,068
1936	439,088	272	439,360	408,293	10,655	418,948
1937	445,531	258	445,789	430,777	13,145	443,922
1938	348,545	241	348,786	336,281	10,490	346,771
1939	394,855	359	395,214	376,098	11,590	387,888
1940	460,772	372	461,144	430,910	16,466	447,766
1941	514,149	348	514,497	492,115	20,740	512,855
1942	582,693	498	583,191	540,050	22,943	562,993
1943	590,177	758	590,935	593,797	25,836	619,633
1944	619,576	634	620,210	589,599	26,032	615,631
1945	577,617	467	578,084	559,567	27,956	587,523
1946	533,922	435	534,357	500,386	41,197	541,583
1947	630,624	290	630,914	545,891	68,667	614,558
1948	599,518	291	599,809	519,909	45,930	565,839
1949	437,868	315	438,183	445,538	27,842	473,380
1950	516,311	347	516,658	454,202	25,468	479,670
1951	533,665	292	533,957	468,904	56,722	525,626
1952	466,841	262	467,103	418,757	47,643	466,400
1953	457,290	227	457,517	426,798	33,760	460,558
1954	391,706	199	391,905	363,060	31,041	394,101
1955	464,633	337	464,970	423,412	51,277	474,689
1956	500,874	356	501,230	432,858	68,553	501,411
1957	492,704	367	493,071	413,668	76,446	490,114
1958	410,446	307	410,753	366,703	50,293	416,996
1959	412,028	375	412,403	366,256	37,253	403,509
1960	415,512	260	415,772	380,429	36,541	416,970
1961	402,977	164	403,141	374,405	34,970	409,375
1962	422,149	232	422,381	387,774	38,413	426,187
1963	458,928	267	459,195	409,225	47,078	456,303
1964	486,998	293	487,291	431,116	47,696	478,812
1965	512,088	184	512,272	459,164	50,181	509,345
1966	533,881	178	534,059	486,266	49,302	535,568
1967	552,626	227	552,853	480,416	49,528	529,944
1968	545,245	224	545,469	498,830	50,637	549,467
1969	560,505	109	560,614	507,275	56,234	563,509
1970	602,932	36	602,968	515,619	70,944	586,563
1971	552,192	111	552,303	494,862	56,633	551,495
1972	595,386	47	595,433	516,776	55,997	572,773
1973	591,738	127	591,865	556,022	52,870	608,892
1974	603,406	2,080	605,486	552,709	59,926	612,635
1975	648,438	940	649,378	556,301	65,669	621,970
1976	678,685	1,203	679,888	598,750	59,406	658,156
1977	691,344	1,803	693,147	620,487	53,687	674,174
1978	665,127	2,953	668,080	621,330	39,825	661,155
1979 p/	770,000	2,059	772,059	676,650	64,783	741,433

p/ Preliminary

Figure 48. Coal Supply and Disposition

From 1949 through 1959, domestic coal consumption declined 98 million short tons, and coal production declined only 48 million short tons. This difference was accompanied by large increases in coal stockpiled at electric utilities. From 1959 through 1969, coal consumption increased at an average annual rate of 2.7 percent. During this period, coal produced from underground mines increased

66 million short tons while production from surface mines increased nearly 82 million short tons. Coal consumption increased at an average annual rate of 2.5 percent between 1969 and 1979. From 1970 through 1979, coal production from surface mines increased 202 million short tons, whereas production at underground mines declined 39 million short tons.

Source: Energy Information Administration, Annual Report to Congress, Vol. II, 1979

**Figure 18. Coal Supply and Disposition,
Recent Years Average
(Relative Percentages of Major Segments)**

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NATIONAL SUMMARY

BLS Productivity¹ Indices for Bituminous Coal Mining and Selected Industries (1967 = 100)

<u>Year</u>	<u>Bituminous Coal Mining ^{2/}</u>	<u>Total Mining Industries</u>	<u>Total Manufacturing Industries</u>	<u>Non-Farm Business Sector</u>
1974	83.9	96.6	116.5	106.2
1975	72.1	89.2	114.9	108.6
1976	70.8	85.0	122.4	112.2
1977	69.0	80.3	126.1	115.8
1978	74.7	85.0	128.0	116.8

na - Not available

^{1/} Output per employee-hour for both production and non-production workers.

^{2/} For production workers only.

Source: Bureau of Labor Statistics.

PRODUCTIVITY TRENDS BY METHOD OF MINING, 1948-1978

1948-1978	Annual increase rate of	(+) 2.8%
1960-1978	Annual increase rate of	(+) 0.9%
Since 1969	Productivity decreasing at annual rate of	(-) 4.1%

Source: Energy Information Administration, Annual Report to Congress, Vol. II, 1978.

Bituminous Coal Production by Method of Mining (1,000 Net Tons)

<u>Year</u>	<u>underground</u>		<u>Surface</u>		<u>Total Production</u>
	<u>Quantity</u>	<u>% of Total</u>	<u>Quantity</u>	<u>% of Total</u>	
1974	277,309	46.0	326,097	54.0	603,406
1975	292,826	45.2	355,612	54.8	648,438
1976	294,880	43.4	383,805	56.6	678,685
1977	265,950	38.4	425,394	61.6	691,344
1978	242,177	36.4	422,950	63.6	665,127

COAL PRODUCTION BY REGION AND MINING METHOD, 1945-1972-1978

		<u>Appalachia*</u>			<u>Interior**</u>			<u>Far West***</u>			<u>National</u>		
		<u>Surface</u>	<u>Deep</u>	<u>Total</u>	<u>Surface</u>	<u>Deep</u>	<u>Total</u>	<u>Surface</u>	<u>Deep</u>	<u>Total</u>	<u>Surface</u>	<u>Deep</u>	<u>Total</u>
1978****	Million Tons	168.0	175.8	334.0	99.5	43.5	143.0	127.2	15.4	142.6	394.7	234.7	629.4
	Percent	49	51	100	70	30	100	89	11	100	63	37	100
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	336.1	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.

**** Totals may not add up due to rounding.

Source: Bureau of Mines
EIA-7

**Figure 17. Coal Production By Region and
By Type of Mining, 1960-1978**
(Million Short Tons)

Figure 19. Regional Patterns of Coal Production, 1976-1978

Tons Produced

Number of Mines

SOURCE: President's Commission on Coal, Coal Data Book, February 1980.

Source: See accompanying table.

U.S. COAL* PRODUCTION BY STATES AND METHOD OF MINING, 1977

(thousand tons)

		UNDERGROUND		SURFACE		Total
		Tons	Percent of Total	Tons	Percent of Total	
WEST	Alaska	--	--	665	100	665
	Arizona	--	--	11,475	100	11,475
	Colorado	4,205	35	7,715	65	11,920
	Montana	--	--	29,320	100	29,320
	New Mexico	--	--	11,255	100	11,255
	North Dakota	--	--	12,165	100	12,165
	Utah	9,240	100	--	--	9,240
	Washington	--	--	5,055	100	5,055
	Wyoming	--	--	44,500	100	44,500
Total		13,445	10	122,150	90	135,595
MIDWEST	Arkansas	20	4	550	96	570
	Illinois	29,590	55	24,290	45	53,880
	Indiana	525	2	27,470	98	27,995
	Iowa	--	--	525	100	525
	Kansas	--	--	630	100	630
	Kentucky, W.	23,010	45	27,785	55	50,795
	Missouri	--	--	6,625	100	6,625
	Oklahoma	--	--	5,345	100	5,345
	Texas	--	--	16,765	100	16,765
Total		53,145	23	109,985	67	163,130
APPALACHIA	Alabama	6,580	31	14,640	69	21,220
	Georgia	--	--	185	100	185
	Kentucky, E.	41,005	44	51,145	56	92,150
	Maryland	260	8	3,030	92	3,290
	Ohio	13,925	30	32,280	70	46,205
	Pennsylvania	38,365	46	44,860	54	83,225
	Tennessee	4,675	45	5,645	55	10,320
	Virginia	26,200	69	11,650	31	37,850
	West Virginia	74,030	78	21,375	22	95,405
Total		205,040	53	184,810	47	389,850
TOTAL U.S.		271,630	39	416,945	61	688,575

* Bituminous coal and lignite.

Source: Energy Information Administration.

Employment & Productivity

<u>Year</u>	<u>Employment</u> <u>(Daily Average)</u>	<u>Average Output</u> <u>Per Person Per Day</u> <u>(Net Tons)</u>	<u>Average No.</u> <u>Days Worked</u>
1974	164,701	17.38	206
1975	189,880	14.74	232
1976	202,280	14.44	232
1977	221,428	14.84	210
1978	223,300	14.28	207

Price Indicators

<u>Year</u>	<u>Underground</u> <u>Mines</u>	<u>Surface</u> <u>Mines</u>	<u>All</u> <u>Mines</u>	<u>Sold in</u> <u>Open</u> <u>Market</u>	<u>Not Sold in</u> <u>Open Market</u>	<u>At Merchant</u> <u>Coke Ovens</u>	<u>Average Delivery</u> <u>Price at Steam</u> <u>Electric Plants</u> <u>(\$/Million Btu)</u>
1974	19.86	12.25	15.75	15.16	19.86	34.20	0.71
1975	26.28	13.43	19.23	18.02	26.99	52.23	0.81
1976	27.10	14.00	19.43	18.90	na	54.48	0.85
1977	28.25	14.56	19.82	19.11	24.93	57.33	0.95
1978	30.94	16.53	21.78	na	na	56.68	1.12

1/ Preliminary.

na - not available

Source: U.S. Dept. of Energy

U.S. COAL INDUSTRY EMPLOYMENT, 1950-1978

PERSONS WORKING DAILY	(thousands)	483	260	190	149	144	162	147	177	218	215	230	241
YEAR		1950	1955	1960	1965	1970	1972	1973	1974	1975	1976	1977	1978
MAN- HOURS WORKED	(millions)	711	419	282	249	260	268	278	297	368	383	391	367

Source: Mine Safety and Health Administration.

President's Commission on Coal, Coal Data Book, February 1980

U.S. COAL INDUSTRY EMPLOYMENT BY MINING METHOD AND REGION, 1969-1978

Source: Mine Safety and Health Administration
President's Commission on Coal

**EARNINGS* — BITUMINOUS COAL INDUSTRY AND OTHER MAJOR INDUSTRIES,
1948-1978
(1977 dollars per hour)****

* Earnings are hourly averages for the year, except for 1978 figures, which are hourly earnings for October, 1978.

** GNP implicit price deflators are used in computing 1977 dollar wages.

Source: Bureau of Labor Statistics.

President's Commission on Coal

Figure 58. Prices of Bituminous Coal and Lignite and Anthracite

F.O.B. mine coal prices were relatively unchanged from 1949 to 1969, and only increased moderately from 1970 to 1973. Prices rose rapidly after 1974. Coal price increases since 1977 have been tempered by the shift to Western coals which

have lower-than-average mine prices. Because of the long-term contract buying by electric utilities, their price is sometimes lower than the reported mine price.

Source: Energy Information Administration, Annual Report to Congress, Vol. II, 1979

NATIONAL SUMMARY

The 50 Largest Bituminous Mines in 1978

NAME OF MINE	COMPANY	STATE	Year In Operation	PRODUCTION		% Change 1978/1977
				1978	1977	
Belle Ayr (S)	AMAX Coal Co.	1 Wyo	1972	18,065,864	13,331,844	+ 35.5%
Rosebud (S) (C)	Western Energy Co.	2 Mont	1968	10,576,000	9,773,676	+ 8.2
Decker Nos. 1 & 2 (S)	Decker Coal Co.	3 Mont	1972	9,073,592	10,390,421	- 12.7
Navajo (S)	Utah International Inc.	4 N.M.	1963	8,000,000	6,900,000	+ 15.9
Kayenta (S)	Peabody Coal Co.	5 Ariz	1974	6,771,768	6,897,578	- 1.8
Jim Bridger (S)	Bridger Coal Co.	6 Wyo.	1973	5,175,540	5,448,953	- 5.0
Centralia (S) (C)	Washington Irr. & Devel. Co.	7 Wash.	1970	4,700,000	4,955,242	- 5.2
River King (D&S)	Peabody Coal Co.	8 Ill.	1957	4,597,514	4,521,969	+ 1.7
Elkol-Sorenson (S)	Kemmerer Coal Co.	9 Wyo	1963	4,061,794	4,385,147	- 7.4
Cordero (S)	Sunoco Energy Devel. Co.	10 Wyo.	1976	3,800,000	2,128,545	+ 78.5
Glenharold (S)	Consolidation Coal Co., Western Reg.	11 N.D.	1965	3,686,094	3,382,000	+ 9.0
Center (S)	Baukol-Noonan Inc.	12 N.D.	1973	3,400,000	1,791,273	+ 89.8
Dave Johnston (S) (C)	Glenrock Coal Co.	13 Wyo.	1958	3,326,616	3,326,616	-
Captain (S)	Southwestern Illinois Coal Corp.	14 Ill.	1964	3,200,000	3,100,000	+ 3.2
Medicine Bow (S)	Arch Mineral Corp.	15 Wyo.	1975	3,100,000	2,800,000	+ 10.7
McKinley (S)	Pittsburg & Midway Coal Mining Co.	16 N.M.	1959	2,992,958	1,369,199	+ 118.6
Energy No. 1 (S)	Energy Fuels Corp.	17 Colo.	1962	2,909,272	3,048,584	- 4.6
Gascoyne (S) (C)	Knife River Coal Mining Co.	18 N.D.	before 1950	2,871,839	2,520,363	+ 14.0
Rosebud (S)	Rosebud Coal Sales Co.	19 Wyo.	1962	2,868,048	2,708,888	+ 5.9
Big Horn (S)	Big Horn Coal Co.	20 Wyo.	before 1950	2,838,862	2,394,532	+ 18.6
Seminole NO. 2 (S)	Arch Mineral Corp.	21 Wyo.	1971	2,800,000	2,800,000	-
Sinclair (D&S)	Peabody Coal Co.	22 Ky. W.	1962	2,655,851	3,625,599	- 26.8
Rawhide (S)	Carter Mining Co.	23 Wyo.	1975	2,620,000	1,000,000	+ 162.0
San Juan (S)	Western Coal Co.	24 N.M.	1974	2,613,030	2,186,637	+ 19.5
Abasloka (S)	Westmoreland Resources, Inc.	25 Mont.	1974	2,554,201	4,529,053	- 43.6
Lynnville (S)	Peabody Coal Co.	26 Ind.	1955	2,552,602	3,365,003	- 75.9
Muskingum (S) (C)	Central Ohio Coal Co.	27 Ohio	1952	2,525,651	3,125,220	- 19.2
Black Mesa (S)	Peabody Coal Co.	28 Ariz.	1970	2,515,820	4,427,704	- 43.2
Seminole No. 1 (S)	Arch Mineral Corp.	29 Wyo.	1971	2,500,000	2,300,000	+ 8.7
Leahy (S)	AMAX Coal Co.	30 Ill.	1971	2,274,880	2,342,907	- 2.9
River Queen (D&S)	Peabody Coal Co.	31 Ky. W.	1957	2,224,959	3,766,210	- 40.9
Moss No. 3 (D&S)	Clinchfield Div. Pittston Co.	32 Va.	1958	2,221,440	3,327,634	- 33.2
Old Ben No. 2 (S)	Old Ben Coal Co.	33 Ind.	1975	2,154,693	2,424,483	- 11.1
No. 1 Strip (S)	Mountain Drive Coal Corp.	34 Ky.	1967	2,100,000	1,606,824	+ 30.7
No. 10 (D)	Peabody Coal Co.	35 Ill.	1952	2,096,287	2,807,593	- 25.3
Big Sky (S)	Peabody Coal Co.	36 Mont.	1970	2,064,886	2,343,877	- 11.9
No. 1 (C)	Monterey Coal Co.	37 Ill.	1970	2,006,000	2,524,815	- 20.6
Martiki (S)	Martiki Coal Corp.	38 Ky.	1975	2,000,000	1,480,976	+ 35.1
Black Thunder (S) (C)	Thunder Basin Coal Co.	39 Wyo.	1975	1,983,334	42,000	-
Burning Star No. 4 (S)	Consolidation Coal Co. Midwestern Reg.	40 Ill.	1973	1,958,683	2,016,000	- 2.8
Universal (S)	Peabody Coal Co.	41 Ind.	1970	1,947,341	2,376,732	- 18.1
Beulah (S) (C)	Knife River Coal Mining Co.	42 N.D.	before 1950	1,887,267	1,885,230	+ 0.1
Ireland (D)	Consolidation Coal Co., Eastern Reg.	43 W. Va.	1957	1,860,986	1,626,232	+ 14.4
Burning Star No. 5 (S)	Consolidation Coal Co. Midwestern Reg.	44 Ill.	1975	1,832,714	1,832,714	-
Jacobs Ranch (S)	Kerr-McGee Coal Corp.	45 Okla.	1974	1,800,000	-	-
Old Ben No. 1 (S)	Old Ben Coal Co.	46 Ind.	before 1950	1,780,611	2,388,212	- 26.3
Pevier (D&S)	Island Creek Coal Co.	47 Ky. W.	1972	1,726,726	2,188,704	- 21.1
Maple Creek 1 & 2 (C)	U.S. Steel Corp.	48 Pa.	1959	1,614,000	2,044,000	- 21.0
Robena (C)	U.S. Steel Corp.	49 Pa.	before 1950	1,612,000	2,233,000	- 27.8
Robinson Run (D)	Consolidation Coal Co. No. W. Va. Reg.	50 W. Va.	1968	1,586,351	2,099,000	- 24.4
TOTAL PRODUCTION, 50 MINES				170,085,874	165,801,189	+ 2.6
U.S. TOTAL PRODUCTION, Bituminous and Lignite				665,127,000	661,344,000	- 3.8
% LISTED MINES TO NATIONAL TOTAL				25.6%	24.0%	

SYMBOLS: (C) Captive Mines (S) Surface Mines (D) Deep Mines

SOURCE: Keystone Coal Industry Manual, McGraw-Hill Publishing Co.

Growth of the Bituminous Coal Mining Industry

		Value ¹			
	Production (Net Tons)	Total	Average Per Ton	Men Employed	Number of Mines
1920	568,666,683	\$2,129,933,000	\$3.75	639,547	8,921
1921	415,921,950	1,199,983,600	2.89	663,754	8,038
1922	422,268,099	1,274,820,000	3.02	687,958	9,299
1923	564,564,662	1,514,621,000	2.68	704,793	9,331
1924	483,686,538	1,062,626,000	2.20	619,604	7,586
1925	520,052,741	1,060,402,000	2.04	588,493	7,144
1926	573,366,985	1,183,412,000	2.06	593,647	7,177
1927	517,763,352	1,029,657,000	1.99	593,918	7,011
1928	500,744,970	933,774,000	1.86	522,150	6,450
1929	534,988,593	952,781,000	1.78	502,993	6,057
1930	467,526,299	795,483,000	1.70	493,202	5,891
1931	382,089,396	588,895,000	1.54	450,213	5,642
1932	309,709,872	406,677,000	1.31	406,380	5,427
1933	333,630,533	445,788,000	1.34	418,703	5,555
1934	359,368,022	628,383,000	1.75	458,011	6,258
1935	372,373,122	658,063,000	1.77	462,403	6,315
1936	439,087,903	770,955,000	1.76	477,204	6,875
1937	445,531,449	864,042,000	1.94	491,864	6,548
1938	348,544,764	678,653,000	1.95	441,333	5,777
1939	394,855,325	728,348,366	1.84	421,788	5,820
1940	460,771,500	879,327,227	1.91	439,075	6,324
1941	514,149,245	1,125,362,836	2.19	456,981	6,822
1942	582,692,937	1,373,990,608	2.36	461,991	6,972
1943	590,177,069	1,584,644,477	2.69	416,007	6,620
1944	619,576,240	1,810,900,542	2.92	393,347	6,928
1945	577,617,327	1,768,204,320	3.06	383,100	7,033
1946	533,922,068	1,835,539,476	3.44	396,434	7,333
1947	630,623,722	2,622,634,946	4.16	419,182	8,700
1948	599,518,229	2,993,267,021	4.99	441,631	9,079
1949	437,868,036	2,136,870,571	4.88	433,698	8,559
1950	516,311,053	2,500,373,779	4.84	415,582	9,429
1951	533,664,732	2,626,030,137	4.92	372,897	8,009
1952	466,840,782	2,289,180,401	4.90	335,217	7,276
1953	457,290,449	2,247,820,694	4.92	293,106	6,671
1954	391,706,300	1,769,619,723	4.52	227,397	6,130
1955	464,633,408	2,092,382,737	4.50	225,093	7,856
1956	500,874,077	2,412,004,151	4.82	228,163	8,520
1957	492,703,916	2,508,314,127	5.08	228,635	8,539
1958	410,445,547	1,996,281,274	4.86	197,402	8,264
1959	412,027,502	1,965,606,901	4.77	179,636	7,719
1960	415,512,347	1,950,425,049	4.69	169,400	7,865
1961	402,978,802	1,844,562,662	4.58	150,474	7,648
1962	422,149,325	1,891,554,474	4.48	143,822	7,740
1963	458,928,175	2,013,309,368	4.39	141,646	7,040
1964	486,997,952	2,105,581,847	4.45	128,698	7,630
1965	512,088,263	2,276,022,033	4.44	133,732	7,228
1966	533,881,210	2,421,292,716	4.54	131,752	6,749
1967	552,626,000	2,555,378,000	4.62	131,523	5,873
1968	545,245,000	2,546,340,000	4.67	127,894	5,327
1969	560,505,000	2,795,509,000	4.99	124,532	5,118
1970	602,932,000	3,772,662,000	6.26	140,140	5,601
1971	552,192,000	3,904,562,000	7.07	145,664	5,149
1972	595,386,000	4,561,983,000	7.66	149,265	4,879
1973	591,000,000	4,976,220,000	8.42	157,800	4,650

¹ For the years 1920 to 1933 inclusive, and 1939 exclude selling expenses.

in the United States

Average Number of Days Worked	Net Tons Per Man		Percent of Underground Production				Percent of Total Production				
	Per Day	Per Year	Cut by Machines	Mined by Continuous Mining Machines	Mechanically Loaded	Mechanically Cleaned ²	Strip	Mined			
								Auger	Underground		
220	4.00	881	60.7			3.3	1.5		98.5	1920	
149	4.20	627	66.4			2.4	1.2		98.8	1921	
142	4.28	609	64.8				2.4		97.6	1922	
179	4.47	801	68.3		0.3	3.8	2.1		97.9	1923	
171	4.56	781	71.5		0.7		2.8		97.2	1924	
195	4.52	884	72.9		1.2		3.2		96.8	1925	
215	4.50	966	73.8		1.9		3.0		97.0	1926	
191	4.55	872	74.9		3.3	5.3	3.6		96.4	1927	
203	4.73	959	76.9		4.5	5.7	4.0		96.0	1928	
219	4.85	1,064	78.4		7.4	6.9	3.8		96.2	1929	
187	5.06	948	81.0		10.5	8.3	4.3		95.7	1930	
160	5.30	849	83.2		13.1	9.5	5.0		95.0	1931	
146	5.22	762	84.1		12.3	9.8	6.3		93.7	1932	
167	4.78	797	84.7		12.0	10.4	5.5		94.5	1933	
178	4.40	785	84.1		12.2	11.1	5.8		94.2	1934	
179	4.50	805	84.2		13.5	12.2	6.4		93.6	1935	
199	4.62	920	84.8		16.3	13.9	6.4		93.6	1936	
193	4.69	906			20.2	14.6	7.1		92.7	1937	
162	4.89	790	87.5		26.7	18.2	8.7		91.3	1938	
178	5.25	936	87.9		31.0	20.1	9.6		90.4	1939	
202	5.19	1,049	88.4		35.4	22.2	9.4		90.6	1940	
216	5.20	1,125	89.0		40.7	22.9	10.7		89.3	1941	
246	5.12	1,261	89.7		45.2	24.4	11.5		88.5	1942	
264	5.38	1,419	90.3		48.9	24.7	13.5		86.5	1943	
278	5.67	1,575	90.6		42.9	25.6	16.3		83.7	1944	
261	5.73	1,508	90.8		56.1	25.6	19.0		81.0	1945	
214	6.30	1,347	90.8		58.4	26.0	21.1		78.8	1946	
234	6.42	1,504	90.0		60.7	27.7	22.1		77.9	1947	
217	6.26	1,358	90.7	0.1	64.3	30.2	23.3		76.7	1948	
157	6.43	1,010	91.4	0.8	67.0	35.1	24.2		75.8	1949	
183	6.77	1,239	91.8	1.2	69.4	38.5	23.9		76.1	1950	
203	7.04	1,429	93.4	1.5	73.1	45.0	22.0		78.0	1951	
180	7.47	1,389	92.8	2.3	75.6	48.7	23.3	0.3	76.4	1952	
191	8.17	1,560	92.3	3.4	79.6	52.9	23.1	0.5	76.4	1953	
182	9.47	1,724	88.8	5.7	84.0	59.4	25.1	1.1	73.8	1954	
210	9.84	2,064	88.1	8.0	84.6	58.7	24.8	1.3	73.9	1955	
214	10.28	2,195	84.6	10.9	84.0	58.4	25.4	1.6	73.0	1956	
203	10.59	2,155	80.9	14.9	84.8	61.7	25.2	1.6	73.2	1957	
184	11.33	2,079	75.3	19.7	84.9	63.1	28.3	1.8	69.9	1958	
188	12.22	2,294	72.1	23.2	86.0	65.5	29.4	1.8	68.8	1959	
191	12.83	2,453	67.8	27.4	86.3	65.7	29.5	1.9	68.6	1960	
193	13.87	2,678	64.7	30.9	86.3	65.7	30.3	2.0	67.7	1961	
199	14.72	2,935	63.3	32.1	85.7	64.3	30.9	2.5	66.6	1962	
205	15.83	3,240	61.0	34.5	85.8	63.1	31.4	2.7	65.9	1963	
225	16.84	3,784	57.4	38.7	87.4	63.7	31.2	2.7	66.1	1964	
219	17.52	3,829	53.9	42.7	89.2	64.9	32.3	2.8	64.9	1965	
219	18.52	4,052	51.0	45.8	91.7	63.8	33.7	2.9	63.4	1966	
219	19.17	4,198	49.1	47.4 ³	94.5	63.2	33.9	3.0	63.1	1967	
220	19.37	4,263	48.4	47.6 ³	95.7	62.5	34.1	2.8	63.1	1968	
226	19.90	4,501	46.2	49.7 ³	96.6	59.7	35.2	2.9	61.9	1969	
228	18.84	4,302	46.1	50.1 ³	97.2	53.6	40.5	3.3	56.2	1970	
210	18.02	3,791	40.6	55.4 ³	98.2	49.1	46.9	3.1	50.0	1971	
225	17.74	3,989	37.4	58.7 ³	99.0	49.2	46.3	2.6	51.1	1972	
224	16.76	3,745	35.0	na	99.2	49.1	46.6	2.4	51.0	1973	

² For 1920 to 1926, these percentages are exclusive of coal cleaned at central washeries operated by consumers; after 1926, when data became available on the tonnage cleaned by consumer-operated plants, the percentage include the total tons cleaned at the mines and at consumer-operated washeries.

³ Mined by long wall machines, 1967, 0.9 percent; 1968, 1.3 percent; 1969, 1.8 percent; 1970, 2.1 percent; 1971, 2.4 percent; 1972, 2.6 percent.

Salient Statistics U. S. Bituminous and Lignite

Item	1973	1974	1975	1976	1977 (Preliminary) 1/
Production-----thousand short tons-----	591,738	603,406	618,438	678,685	688,575
Value-----thousands-----	\$5,049,612	\$9,502,347	\$12,472,486	\$13,189,481	\$14,115,788
Consumption-----thousand short tons-----	556,022	552,709	556,301	598,750	619,616
Stocks at end of year:					
Industrial consumers and retail years					
thousand short tons-----	103,022	95,528	117,115	133,555	152,317
Stocks on upper lake docks-----do-----	822	1,051	1,185	835	738
Exports 2/-----do-----	52,870	59,926	65,669	59,406	53,687
Imports 2/-----do-----	127	2,080	940	1,203	1,803
Price indicators, average per net ton:					
Cost of coking coal at merchant coke ovens-----	\$19.77	\$34.20	\$52.63	\$54.90	\$55.50
Railroad freight charge 3/-----	\$3.71	\$4.71	\$5.23	\$5.86	\$6.51
Value f.o.b. mines-----	\$8.53	\$15.75	\$19.23	\$19.43	\$20.50
Method of Mining:					
Underground-----total-----thousand short tons-----	299,353	277,309	292,326	294,880	271,630
Percentage mined by underground methods-----	50.6	46.0	45.2	43.4	39.4
Surface-----total-----thousand short tons-----	292,384	326,097	355,612	383,805	416,945
Percentage mined by surface methods-----	49.4	54.0	54.8	56.6	60.6
Number of mines-----	4,744	5,247	6,168	6,161	6,200
Average number of men working daily: 4/					
Underground mines-----	111,083	119,416	134,710	140,260	145,896
Surface mines-----	37,038	47,285	55,170	62,020	68,881
Total-----	148,121	166,701	189,880	202,280	214,777
Average number of days worked:					
Underground mines-----	231	205	228	231	214
Surface mines-----	215	208	241	235	225
Total-----	227	206	232	232	218
Production per man per day: 4/					
Underground mines-----short tons-----	11.66	11.31	9.54	9.10	8.70
Surface mines-----do-----	36.67	33.16	26.69	26.40	26.90
Total-----	17.58	17.58	14.74	14.46	14.74

1/ Subject to revision upon completion of annual canvass.

2/ Bureau of the Census, U.S. Department of Commerce.

3/ Interstate Commerce Commission.

4/ Estimates based on data supplied by Health and Safety Analysis Center, Mine Safety and Health Administration.

Source: Energy Data Reports.

Table 7 - Salient statistics of the bituminous coal and lignite industry in the United States

Item	1975	1976	1977	1978	1979 (Preliminary)
Production <u>1/</u> -----thousand short tons----	648,438	678,685	691,344	665,127	770,000
Value <u>1/</u> -----thousands--	\$12,472,486	\$13,189,481	13,705,219	\$14,486,256	\$18,095,000
Consumption <u>2/</u> -----thousand short tons--	557,535	598,750	620,487	621,330	676,650
Stocks at end of year:					
Industrial consumers and retail dealer yards <u>2/</u> -----thousand short tons--	127,150	133,555	154,875	143,573	176,411
Stocks on upper lake docks <u>2/</u> -----do-----	1,185	835	738	698	857
Exports <u>3/</u> -----do-----	65,669	59,406	53,687	39,825	64,783
Imports <u>3/</u> -----do-----	940	1,203	1,647	2,953	2,059
Price indicators, average per net ton:					
Cost of coking coal at merchant coke ovens <u>2/</u> -----	\$52.23	\$54.48	\$57.33	\$56.68	\$61.50
Railroad freight charge <u>4/</u> -----	\$5.23	\$5.86	\$6.48	\$7.32	\$8.20
Value f.o.b. mines <u>1/</u> -----	\$19.23	\$19.43	\$19.82	\$21.78	\$23.50
Method of Mining: <u>1/</u>					
Underground -----total-----thousand short tons--	292,826	294,880	265,950	242,177	301,435
Percentage mined by underground methods -----	45.2	43.4	38.5	36.4	39.1
Surface -----total-----thousand short tons--	355,612	383,805	425,394	422,950	468,565
Percentage mined by surface methods -----	54.8	56.6	61.5	63.6	60.9
Number of mines <u>1/</u> -----	6,168	6,161	6,077	6,075 <u>5/</u>	6,000
Average number of men working daily: <u>1/</u>					
Underground mines -----	134,710	140,260	151,495	146,050 <u>5/</u>	169,585
Surface mine -----	55,170	62,020	69,933	77,250 <u>5/</u>	82,147
Total -----	189,880	202,280	221,428	223,300 <u>5/</u>	251,732
Average number of days worked: <u>1/</u>					
Underground mines -----	228	231	202	201 <u>5/</u>	225
Surface mines -----	241	235	229	219 <u>5/</u>	230
Total -----	232	232	210	207 <u>5/</u>	227
Production per man per day: <u>1/</u>					
Underground mines -----short tons--	9.54	9.10	8.69	8.25 <u>5/</u>	7.90
Surface mines -----do-----	26.69	26.40	26.59	25.00 <u>5/</u>	24.80
Total -----	14.74	14.46	14.84	14.26 <u>5/</u>	13.50

1/ Energy Information Administration, "Bituminous Coal and Lignite, Production and Mine Operation - Annual Report".

(Form EIA-7), and Bureau of Mines Form 6-1385A.

2/ Energy Information Administration, "Monthly Power Plant Report" (FPC Form 4), "Monthly Fuel Consumption Report - Manufacturing Plants" (Form EIA-3), "Coke and Coal Chemicals - Monthly/Annual" (Form EIA-5/5A and "Bituminous Coal and Lignite - Quarterly Distribution Report" (Form EIA-6), "Monthly Coal Report - Retail Dealers and Upper Lake Docks" (Form EIA-2).

3/ U.S. Department of Commerce, Bureau of the Census, Monthly Reports IM 145 (Imports) and EM 522 (Exports).

4/ Interstate Commerce Commission, Freight Commodity Statistics.

5/ Subject to revision.

TABLE 1

HISTORICAL TRENDS IN BITUMINOUS COAL MINING

	Production (million tons)	Employment	Productivity (tons/workday)
1950	516.3	415,582	6.77
1951	533.7	372,897	7.04
1952	466.8	335,217	7.47
1953	457.3	293,106	8.17
1954	391.7	227,397	9.47
1955	464.6	225,093	9.84
1956	500.9	228,163	10.28
1957	492.7	228,635	10.59
1958	410.4	197,402	11.33
1959	412.0	179,636	12.22
1960	415.5	169,400	12.83
1961	403.0	150,474	13.87
1962	422.1	143,822	14.72
1963	458.9	141,646	15.83
1964	487.0	128,698	16.84
1965	512.1	133,732	17.52
1966	533.9	131,752	18.52
1967	552.6	131,523	19.17
1968	545.2	127,894	19.37
1969	560.5	124,532	19.90
1970	602.9	140,140	18.84
1971	552.2	145,664	18.02
1972	595.4	149,265	17.74
1973	591.7	148,121	17.58
1974	603.4	166,701	17.58
1975	648.4	189,880	14.74
1976	678.7	202,280	14.46
1977	688.6	214,777	14.74
1978	653.8	221,000	14.55
1979 <u>1/</u>	770.0	243,923	14.56

1/ Preliminary

Sources:

1947-1975 -- U. S. Department of the Interior, Bureau of Mines,
Minerals Yearbook, "Bituminous Coal & Lignite," Annual.

1976-1978 -- U. S. Department of Energy, Energy Information
Administration, Energy Data Report, "Weekly Coal Report."

1979 Production data -- U. S. Department of Energy,
Energy Information Administration Energy Data Report,
"Weekly Coal Report."

1979 Employment data -- U. S. Department of Labor, Mine Safety
and Health Administration, Mine Injuries & Worktime
Quarterly, January-December, 1979.

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PRODUCTION

Production by Districts (1,000 Net Tons)

District	1974	1975	1976	1977	% Change 77/76
1. Eastern Pennsylvania ...	51,838	55,014	56,860	55,748	- 2.0
2. Western Pennsylvania ...	33,241	34,233	34,066	34,262	+ 0.6
3. Northern West Virginia .	33,158	35,133	34,757	33,490	- 3.6
4. Ohio	45,409	46,770	46,582	47,918	+ 2.9
5. Panhandle	7,216	7,418	7,531	6,544	- 13.1
6. Southern Numbered 1	24,283	27,057	29,155	24,204	- 16.9
7. Southern Numbered 2	161,772	166,795	174,111	168,300	- 3.3
8. West Kentucky	51,841	56,357	52,834	52,305	- 1.0
9. Illinois	58,215	59,537	58,239	53,493	- 8.2
10. Indiana	23,726	25,124	25,369	27,797	+ 9.6
11. Iowa	590	622	616	513	- 16.7
12. Southeastern	20,801	24,056	23,119	23,344	+ 1.0
13. Arkansas-Oklahoma	858	1,053	973	1,224	+ 25.8
14. Southwestern	14,978	19,428	23,924	28,443	+ 18.9
15. Northern Colorado	308	483	337	604	+ 79.2
16. Southern Colorado	7,479	8,751	9,945	12,194	+ 22.6
17. New Mexico	14,949	14,755	19,335	21,335	+ 10.4
18. Wyoming	20,703	23,804	30,836	46,028	+ 49.3
19. Utah	5,858	6,961	7,967	8,581	+ 7.7
20. North-South Dakota	7,463	8,515	11,102	12,028	+ 8.3
21. Montana	14,106	22,054	26,231	27,226	+ 3.8
22. Washington	4,613	4,509	4,815	5,761	+ 19.7
TOTAL U. S.	603,406	648,438	678,685	691,344	+ 1.9

Underground Production by Type of Mining (1,000 Net Tons)

Year	Total Underground Production	Continuous Mining		Longwall Mining		Cutting Machine		Cut by hand or shot from solid	
		Quantity	% of Total	Quantity	% of Total	Quantity	% of Total	Quantity	% of Total
1973	299,353	178,600	59.7	9,442	3.2	107,024	35.8	4,288	1.3
1974	277,309	171,297	61.8	9,574	3.5	91,490	33.0	4,947	1.7
1975	292,826	185,602	63.4	9,113	3.1	93,662	32.0	4,649	1.5
1976	294,880	185,798	63.0	11,234	3.8	94,529	32.1	3,318	1.1
1977	265,950	171,742	64.6	13,300	5.0	75,047	28.2	5,519	2.1

1/ 1977 underground production includes 341,000 tons mined by shortwall machines.

Average Output Per Unit Per Year by Type of Mining Machine (1,000 Net Tons)

Year	Continuous Mining Machine	Longwall Mining Machine	Coal Cutting Machine
1973	96	189	70
1974	87	181	60
1975	84	182	59
1976	79	197	52
1977	64	182	50

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Number and Production of Bituminous Mines 1972

By Size of Output and Type of Mining

Size of mines	Mines		Production	
	Number	Percent-ages	Thousand Short tons	Percent-ages
UNDERGROUND MINES				
Class 1 — 500,000 tons and over	169	8.5	173,479	57.4
Class 2 — 200,000 to 500,000 tons	203	10.1	67,902	22.3
Class 3 — 100,000 to 200,000 tons	174	8.8	25,456	8.3
Class 4 — 50,000 to 100,000 tons	204	10.2	15,392	5.0
Class 5 — 10,000 to 50,000 tons	699	35.0	18,964	6.2
Class 6 — less than 10,000 tons	547	27.4	2,906	0.8
Total	1,996	100.0	304,103	100.0
STRIP MINES				
Class 1 — 500,000 tons and over	111	4.8	163,124	59.0
Class 2 — 200,000 to 500,000 tons	104	4.7	31,020	11.2
Class 3 — 100,000 to 200,000 tons	223	9.6	30,359	11.0
Class 4 — 50,000 to 100,000 tons	369	15.9	25,609	9.2
Class 5 — 10,000 to 50,000 tons	1,016	44.0	22,948	8.2
Class 6 — less than 10,000 tons	486	21.0	2,673	1.4
Total	2,309	100.0	275,730	100.0
AUGER MINES				
Class 1 — 500,000 tons and over	0	.0	0	0
Class 2 — 200,000 to 500,000 tons	3	0.1	1,391	9.2
Class 3 — 100,000 to 200,000 tons	20	3.4	2,708	17.4
Class 4 — 50,000 to 100,000 tons	44	8.0	3,071	19.7
Class 5 — 10,000 to 50,000 tons	230	40.0	6,796	43.6
Class 6 — less than 10,000 tons	277	48.6	1,586	10.1
Total	574	100.0	15,554	100.0
TOTAL, ALL MINES				
Class 1 — 500,000 tons and over	280	6.1	336,604	56.5
Class 2 — 200,000 to 500,000 tons	310	6.3	100,313	16.8
Class 3 — 100,000 to 200,000 tons	417	8.5	58,523	9.8
Class 4 — 50,000 to 100,000 tons	617	12.6	44,072	7.4
Class 5 — 10,000 to 50,000 tons	1,945	39.8	48,708	8.1
Class 6 — less than 10,000 tons	1,310	26.7	7,165	1.4
Total	4,879	100.0	595,386	100.0

Source: U.S. Minerals Yearbook

Number and Production of Mine by Size of Output and by Method of Mining

<u>Year</u>	<u>Over 500,000 net tons</u>	<u>200,000 to 500,000 net tons</u>	<u>100,000 to 200,000 net tons</u>	<u>50,000 to 100,000 net tons</u>	<u>10,000 to 50,000 net tons</u>	<u>Less than 10,000 net tons</u>	<u>Total</u>
Number of Mines							
1973	280	308	384	600	2,079	1,093	4,744
1974	273	327	440	776	2,180	1,251	5,247
1975	284	327	463	800	2,417	1,877	6,168
1976	283	237	638	849	2,408	1,746	6,161
1977	265	361	566	977	2,388	1,520	6,077
Production (1,000 Net Tons)							
1973	344,380	95,074	52,629	41,707	52,391	5,553	591,738
1974	324,969	102,331	60,421	55,245	54,643	5,798	603,406
1975	359,284	101,633	64,250	55,968	58,597	8,706	648,438
1976	367,790	82,164	100,631	60,425	59,178	8,497	678,685
1977	362,768	112,911	79,533	68,861	59,835	7,435	691,344
Production As a Percent of Total							
1973	58.2	16.1	8.9	7.0	8.9	0.9	100.0
1974	53.8	16.9	10.0	9.2	9.1	1.0	100.0
1975	55.4	15.7	9.9	8.6	9.0	1.3	100.0
1976	54.2	12.1	14.8	8.9	8.7	1.3	100.0
1977	52.5	16.3	11.5	10.0	8.7	1.1	100.0
Number of Underground Mines							
1973	175	198	156	217	604	387	1,737
1974	162	183	187	227	766	514	2,039
1975	163	193	197	282	800	657	2,292
1976	160	132	277	322	855	676	2,422
1977	135	165	235	363	982	622	2,502
Underground Production (1,000 Net Tons)							
1973	182,914	62,244	22,346	15,043	14,934	1,873	299,353
1974	155,904	58,865	26,110	15,941	18,322	2,167	277,309
1975	162,581	60,824	27,343	19,720	19,515	2,842	292,826
1976	155,408	46,972	45,136	23,073	21,329	2,962	294,880
1977	128,196	51,753	33,337	25,314	24,615	2,736	265,950
Percent of Underground Production							
1973	61.1	20.8	7.5	5.0	5.0	0.6	100.0
1974	56.2	21.2	9.4	5.8	6.6	0.8	100.0
1975	55.5	20.8	9.3	6.7	6.7	1.0	100.0
1976	52.7	15.9	15.3	7.8	7.2	1.0	100.0
1977	48.2	19.5	12.5	9.5	9.3	1.0	100.0
Number of Surface Mines							
1973	105	110	228	383	1,475	706	3,007
1974	111	144	253	549	1,414	737	3,208
1975	121	134	266	518	1,617	1,220	3,876
1976	123	105	361	527	1,553	1,070	3,739
1977	130	196	331	614	1,406	898	3,575
Surface Production (1,000 Net Tons)							
1973	161,466	32,830	30,284	26,665	37,456	3,680	292,384
1974	169,064	43,465	34,311	39,304	36,322	3,632	326,098
1975	196,704	40,809	36,906	36,248	39,081	5,864	355,612
1976	212,382	35,192	55,495	37,352	37,849	5,535	383,805
1977	234,573	61,158	46,196	43,548	35,220	4,700	425,394
Percent of Surface Production							
1973	55.2	11.2	10.4	9.1	12.8	1.3	100.0
1974	51.8	13.3	10.5	12.1	11.1	1.1	100.0
1975	55.3	11.5	10.4	10.2	11.0	1.7	100.0
1976	55.3	9.2	14.5	9.7	9.9	1.4	100.0
1977	55.2	14.4	10.9	10.2	8.3	1.1	100.0

**1978 COAL PRODUCTION BY COMPANIES
(Bituminous & Lignite)**

**Table No. 1
Annual Production of Top Bituminous Coal Operating Groups
(Including Captives)**

Year	Top 50 Tonnages	Annual Production	%
1978	397,908,390	653,800,000	60.8
1977	419,483,159	691,344,000	60.6
1976	428,973,750	678,685,000	63.2
1975	418,659,396	648,438,000	64.5
1974	393,377,483	603,406,000	65.0
1973	409,157,204	591,738,000	69.2
1972	399,448,778	595,000,000	67.0
1971	357,492,567	552,192,000	64.7
1970	407,025,570	602,932,000	67.4
1969	383,546,200	560,505,000	68.4
1968	374,221,189	545,245,000	68.6
1967	365,403,669	552,626,000	66.1
1966	341,129,969	533,881,210	63.8
1965	319,354,805	512,088,263	62.3
1964	302,213,579	486,997,952	62.0
1963	275,701,826	458,928,175	60.0
1962	256,196,302	422,149,305	60.6
1961	239,652,075	402,976,802	59.4
1960	248,936,537	415,512,347	59.9
1959	244,222,585	412,027,502	59.2
1958	241,067,718	410,445,547	58.7
1957	288,681,591	492,703,916	58.5
1956	279,844,275	500,874,077	55.9
1955	254,503,011	464,633,408	54.7
1954	211,812,342	391,706,300	54.0
1953	242,677,400	457,290,449	53.5
1952	232,333,768	466,840,782	50.0
1951	254,156,803	533,664,732	47.6
1950	233,393,064	516,311,053	45.2
1949	190,321,125	437,868,036	43.5
1948	256,567,797	599,518,229	42.8
1947	263,477,220	630,623,722	41.8
1946	230,346,662	533,922,068	43.1
1945	254,680,178	577,617,327	44.1
1944	277,902,542	619,576,240	44.8
1943	268,399,422	590,177,069	45.5

COAL MINES

Number of Active Coal Mines, by States

State	1973	1974	1975	1976	1977
Alabama.....	105	136	236	257	276
Alaska.....	1	1	1	1	1
Arizona.....	1	2	2	2	3
Arkansas.....	11	7	8	12	19
Colorado.....	30	31	33	36	51
Georgia.....	-	-	3	3	5
Illinois.....	55	55	58	62	72
Indiana.....	39	41	62	64	102
Iowa.....	12	8	10	12	10
Kansas.....	4	7	4	6	8
Kentucky.....	1,443	1,789	2,401	2,215	2,096
Eastern.....	1,362	1,684	2,219	2,054	1,911
Western.....	81	105	182	161	185
Maryland.....	56	62	69	64	72
Missouri.....	10	10	13	13	15
Montana.....	9	8	8	7	8
New Mexico.....	6	6	5	7	7
North Dakota.....	12	13	10	11	10
Ohio.....	235	257	348	297	311
Oklahoma.....	11	14	31	37	44
Pennsylvania.....	964	1,061	835	854	856
Tennessee.....	119	125	166	185	185
Texas.....	3	4	4	5	6
Utah.....	16	15	20	24	26
Virginia.....	650	682	745	795	778
Washington.....	3	3	4	4	2
West Virginia.....	932	891	1,072	1,167	1,096
Wyoming.....	17	19	20	21	18
TOTAL U.S.	4,744	5,247	6,168	6,161	6,077

Number of Active Coal Mines by Districts

District	1973	1974	1975	1976	1977
1. Eastern Pennsylvania.....	740	810	659	636	597
2. Western Pennsylvania.....	302	338	277	295	346
3. Northern West Virginia.....	249	246	320	344	301
4. Ohio.....	235	257	348	297	311
6. Panhandle.....	16	11	12	12	12
7. Southern Numbered 1.....	321	343	368	440	410
8. Southern Numbered 2.....	2,436	2,734	3,438	3,359	3,192
9. West Kentucky.....	81	105	182	161	185
10. Illinois.....	55	55	58	62	72
11. Indiana.....	39	41	62	64	102
12. Iowa.....	12	8	10	12	10
13. Southeastern.....	124	159	271	293	321
14. Arkansas-Oklahoma.....	15	13	22	24	30
15. Southwestern.....	24	29	38	49	62
16. Northern Colorado.....	2	3	4	4	3
17. Southern Colorado.....	30	30	31	35	50
18. New Mexico.....	5	6	5	6	8
19. Wyoming.....	17	19	20	21	18
20. Utah.....	16	15	20	24	26
21. North-South Dakota.....	12	13	10	11	10
22. Montana.....	9	8	8	7	8
23. Washington.....	4	4	5	5	3
TOTAL U.S.	4,744	5,247	6,168	6,161	6,077

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EMPLOYMENT

Employment by Districts (Daily Average)

<u>District</u>	<u>1973</u>	<u>1974</u>	<u>1975</u>	<u>1976</u>	<u>1977</u>
1. Eastern Pennsylvania.....	14,418	15,204	18,500	19,276	19,866
2. Western Pennsylvania.....	11,988	12,323	12,920	14,835	14,977
3. Northern West Virginia.....	9,977	10,499	11,680	11,467	13,231
4. Ohio.....	9,700	10,771	13,430	15,004	15,711
6. Panhandle.....	2,827	3,198	3,470	3,361	3,556
7. Southern Numbered 1.....	15,020	14,616	17,700	19,889	20,968
8. Southern Numbered 2.....	50,555	60,712	64,960	68,047	74,879
9. West Kentucky.....	7,476	9,221	10,620	10,012	12,698
10. Illinois.....	10,500	11,867	12,850	13,272	14,806
11. Indiana.....	2,680	2,537	3,040	3,769	3,942
12. Iowa.....	128	94	120	140	121
13. Southeastern.....	5,432	6,973	9,060	10,222	10,833
14. Arkansas-Oklahoma.....	264	290	480	425	629
15. Southwestern.....	1,295	1,530	2,040	2,676	3,175
16. Northern Colorado.....	139	148	120	111	146
17. Southern Colorado.....	1,539	1,990	2,120	1,796	3,196
18. New Mexico.....	620	739	980	1,167	1,332
19. Wyoming.....	1,011	1,240	1,630	2,442	2,689
20. Utah.....	1,603	1,514	2,550	2,614	2,703
21. North-South Dakota.....	265	373	380	429	559
22. Montana.....	292	397	640	715	809
23. Washington.....	392	465	600	611	602
TOTAL U.S.	148,121	166,701	189,880	202,280	221,428

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Output Per Person Per Day by States (Net Tons)

State	1973	1974	1975	1976	1977
Alabama.....	15.79	12.49	11.19	10.72	11.43
Alaska.....	33.86	33.36	30.65	35.31	41.83
Arizona.....	67.90	78.95	69.66	69.12	49.57
Arkansas.....	12.35	11.34	8.25	8.76	6.78
Colorado.....	17.46	19.56	18.89	25.87	16.91
Georgia.....	-	-	9.79	7.84	8.43
Illinois.....	23.56	20.03	17.61	16.61	15.08
Indiana.....	35.98	32.02	29.50	27.72	26.39
Iowa.....	21.20	20.46	20.15	18.54	15.87
Kansas.....	16.20	13.51	13.76	20.39	14.98
Kentucky.....	21.29	19.26	16.99	16.53	15.65
Eastern.....	18.13	16.84	15.40	14.76	14.68
Western.....	28.02	24.14	20.22	20.84	17.76
Maryland.....	28.20	24.54	20.69	15.93	17.80
Missouri.....	30.39	20.02	21.14	24.53	28.24
Montana.....	127.11	130.94	127.25	120.67	125.21
New Mexico.....	48.84	46.66	36.86	41.70	48.27
North Dakota.....	102.36	66.83	86.86	93.70	93.13
Ohio.....	21.26	17.01	15.13	14.33	13.67
Oklahoma.....	19.82	17.66	14.79	17.14	19.24
Pennsylvania.....	12.52	13.68	11.46	11.02	11.48
Tennessee.....	20.54	15.90	12.94	9.91	11.64
Texas.....	100.75	80.50	76.49	72.49	49.89
Utah.....	14.36	15.32	13.85	13.79	16.45
Virginia.....	12.65	11.88	10.69	10.40	10.98
Washington.....	38.90	44.31	27.11	30.18	37.19
West Virginia.....	11.83	10.79	9.15	8.64	8.24
Wyoming.....	55.94	65.93	61.78	51.91	68.53
TOTAL U.S.	17.58	17.58	14.74	14.46	14.84

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AVERAGE VALUE

Average Value by States (Per Ton FOB Mine)

State	1974	1975	1976	1977	1978
Alabama	\$ 21.79	\$ 26.53	\$ 28.37	\$28.88	\$31.33
Arkansas	21.28	32.76	36.15	W	39.86
Colorado	9.38	16.53	15.30	16.79	17.11
Georgia	-	-	-	-	52.23
Illinois	10.00	14.64	15.90	17.28	20.46
Indiana	8.36	11.15	12.34	13.83	18.18
Iowa	7.79	11.08	13.56	12.71	16.10
Kansas	7.61	19.78	19.45	18.93	20.28
Kentucky	17.06	17.40	19.79	20.02	23.86
Eastern	22.01	20.79	23.03	21.67	25.30
Western	8.92	12.16	14.18	17.07	20.36
Maryland	20.81	19.38	21.90	17.68	19.40
Missouri	6.36	8.52	9.37	10.38	17.89
Montana	3.90	5.06	4.90	5.93	7.37
New Mexico	W	W	W	7.94	10.08
North Dakota	2.19	3.17	3.74	4.03	5.17
Ohio	12.32	16.40	16.61	17.70	21.77
Oklahoma	10.51	16.69	15.98	17.64	21.42
Pennsylvania	20.35	25.09	25.33	25.60	27.86
Tennessee	18.02	17.10	16.31	21.86	23.21
Texas	-	-	-	-	6.04
Utah	12.24	19.84	22.93	20.32	21.52
Virginia	24.94	30.46	24.12	29.65	30.50
Washington	W	W	W	11.28	12.07
West Virginia	21.65	29.35	30.12	31.03	33.15
Wyoming	5.02	6.74	7.00	8.21	9.11
TOTAL U.S.	\$ 15.75	\$ 19.23	\$ 19.43	\$19.82	\$21.78

W - Withheld to avoid disclosing individual company data.

Source: Dept. of Energy

Average Value by Districts (Per Ton FOB Mine)

District & Number	1971	1972	1973	1974	1975
1. Eastern Pennsylvania	\$ 8.12	\$ 8.25	\$ 9.27	\$ 18.84	\$ 21.84
2. Western Pennsylvania	8.78	9.93	11.42	22.51	29.11
3. Northern West Virginia	7.36	8.16	9.03	16.22	22.65
4. Ohio	5.24	5.96	7.40	12.32	16.40
6. Panhandle	6.55	7.49	8.86	12.23	15.29
7. Southern Numbered 1	13.21	14.45	15.73	28.72	41.97
8. Southern Numbered 2	8.18	8.86	10.08	22.93	24.80
9. West Kentucky	4.83	5.23	5.93	8.92	12.16
10. Illinois	5.46	6.14	6.71	10.00	14.64
11. Indiana	5.18	5.58	6.06	8.36	11.15
12. Iowa	4.66	4.86	5.46	7.79	11.08
13. Southeastern	7.97	9.43	10.88	21.58	26.12
14. Arkansas-Oklahoma	10.53	9.04	13.61	20.39	34.47
15. Southwestern	5.16	4.86	4.41	4.63	6.07
16. Northern Colorado	5.25	5.17	W	6.49	11.93
17. Southern Colorado	6.71	7.25	7.89	10.15	18.37
18. New Mexico	2.62	2.68	2.83	3.15	W
19. Wyoming	3.39	3.74	4.09	5.02	6.74
20. Utah	7.37	8.93	11.19	12.24	19.84
21. North-South Dakota	1.91	2.02	2.07	2.19	3.17
22. Montana	1.82	2.03	2.82	3.90	5.06
23. Washington	7.27	7.07	7.08	6.42	W
TOTAL U.S.	\$ 7.07	\$ 7.66	\$ 8.53	\$ 15.75	\$ 19.23

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AVERAGE VALUE

Average Value of Coal Sold in Open Market by States (Per Ton FOB Mine)

State	1972	1973	1974	1975	1977
Alabama	\$ 8.46	\$ 10.01	\$ 20.55	\$ 25.40	\$27.76
Alaska	W	W	W	W	W
Arkansas	10.93	13.37	18.60	24.16	W
Colorado	4.95	5.32	6.65	11.59	14.73
Illinois	6.01	6.55	9.64	14.12	16.86
Indiana	5.58	6.06	8.36	11.15	13.83
Iowa	4.88	5.46	7.79	11.08	12.71
Kansas	6.39	7.35	7.61	19.78	18.93
Kentucky	6.55	7.31	16.36	15.79	19.36
Maryland	5.46	7.63	20.81	19.38	17.31
Missouri	5.20	5.37	6.36	8.52	10.38
Montana	2.03	2.83	3.91	5.06	6.07
New Mexico	3.00	2.91	W	W	6.54
North Dakota	2.02	2.00	2.03	2.90	3.78
Ohio	5.96	7.30	12.30	16.34	17.67
Oklahoma	7.28	6.99	9.84	16.67	17.63
Pennsylvania	8.06	8.71	17.85	20.66	22.66
Tennessee	7.23	8.13	18.02	17.10	21.90
Utah	7.34	6.50	10.66	14.21	16.85
Virginia	10.03	11.00	24.94	30.27	28.57
Washington	6.61	14.10	22.58	17.82	28.75
West Virginia	10.12	11.13	20.77	28.04	29.18
Wyoming	4.02	4.31	5.32	7.18	8.52
TOTAL U.S.	\$ 7.35	\$ 8.00	\$ 15.16	\$ 18.02	\$19.11

W - Withheld to avoid disclosing individual company data.

Note: 1976 data are not available.

MACHINERY

Underground Coal Mining Equipment (Units)

<u>Year</u>	<u>Continuous Miners</u>	<u>Longwall</u>	<u>Cutting Machine</u>	<u>Mobile Loading Machine</u>	<u>Pneum or Coal Drill</u>	<u>Roof or Rock Drill</u>
1973	1,866	50	1,535	2,015	1,788	2,844
1974	1,959	53	1,515	2,151	2,050	3,782
1975	2,199	50	1,595	1,721	2,161	3,702
1976	2,366	57	1,803	1,654	2,269	3,999
1977	2,677	73	1,495	1,583	2,041	4,607

Surface Coal Mining Equipment (Units)

<u>Year</u>	<u>Power Shovels</u>	<u>Dragline Excavators</u>	<u>Augers</u>	<u>Bull-Dozers</u>	<u>Front-end Loaders</u>	<u>Carry All Scrapers</u>
1973	2,276	772	694	4,499	2,658	390
1974	1,468	1,103	925	6,929	4,770	834
1975	1,744	1,257	1,253	8,975	6,397	1,203
1976	1,649	1,277	1,066	8,891	6,456	1,286
1977	1,384	1,751	920	12,683	9,399	2,289

MACHINERY

Power Shovels & Dragline Excavators Used at Surface Coal Mines

<u>State</u>	<u>1973</u>	<u>1974</u>	<u>1975</u>	<u>1976</u>	<u>1977</u>
Alabama	114	149	223	252	230
Alaska	-	-	-	-	-
Arizona	4	4	7	8	24
Arkansas	8	10	10	12	17
Colorado	9	10	16	24	21
Georgia	-	-	2	2	1
Illinois	110	106	113	121	106
Indiana	113	115	170	161	249
Iowa	20	7	12	14	9
Kansas	8	10	7	10	3
Kentucky	734	283	464	358	481
Maryland	66	80	82	82	74
Missouri	27	29	30	35	33
Montana	10	14	15	19	20
New Mexico	9	7	7	9	19
North Dakota	27	26	26	26	23
Ohio	329	345	348	359	308
Oklahoma	18	21	29	35	40
Pennsylvania	785	886	964	975	1,038
Tennessee	79	63	55	37	37
Texas	11	14	16	17	21
Utah	-	-	-	-	-
Virginia	236	93	91	102	112
Washington	7	6	6	7	1
West Virginia	298	266	274	226	153
Wyoming	27	27	34	35	115
TOTAL U.S.	<u>3,048</u>	<u>2,571</u>	<u>3,001</u>	<u>2,926</u>	<u>3,135</u>

Note: Due to changes made by the Bureau of Mines in the computing methods, data reported for years after 1974 are not comparable with those in the previous years.

COAL PREPARATION

Cleaning Plant Operations (1,000 Net Tons)

<u>Year</u>	<u>Total raw coal moved to cleaning plants</u>	<u>Coal obtained in cleaning process</u>	<u>Refuse resulting in cleaning process</u>	<u>Percent of refuse to raw coal</u>
1972	398,678	292,829	105,850	26.6
1973	397,646	288,918	108,728	27.3
1974	363,334	265,150	98,184	27.0
1975	374,094	266,993	107,101	28.6
1976	379,236	268,830	110,408	29.1
1977	358,824	253,917	104,907	29.2

CONSUMPTION

Consumption of Bituminous Coal by Consumer Class

(1,000 Net Tons)

Year	Electric Utilities	Industrial			Residential and Commercial	Grand Total
		Coke Plants	Other Industrial	Total		
1975	404,483	83,272	62,498	145,770	7,282	557,535
1976	447,021	84,324	60,505	144,829	6,900	598,750
1977	475,701	77,369	60,398	137,767	7,020	620,487
1978	480,171	71,078	62,167	133,245	7,914	621,330
1979 p/	527,757	76,735	65,027	141,762	7,131	676,650

AS PERCENT OF TOTAL

1975	72.6	14.9	11.2	26.2	1.3	100.0
1976	74.7	14.1	10.1	24.2	1.2	100.0
1977	76.7	12.5	9.7	22.2	1.1	100.0
1978	77.3	11.4	10.0	21.4	1.3	100.0
1979 p/	78.0	11.3	9.6	21.0	1.1	100.0

p/ Preliminary

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

Consumption (millions of tons)

Source: Federal Energy Administration, National Energy Outlook, 1976

Figure 49. Coal Consumption by End-Use Sector

The downward trend in coal consumption between 1950 and 1960 reflected the substitution of petroleum and natural gas for coal by electric utilities, in the residential and commercial markets, and for railway transportation. Beginning in

1962, total coal consumption increased steadily, with minor declines, and reached a record high of 681 million short tons in 1979. During that year, electric utilities accounted for 78 percent of total coal consumption.

Source: Energy Information Administration, Annual Report to Congress, Vol. II, 1979

Table 63. Fossil Fuels Consumed by the Electric Utility Industry to Produce Electricity, 1949-1979

Year	Anthracite (million short tons)	Coal Bituminous Coal and Lignite (million short tons)	Total (million short tons)	Petroleum ¹		Natural Gas (billion cubic feet)
				Oil (million barrels)	Petroleum Coke (million short tons)	
1949	3.4	80.6	84.0	66.3	NA	550
1950	3.6	88.3	91.9	75.4	NA	629
1951	3.9	101.9	105.8	63.9	NA	764
1952	3.8	103.3	107.1	67.2	NA	910
1953	3.6	112.3	115.9	82.2	NA	1,034
1954	3.2	115.2	118.4	66.7	NA	1,165
1955	3.2	140.5	143.8	75.3	NA	1,153
1956	3.3	155.0	158.3	72.7	NA	1,239
1957	3.4	157.4	160.8	79.7	NA	1,336
1958	2.8	152.9	155.7	77.7	NA	1,373
1959	2.6	165.8	168.4	88.3	NA	1,629
1960	2.8	173.9	176.6	85.3	NA	1,725
1961	2.5	179.6	182.1	85.7	NA	1,825
1962	2.3	190.9	193.2	85.8	NA	1,966
1963	2.1	209.2	211.3	93.3	NA	2,144
1964	2.2	223.2	225.4	101.1	NA	2,323
1965	2.2	242.6	244.8	115.2	NA	2,321
1966	2.2	264.3	266.5	140.9	NA	2,610
1967	2.2	272.0	274.2	161.3	NA	2,746
1968	2.2	295.6	297.8	188.6	NA	3,148
1969	1.9	308.8	310.6	251.0	NA	3,488
1970	1.9	318.3	320.2	335.5	0.6	3,932
1971	1.6	325.7	327.3	396.5	0.6	3,976
1972	1.6	350.2	351.8	493.8	0.6	3,977
1973	1.4	387.8	389.2	560.2	0.5	3,660
1974	1.5	390.3	391.8	536.3	0.6	3,443
1975	1.5	404.5	406.0	506.1	0.1	3,158
1976	1.3	447.0	448.4	555.9	0.1	3,081
1977	1.4	475.7	477.1	623.7	0.1	3,191
1978	1.1	480.2	481.2	635.8	0.4	3,188
1979 ²	1.0	527.8	528.8	523.5	0.3	3,490

¹ These data are petroleum consumed by electric utilities and do not equate to petroleum supplied to (or delivered to) electric utilities. Oil includes jet fuel, residual fuel oil, (including crude oil burned as fuel), and distillate fuel oil.

² Preliminary.

NA = Not available.

Note: Sum of components may not equal total due to independent rounding.

Sources: • 1949 through September 1977—Federal Power Commission, Form 4, "Monthly Power Plant Report." • October 1977 through 1978—U.S. Department of Energy, Energy Information Administration, Federal Power Commission, Form 4, "Monthly Power Plant Report."

Source: Energy Information Administration, Annual Report to Congress, Vol. II, 1979

SHIPMENTS

Exports of Bituminous Coal (1,000 Net Tons)

Country of Destination	1974	1975	1976	1977	1978	% Change 78/77
Belgium-Luxembourg 2/ ...	1,109	627	2,202	1,516	1,054	- 30.52
Canada	13,706	16,735	16,497	17,166	15,239	- 11.2
France	2,510	3,583	3,427	2,086	1,618	- 22.4
Germany (Fed. Rep.) 2/ ..	1,484	1,989	994	888	617	- 30.5
Italy	3,903	4,493	4,211	4,116	3,212	- 22.0
Japan	27,346	25,423	18,803	15,862	10,083	- 36.4
Netherlands 2/	2,545	2,093	3,490	1,962	1,061	- 45.9
Spain	2,017	2,691	2,513	1,570	758	- 51.7
United Kingdom	1,405	1,888	843	607	397	- 34.6
Other Countries	3,901	6,147	6,426	7,914	5,786	- 26.8
TOTAL	59,926	65,669	59,406	53,687	39,825	- 25.82

1/ Excludes shipments to U. S. military forces.

2/ Shipments as indicated in vessel manifests upon departure U.S. ports and includes tonnages for transshipment to undesignated European destinations.

Imports of Bituminous Coal (1,000 Net Tons)

Origin Country	1974	1975	1976	1977	1978
Australia	144	117	-	118	1,029
Canada	596	190	59	51	53
Germany (Fed. Rep.)	513	88	1/	309	1/
Netherlands	171	-	-	1/	62
Poland	468	172	362	361	711
South Africa (Rep. of) ...	172	370	781	808	1,098
Other Countries	16	2	1/	156	1/
TOTAL	2,080	940	1,203	1,803	2,953

1/ Less than one hundred tons.

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STOCKS

Stocks at End of Year by Consumer Class (1,000 Net Tons)

<u>At End of Year</u>	<u>Electric Utilities</u>	<u>INDUSTRIAL</u>			<u>Residential and Commercial</u>	<u>Grand Total</u>
		<u>Coke Plants</u>	<u>Other Industrial</u>	<u>Total</u>		
1975	109,742	8,671	8,504	17,175	233	127,150
1976	116,436	9,804	7,075	16,879	240	133,555
1977	130,899	12,721	11,035	23,756	220	154,875
1978	126,047	8,162	9,004	17,166	360	143,573
1979	156,425	10,028	9,618	19,646	340	176,411

Figure 50. Year-End Stocks of Bituminous Coal and Lignite by End-Use Sector

The trend in coal stocks was upward from the early 1960's through 1979 as the need for additional inventories became necessary to meet the growing demand

for electricity. By the end of 1979 the stock level had reached 176 million short tons, the largest year-end total on record.

Source: Energy Information Administration, Annual Report to Congress, Vol. II, 1979

DAYS SUPPLY

Days Supply¹ by Consumer Class

<u>At End of Year</u>	<u>Electric Utilities</u>	<u>Iron Coke Plants</u>	<u>Steel & Rolling Mills</u>	<u>Other Manufacturing & Mining Industries</u>	<u>Retail Dealers</u>	<u>Total</u>
1973	78	27	19	43	9	63
1974	73	31	32	38	9	62
1975	91	40	33	44	7	77
1976	87	44	19	34	6	74
1977	98	64	23	47	7	88
1978	90	38	31	41	12	78

1/ Based on average daily consumption rate during the month.

DISTRIBUTION

Distribution of Bituminous Coal and Lignite, by District of Origin (1,000 Net Tons)

<u>District of Origin 1/</u>	<u>1974</u>	<u>1975</u>	<u>1976</u>	<u>1977 2/</u>	<u>1978</u>
1	50,448	52,675	54,448	57,633	54,763
2	35,392	35,058	33,751	32,030	27,729
3 and 6	40,209	42,421	41,585	39,237	34,889
4	45,284	46,150	45,810	46,315	41,055
7	28,784	28,840	26,883	22,789	17,915
8	155,517	159,509	160,686	159,036	152,464
9	52,380	55,664	52,101	50,242	37,704
10	59,085	60,029	58,526	54,326	48,490
11	23,911	25,111	25,609	26,081	23,069
12	597	644	540	502	468
13	20,469	23,574	23,309	22,935	21,055
14	742	1,007	094	1,188	1,233
15	14,981	19,530	24,063	27,655	31,642
16	300	457	327	605	784
17	7,676	8,613	10,039	12,275	13,462
18	14,697	15,306	19,105	21,754	20,822
19	20,799	23,794	31,174	46,023	58,323
20	6,086	7,039	7,999	9,179	9,093
21	7,429	8,570	11,233	11,974	11,989
22 and 23	18,693	26,833	31,093	32,950	31,997
Total	603,479	640,826	659,175	674,729	640,944

Percent of Total

<u>District of Origin 1/</u>	<u>1974</u>	<u>1975</u>	<u>1976</u>	<u>1977 2/</u>	<u>1978</u>
1	8.4	8.2	8.3	8.5	8.5
2	5.9	5.5	5.1	4.7	4.3
3 and 6	6.7	6.6	6.3	5.8	5.4
4	7.5	7.2	6.9	6.9	6.4
7	4.8	4.5	4.1	3.4	2.8
8	25.8	24.9	24.4	23.6	23.8
9	8.7	8.7	7.9	7.4	5.9
10	9.8	9.4	8.9	8.1	7.6
11	4.0	3.9	3.9	3.9	3.6
12	.1	.1	.1	.1	.1
13	3.4	3.7	3.5	3.4	3.3
14	.1	.2	.1	.2	.2
15	2.5	3.0	3.7	4.1	4.9
16	.1	.1	.1	.1	.1
17	1.3	1.3	1.5	1.8	2.1
18	2.4	2.4	2.9	3.2	3.3
19	3.4	3.7	4.7	6.8	9.1
20	1.0	1.1	1.2	1.4	1.4
21	1.2	1.3	1.7	1.8	2.2
22 and 23	3.1	4.2	4.7	4.9	5.0
Total	100.0	100.0	100.0	100.0	100.0

1/ For definitions of bituminous coal and lignite producing districts, see Appendix 4.

2/ Beginning with the fourth quarter of 1977, coal inventories were excluded from the bituminous coal and lignite distribution data.

DISTRIBUTION

Distribution¹ of Bituminous Coal and Lignite in the United States, Canada, and Mexico, by Consumer Use (1,000 Net Tons)

<u>Consumer Use</u>	<u>1974</u>	<u>1975</u>	<u>1976</u>	<u>1977 2/</u>	<u>1978</u>
Electric Utilities	392,551	438,558	463,058	489,880	479,950
Coke plants	93,158	92,497	92,678	84,959	71,123
All other industrial	63,222	53,435	53,128	59,602	60,832
Retail sales	<u>6,792</u>	<u>5,043</u>	<u>4,137</u>	<u>3,088</u>	<u>2,087</u>
Total	555,723	589,533	613,001	637,529	613,992

Percent of Total

Electric utilities	70.6	74.4	75.5	76.8	78.2
Coke plants	16.8	15.7	15.1	13.3	11.6
All other industrial	11.4	9.1	8.7	9.3	9.9
Retail sales	<u>1.2</u>	<u>.9</u>	<u>.7</u>	<u>.5</u>	<u>.3</u>
Total	100.0	100.0	100.0	100.0	100.0

1/ Excludes railroad fuel, vessel fuel, Great Lakes commercial docks, coal used at mines and sales to employees, net change in mine inventory, and overseas exports (excluding Canada and Mexico).

2/ Beginning with the fourth quarter of 1977, the consumer use of shipments to Mexico and shipments within Alaska were excluded from total figures to avoid disclosure of individual respondent data.

Distribution¹ of Bituminous Coal and Lignite in the United States, Canada, and Mexico, by Method of Movement (1,000 Net Tons)

<u>Method of Movement</u>	<u>1974</u>	<u>1975</u>	<u>1976</u>	<u>1977 2/</u>	<u>1978</u>
All-Rail	298,731	320,140	331,048	339,382	324,252
River and ex-river	102,517	107,025	107,503	106,844	96,301
Great Lakes	32,083	33,963	33,029	31,595	30,200
Tidewater	6,259	5,353	5,344	4,535	3,813
Truck	71,497	69,679	69,410	85,609	93,531
Tramway, conveyor, and private railroad	<u>44,636</u>	<u>53,373</u>	<u>66,667</u>	<u>69,564</u>	<u>65,893</u>
Total	555,723	589,533	613,001	637,529	613,992

Percent of Total

All-rail	53.8	54.3	54.0	53.2	52.8
River and ex-river	18.4	18.2	17.5	16.8	15.7
Great Lakes	5.8	5.8	5.4	5.0	4.9
Tidewater	1.1	.9	.9	.7	.6
Truck	12.9	11.8	11.3	13.4	15.2
Tramway, conveyor, and private railroad	<u>8.0</u>	<u>9.1</u>	<u>10.9</u>	<u>10.9</u>	<u>10.7</u>
Total	100.0	100.0	100.0	100.0	100.0

1/ Excludes railroad fuel, vessel fuel, Great Lakes commercial docks, coal used at mines and sales to employees, net change in mine inventory, and overseas exports (excluding Canada and Mexico).

2/ Beginning with the fourth quarter of 1977, the transportation mode of shipments to Mexico and shipments within Alaska were excluded from total figures to avoid disclosure of individual respondent data.

Anthracite Production by Method (1,000 Net Tons)

<u>Year</u>	<u>Underground</u>	<u>Strip</u>	<u>Culm</u>	<u>Dredge</u>	<u>Total Production</u>
1973	726	3,280	2,384	441	6,830
1974	657	2,869	2,940	150	6,617
1975	641	2,564	2,922	76	6,203
1976	584	2,999	2,557	88	6,228
1977	641	3,104	2,033	83	5,861

Anthracite Consumption (1,000 Net Tons)

<u>Year</u>	<u>Residential & Commercial Heating</u>	<u>Electric Utilities</u>	<u>Iron & Steel Industry</u>		<u>Colliery Fuel</u>	<u>Other Uses</u>	<u>Total Domestic</u>	<u>Exports 1//</u>
			<u>Coke Making</u>	<u>Sintering & Pelletizing</u>				
1973	2,917	1,442	467	231	11	603	5,671	717
1974	2,577	1,498	444	367	12	550	5,448	735
1975	2,128	1,482	326	237	10	925	5,108	640
1976	2,016	1,350	380	140	12	1,142	5,040	615
1977	1,934	1,426	370	144	10	919	4,803	625

Productivity & Employment

<u>Year</u>	<u>No. of Mines</u>	<u>Average Number of Days Worked</u>	<u>Average Number Employed Daily</u>	<u>Output Per Person-Day (Net Tons)</u>
1973	369	234	4,083	7.15
1974	340	219	3,847	7.87
1975	350	214	3,907	7.45
1976	357	235	3,686	7.19
1977	375	229	3,655	6.97

Average Value of Anthracite Per Ton

<u>Year</u>	<u>Total Production Value</u>	<u>Average Value Per Tons</u>	<u>Pea & Larger</u>	<u>Buckwheat No. 1 and Smaller</u>	<u>All Sizes</u>
1973	\$ 90,260	\$13.22	\$18.76	\$11.30	\$13.65
1974	144,695	21.87	30.41	18.83	22.19
1975	198,481	32.00	45.04	27.61	32.26
1976	209,234	33.59	46.71	29.11	33.92
1977	202,373	34.53	44.74	31.15	34.86

1/ Excludes dredge coal.

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APPENDIX 3

Units of Measure

Weight

1 metric ton	contains	1,000 kilograms or 2,204.62 pounds
1 long ton	contains	2,240 pounds
1 short ton	contains	2,000 pounds

Conversion Factors for Crude Oil (Average Gravity)

1 barrel	contains	42 gallons
1 barrel	weighs	0.136 metric tons (0.150 short tons)
1 metric ton	contains	7.33 barrels
1 short ton	contains	6.65 barrels

Conversion Factors for Uranium

1 short ton (U ₃ O ₈)	contains	0.769 metric tons of uranium
1 short ton (UF ₆)	contains	0.613 metric tons of uranium
1 metric ton (UF ₆)	contains	0.676 metric tons of uranium

Approximate Heat Content of Various Fuels

	1973	1974	1975	1976	1977-78-79
Bituminous coal and lignite					
Production	Btu/short ton	24,010,000	23,730,000	23,200,000	23,150,000
Imports	Btu/short ton	25,000,000	25,000,000	25,000,000	25,000,000
Exports	Btu/short ton	27,000,000	27,000,000	27,000,000	27,000,000
Consumption, average	Btu/short ton	23,650,000	23,070,000	22,800,000	22,750,000
Electric utility consumption	Btu/short ton	22,180,000	21,800,000	21,660,000	21,520,000
Non-utility consumption	Btu/short ton	27,020,000	26,120,000	25,810,000	26,020,000
Coke	Btu/short ton	26,000,000	26,000,000	26,000,000	26,000,000
Anthracite					
Production	Btu/short ton	23,170,000	22,560,000	23,390,000	22,770,000
Imports and Exports	Btu/short ton	25,400,000	25,400,000	25,400,000	25,400,000
Consumption, average	Btu/short ton	22,710,000	21,950,000	21,740,000	22,150,000
Electric utility consumption	Btu/short ton	17,200,000	17,200,000	17,060,000	17,530,000
Non-utility consumption	Btu/short ton	24,590,000	23,750,000	23,650,000	23,840,000
Crude petroleum*					
Production	Btu/barrel	5,800,000	5,800,000	5,800,000	5,800,000
Imports	Btu/barrel	5,817,131	5,826,768	5,821,375	5,808,452
Exports	Btu/barrel	5,800,000	5,800,000	5,800,000	5,800,000
Petroleum products					
Consumption, average	Btu/barrel	5,514,605	5,436,758	5,494,291	R5,504,484
Electric Utility Consumption	Btu/barrel	6,128,488	6,128,058	6,109,112	6,129,283
Non-utility Consumption	Btu/barrel	5,454,865	5,443,438	5,437,208	5,444,956
Imports	Btu/barrel	5,983,262	5,959,487	5,934,666	5,980,372
Exports	Btu/barrel	5,752,055	5,773,222	5,746,991	5,743,408
Crude Petroleum and Products					
Imports, average	Btu/barrel	5,897,122	5,883,985	5,857,876	5,856,076
Exports, average	Btu/barrel	5,752,455	5,773,577	5,748,482	5,745,450
Natural gas plant liquid production	Btu/barrel	4,049,369	4,010,663	3,983,763	3,964,050
Natural gas, dry					
Production and consumption	Btu/cubic foot	1,021	1,024	1,021	1,020
Electric Utility Consumption	Btu/cubic foot	1,024	1,022	1,026	1,023
Non-utility consumption	Btu/cubic foot	1,020	1,024	1,020	1,019
Imports	Btu/cubic foot	1,026	1,027	1,026	1,025
Exports	Btu/cubic foot	1,023	1,016	1,014	1,013
Hydropower	Btu/kWh	10,389	10,442	10,406	10,373
Nuclear power	Btu/kWh	10,903	11,161	11,013	11,047
Geothermal power	Btu/kWh	21,674	21,674	21,611	21,611

Refined Petroleum Products:

	Btu/barrel
Asphalt	6,636,000
Aviation gasoline	5,048,000
Butane	4,326,000
Butane—propane mixture**	4,130,000
Distillate fuel oil	5,825,000
Ethane	3,082,000
Isobutane	3,974,000
Jet fuel—kerosene type	5,670,000
Jet fuel—naphtha type	5,355,000
Kerosene	5,670,000
Lubricants	8,065,000
Motor gasoline	5,253,000
Natural gasoline	4,620,000
Petrochemical feedstocks	
Naphtha 400°	5,248,000

Other oils over 400°

	Btu/barrel
Still gas	5,825,000
Petroleum coke	6,000,000
Plant condensate	6,024,000
Propane	5,418,000
Residual fuel oil	3,836,000
Road oil	6,287,000
Special naphtha	6,636,000
Still gas	5,248,000
Unfinished oils	8,000,000
Wax	5,825,000
Miscellaneous	5,537,000
	5,796,000

*Includes lease condensate.

**60 percent butane and 40 percent propane.

NA=Not available.

R=Revised data.

Fuel and Power Conversion Factors (Continued)

One Ton of Bituminous Coal Production Equals: 1/

Weighted Average Btu per Unit:

Bituminous Coal	1 ton	22,900,000 per ton
Pennsylvania Anthracite	0.902 tons	25,400,000 per ton
Crude Petroleum	3.948 barrels	5,800,000 per barrel
Natural Gas Liquids	5.709 barrels	4,011,000 per barrel
Natural Gas, Wet	20,913 cubic feet	1,095 per cubic foot
Natural Gas, Dry	22,451 cubic feet	1,020 per cubic foot
Coke 2/	0.923 tons	24,800,000 per ton
Coke Breeze 3/	1.091 tons	21,000,000 per ton
Blast Furnace Gas	229,000 cubic feet	100 per cubic foot
Coke Oven Gas	41,636 cubic feet	550 per cubic foot
Manufactured Gas 4/	42,407 cubic feet	540 per cubic foot
Tar and Pitch	3.408 barrels	6,720,000 per barrel
Kerosine	4.039 barrels	5,670,000 per barrel
Gasoline (including aviation)	4.364 barrels	5,248,000 per barrel
Distillate Fuel Oil	3.931 barrels	5,825,000 per barrel
Residual Fuel Oil	3.642 barrels	6,287,000 per barrel
Acid Sludge	5.089 barrels	4,500,000 per barrel
Refinery (still) Gas	3.817 barrels	6,000,000 per barrel
Petroleum Coke	3.801 barrels	6,024,000 per barrel
Wood	1.093 cords	20,960,000 per cord
Hydro Power 5/	2,208 kilowatt-hours	10,373 per kilowatt-hour
Nuclear Power 5/	2,148 kilowatt-hours	10,660 per kilowatt-hour
Electricity (variable)	Kilowatt-hours	3412.193 per kilowatt-hour
Mechanical Energy	9,000 horsepower-hours	2544.48 per horsepower-hour

1/ Based on 1977 published weighted average Btu values for fuels and energy.

2/ Assuming 4 percent moisture as consumed.

3/ Assuming 12 percent moisture as consumed.

4/ Sold by Utilities.

5/ Hydro power is converted to theoretical energy inputs calculated from national average heat rates for fossil-fuels steam-electric plants obtained from the Federal Energy Regulatory Commission. Energy input for nuclear power is converted at an average heat rate of 10,660 Btu per net kilowatt hour.

Classification of Coals by Rank

Class/Group		Fixed carbon limits in percent (Dry, mineral-matter-free basis)		Volatile matter limits, in percent (Dry, mineral-matter-free basis)		Calorific Value limits, in Btu per pound (Moist, mineral-matter-free basis)		Agglomerating Character
		Equal or greater than	Less than	Equal or greater than	Less than	Equal or greater than	Less than	
I. Anthracitic	1. Meta-anthracite	98	--	--	2	--	--	Non-agglomerating 2/
	2. Anthracite	92	98	2	8	--	--	
	3. Semianthracite	86	92	8	14	--	--	
II. Bituminous	1. Low-volatile bituminous coal	78	86	14	22	--	--	Commonly, agglomerating 4/
	2. Medium-volatile bituminous coal	69	78	22	31	--	--	
	3. High-volatile A bituminous coal	--	69	31	--	3/ 14,000	--	
	4. High-volatile B bituminous coal	--	--	--	--	3/ 13,000	14,000	
	5. High-volatile C bituminous coal	--	--	--	--	11,500	13,000	
						10,500	11,500	Agglomerating
III. Subbituminous	1. Subbituminous A coal	--	--	--	--	10,500	11,500	Non-agglomerating
	2. Subbituminous B coal	--	--	--	--	9,500	10,500	
	3. Subbituminous C coal	--	--	--	--	8,300	9,500	
IV. Lignite	1. Lignite A	--	--	--	--	6,300	8,300	
	2. Lignite B	--	--	--	--	--	6,300	

Note:

This classification does not include a few coals, principally nonbanded varieties, which have unusual physical and chemical properties and which come within the limits of fixed carbon or calorific value of the high-volatile bituminous and subbituminous ranks. All these coals either contain less than 48 percent dry, mineral-matter-free fixed carbon, or have more than 15,500 British thermal units per pound, calculated on the moist, mineral-matter-free basis.

1 - Moist refers to coal containing its natural inherent moisture but not including visible water on the surface of the coal.

2 - If agglomerating, classify in low-volatile group of the bituminous class.

3 - Coals having 69 percent or more fixed carbon on the dry, mineral-matter-free basis shall be classified according to fixed carbon, regardless of calorific value.

4 - It is recognized that there may be nonagglomerating varieties in these groups of the bituminous class, and there are a notable exceptions in the high-volatile C bituminous group.

SOURCE: American Society for Testing and Materials 1971, Standard Specifications for Classification of Coal by Rank, ASTM Designation D 388-66.

APPENDIX 4

U.S. Bureau of Mines Production Districts *(As Set Forth in the Bituminous Coal Act of 1937)*

District 1.

Eastern Pennsylvania. The following counties in Pennsylvania: Bedford, Blair, Bradford, Cambria, Cameron, Centre, Clarion, Clearfield, Clinton, Elk, Forest, Fulton, Huntingdon, Jefferson, Lycoming, McKean, Mifflin, Potter, Somerset, Tioga. Armstrong County, including mines served by the P. & S.R.R. on the west bank of the Allegheny River, and north of the Conemaugh division of the Pennsylvania Railroad.

Fayette County, all mines on and east of the line of Indian Creek Valley branch of the Baltimore and Ohio Railroad, Indiana County north of but excluding the Saltsburg branch of the Pennsylvania Railroad between Edri and Blairsville, both exclusive.

Westmoreland County, including all mines served by the Pennsylvania Railroad, Torrance, and east.

All coal-producing counties in the state of Maryland. The following counties in West Virginia; Grant, Mineral, and Tucker.

District 2.

Western Pennsylvania. The following counties in Pennsylvania: Allegheny, Beaver, Butler, Greene, Lawrence, Mercer, Venango, Washington. Armstrong County, west of the Allegheny River and exclusive of mines served by the P. & S.R.R. Indiana County, including all mines served on the Saltsburg branch of the Pennsylvania Railroad north of Conemaugh River.

Fayette County, except all mines on and east of the line of Indian Creek Valley branch of the Baltimore and Ohio Railroad. Westmoreland County, including all mines except those served by the Pennsylvania Railroad from Torrance, east.

District 3.

Northern West Virginia. The following counties in West Virginia: Barbour, Braxton, Calhoun, Doddridge, Gilmer, Harrison, Jackson, Lewis, Marion, Monongalia, Pleasants, Preston, Randolph, Ritchie, Roane, Taylor, Tyler, Upshur, Webster, Wetzel, Wirt, Wood. That part of Nicholas County including mines served by the Baltimore and Ohio Railroad and North.

District 4.

Ohio. All coal-producing counties in Ohio.

District 5.

Michigan. All coal-producing counties in Michigan.

District 6.

Panhandle. The following counties in West Virginia: Brooke, Hancock, Marshall and Ohio.

District 7.

Southern Numbered 1. The following counties in West Virginia: Greenbrier, Mercer, Monroe, Pocahontas, Summers. Fayette County, east of Gauley River and including the Gauley River

branch of the Chesapeake and Ohio Railway and mines served by the Norfolk and Western Railway. McDowell County, that portion served by the Dry Fork branch of the Norfolk and Western Railway and east thereof.

Raleigh County, excluding all mines on the Coal River branch of the Chesapeake and Ohio Railway. Wyoming County, that portion served by the Gilbert branch of the Norfolk and Western Railway lying east of the mouth of Skin Fork of Guyandot River and that portion served by the main line to the Glen Rogers branch of the Norfolk and Western Railway.

The following counties in Virginia: Montgomery, Pulaski, Wythe, Giles, Craig. Tazewell County, that portion served by the Dry Fork branch to Cedar Bluff and from Bluestone Junction to Boissevain branch of the Norfolk and Western Railway and Richlands-Jewell Ridge branch of the Norfolk and Western Railway.

Buchanan County, that portion served by the Richlands-Jewell Ridge branch of the Norfolk and Western Railway and that portion of said county on the headwaters of Dismal Creek, east of Lynn Camp Creek (a tributary of Dismal Creek).

District 8.

Southern Numbered 2. The following counties in West Virginia: Boone, Clay, Kanawha, Lincoln, Logan, Mason, Mingo, Putnam, Wayne, Cabell. Fayette County, west of, but not including mines of the Gauley River branch of the Chesapeake and Ohio Railway. McDowell County, that portion not served by and lying west of the Dry Fork branch of the Norfolk and Western Railway.

Raleigh County, all mines on the Coal River branch of the Chesapeake and Ohio Railway and north thereof. Nicholas County, that part south of and not served by the Baltimore and Ohio Railroad. Wyoming County, that portion served by the Gilbert Branch of the Norfolk and Western Railway lying west of the mouth of the Skin Fork of Guyandot River.

The following counties in Virginia: Dickinson, Lee, Russell, Scott, Wise. All of Buchanan County, except that portion on the headwaters of Dismal Creek, east of Lynn Camp Creek (tributary of Dismal Creek) and that portion served by the Richlands-Jewell Ridge branch of the Norfolk and Western Railway.

Tazewell County, except portions served by the Dry Fork branch of the Norfolk and Western Railway and branch from Bluestone Junction to Boissevain of the Norfolk and Western Railway and Richlands-Jewell Ridge branch of the Norfolk and Western Railway.

The following counties in Kentucky: Bell, Boyd, Breathitt, Carter, Clay, Elliott, Floyd, Greenup, Harlan, Jackson, Johnson, Knott, Knox, Laurel, Lawrence, Lee, Leslie, Letcher, McCreary, Magoffin, Martin, Morgan, Owsley, Perry, Pike, Rockcastle, Wayne, Whitley.

The following counties in Tennessee: Anderson, Campbell, Claiborne, Cumberland, Fentress, Morgan, Overton, Roane, Scott.

The following counties in North Carolina: Lee, Chatham, Moore.

District 9.

West Kentucky. The following counties in Kentucky: Butler, Christian, Crittenden, Daviess, Hancock, Henderson, Hopkins, Logan, McLean, Muhlenberg, Ohio, Simpson, Todd, Union, Warren, Webster.

District 10.

Illinois. All coal-producing counties in Illinois.

APPENDIX 4 (Continued)

District 11.

Indiana. All coal-producing counties in Indiana.

District 12.

Iowa. All coal-producing counties in Iowa.

District 13.

Southeastern. All coal-producing counties in Alabama. The following counties in Georgia: Dade, Walker. The following counties in Tennessee: Marion, Grundy, Hamilton, Bledsoe, Sequatchie, White, Van Buren, Warren, McMinn, Rhea.

District 14.

Arkansas-Oklahoma. The following counties in Arkansas: All counties in the state. The following counties in Oklahoma: Haskell, LeFlore, Sequoyah.

District 15.

Southwestern. All coal-producing counties in Kansas. All coal-producing counties in Texas. All coal-producing counties in Missouri. The following counties in Oklahoma: Coal, Craig, Latimer, Muskogee, Okmulgee, Pittsburg, Rogers, Tulsa, Wagoner.

District 16.

Northern Colorado. The following counties in Colorado: Adams, Arapahoe, Boulder, Douglas, Elbert, El Paso, Jackson, Jefferson, Larimer, Weld.

District 17.

Southern Colorado. The following counties in Colorado: All counties not included in Northern Colorado district. The following counties in New Mexico: All coal-producing counties in the State of New Mexico, except those included in the New Mexico district.

District 18.

New Mexico. The following counties in New Mexico: Grant, Lincoln, McKinley, Rio Arriba, Sandoval, San Juan, San Miguel, Santa Fe, Socorro. The following counties in Arizona: Pinal, Navajo, Graham, Apache, Coconino. All coal-producing counties in California.

District 19.

Wyoming. All coal-producing counties in Wyoming. The following counties in Idaho: Fremont, Jefferson, Madison, Teton, Bonneville, Bingham, Bannock, Caribou, Oneida, Franklin, Bear Lake.

District 20.

Utah. All coal-producing counties in Utah.

District 21.

North Dakota-South Dakota. All coal-producing counties in North Dakota. All coal-producing counties in South Dakota.

District 22.

Montana. All coal-producing counties in Montana.

District 23.

Washington. All coal-producing counties in Washington. All coal-producing counties in Oregon. The State of Alaska.

U.S. Bureau of Mines Production Districts

U.S. COAL FIELDS

Source: Department of the Interior: Energy Perspectives 2, June 1976.

FOUR TYPES OF BITUMINOUS COAL MINES

Shaft Mine

Drift Mine

Slope Mine

Surface Mine

Source: National Coal Association: Bituminous Coal Facts 1972

UNDERGROUND MINING

Source: Elements of Practical Coal Mining, S.M. Cassidy, Ed.,
AIME, New York, 1973.

SURFACE MINING — AREA METHOD

1. Topsoil is removed by scrapers and/or bulldozers and stored for reclamation purposes.
2. Overburden is dislodged by blasting or scraping and then stored.
3. Coal is removed by shovels or scrapers.
4. Mined area is filled with overburden, graded, then covered with topsoil, graded, and seeded.

Source: The President's Commission on Coal, Coal Data Book, Washington, D. C., February 1980.

SURFACE MINING — CONTOUR METHOD

1. Topsoil is removed and stockpiled for later reclamation purposes.
2. A bench is dozed into the side of the slope.
3. Blasting cracks the dense overburden.
4. Overburden is hauled by scrapers or trucks and is backfilled continuously.
5. Coal is removed by loaders and/or shovels and carried out of the mining area along the haul road (which has been cut into the slope).
6. While blasting for the next stage of overburden removal, reclamation of the first cut is beginning: the pit is filled with overburden, reggraded, layered with topsoil, then seeded.

Source: President's Commission on Coal, Coal Data Book, Washington, D.C., February 1980

SURFACE MINING — MOUNTAINTOP REMOVAL METHOD

- A particular type of contour mining, in which mining proceeds all the way across the top of the mountain.
- 1. A drill bench is cut from the side of a mountain, both for use as a haul road, and for extending drilling.
- 2. Topsoil is removed and stockpiled.
- 3. The overburden is drilled for placement of explosives.
- 4. Blasting loosens the overburden.
- 5. Loaders or shovels load the overburden into trucks and it is backfilled in a previously-mined portion of the pit or placed in a head-of-hollow fill.
- 6. The exposed coal may be blasted or loaded from the seam, depending on its hardness. Trucks haul the coal out of the pit area.
- 7. The backfilled pit is graded, spread with topsoil, and revegetated, while the next "cut" is begun. A flat to gently-rolling area results.

Source: President's Commission on Coal, Coal Data Book, Washington, D. C., February 1980.

SURFACE MINING — AUGER METHOD

National Coal Association

Elements of Practical Coal Mining, ADME, 1973.

- Augering is a supplementary mining method, used to reach coal which cannot be economically strip mined because of deep overburden.

1. After the coal seam has been mined out to the desired depth (to the highwall face, as determined by the stripping ratio), an auger (like a large drill) is employed to bore horizontally into the seam, perpendicular to the bench.
2. As the auger bores, it carries back out to the pit area the loosened coal.
3. This coal is then trucked out of the mine area to be stored; reclamation of the pit begins.

Major Coal Producers by Size of Output

Producing organizations with annual coal production of 100,000 tons or more are listed alphabetically by size classifications, with state(s) of operation and type of mining as follows:

U Underground Mining
S Strip Mining
A Auger Mining
B Bank Coal (Anth.)

Affiliated producing companies that are a part of a larger group (as reported in KEYSTONE's annual company analysis "U.S. Coal Production By Company") are listed in the size classification of their over-all group. In some cases where the tonnage of individual affiliated companies is smaller than the size classification in which they are listed, their actual tonnage classification is shown in ().

Groupings of companies in Classifications 1, 2 and 3 (1,000,000 tons and up) are based for the most part on 1973 tonnages. A few companies for whom we do not yet have 1973 tonnages, but which fell in this category in 1972 are included. Listings in other classifications are based on the latest tonnage available at the time this analysis was prepared, 1973 or 1972. KEYSTONE's annual company analysis of "U.S. Coal Production By Company" to be published in June, 1974, will provide actual 1973 tonnages for all firms producing 100,000 tons or more.

Size Classifications

Class. 1—3,000,000 Tons and Over
Class. 2—2,000,000 to 2,999,999 Tons
Class. 3—1,000,000 to 1,999,999 Tons
Class. 4—700,000 to 999,999 Tons
Class. 5—500,000 to 699,999 Tons
Class. 6—400,000 to 499,999 Tons
Class. 7—300,000 to 399,999 Tons
Class. 8—200,000 to 299,999 Tons
Class. 9—100,000 to 199,999 Tons
Class. 10—99,000 Tons or Less

Class. 1 3,000,000 Tons and Over

Alabama By-Products Corp.—Ala.—U
Amigo Smokeless Coal Co.—W. Va.—U (5)
Amax Coal Co.—Ill., Ind., Ky., Wyo.—U & S
Arch Coal Co.—Ala.—S(3)
Badger Coal Co.—W. Va.—U(3)
Beatrice Pocahontas Co.—Va.—U(3)
Beth-Elkhorn Corp.—Ky.—USA
Bethlehem Mines Corp.—Pa., W. Va.—USA
Big Horn Coal Co.—Wyo.—S—(4)
Bishop Coal Co.—W. Va.—U(3)
Buckeye Coal Co.—Pa.—U(3)
Buffalo Mining Co.—W. Va.—U(3)
Carbon Fuel Co.—W. Va.—(3)
Central Appalachian Coal Co.—W. Va.—U(5)
Central Coal Co.—W. Va.—(7)
Central Ohio Coal Co.—Ohio—S

Coal Processing Corp.—Va.—U(6)
Consolidation Coal Co.
Blacksville Div.—W. Va.—U(2)
Central Div.—Ohio—U & S
Christopher Coal Co. Div.—W. Va.—US
Mountaineer Coal Co. Div.—W. Va.—U & S
Ohio Valley Div.—W. Va.—U
Pittsburgh Coal Co. Div.—Pa.—U
Pocahontas Fuel Co. Div.—W. Va.—US
Rowland Div.—W. Va.—US(4)
Tennessee Div.—Tenn.—U(3)
Mid-Western Div.—Ill.—U & S
Western Div.—N.D.—S(2)
Cumberland Collieries—Va.—U(5)
Decker Coal Co.—Mont.—(4)
Eads Coal Co.—Ill.—S(4)
Eastern Associated Coal Corp.—Pa., W. Va.—U
Eastern Coal Corp.—Ky.—U(3)
Elkay Mining Co.—W. Va.—U(5)
Falcon Coal Co., Inc.—Ky.—S
Florence Mining Co.—Pa.—U
Freeman Coal Mining Corp.—Ill.—U
Gateway Coal Co.—Pa.—U(3)
Gilbraltar Coal Co.—Ky.—S—U(3)
Gunn-Quealy Coal Co.—Wyo.—U(9)
Harmar Coal Co.—Pa.—U(4)
Helen Mining Co.—Pa.—U(4)
Helvetia Coal Co.—Pa.—(3)
Island Creek Coal Co.—Ky., Pa., Va., W. Va.—U
Itmann Coal Co.—W. Va.—U(3)
Jewell Coal & Coke Co.—Va.—U(3)
Jewell Ridge Coal Corp.—Wyo.—U(2)
Jones & Laughlin Steel Corp.—Pa.—U(2)
Kemmerer Coal Co.—Wyo.—S(2)
Kentland Elkhorn Coal Corp.—Ky.—U(3)
Kentucky Carbon Corp.—Ky.—(3)
Kings Stations Coal Corp.—Ind.—U(4)
Mathies Coal Co.—Pa.—U(2)
Midland Coal Co.—Ill.—S
Nacco Mining Co.—Ohio—U(3)
National Coal Mining Co.—W. Va.—U(4)
North American Coal Corp.—Ohio, Pa., N.D.—U & S
Old Ben Coal Co.—Ill.—U
Old Ben Coal Co.—Ind.—S
Old Ben Coal Co.—Va.—U(6)
Olga Coal Co.—W. Va.—U(3)
Oneida Mining Co.—Pa.—U(6)
Peabody Coal Co.—Ala., Ark., Colo., Ill., Ind., Ky., Mo., Mont., Ohio, Okla., Utah—USA
Pittsburgh & Midway Coal Mining Co.—Ky., Colo., Kan., Mo., N.M.—U & S
Pittston Co., Clinchfield Coal Div.—Va.—U
Quarto Mining Co.—Ohio—U(4)
Ranger Fuel Corp.—W. Va.—U—(4)
Republic Steel Corp.—Ky., Pa.—U
Rochester & Pittsburgh Coal Co.—Pa., U
Rosebud Coal Sales Co.—Wyo.—S(3)
Sewell Coal Co.—W. Va.—U(3)
Shamrock Coal Co.—Ky.—U(3)
Snap Creek Coal Co.—W. Va.—U(9)
Southern Appalachian Coal Co.—W. Va.—U(3)

Southern Ohio Coal Co.—Ohio—(7)
Southwestern Illinois Coal Corp.—Ill.—S
United Electric Coal Cos.—Ill.—S
United States Steel Corp.—Ala., Ky., Pa., W. Va., Colo., Utah—U & A
Utah International, Inc.—N.M.—S
Valley Camp Coal Co.—W. Va.—S, A
Virginia Pocahontas Co.—Va.—U(7)
Walker-Fayette Coal Co.—Ala.—S(4)
Washington Irrig. & Devel. Co.—Wash.—S
Western Energy Co.—Mont.—S
Westmoreland Coal Co.—Va. & W. Va.—U
Windsor Power House Coal Co.—W. Va.—U(5)
Youngstown Mines Corp.—W. Va.—U(4)
Zeigler Coal Co.—Ill., Ky. W.—U

Class. 2 2,000,000 to 2,999,999 Tons

Ashland Mining Corp.—W. Va.—U(10)
Barnes & Tucker Co.—Pa.—U
Baukol-Noonan, Inc.—N.D.—U & S
Blair Fork Coal Co.—Ky.—S(5)
Blue Diamond Coal Co.—Ky.—U(3)
Breathitt County Coal Corp.—Ky.—S, A
C & K Coal Co.—Pa.—S
Cannelton Coal Co.—W. Va.—U & S
Clintwood Mining Co.—Va.—U(6)
Harman Mining Corp.—Va.—U(4)
Inland Steel Co.—Ill.—U
Kaiser Steel Corp.—N.M., Utah—U
King Knob Coal Co.—W. Va.—S, A
Knife River Coal Mining Co.—Mont., N.D.—S
Majestic Collieries Co.—Ky.—U(4)
Monterey Coal Co.—Ill.—U
National Mines Corp.—Ky., Pa.—U
Pacific Power & Light Co.—Wyo.—S
R&F Coal Co.—Ohio—S
Sahara Coal Co.—Ill.—U
Scotia Coal Co.—Ky.—U(4)
Scotia Coal Co.—Tenn.—U(10)
Speidel Fuel Corp.—Ohio—S(4)
Sovereign Coal Corp.—Ky.—U(7)
Webster County Coal Corp.—Ky.—U
Youghiogeny & Ohio Coal Co.—Ohio—U

Class. 3 1,000,000 to 1,999,999 Tons

Amherst Coal Co.—W. Va.—USA
Armco Steel Corp., Mng. Div.—W. Va.—U
Barbour Coal Co.—W. Va.—S & A
Benjamin Coal Co.—Pa.—U, S
Black Creek Coal Sales Agency—Ala.—S(7)
Blackwood Fuel Co., Inc.—W. Va.—(6)
Bradford Coal Co.—Pa.—S
Brown Badgett, Inc.—Ky.—S
Burgess Mng. & Constr. Corp.—Ala.—S
Canterbury Coal Co.—Pa.—U(5)
Cedar Coal Co.—W. Va.—S, A
Cimarron Coal Corp.—Ky.—S
Cravat Coal Co.—Ohio—S

Drummond Coal Co., Inc.—H.E.—Ala.—S(6)
 Duquesne Light Co.—Pa.—U
 Eastover Mining Co.—Ky.—U
 Guaranty Gas Coal Co. Properties—Ky.—U
 Hawley Coal Mining Corp.—W. Va.—U(4)
 Kellerman Mining Co.—Ala.—S(4)
 Kristianson & Johnson Coal Co., Inc.—Pa.—S(6)
 Marty Corp.—Ky.—U
 Mounatin Drive Coal Co.—Ky.—S
 National Mines Corp.—Pa.—U(4)
 Oglebay Norton Co.—Ohio—U
 Ohio Coal & Construction Corp.—Ohio—S, A
 Peter White Coal Mining Corp.—W. Va.—U(8)
 Pocahontas Red Ash Mining Co.—W. Va.—U(10)
 Semet-Solvay Div., Allied Chem. Corp.—W. Va.—U
 Slab Fork Coal Co.—W. Va.—U
 Southern Electric Gen. Co.—Ala.—U
 Terry Elkhorn Mining Co.—Ky.—S
 Union Carbide Corp., Ferroalloys Div.—W. Va., Pa.—U
 Virginia Iron Coal & Coke Co.—Va.—U, S & A
 Woodward Co.—Ala.—U & S
 Wright Coal Co.—Ky.—S(6)

Class. 4
700,000 to 999,999 Tons

Caney Creek Coal Co.—Ky.—S
 Green Coal Co.—Ky.—S
 Greenwich Collieries Co.—Pa.—U
 International Harvester Co.—Ky.—U
 Jones & Brague Mining Co.—Pa.—S
 New River Co.—W. Va.—U
 Omar Mining Co.—W. Va.—USA
 Patsy Development Co.—Ky.—U(10)
 Pikeville Coal Co.—U
 Powellton Co.—W. Va.—U
 Tackett & Manning Coal Corp.—Ky.—S & A
 Taylor & Son Coal Co.—Ala.—S
 Twilight Industries, Inc.—Pa.—S, A
 Wolf Creek Collieries Co.—Ky.—U

Class. 5
500,000 to 699,999 Tons

Aloe Coal Co.—Pa.—S
 Apache Coal Co.—Ky.—U(7)
 B & N Coal Co.—Ohio—S
 Badgett Coal Co., Russell J.—Ky.—S
 Bane Mining Co.—Ky.—U(7)
 Bankhead Mining Co., Inc.—Ala.—S
 Boich Mining Co.—Ohio—S
 C F & I Steel Corp.—Colo.—U
 Charm Mining Co.—Ohio—S
 Hardy Coal Co.—Ohio—S & A
 Holston Corp.—Va.—U(9)
 Imperial Colliery Co.—W. Va.—U(6)
 Jamar Coal Co.—Ohio—S
 Leechburg Mining Co.—Pa.—U
 Lynn Camp Coal Corp.—Va.—U(9)
 Marietta Coal Co., Inc.—Ohio—S
 Mid-Continent Coal & Coke Co.—Colo.—U
 Milburn Colliery Co.—W. Va.—U(8)
 Mt. Mining Co., Inc.—Ky.—S & A(6)

Mynu Coals, Inc.—W. Va.—S & A
 Newcon Coals, Inc.—Ky.—S & A
 New Garden Coal Corp.—Va.—U(8)
 Oak Leaf Coal Co.—W. Va.—USA
 Ohio River Collieries Co.—Ohio—S & A
 Peerless Eagle Coal Co.—W. Va.—U
 Penn Allegheny Coal Co., Inc.—Pa.—U
 Peter Cave Coal Co.—Ky.—U
 Pyro Mining Co.—Ky.—U
 Raven Smokeless Coal Co.—Va.—U(10)
 River Coal Co., Inc.—Ky.—S, A
 Ron Ell Coal Corp.—Ky.—S & A(10)
 So. Hopkins Coal Co.—Ky.—U
 Southwestern Virginia Coal Corp.—Va.—U
 Stansbury & Co., Inc.—Ky.—S & A
 Star Fire Coals, Inc.—Ky.—S & A
 United Pocahontas Coal Co.—W. Va.—U, A, S
 United States Fuel Co.—Utah—U
 United States Pipe & Foundry Co.—Ala.—U
 Whitesville A & S Coal Co.—W. Va.—U & S
 Wyodak Resources Development Corp.—Wyo.—S

Class. 6
400,000 to 499,999 Tons

A. K. P. Coal Co.—Ky.—U
 Allegheny River Mining Co.—Pa.—U
 Brownies Creek Collieries, Inc.—Ky.—S & A
 Buffalo Coal Co., Inc.—Md.—USA
 Campbell & Sons, Inc.—B.R.—Ky.—U
 Caney Br. Coal Co., Inc.—Ky.—U, A, S
 Clemens Coal Co.—Kans.—S
 Cooney Brothers Coal Co.—Pa.—S
 Crescent Coal Co.—Ky.—S & A
 Douglas Coal Co.—W. Va.—S
 Fetterolf Coal Co., Inc.—Pa.—S
 Hallmark & Reid Coal Co.—Ala.—S
 Johns Creek Elkhorn Coal Corp.—Ky.—U
 Laxare, Inc.—W. Va.—USA
 Ligon Preparation Co.—Ky.—U
 Mitchell & Neely, Inc.—Ala.—S
 North Cambria Fuel Co.—Pa.—U & S
 Queen Brothers Coal Co., Inc.—W. Va.—S
 Reliable Coal Corp.—W. Va.—U
 Robinson-Phillips Coal Co.—W. Va.—USA
 Royal Coal Co.—W. Va.—U
 Rushton Mining Co.—Pa.—U
 Ryan's Creek Coal Co., Inc.—Ky.—U
 Solar Fuel Co.—Pa.—U
 South-East Coal Co.—Ky.—U
 Triple Elkhorn Mining Co.—Ky.—S
 Tunnelton Mining Co.—Pa.—U
 Waterloo Coal Co., Inc.—Ohio—S
 Weirs Creek Co.—Ky.—S
 White Ash Mining Corp.—Ky.—USA

Class. 7
300,000 to 399,999 Tons

A Seam Coal Co.—Ky.—S & A
 Adkins Coal Co.—Ky.—U
 Allison Engineering Co.—Pa.—S
 Ambrosia Coal & Const. Co.—Pa.—S
 Anderson & Anderson Constr., Inc.—W. Va.—S & A
 Baughman Coal Co., R.D.—Pa.—S

Bedway Coal Co.—Ohio—S
 Belmon's Coals, Inc.—Ky.—U
 Black Diamond Coal Mining Co.—Ala.—U & S
 Canada Coal Co.—Ky.—U
 Carbon Fuel Co.—Utah—U
 Center Coal, Inc.—Ky.—S
 Chafin Coal Co.—W. Va.—U
 Clayton Coal Co.—Colo.—U
 Coal Stone Mining Co., Inc.—Ky.—S & A
 Cross Creek Coal Co., Inc.—Ohio—S
 Daniels, Morris & Marshall, Inc.—Ky.—S & A
 Delta Mining Co.—Ohio—S
 Douglas Eagle Coal Co.—W. Va.—U
 Doverspike Bros. Coal Co.—Pa.—U & S
 Eagle Coal & Dock Co.—W. Va.—U & S
 Energy Development Co.—Wyo.—S
 G. M. & W. Coal Co., Inc.—Pa.—U
 Grafton Coal Co.—W. Va.—S, A
 Grundy Mining Co.—Tenn.—U
 Hawk Brothers Contr. Co.—Pa.—S
 Hobet Mining & Const. Co.—W. Va.—S & A
 Ikerd & Bandy Co., Inc.—Ky.—U, S
 Jo-Ann Coal Co.—Ky.—S & A
 Kentucky Bell Coal Mining Co.—Ky.—A, S
 Kessler Coals, Inc.—W. Va.—U
 LaRosa Fuel Co., Inc.—W. Va.—S
 Marigold Coal Co., Inc.—Ala.—S
 Ohio Amco, Inc.—Ohio—U
 Oliver Springs Mining Co.—Tenn.—U
 P & N Coal Co., Inc.—Pa., A, S
 Perry & Hylton, Inc.—W. Va.—S
 Pine Rock Coals, Inc.—W. Va.—S, A
 Plateau Mining Co.—Utah—U
 Rita Coal Co.—Ky.—U
 River Processing Inc.—Ky.—S & A
 Riverton Coal Co.—W. Va.—U
 Shackleford Coal Co.—Ky.—U
 Shawville Coal Co., Inc.—Pa.—S & A
 Stahlman Coal Co., Inc. W.P.—Pa.—S
 Standard Sign & Signal Co.—Ky.—U
 State Industries, Inc.—Pa.—S
 Trace Fork Coal Co., Inc.—W. Va.—U
 Volunteer Mining Co.—Tenn.—U
 Wheeling-Pittsburgh Steel Corp.—W. Va.—U
 White Contr. Co., R.N.—W. Va.—S & A

Class. 8
200,000 to 299,999 Tons

Abston Constr. Co.—Ala.—S
 Anthony Mining Co.—Ohio—S
 Associated Drilling, Inc.—Pa.—U
 B. & G. Constr. Co., Inc.—Pa.—S, A
 Benedict, Inc.—Ohio—S
 C & P Coal Co.—W. Va.—S
 Cal-Glo Coal, Inc.—Ky.—USA
 Carlin, Inc., R. S.—Pa.—S
 Carpentertown Coal & Coke Co.—Pa.—U, S & A
 Chapman, Inc., L. R.—Ind.—S
 Corum & Co., Inc.—Ky.—S
 Daugherty Coal Co.—W. Va.—S
 Deskins Mining Co.—W. Va.—S
 Elliot Coal Mining Co.—Pa.—U, S
 Ferris Coal Co.—Ohio—S
 Ford Coal Co.—W. Va.—S & A
 Forsyth-Energy, Inc.—Ill.—U
 Galloway Land Co.—W. Va.—U

Garland Coal & Mining Co.—Ark., Okla.—S
 Glen Irvan Coal Co.—Pa.—S & A
 Hepburnia Coal Co.—Pa.—S
 Hite Preparation Co.—Ky.—U
 Hope Mining Co., Inc.—W. Va.—U
 Huberta Coal Co., Inc.—Ohio—S
 Imperial Coal Co.—Colo.—U
 Industrial Mining Co.—Ohio—S, A
 J. R. Sales, Inc.—Pa.—U
 James Bros. Coal Co.—Ohio—S
 Ken-Lick Coal Co.—Ky.—A
 Kentucky Elkhorn Coals, Inc.—Ky.—USA
 Kentucky Prince Coal Corp.—Ky.—S & A
 Kermit Coal Co., Inc.—W. Va.—U
 Kerry Coal Co.—Pa.—S, A
 Kickapoo Coal Co.—Ky.—U
 King Quarries—Ohio—S
 Lady Jane Collieries, Inc.—Pa.—U
 Laura Coal & Coke Co., Inc.—W. Va.—U
 Leckie Smokeless Coal Co.—W. Va.—U & S
 Loftis Coal Co., Inc.—Ky.—U
 Longwall Mining Inc.—Pa.—U
 Lovilia Coal Co.—Iowa—U
 Lucas Coal Co.—Pa.—S
 Mary Mounts Coal Co.—Ky.—S & A
 Mays Coal Co.—Pa.—S
 Mountain Clay, Inc.—Ky.—S & A
 National Coals, Inc.—W. Va.—U
 Nicholson Run Coal Co.—Pa.—S
 No. Ten Coal Mining Corp.—W. Va.—U
 Ohio Edison Co.—Ohio—S
 Orange Coal Co.—Ohio—S & A
 Oxford Mining Co., Inc.—Ky.—U
 P. B. S. Coals, Inc.—Pa.—S & A
 Paragon Jewel Coal Co., Inc.—Va.—U
 (9)
 Peaker Run Coal Co., Ohio Auger Mining Div.—Ohio—S
 Penn Pocahontas Coal Co.—Pa.—S
 Pennweir Constr. Co.—Pa.—S
 Perry County Coal Corp.—Ky.—U
 Pettito Bros., Inc.—W. Va.—S
 Polen Coal Co.—Ohio—S & A
 Princess Susan Coal Co.—W. Va.—S & A
 Raccoon-Elkhorn Coal Co.—Ky.—U
 Rapoca Coal & Dock Co.—Ky.—S
 Republic Products—Ala.—S
 River Coal Co.—Ohio—S
 S & D Construction Corp.—Ohio—S & A
 Simca Mining, Inc.—Pa.—S
 Spradlin Coal Co.—Tenn.—S
 Stott Coal Co., J. M.—Pa.—S
 Swisher Coal Co.—Utah—U
 Teramana Bros. Coal Co.—Ohio—A & S
 Universal Coal Co., Inc.—Va.—U(9)
 Upahur Coals, Ltd.—W. Va.—U
 Valley Coal Co.—Pa.—U, S
 Wedron Constr. Co.—Ohio—S
 Western Slope Carbon, Inc.—Colo.—U
 Wilmot Mining Co.—Ohio—S
 Zacherl Coal Co., Inc.—Pa.—S

**Class. 9
 100,000 to 199,999 Tons**

Allegheny Mining Corp.—W. Va.—S

Allen Bros. Coal Co.—Tenn.—S
 Ankeny, Donald K.—Pa.—S
 Arcadia Co., Inc.—Pa.—S & A
 Bannock Coal Co.—Ohio—S
 Bear Coal Co.—Colo.—U
 Bear Creek Coal Co.—Tenn.—S
 Belva Coal Corp.—W. Va.—USA
 Big Ben Coal Co.—Iowa—U
 Big Mountain Coals, Inc.—W. Va.—S & A
 Black Fox Mining & Development Corp.—Pa.—S
 Bologna Mining Co.—Ohio, Pa., W. Va.—S
 Branham & Baker Coal Co.—Ky.—S & A
 Brant Coal Co., Franklin—Pa.—S & A
 Brooklyn Coal Co.—W. Va.—S & A
 Brookside-Pratt Mng. Co.—Ala.—S
 Brookwood Equip. Co.—Ala.—S
 Brown Mining Corp.—W. Va.—S & A
 Browning Coal Co.—Utah—U
 Buckeye Coal Mining Co.—Ohio—S
 Buck Knob Coal Co., Inc.—Ky.—S, A
 Bull Creek Coal & Dock Co.—Va.—U
 Bull Creek Mining Corp.—Ky.—S & A
 Busby Coal Co.—Ala.—S
 C. R. & R. Trucking Co., Inc.—Ky.—S & A
 C & S Coal Corp.—Ky.—U
 C & W Coal Co.—W. Va.—U, S
 C & W Mining Co., Inc.—Ohio—USA
 Call & Ramsey Coal Co.—Ky.—S & A
 Calvert & Youngblood Coal Co., Inc.—Ala.—S
 Capitol Fuels, Inc.—W. Va.—S, A, U
 Carolina Mining, Inc.—Ky.—S, A, U
 Coalite, Inc.—Ala.—S
 Colowyo Coal Co.—Colo.—U
 Corley Co.—Colo.—S
 Croner, Inc.—Pa.—S
 Dean Contr. Inc., E. C.—Pa.—S
 Diamond Fork Coal Co.—Ky.—A, S
 Dino Contractors, Inc.—W. Va.—S, A
 Dixie Fuel Co.—Ky.—U
 Dixie Pine Coal Co.—Tenn.—S
 Dixon Run Coal Co.—Pa.—U
 Dodds Coal Co.—Pa.—S & A
 East Fairfield Coal Co.—Ohio—S
 East Ky. Const. & Mng. Co.—Ky.—S & A
 Eberhart Coal, Inc.—Ohio—S
 Eidemiller, Inc., Adam—Pa.—S
 Empire Coal Co.—Ohio—S
 Empire Coal Co.—Pa.—S
 Erwin Coal Corp.—Ky.—S & A
 Expansion Coal Co.—W. Va.—U
 F & F Mining Corp.—W. Va.—S & A
 Fairpoint Coal Co.—Ohio—S
 Farco Co., Inc.—Tenn.—S & A
 Four Leaf Coal Co.—Tenn.—S
 Friend Const. Co., Inc., H. J.—W. Va.—S & A
 Frontier Coals, Inc.—Ky.—S, A
 Genoa Coal Corp.—W. Va.—U
 Goeglein Coal Co.—Ohio—S
 Grays Knob Coal Co.—Ky.—U
 Guinea Hill Mining Co.—Tenn.—S
 Hamilton Contr. Co.—Pa.—S
 Hamlin Coal Co.—Pa.—A, S
 Hampshire Mining Corp.—W. Va.—U
 Harlan Fuel Co., Inc.—Ky.—U
 Harman Coal Corp.—Pa.—USA
 Hawkeye Elkhorn Coal Co., Inc.—Ky.—A, S

Highway Safety Materials, Inc.—Ky.—S
 Hop Coal Co.—Ky.—A, S
 Horner Coal Co., Inc.—W. Va.—S
 Husky Industries—N. D.—S
 Indian Head Mining Co.—Ky.—U
 J & C Elkhorn Co.—Ky.—S & A
 Jandy Coal Co., Inc.—Pa.—U
 Johnson & Morgan Co.—Pa.—S
 K. O. K. Coal Co.—Ky.—U
 Karst-Robbins Coal Co.—Ky.—U
 Kettle Creek Corp.—Pa.—S
 L & D Coal Co.—W. Va.—U
 L. & E. Constr. & Equip. Co.—Pa.—S
 Lasky Constr. Co.—Pa.—S
 Laurel Mining Co., Inc.—Ky.—S & A
 Leemike Coal Co., Inc.—Ky.—USA
 Little Hackney Creek Coal Co.—Ky.—U
 Manor Mng. & Contr. Corp.—Pa.—U
 Markle-Bullers Coal Co.—Pa.—S & A
 Mary Ruth Corp.—Md.—S
 Metzler Coal Co., Tommy—Tenn.—S
 Moran Coal Co., Inc.—Md.—U
 Natural Bridge Coal Co.—Ala.—S
 Ohio Mining Co.—W. Va.—U & S
 Oliver Coal Corp.—Ohio—S
 P & L Coal Co., Inc.—Pa.—S
 Pee Wee Mining Co.—Tenn.—U
 Peggs Run Coal Co., Inc.—Pa.—U
 Pengrove Coal Co.—Pa.—S
 Penn Hill Coal Corp.—Pa.—U
 Perry-Ross Coal Co.—Pa.—S
 Pine Br. Coal Sales, Inc.—Ky.—A, S
 Pioneer Coal Co.—Ky.—U, A
 Poe Coal Co.—Ala.—S
 Powell Coal Co., C. E.—Pa.—S
 Puskarich Mining, Inc.—Ohio—S
 R. & T. Enterprises, Inc.—Ohio—S & A
 Ramo Mining Co.—W. Va.—S & A
 Rayburn Mining Co.—W. Va.—S & A
 River Hill Coal Co., Inc.—Pa.—S
 Roaring Creek Coal Co.—W. Va.—U & S
 Rogers Bros. Const. Co.—W. Va.—S
 Round Mountain Coal Co., Inc.—Ky.—A, S
 Sanner Brothers Coal Co.—Pa.—S
 Siegel, Harold A.—Pa.—S
 Silengo Coal Co.—Colo.—U
 Slater Mining Corp.—Ky.—U
 Southern Utah Fuel Co.—Utah—U
 Svonavec, Inc.—Pa.—S
 Sycamore Mining Co.—W. Va.—U
 Tarheel Coals, Inc.—Ky.—S & A
 Terry Const. Co., L. H.—Ky.—S
 Terry Glenn Coal Co.—Ky.—U
 Thacker Contr. Co., J. L.—Ky.—A, S
 Thornberry Const., Inc.—Ind.—S
 Tower Mt. Coals, Inc.—Ky.—S & A
 Tri-Moore Mining Co.—Ky.—U
 V.H.R. Coal Co.—Ala.—S
 Veon, Inc., Ralph A.—Pa.—A & S
 Walden Ridge Coal Co.—Tenn.—S
 Walnut Mtn., Inc.—Tenn.—S
 Wenver & Sons, A. P.—Pa.—S
 Wergin Mining Co.—W. Va.—S
 Weskol Mining Co.—Ky.—S & A
 Western Coal Corp.—W. Va.—S
 West Freedom Mining Corp.—Pa.—S & A
 White Mining Corp.—Ky.—A, S
 Willowbrook Mining Co.—Pa.—S
 Winner Bros. Coal Co., Inc.—Md.—U
 Winston Coal Co.—W. Va.—A & S
 Winters Coal Co.—Ala.—S
 Zimnox Co.—Ohio—S

Major Coal Producers by Size of Output

Producing organizations with annual coal production of 100,000 tons or more are listed alphabetically by size classifications, with state(s) of operation and type of mining as follows:

U Underground Mining
S Strip Mining
A Auger Mining
B Bank Coal (Anth.)

Affiliated producing companies that are a part of a larger group (as reported in KEYSTONE's annual company analysis "U.S. Coal Production By Company") are listed in the size classification of their over-all group. In some cases where the tonnage of individual affiliated companies is smaller than the size classification in which they are listed, their actual tonnage classification is shown in ().

Groupings of companies in Classifications 1, 2 and 3 (1,000,000 tons and up) are based for the most part on 1977 tonnages. A few companies for whom we do not yet have 1977 tonnages, but which fell in this category in 1976 are included. Listings in other classifications are based on the latest tonnage available at the time this analysis was prepared, 1977 or 1976. KEYSTONE's annual company analysis of "U.S. Coal Production By Company" to be published in June, 1978, will provide actual 1977 tonnages for all firms producing 100,000 tons or more.

Size Classifications

Class. 1—3,000,000 Tons and Over
Class. 2—2,000,000 to 2,999,999 Tons
Class. 3—1,000,000 to 1,999,999 Tons
Class. 4—700,000 to 999,999 Tons
Class. 5—500,000 to 699,999 Tons
Class. 6—400,000 to 499,999 Tons
Class. 7—300,000 to 399,999 Tons
Class. 8—200,000 to 299,999 Tons
Class. 9—100,000 to 199,999 Tons
Class. 10—99,000 Tons or Less

Class. 1 3,000,000 Tons and Over

Affinity Mining Co.—W. Va.—U(8)
Alabama By-Products Corp.—Ala.—U & S
AMAX Coal Co.—Ill., Ind., Ky., Wyo.—S
Amigo Smokeless Coal Co.—W. Va.—U(8)
Arch Mineral Corp.—Wyo.—S
Avery Coal Co.—Pa.—S(3)
Badger Coal Co.—W. Va.—U & S(5)
Beatrice Pocahontas Co.—Va.—U(5)
Beth-Elkhorn Corp.—Ky.—U, S & A
Bethlehem Mines Corp.—Pa., W. Va.—U, S & A
Big Horn Coal Co.—Wyo.—S(2)
Bishop Coal Co.—W. Va.—U(4)
Bratzel Mines—Utah—U(4)
Bridger Coal Co.—Wyo.—S
Buffalo Mining Co.—W. Va.—U & S(4)
C&K Coal Co.—Pa.—S(2)
Cambria Coal Co.—Pa.—S(5)
Cedar Coal Co.—W. Va.—U & S(3)
Central Appalachian Coal Co.—W. Va. S & U(6)

Central Ohio Coal Co.—Ohio—S
Consolidation Coal Co.
Eastern Reg.—Pa. W. Va.—U
Midwestern Reg.—Ill., Ohio—U & S
Northern W. Va. Reg.—W. Va.—U & S
Southern Appalachian Reg.—Tenn., W. Va.—U & S
Western Reg.—N.D., Utah, Can.—U & S
Cumberland Collieries—Va.—S(3)
Decker Coal Co.—Mont.—S
Drummond Coal Co. Div., H. E.—Ala.—S
Eastern Associated Coal Co.—Pa., W. Va.—U
Eastern Coal Corp.—Ky.—U(5)
Elkay Mining Co.—W. Va.—U & S(4)
Empire Energy Corp.—Colo.—U(6)
Energy Fuels Corp.—Colo.—S
Falcon Coal Co., Inc.—Ky.—S
Florence Mining Co.—Pa.—U(3)
Freeman-United Coal Mining Co.—Ill.—U & S
Gibraltar Coal Co.—Ky. S(4)
Harmar Coal Co.—Pa.—U(6)
Helen Mining Co.—Pa.—U(4)
Helvetia Coal Co.—Pa.—U(3)
Industrial Generating Co.—Tex.—S
Island Creek Coal Co.—Ky., Pa., Va., Ohio, W. Va.—U
Itmann Coal Co.—W. Va.—U(1)
Jewell Coal & Coke Co.—Va.—U(3)
Jewell Ridge Coal Corp.—Va.—U & S(2)
Kemmerer Coal Co.—Wyo.—S
Kentland Elkhorn Coal Corp.—Ky.—U(7)
Kiewit, Peter & Sons Co.—Mont. & Wyo.—S
Knife River Coal Mining Co.—Mont., N.D.—S
Mapco Inc.—Ky.—U & S
Martiki Coal Corp.—Ky.—S(3)
Mathies Coal Co.—Pa.—U(3)
Nacco Mining Co.—Ohio—U(3)
National Coal Mining Co.—W. Va.—U(9)
NERCO—Mont., Wyo.—S
North American Coal Corp.—Ohio, Pa., N.D.—U & S
Old Ben Coal Co.—Ill., Ind., Va.—U & S
Peabody Coal Co.—Ala., Ariz., Ark., Colo., Ill., Ind., Ky., Mo., Mont., Ohio, Okla., Utah—U, S & A
Pittsburg & Midway Coal Mining Co.—Ky., Colo., Mo., N.M.—U & S
Pittston Co., Clinchfield Coal Div.—Va., W. Va.—U & S
Pontiki Coal Corp.—Ky.—U(6)
Quarto Mining Co.—Ohio—U(3)
R & F Coal Co.—Ohio—S
Ranger Fuel Corp.—W. Va.—U & S(5)
Rocheater & Pittsburgh Coal Co.—Pa.—U & S
Rosebud Coal Sales Co.—Wyo.—S(2)
Sewell Coal Co.—W. Va.—U & S(3)
Shamrock Coal Co.—Ky.—U(3)
Shannon Coal Co.—Pa.—S(3)
Snap Creek Coal Co.—W. Va.—U(10)
Southern Appalachian Coal Co.—W. Va.—U & S(4)

Southern Ohio Coal Co.—Ohio, W. Va.—U(2)
Southwestern Illinois Coal Corp.—Ill.—S
Stahlman Coal Co.—Pa.—S(5)
United States Steel Corp.—Ala., Ky., Pa., W. Va., Colo., Utah—U & S
Utah International, Inc.—N.M.—S
VP-5 Mining—Va.—U(10)
Valley Camp Coal Co.—W. Va.—U & S(2)
Valley Camp of Utah—Utah—U(8)
Vantage Coal Corp.—Pa.—S(5)
Virginia Iron Coal & Coke Co.—Va.—U, S & A(3)
Virginia Pocahontas Co.—Va.—U(7)
Walker-Fayette Coal Co.—Ala.—S(5)
Washington Irrig. & Devel. Co.—Wash.—S
Webster County Coal Corp.—Ky.—U(2)
Western Energy Co.—Mont.—S
Westmoreland Coal Co.—Va. & W. Va.—U, S & A
Westmoreland Resources—Mont.—S
Windsor Power House Coal Co.—W. Va.—U(5)
Zeigler Coal Co.—Ill., Ky. W.—U

Class. 2 2,000,000 to 2,999,999 Tons

American Coal Co.—Utah—U
American Industries & Resources Corp.—Ala., Ky., Mo., Ohio, Pa., W. Va.—S
Armco Steel Corp. Mng. Div.—W. Va.—U(3)
Baukol-Noonan, Inc.—N.D.—S
Benjamin Coal Co.—Pa.—S(3)
Big Mountain Coals, Inc.—W. Va.—S(5)
Carbon Fuel Co.—W. Va.—U, S & A(3)
Eastover Mining Co.—Ky.—U, S, A
Emerald Mines Corp.—Pa.—U(8)
Empire Coal Co.—Pa.—S(7)
Gateway Coal Co.—Pa.—U(3)
Greenwich Collieries Co.—Pa.—U(3)
International Energy Corp.—Ala., Mo.—S(10)
Jones & Laughlin Steel Corp.—Pa.—U(3)
Kentucky Carbon Corp.—Ky.—U(4)
Lykes Resources, Inc.—Pa., W. Va.—U
Midland Coal Co.—Ill.—S
Missouri Mining Co.—Mo.—S(4)
Monterey Coal Co.—Ill.—U
National Mines Corp.—Ark., Ky E., Pa., W. Va.—U & S
Nemacolin Mines Corp.—Pa.—U(4)
Ohio Coal & Const. Corp.—Ohio—S(3)
Olga Coal Co.—W. Va.—U(4)
Oneida Mining Co.—Pa.—U(8)
Penn United Energies Inc.—Pa.—S(10)
Pennsylvania Mines Corp.—Pa.—U
Republic Steel Corp.—Ala., Ky., Pa., W. Va.—U
Rushon Mining Co.—Pa.—U(7)
Sunoco Energy Development Co.—Wyo.—S
Triex Excavating Co.—Ky.—S(10)
Tunnell Mining Co.—Pa.—U(7)
Universal Coal & Energy Co.—Mo., Ohio—S(6)

Western Coal Co.—N.M.—S
West Va. Energies Inc.—W. Va.—S(10)
Youngstown Mines Corp.—W. Va.—U(9)

Class. 3
1,000,000 to 1,999,999 Tons

Addington Bros. Mining, Inc.—Ky.—S & A
Amherst Coal Co.—W. Va.—U & S
Appalachian Contracting Co.—Ky.—S & A(9)
Ashland Mining Co.—W. Va.—S & A(10)
Bankhead Mining Co.—Ala.—S(6)
Barbour Coal Co.—W. Va.—S & A
Barnes & Tucker Co.—Pa.—U
Bedcor, Inc.—W. Va.—S(10)
Black Watch Black Diamond—Va.—U, S & A(4)
Blue Diamond Coal Co.—Ky., Va.—U, S & A
Blue Diamond Mining—Ky.—S & A(3)
Bradford Coal Co.—Pa.—S
Brown Radgett, Inc.—Ky.—S
Cannelton Coal Co.—W. Va.—U & S
Canterbury Coal Co.—W. Va.—U(6)
Carbon Fuel Co.—W. Va.—U & S(3)
Certicoals Inc.—W. Va.—S & A(10)
Cherokee Coal Co.—Kans., Okla.—S
Cimarron Coal Corp.—Ky.—S
Clintwood Mining Co.—Va.—U, S & A(9)
Coastal States Energy Co.—Utah—U
Cobb Coal Co.—Ala.—S(5)
Cravat Coal Co.—Ohio—S(4)
Delta Coal Co.—Pa.—U(6)
Doverspike Bros. Coal Co.—Pa.—S & A(5)
Duquesne Light Co.—Pa.—U
Eastover Mining Co.—Ky., Va.—U & A(3)
Energy Development Co.—Wyo.—U & S
Fetterolf Coal Co., M.F.—Pa.—U & S
G. M. & W. Coal Co., Inc.—Pa.—U(4)
Green Coal Co.—Ky.—S
Harman Mining Corp.—Va.—U, S & A(5)
Ikerd-Bandy Co., Inc.—Ky.—S(8)
Inland Steel Co.—Ill.—U
Jefferson Coal Co.—Ala.—S(9)
Kaiser Steel Corp.—N.M., Utah—U & S
Kaneb Services, Inc.—Ky., Md.—U, S & A
Kentucky Carbon Corp.—Ky.—U, S & A(5)
King Knob Coal Co.—W. Va.—S
Kristianson & Johnson Coal Co., Inc.—Pa.—S(5)
Lee Construction Co.—Ky.—S(8)
Leece, Inc.—Ky.—U & S(4)
Majestic Collieries Co.—Ky. E.—S(7)
Maple Mining Co.—W. Va.—U(8)
Martin County Coal Corp.—Ky. E.—U & S
Mears Coal Co.—Pa.—U & S(5)
Mountain Clay, Inc.—Ky.—S & A(10)
Mountain Drive Coal Co.—Ky.—U & S
Norton Coal Co.—Va.—U, S & A(5)
Phillips Coal Inc.—Md.—S(9)
Puskarich Mining Inc.—Ohio—S(8)
Rapoca Energy Corp.—Va.—U, S & A
Robertson & Associates, Inc.—Ala., Ill.—U & S
Sahara Coal Co.—Ill.—U & S
Scotia Coal Co.—Ky., Va.—U(4)
Semet-Solvay Div., Allied Chem. Corp.—W. Va.—U & S
South-East Coal Co., Inc.—Ky. E.—U

South Hopkins Coal Co.—Ky.—U
South Side Mining & Constr. Co.—Ky.—S(8)
Sovereign Coal Corp.—Ky. E.—U, S & A(7)
Stansbury & Co., Inc.—Ky.—S & A(5)
Stott Coal Co., Inc.—Pa.—S(9)
Upshur Coals Corp.—W. Va.—U(8)
Youghiogheny & Ohio Coal Co.—Ohio—U
Zapata Coal Corp.—W. Va.—U & S(6)

Class. 4
700,000 to 999,999 Tons

Aloe Coal Co.—Pa.—S(7)
Bannock Coal Co.—Ohio—S(7)
Beckley Coal Mining Co.—W. Va.—U
Bills Coal Co.—Kans., Mo., Okla.—U & S
Blackwood Fuel Corp.—Va.—U, S & A—(9)
Burgess Mng. & Constr. Corp.—Ala.—S
Coal Resources Corp.—Ky.—U
Cooney Brothers Coal Co.—Pa.—S
Diamond Coal Co. Inc.—Ky. E.—S & A
Five Oaks Coal Co.—Va.—A(9)
Grafton Coal Co.—W. Va.—S
Hardy Coal Co.—Ohio—S & A
Hawley Coal Mining Corp.—W. Va.—U & S
Jones & Brague Mining Co.—Pa.—S
Kitchikan Fuel Corp.—W. Va.—U, S & A(8)
Lester Coal Co.—Va.—S & A(8)
Luzerne Coal Co.—Pa.—S
Marietta Coal Co., Inc.—Ohio—S
Mid-Continent Coal & Coke Co.—Colo.—U
Oglebay Norton Co.—Ohio—U
Ohio River Collieries Co.—Ohio—S(7)
Paramount Mining Corp.—Va.—S
Permac, Inc.—Va.—(7)
Pyro Mining Co.—Ky. W.—U
Resource Exploration & Mining Inc.—Wyo.—S
River Coal Co.—Ky. E.—S & A
Royal Coal Co.—W. Va.—U(6)
Sidwell Bros., Inc.—Ohio—S
Slab Fork Coal Co.—W. Va.—U
South East Coal Co.—Ky.—U
Star Fire Coals, Inc.—Ky.—S & A
Union Carbide Corp., Metals Div.—W. Va.—U
United Pocahontas Coal Co.—W. Va.—U(7)
Usibelli Coal Mines Inc.—Alaska—S
Walter, Jim, Resources, Inc.—Ala.—U
Peter White Coal Mining Corp.—W. Va.—S & A(5)
Wolf Creek Collieries Co.—Ky.—U
Wyodak Resources Dev. Corp.—Wyo.—S

Class. 5
500,000 to 699,999 Tons

Appolo Fuels, Inc.—Ky. E.—S
Beasley Energy, Inc.—Ohio, W. Va.—S
Buffalo Coal Co., Inc.—W. Va.—S(6)
C F & I Steel Corp.—Colo.—U
Canada Coal Co.—Ky.—U
Caney Creek Coal Co.—Ky.—S
Contracting Enterprises—Va.—S
Crestcoal Co.—Ky.—S & A
Daniels, Morris & Marshall, Inc.—Ky.—S & A
Davis Trucking Co.—W. Va.—S(9)
Energy Development Corp.—W. Va.—U, S & A
Grundy Mining Co.—Tenn.—U

ICI America Inc.—Tex.—S
J. M. T. Company—Ky. W.—S
Jumacris Mining, Inc.—W. Va.—U
Kanawha Coal Co.—W. Va.—U
Ligon Preparation Co.—Ky.—U
Mead Coal—Ala.—U
North Cambria Fuel Co.—Pa.—S
Old Home Manor Inc.—Pa.—S
P & N Co., Inc.—Pa.—S & A
Peach Creek Processing Co.—W. Va.—U & S
Penn. Allegheny Coal Co., Inc.—Pa.—U
Pikeville Coal Co.—Ky. E.—U
Plateau Mining Co.—Utah—U
Ray Coal Co.—Ky.—U, S & A
River Processing Co.—Ky.—S & A
Tackett & Manning Coal Corp.—Ky.—S & A
Thornberry Const., Inc.—Ind.—S
Twilight Industries, Inc.—Pa.—S
United States Fuel Co.—Utah—U
Wolverine Mining Corp.—Ky. E.—S

Class. 6
400,000 to 499,999 Tons

Allegheny Mining Corp.—Md., W. Va.—S
Apache Mining Co.—Ky. E.—U
Boich Mining Co.—Ohio—S
Cardinal Mining Co.—Pa.—S
Chafin Coal Co.—W. Va.—U
Daniel Constr. Co.—Ky. E.—S & A
Elliot Coal Mining Co., Inc.—Pa.—S
Gilbert Fuel Co.—Ohio—S
Hamilton Contr. Co.—Pa.—S
Harlan Fuel Co., Inc.—Ky. E.—U
Hobet Mining & Constr. Co.—W. Va.—S
Holmes Limestone Co.—Ohio—S
International Harvester Co.—Ky. E.—U
Kermit Coal Co. Inc.—W. Va.—U
Longbranch Coal Co.—Ky. E.—S & A
Marty Corp.—Ky. E.—S
NewEra Resources, Inc.—Ky. E.—U & S
New River Co.—W. Va.—U & S
Omar Mining Co.—W. Va.—U & S
Peter Cave Coal Co.—Ky. E.—U
Polls Creek Coal Co., Inc.—Ky. E.—S & A
River Hill Coal Co., Inc.—Pa.—S
Savoy Coals, Inc.—Ky. E.—S & A
Shackleford Coal Co.—Ky.—U
Solar Sources—Ind.—S
Southwestern Va. Coal Corp.—Va.—S & A
Sterling Smokeless Coal Co.—W. Va.—U & S
Swisher Coal Co.—Utah—U
Trace Fork Coal Co.—W. Va.—U
Universal Minerals, Inc.—Pa.—S
W-P Coal Co.—W. Va.—U & S

Class. 7
300,000 to 399,999 Tons

Belva Coal Co., Inc.—W. Va.—U & S
Benedict, Inc.—Ohio—S
Birwil, Inc.—Ky. E.—S
Boyd County Coal Co.—Ky. E.—S
Buckhorn Mining Co., Inc.—Ky. E.—S & A
C. A. B. Coal Corp.—Ohio—S
Cal-Glo Coal, Inc.—Ky. E.—U, S & A
Carpentertown Coal & Coke Co.—Pa.—U, S & A
Clemens Coal Co.—Kans.—S
Coalite Inc., Div. Brilliant Coal Co.—Ala.—S
Crescent Hills Coal Co., Inc.—Pa.—U & S

Crescent Industries Inc.—Ky. E.—A
 Dunavant Coal Co.—Ky. E.—U, S & A
 Eagle Coal & Dock Co.—W. Va.—U & S
 Eidemiller, Inc., Adam—Pa.—S
 Empire Coal Co.—Ohio—S
 Garland Coal & Mining Co.—Ark., Okla.—S
 Hallmark Coal Co., Inc.—Ala.—S
 Hawk Contr. Co.—Pa.—S
 Hawkeye Elkhorn Coal Co., Inc.—Ky. E.—U & S
 Hepburnia Coal Co.—Pa.—S
 Hite Preparation Co.—Ky.—U
 Holston Corp.—Va.—U(9)
 Imperial Colliery Co.—W. Va.—U & S
 Jaymar Coal Co.—Ohio—S
 Ky. Central Coal Corp.—Ky.—S & A
 Kentucky-Virginia Coal Corp.—Ky. E.—U & S
 Kessler Coals, Inc.—W. Va.—U
 King Coal Co.—Ala.—S
 LaRosa Fuel Co., Inc.—W. Va.—S
 Laurel Run Mining Co.—W. Va.—U
 Leckie Smokless Coal Co.—W. Va.—U & S
 Long Pit Mining Co.—Tenn.—A & S
 Lucas Coal Co.—Pa.—S
 Maidsville Coal Co.—W. Va.—U & S
 Milburn Colliery Co.—W. Va.—U
 Mineral Hill Corp.—Pa.—S
 Mitchell & Neely, Inc.—Ala.—S
 Newcon Coals, Inc.—Ky. E.—S & A
 New Garden Coal Corp.—Va.—U & S (8)
 P. B. S. Coals, Inc.—Pa.—S & A
 P & H Equipment Co.—Tenn.—U & S
 Peerless Eagle Coal Co.—W. Va.—U
 Penn Pecahontas Coal Co.—Pa.—S
 Powellton Co.—W. Va.—U
 Princess Susan Coal Co.—W. Va.—A & S
 Robinson-Phillips Coal Co.—W. Va.—U & S
 Sandy Fork Mining Co., Inc.—Ky. E.—S & A
 Sanner Brothers Coal Co.—Pa.—S
 Schlabach Coal Co.—Ohio—S
 Sextet Mining Corp.—Ky.—S
 Silengo Coal Co.—Colo.—S
 Solar Fuel Co.—Pa.—U & S
 South Central Coal Co.—Ky. E.—S & A
 Standard Sign & Signal Co.—Ky. E.—U
 Temco Mining, Inc.—Ky. E.—S & A
 Tesoro Coal Co.—Ky. E.—S & A
 3 States Trucking, Inc.—Ill.—U
 Triple Elkhorn Mining Co.—Ky. E.—S
 Valley Coal Co., Inc.—Pa.—U & S
 Waterloo Coal Co., Inc.—Ohio—U & S
 Weebro, Inc.—Ky. W.—S
 W. Va. Rebel Co.—Ky. E.—S
 Whitesville, A & S Coal Co.—W. Va.—S

Class. 8 200,000 to 299,999 Tons

Abston Constr. Co.—Ala.—S
 Ace Drilling Coal Co., Inc.—Pa.—S
 Ambrosia Coal & Const. Co.—Pa.—S
 Anderson & Anderson Const. Inc.—W. Va.—S
 Ankeny, Donald K.—Pa.—S
 Anthony Mining Co.—Ohio—S & A
 Apache Coal Co.—Ky.—U(10)
 Associated Drilling, Inc.—Pa.—U
 Bailey Mining Co., Inc.—Ky. E.—U
 Bane Mining Co.—Ky.—U(9)
 Baughman Coal Co., R. D.—Pa.—S
 Bedway Coal Co.—Ohio—S & A
 Bennoc, Inc.—Ohio—S

Betty B Coal Co.—Va.—U
 Blackhawk Mining Co.—Ky. E.—S
 Bologna Mining Co.—Pa., W. Va.—S
 Brown Auger Mining—Ohio—A(10)
 Brownies Creek Collieries—Ky. E.—S & A
 Buffalo Coal Co., Inc.—Md.—S
 C & W Mining Co., Inc.—Ohio—U & S
 Calvert & Marsh Coal Co., Inc.—Ala.—S
 Cammos Coal Mining Co.—Pa.—S(9)
 Caney Br. Coal Co., Inc.—Ky. E.—S & A
 Carr Creek Fuel Co.—Ky.—U
 Center Coal, Inc.—Ky.—S
 Chapperal Coal Corp.—Ky. E.—U
 Cheyenne Sales Co.—W. Va.—S
 Circle C Coal Co.—Ky. E.—S & A
 Clifton Coal Co., Inc.—Pa.—S
 Collins & May Mining Co.—Ky. E.—S
 Cumberland Coal Corp.—Tenn.—S
 D & C Mining Co., Inc.—W. Va.—S(9)
 Daugherty Coal Co.—W. Va.—S
 Delta Mining, Inc.—Md.—U
 Diamond T Coal Co.—Pa.—S
 Dixie Fuel Co.—Ky. E.—U
 Dorothy Duke Mining Co.—W. Va.—U
 Douglas Coal Co.—W. Va.—S
 Dry Lake Coal Co., Inc.—Ky. E.—U
 Expansion Mining Co.—W. Va.—(9)
 Garbart Construction Co., Inc.—W. Va.—S
 Glacial Minerals, Inc.—Pa.—S
 Glen Irvan Coal Co.—Pa.—U & S
 Glenn Coal Co.—Pa.—S
 Golden Oak Mining Co.—Ky. E.—S & A
 Harlan No. 4 Coal Co.—Ky.—U
 Hawks Nest Mining Co.—W. Va.—U (10)
 High Spur Coal Co.—W. Va.—S
 Industrial Mining Co.—Ohio—S & A
 Invesco International Corp. of Alabama, Inc.—Ala.—S
 J & D Coal Co.—Ky. E.—S & A
 J. T. Corp.—Ohio—S
 Jandy Coal Co.—Pa.—U
 Johns Creek Elkhorn Coal Corp.—Ky. E.—U
 Johnson Coal Co., Inc.—Ky. E.—U
 Johnstown Coal & Coke Co.—Pa.—U & S
 Kann, John—Pa.—S
 Kern Coal & Vega Coals Inc.—Ky. E.—S
 Ken-Lick Coal Co.—Ky.—A & S
 Kentucky Prince Coal Co.—Ky. E.—S & A
 Kerr Coal Co.—Colo.—S
 Kerry Coal Co.—Pa.—S & A
 King Quarries—Ohio—S
 Lady Jane Collieries, Inc.—Pa.—U
 Lakeside Coal Co., Inc.—Ala.—S
 Leechburg Mining Co.—Pa.—U
 Lee Mike Coal Co., Inc.—Ky. E.—S & A
 Loftis Coal Co., Inc.—Ky.—U
 Logan Lucas Coal Co.—Ky. E.—U
 Lookout Mountain Coal Co.—Ga.—S
 Lovilia Coal Co.—Iowa—U
 Markle-Bullers Coal Co.—Pa.—S
 MASH, Inc.—Tenn.—U
 Musteller Coal Co.—W. Va.—U & S
 McCoy-Alma Coal Corp.—Ky. E.—U & S
 McCoy Elkhorn Coal Corp.—Ky. E.—U
 Mercury Coal & Coke Inc.—W. Va.—S
 Middle States Coal Co., Inc.—Ky. E.—S & A
 Mt. Mining Co., Inc.—W. Va.—S
 Mynu Coals, Inc.—W. Va.—S
 Ohio Edison Co.—Ohio—S
 Oliver Springs Mining Co.—Tenn.—U

Orbit Mining Co., Inc.—Ky.—S
 Owens Coal Mining Co.—Pa.—S & A
 P & K Ltd.—Okla.—S
 P. V. Corp.—Ind.—S
 Peaker Run Coal Co.—Ohio, W. Va.—S
 Petitto Bros. Inc.—W. Va.—S
 Piney Creek Coal Co.—W. Va.—U & S
 Pratt Mining Co.—W. Va.—S
 R. E. M. Coal Co., Inc.—Pa.—S
 Raven Hocking Coal Corp.—Ohio—S
 Reddinger, Terry—Pa.—S
 Reliable Coal Corp.—W. Va.—U
 Richland Coal Co.—Ky. E.—S
 Ridgeway Fuel Corp.—Ky. E.—S & A
 Rita Coal Co.—Ky.—U
 Riverton Coal Co.—W. Va.—U
 Rough River Coal Co.—Ky.—S
 Shawville Coal Co., Inc.—Pa.—S
 Shemco Coal Inc.—Tenn.—S
 Straight Creek Mining Co.—Ky. E.—S
 Sugar Loaf Mining Co.—Ark.—S
 T & T Darby Coal Co., Inc.—Ky. E.—S & A
 Tarheel Coals, Inc.—Ky. E.—S & A
 Valley Mining Inc.—Ohio—S(9)
 Volunteer Mining Co.—Tenn.—U
 Western Coal Corp.—Ky. E.—S
 Will Construction Co., Inc.—Ind.—S
 Williamson Coal Co.—Ill.—U
 Wilmot Mining Co.—Ohio—S

Class. 9 100,000 to 199,999 Tons

A. B. C. Corporation—Ala.—S
 A. & E. Coal Co.—Ky. E.—U
 A. & H. Coal Co.—Pa.—S
 A. K. P. Coal Co.—Ky. E.—U
 Allied Coal Corp.—Ky. E.—U
 Alumbaugh Coal Corp.—Pa.—A & S
 Anderson Co., M.C.—Tenn.—U
 Arcadia Co., Inc.—Pa.—S
 B & G Construction Co., Inc.—Pa.—S
 BG & M Coal Co.—Ky. E.—A & S
 B. & H. Elkhorn Coal Co., Inc.—Ky. E.—S & A
 B & N Coal Inc.—Ohio—S
 B. W. H. Inc.—Ky. E.—S
 Bailey Hill Coal Co., Inc.—Ky. E.—U
 Bear Coal Co.—Colo.—U
 Belibe Coal Corp.—Va.—U
 Benle Coal Corp.—Ky. E.—S & A
 Bentley Coal Co., Inc.—Pa.—S
 Berry Coal Co.—Ala.—S
 Big Hill Coal Co.—Ky. E.—U
 Black Energy Mining Co.—Ky. W.—S
 Bluebird Collieries, Inc.—Ky.—S & A
 Blue Gem Coal & Land Corp.—Ky.—S & A
 Bon Trucking Co.—Ky. E.—S & A
 Branham & Baker Coal Co.—Ky.—S & A
 Brazil Coal & Clay—Ind.—S
 Bridgeview Coal Co.—Md.—S
 Brookwood Eqpt. Co., Inc.—Ala.—S
 Brown Co., Earl M.—Pa.—S
 Buckeye Coal Mining Co.—Ohio—S & A
 Bull Run Mining Co.—W. Va.—U
 Burford, S. S. "Joe," Inc.—W. Va.—S & A
 Burnam Coal Co.—Pa.—S
 C. R. & R. Trucking Co., Inc.—Ky. E.—S & A
 C. & W. Coal Co.—Ky. E.—S & A
 Cullahan-Elkhorn Coal Co., Inc.—Ky. E.—U
 Calvert & Youngblood Coal Co., Inc.—Ala.—S
 Cambria Mills Coal Co., Inc.—Pa.—S
 Capitol Fuels, Inc.—W. Va.—U

Carbonex Coal Co.—Okla.—S
 Carlin, Inc.—R.S.—Pa.—S
 Caudill Const. Co., Inc.—Ky.—E—S(9)
 Central Utility—Ind.—S
 Century Inc.—Ky.—E.—S
 Chiles Drilling Co., Inc.—Ky.—E.—S
 Christopher Coal Sales, Inc.—W. Va.—U
 Circle B Coal Co.—Ky.—S
 Clarion Fossil Fuels Corp.—Pa.—S
 Clear Creek Coal Co.—Tenn.—U
 Coal Fuels Inc.—Ky.—E.—U
 Coffey Constr. Co., Paul.—Ky.—E.—S
 Cole & White, Inc.—Ky.—E.—S
 Columbine Mining Co.—Wyo.—S
 Co-op Mining Co.—Utah.—U
 Crooksville Coal Co., Inc.—Ohio.—S
 D & H Coal Co., Inc.—Tenn.—S
 D & L Coal Co., Inc.—W. Va.—S
 DIME Coal Corp.—W. Va.—S
 D & S Coal Co., Inc.—Ky.—W.—S
 Dan Branch Mining Co.—Tenn.—U
 Daniel Boone Coal Co. of W. Va., Inc.—W. Va.—U
 R. R. Dawson Bridge Co.—Ky.—S
 Dean Construction, Inc.—E.C.—Pa.—S
 DeKins B. Coal Co.—Ky.—E
 Dippel & Dippel Coal Co.—W. Va.—S
 Donbow Mining Co., Inc.—Ky.—W.—S
 Dow Mining Co.—Ohio.—S
 Drake Coal Co., Inc.—Ky.—E.—S
 Eagle Ridge Coal Co.—W. Va.—S
 East Coal Co.—Ky.—E.—U
 East Fairfield Coal Co.—Ohio.—S
 Eastport Coal Co.—Ohio.—S
 Eastport Coal Co.—W. Va.—U
 Elm Coal Corp.—Ky.—E.—S
 Empire Case Co.—Ala.—S
 English Coal Co., Inc.—Ind.—S
 Extra Equipment & Supply Co.—Pa.—S
 F & F Mining Corp.—W. Va.—S & A
 Fairpoint Coal Co.—Ohio.—S
 Ferns Coal Co.—Ohio.—S
 Fisher Mining Co.—Pa.—S
 Flat Top Mining, Inc.—Ky.—E.—S & A
 Flood Mining Co., Inc.—Ala.—S
 Foertsch Const. Co.—Ind.—S
 Ford, Winston Co., Inc.—Ky.—S & A
 Four Leaf Coal Co.—Tenn.—S
 F.M. Coal & Energy Co., Inc.—Ky.—E.—S
 Four Star Mining Co.—Okla.—S
 Fran Contracting, Inc.—Pa.—S
 Fran-Ru Enterprises, Inc.—Pa.—S
 Frontier Coals, Inc.—Ky.—E.—S
 Fuel Dynamics Co.—Okla.—S
 GAK Co.—Pa.—U
 Gale Coal Co.—Ky.—E.—A & S
 Galloway Co., Inc.—W. Va.—S & A
 Gamble Coals, Inc.—W. Va.—U
 Gearhart, Alvin.—Pa.—S
 General Refractories Co.—Ky.—E.—S
 Genex Greer Inc.—Ky.—E.—S
 Globe Coal Co.—Ky.—E.—U
 Goff Brothers Coal Co.—W. Va.—U
 Golden Glow Coals, Inc.—Ky.—E.—U
 Grafton Coal Co., Inc.—Md.—S
 Grays Knob Coal Co.—Ky.—E.—U
 Griffith Coal Co.—Ky.—E.—U
 Guardian Coal Co.—Ky.—E.—S
 Gum Branch Coal Co.—Ky.—U
 H. & P. Coal Co., Inc.—Ky.—E.—S
 Halfway Coal Yard, Inc.—Pa.—S
 Hampshire Mining Corp.—Md.—U
 Hansford Coal Co.—W. Va.—S
 Hanslovan Coal Co., Ed.—Pa.—S
 Hardly Able Coal Co., Inc.—Ky.—E.—S
 Harless Coal Co.—W. Va.—U
 Harmon Coal Co.—Pa.—S
 Harmony Mining Co.—Pa.—U
 Hawkins Coal Co.—Ky.—E.—A & S
 Helco Minerals Corp.—Ky.—E.—S

Henry Coal Co.—Pa.—S
 Hoke, Charles—Ky.—S & A
 Howard & Russell Coal Co., Inc.—Ky.—E.—S
 Husky Industries—N. D.—S
 Imperial Mining Co.—Ind.—S
 Indian Head Mining Co.—Ky.—U
 Indian Ridge Coal Co.—W. Va.—U
 J. & J. Mining Co.—W. Va.—U
 Jackson Mining Co., Inc.—Tenn.—U
 Jader Fuel Co.—Ill.—U
 Johnson & Morgan—Pa.—S
 K & D Corp.—Ky.—W.—S & A
 K & R Enterprises, Inc.—Ohio.—U
 K.W.D. Construction Co.—W. Va.—S
 Karst-Robbins Coal Co.—Ky.—E.—S & A
 Keffer & Rose Enterprises—Ohio.—S & A
 Kentucky Bell Coal Mining Co.—Ky.—E.—S & A
 Kentucky Elkhorn Coals, Inc.—Ky.—U.—S & A
 Ky. Harlan Coal Co., Inc.—Ky.—E.—U
 Koester Coal Co.—Ind.—S
 L & D Incorporated—W. Va.—U
 L & E Constr. & Equip. Co., Inc.—Pa.—S
 Lugo, Inc.—Tenn.—S
 Lake Coal, Inc.—Ky.—S & A
 Larkins Coal Co., Glenn.—Ky.—S
 Lasky Constr. Co., Inc.—Pa.—S
 Laura Coal & Coke Co., Inc.—W. Va.—U
 Laurel Creek Mining Co.—W. Va.—U
 Lawrence Coal Co.—Pa.—S
 Lee Mining Co.—Ky.—F.—S & A
 Leon's Coal Co.—Okla.—S
 Les Juan Corp.—Ky.—E.—S
 Lewis Coal & Coke Co.—W. Va.—S
 Little Bill Coal Co.—Ky.—E.—U
 Little Hackney Creek Coal Co.—Ky.—U
 Logan Mohawk Coal Co.—W. Va.—U
 Lone Mountain Coal Co.—Tenn.—U
 Longwa, Inc.—Tenn.—S
 Longwall Mining, Inc.—Pa.—U
 Lunar Mining, Inc.—Pa.—U
 M & C Coal Co., Inc.—W. Va.—U
 M & M Coal Co.—Ky.—E.—U
 Mac Mining Co.—Ky.—E.—S & A
 Mack Mining, Inc.—Ohio.—S & A
 Majestic Mining, Inc.—W. Va.—S
 Manor Mining & Contr. Corp.—Pa.—U
 Marcus Coal Co., Inc.—W. Va.—U
 Markolino Coal & Coke Co.—Pa.—S
 Martin Coal Co., James E.—Pa.—S & A
 Mary Mounts Constr. Co.—Ky.—E.—S & A
 Matahorn Mining Corp.—Ky.—W.—S
 McCall Enterprises, Inc.—Tenn.—S
 McDonald Land & Mining Co., Inc.—Pa.—S
 McIntire Coal Co., Inc., W. J.—Pa.—S & A
 McNabb Coal Co.—Okla.—S
 Mineral Development Co.—W. Va.—U
 Monarch Coal Co.—Ky.—E.—U, S & A
 Mt. Victory Coal Co., Inc.—Ky.—E.—U
 Mountaineer Resources, Inc.—Ky.—E.—S
 Mulzer Crushed Stone Co.—Ind.—S
 N & G Construction Inc.—Ohio.—S
 NADA Coal Co.—W. Va.—U & S
 Nally & Hamilton Enterprises, Inc.—Ky.—E.—S
 Nardei Contracting Co., Inc.—Pa.—S
 No. Ten Coal Mining Corp.—W. Va.—U
 Odell Construction Co., Inc.—Ky.—E.—S
 Ohio Amco, Inc.—Ohio.—U
 Orange Coal Co.—Ohio.—S
 Park Coal Co.—Ind.—S
 Pengrove Coal Co.—Pa.—S
 Penn Coal Co.—Pa.—S

Pennweir Const. Co.—Pa.—S
 Percival, Paul.—Pa.—S
 Perry Bros. Coal Co.—Pa.—S
 Perry County Coal Corp.—Ky.—U
 Perry & Hyllon, Inc.—W. Va.—S
 Peter Fork Mining Co.—Ky.—E.—S
 Pike Coal Co.—Pa.—S
 Pine Br. Coal Sales, Inc.—Ky.—E.—S & A
 Pioneer Coal Co.—Ky.—U
 Poe Coal Co.—Ala.—S
 Polar Coal Co.—Pa.—S
 Pond Creek Mining Co.—W. Va.—U
 Potter Mining Co., Inc.—Ky.—E.—U
 Power Contracting Co., Inc.—Pa.—S
 Pratt Bros. Coal Co., Inc.—Ky.—E.—U
 Preece Coal Co., Inc.—Ky.—E.—U
 Preston Energy, Inc.—W. Va.—U
 Purco Coal, Inc.—Pa.—S
 Quadrangle Coal Co.—Ky.—E.—S
 Quality Coal Co.—Ky.—E.—U
 R. J. & F. Coal Co.—Ky.—S & A
 Reckart Brothers Mining—W. Va.—S (10)
 Reckart Mining Co.—W. Va.—S (10)
 Reclamation & Air Survey, Inc.—Ohio.—S
 Red Cedar Mining Corp.—Ky.—E.—S & A
 Rita Sue Coal Co.—Ky.—E.—S & A
 Rondell Co.—Pa.—S
 Rowland Pugh Mining Co.—Ala.—S
 Royal Darby Coal Co.—Ky.—E.—U
 Russell Coal Co.—Ala.—S
 Ruth Coal Co. L.T.—Ky.—E.—S
 Ryan's Creek Coal Co., Inc.—Ky.—E.—U
 S & D Trucking Co.—Pa.—S
 Sam Coal Co.—Tenn.—U & S
 Seitz Montgomery Coal Co., Inc.—Ky.—E.—S & A
 Sequatchie Valley Coal Corp.—Tenn.—U
 Shale Hill Coal Co.—Pa.—S
 Simca Mining, Inc.—Pa.—S
 Soldier Creek Coal Co.—Utah.—U
 Southwind Coal Mining Co., Inc.—Ky.—S
 Spring Br. Coal Co., Inc.—Ky.—E.—U
 Stansbury Coal Co.—Wyo.—U
 Sugar Hill Limestone Co.—Pa.—S
 Sullivan Long Hagerly Coal Co.—Ala.—S
 Sunbeam Coal Corp.—Pa.—S
 Superior Pocahontas Coal Co.—W. Va.—U
 Svonavec, Inc.—Pa.—S
 T. G. & C. Coal Co., Inc.—Md.—S
 Taft, A. J., Coal Co.—Ala.—S
 Tebco Inc.—Ky.—E.—S
 Tesone Coal Co.—Pa.—U
 Thomas Coal Co., Inc.—Pa.—S
 Tree Top Coal & Equip. Co., Inc.—Ky.—E.—S
 Triangle Enterprises—Pa.—U
 United Coal Co., Inc.—Ky.—E.—S (10)
 Vargo Coal Co., Inc.—Pa.—S
 Veon, Inc., Ralph A.—Pa.—A & S
 W. S. H. Const. Co., Inc.—Ky.—E.—S
 Walden Ridge Coal Co.—Tenn.—S
 Walnut Mtn., Inc.—Tenn.—S
 Wells Mining Co.—Ohio.—U
 Westco, Inc.—Ky.—W.—S
 West Coal Corp.—Ky.—E.—S & A
 Western Slope Carbon, Inc.—Colo.—U
 West Freedom Mining Corp.—Pa.—S & A
 Westvaco Resources, Inc.—Md.—S
 Willowbrook Mining Co.—Pa.—S
 Wills Creek Energy Co.—Ohio.—S
 Winner Bros. Coal Co., Inc.—Md.—S
 Winston Mining Co., Inc.—Ala.—S
 Wright Coal Co., Inc.—Ky.—E.—U
 Zimnox Coal Co.—Ohio.—S

Ownership of Coal Producing Companies

As an additional service, KEYSTONE has compiled the following list of organizations owning and/or controlling major coal-producing companies. In general, the list includes those coal firms which individually, or in affiliated groups, produce one million or more tons annually. A few other companies have been included.

To make this list more easily usable, the coal-producing firms have been arranged alphabetically with parent or controlling company names following.

An attempt has been made to categorize the industry in which the parent

company is engaged. Broad categories have been selected and are shown in parentheses after the coal company name. These designations apply where the parent company is not in itself a coal producer, and cover utility, steel, oil, chemical, and other. Where the firm is controlled by a coal company, it is so shown.

While this list is quite comprehensive, it is possible that some major companies have been overlooked. Organizations who may have inadvertently been omitted are asked to advise us so they may be included in future issues.

Coal Operating Company

Affinity Mining Co. (Other)
Alabama By-Products Corp. (Other)
Alico Coal Co. (Other)
Akumbaugh Coal Co., Inc. (Other)
Amax Coal Co. (Metal)
American Coal Co. (Utility)
Amherst Coal Co. (Coal)
Amigo Smokeless Coal Co. (Other)
Arch Coal Co. (Oil)
Arch Mineral Corp. (Oil)
Armco Steel Corp. (Steel)
Ashland Mining Corp. (Coal)

Bodger Coal Co. (Other)
Barbour Coal Co. (Coal)
Barnes & Tucker Co. (Chemical)
Baukol-Noonan, Inc. (Coal)
Beatrice Pocahontas Co. (Oil, Steel) (Jointly owned Island Creek, Republic Steel)
Belva Coal Co. (Oil)
Benjamin Coal Co. (Coal)
Both-Elkhorn Coal Corp. (Steel)
Bethlehem Mines Corp. (Steel)
Big Horn Coal Co. (Other)
Big Mountain Coal, Inc. (Steel)
Bishop Coal Co. (Oil)
Black Creek Coal Sales Div. (Coal)
Blackwood Fuel Co., Inc. (Oil)
Blair Fork Coal Co. (Other)
Blue Diamond Coal Co. (Other)
Bradford Coal Co., Inc. (Coal)
Buckeye Coal Co. (Steel)
Buckeye Coal Mining Co. (Steel)
Buckhorn Hazard Coal Corp. (Other)
Buffalo Mining Co. (Other)
Burgess Mining & Construction Corp. (Other)

CF&I Steel Corp. (Steel)
C & K Coal Co. (Chemical)
Cannelton Coal Co. (Steel)
Canterbury Coal Co. (Other)
Carbon Fuel Co. (Coal)
Cedar Coal Co. (Utility)

Parent or Controlling Company

Eastern Gas & Fuel Associates, Inc.
Alabama By-Products Corp.
Pullman, Inc.
Donovan Companies, Inc.
American Metal Climax Inc.
Utah Power & Light Co.
Amherst Coal Co.
Pittston Co.
Ashland Oil Co.
Ashland Oil Co.
Armco Steel Corp.
Sovereign Pocahontas Coal Co.

Pittston Co.
Barbour Coal Co.
Alico Standard Corp.
Baukol-Noonan, Inc.
Occidental Petroleum Co. and Republic Steel Corp.
International Mining & Petroleum Corp.
Benjamin Coal Co.
Bethlehem Steel Co.
Bethlehem Steel Co.
Peter Kiewit Sons Co.
Armco Steel Corp.
Continental Oil Co.
The Drummond Co.
Belco Petroleum Corp.
W. R. Grace Co.
W. R. Grace Co.
Bradford Coal Co., Inc.
Youngstown Sheet & Tube Co.
Keller Steel Co.
General Energy Corp.
Pittston Co.
Burgess Mining & Construction Corp.

CF&I Steel Corp.
Gulf Resources & Chemical Co.
Cannelton Industries, Inc.
Westtrans Industries
Carbon Fuel Co.
American Electric Power Service Corp.

Coal Operating Company

Central Appalachian Coal Co. (Utility)
Central Coal Co. (Utility)
Central Ohio Coal Co. (Utility)
Charter Coal Corp. (Chemical)
Cimarron Coal Corp. (Coal)
Climchfield Coal Div. (Other)
Clintwood Mining Co. (Coal)
Colowyo Coal Co. (Other)
Consolidation Coal Co. (Oil)
Cravat Coal Co. (Coal)
Cumberland Collieries (Coal)

Decker Coal Co. (Other)
H. E. Drummond Coal Div. (Other)
Duquesne Light Co. (Utility)

Eads Coal Co. (Oil)
Eastern Associated Coal Corp. (Other)
Eastern Coal Corp. (Other)
Eastover Mining Co. (Utility)
Elkay Mining Co. (Other)

Falcon Coal Co., Inc. (Coal)
Florence Mining Co. (Coal)
Freeman Coal Mining Corp. (Other)
Fresno Coal Corp. (Other)

Gabriel Valley Enterprises (Other)
Gateway Coal Co. (Steel)
Gibralter Coal Corp. (Metal) (Jointly owned by Peabody Coal and Amax Coal)
Greenwich Collieries Co. (Utility)

Harman Mining Corp. (Coal)
Harmar Coal Co. (Oil)
Hawley Coal Mining Corp. (Oil)
Helen Mining Co. (Coal)
Helvetia Coal Co. (Coal)

Industrial Mining Co. (Steel)
Inland Steel Co. (Steel)
International Harvester Co. (Other)

Parent or Controlling Company

American Electric Power Service Corp.
American Electric Power Service Corp.
American Electric Power Service Corp.
Gulf Resources & Chemical Corp.
Cimarron Coal Corp.
Pittston Co.
Sovereign Pocahontas Coal Corp.
W. R. Grace Co.
Continental Oil Co.
Cravat Coal Co.
Jewell Coal & Coke Co.

Peter Kiewit Sons Co.
The Drummond Co.
Duquesne Light Co.

Ashland Oil Co.
Eastern Gas & Fuel Associates
Pittston Co.
Duke Power Co.
Pittston Co.

Falcon Coal Co., Inc.
North American Coal Corp.
General Dynamics Corp.
General Exploration Co.

General Energy Corp.
Jones & Laughlin Steel Corp.
Kennecott Copper Corp.; American Metal Climax, Inc.
Pennsylvania Power & Light Co.

Sovereign Pocahontas Coal Co.
Continental Oil Co.
Belco Petroleum Corp.
North American Coal Corp.
Rochester & Pittsburgh Coal Co.

Keller Steel Co.
Inland Steel Co.
International Harvester Co.

Ownership of Coal Producing Companies . . . Cont'd

Coal Operating Company

Island Creek Coal Co. (Oil)
Itmann Coal Co. (Oil)

Jewell Coal & Coke Co. (Coal)
Jewell Ridge Coal Corp. (Other)
Johns Creek Elkhorn Coal Corp. (Other)
Jones & Laughlin Steel Corp. (Steel)

Kaiser Steel Corp. (Steel)
Kellerman Mining Div. (Coal)
Kammerer Coal Co. (Coal)
Kentland Elkhorn Coal Corp. (Other)
Kentucky Carbon Corp. (Coal)
Kerr-McGee Coal Corp. (Other)
King Knob Coal Co. (Coal)
Knife River Coal Mining Co. (Utility)
Kristianson & Johnson Coal Co., Inc. (Other)

Majestic Collieries Co. (Coal)
Maple Meadow Mining Co. (Steel)
Marty Corporation (Coal)
Mathies Coal Co. (Oil)
Mead Corporation (Other)
Midland Coal Co. (Metal)
Midway Coal Co. (Other)
Monterey Coal Co. (Oil)
Mountain Drive Coal Co. (Coal)

Nacco Mining Co. (Other)
National Coal Mining Co. (Oil)
National Mines Corp. (Steel)
Natural Bridge Coal Div. (Coal)
New River Coal Co. (R.R.)
North American Coal Corp. (Coal)

Oglebay Norton Co. (Other)
Ohio Coal & Construction Co. (Coal)
Ohio Edison Co. (Utility)
Old Ben Coal Co. (Oil)
Olga Coal Co. (Steel)
Onida Mining Co. (Coal)

Pacific Power & Light Co. (Utility)
Peabody Coal Co. (Metal)
Peter White Coal Mining Corp. (Oil)
Pikeville Coal Co. (Steel)
Pocahontas Rod Ash Mining Corp. (Oil)
Pittsburg & Midway Coal Mining Co. (Oil)
Princess Susan Coal Co. (Other)

Quarto Mining Co. (Coal)

R & F Coal Co. (Coal)
Race Fork Coal Corp.
Ranger Fuel Corp. (Other)
Republic Steel Corp. (Steel)

Parent or Controlling Company

Occidental Petroleum Corp.
Continental Oil Co.

Jewell Coal & Coke Co.
Pittston Co.
General Energy Corp.
Jones & Laughlin Steel Corp.

Kaiser Steel Corp.
The Drummond Co.
Kammerer Coal Co.
Pittston Co.
Carbon Fuel Co.
Kerr-McGee Corp.
King Knob Coal Co.
Montana Dakota Utilities Co.
Westrans Industries

Sovereign Pocahontas Coal Co.
Cannelton Industries, Inc.
Marty Corporation
Continental Oil Co.
Mead Corporation
American Smelting & Refining Co.
Pullman, Inc.
Exxon Corp.
Mountain Drive Coal Co.

North American Coal Corp.
Occidental Petroleum Co.
National Steel Corp.
The Drummond Co.
Chessie System
North American Coal Corp.

Oglebay Norton Co.
Ohio Coal & Construction Co.
Ohio Edison Co.
Standard Oil Co. (of Ohio)
Youngstown Sheet & Tube Co.
North American Coal Corp.

Pacific Power & Light Co.
Kennecott Copper Corp.
Belco Petroleum Corp.
Steel Co. of Canada
Belco Petroleum Corp.
Gulf Oil Co.
Central Penn Industries

North American Coal Corp.

Gulf Resources & Chem. Corps.
W. R. Grace Co.
Pittston Co.
Republic Steel Corp.

Coal Operating Company

Rochester & Pittsburgh Coal Co. (Coal)
Rocky Mountain Energy Co. (Other)

Rosebud Coal Sales (Other)
Rushon Mining Co. (Utility)

Sahara Coal Co. (Coal)
Scotia Coal Co. (Other)
Semet Solvay Div. (Chemical)
Sewell Coal Co. (Other)
Shamrock Coal Co. (Coal)
Slab Fork Coal Co. (Coal)
Snap Creek Coal Co. (Other)
Southern Appalachian Coal Co. (Utility)
Southern Electric Generating Co. (Utility)
Southern Ohio Coal Co. (Utility)
Southern Utah Fuel Co. (Other)
Southwestern Illinois Coal Corp. (Oil)
Sovereign Coal Corp. (Coal)

Tunnelton Mining Co. (Utility)
Twilight Industries, Inc. (Other)

Union Carbide Corp., Ferroalloys Div. (Chemical)
United Electric Coal Cos. (Other)
United States Fuel Co. (Metal)
United States Pipe & Foundry Co. (Other)
United States Steel Corp. (Steel)
Upshur Coals Inc. (Chemical)
Utah International Inc. (Metal)

Valley Camp Coal Co. (Coal)
Virginia Iron Coal & Coke Co. (Coal)
Virginia Pocahontas Co. (Oil)

Walker-Fayette Coal Co. (Oil)
Washington Irrig. & Devel. Co. (Utility)
Webster County Coal Corp. (Other)
Western Energy Co. (Utility)
Westmoreland Coal Co. (Coal)
Westmoreland Resources (Other)

Wheeling-Pittsburgh Steel Corp. (Steel)
Windsor Power House Coal Co. (Utility)
Wyodak Resources Devel. Corp. (Utility)

Youghiogheny & Ohio Coal Co. (Coal)
Youngstown Mines Corp. (Steel)

Zapata Coal Corp. (Other)
Zeigler Coal Co. (Other)

Parent or Controlling Company

Rochester & Pittsburgh Coal Co.
Union Pacific Corp.; Ideal Basic Industries, Inc.

Peter Kiewit Sons Co.
Pennsylvania Power & Light Co.

Sahara Coal Co.
W. R. Grace Co.
Allied Chemical Corp.
Pittston Co.
Jewell Coal & Coke Co.
Slab Fork Co.
Pittston Co.
American Electric Power Service Corp.
Southern Electric Generating Co.
American Electric Power Service Corp.
Coastal States Energy Co.
Ashland Oil Co.
Sovereign Pocahontas Coal Co.

Pennsylvania Power & Light Co.
U.S. Natural Resources Co.

Union Carbide Corp.

General Dynamics Corp.
U.S. Smelting & Refining Co.
Jim Walter Corp.
United States Steel Corp.
Alco Standard, Inc.
Utah International Inc.

Valley Camp Coal Co.
Virginia Iron Coal & Coke Co.
Occidental Petroleum Co.

Ashland Oil Co.
Pacific Pwr. & Lt.; Washington Wt. Pwr.
Mapco Inc.
Montana Power Co.
Westmoreland Coal Co.
Westmoreland Coal Co.; Penn-Virginia Corp.; Morrison-Knudsen Co.; Kewanee Oil Co.
Wheeling-Pittsburgh Steel Corp.
American Electric Power Service Corp.
Black Hills Power & Light Co.

Youghiogheny & Ohio Coal Co.
Youngstown Sheet & Tube Co.

Zapata Corp.
Houston Natural Gas Corp.

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TOTAL REVENUE COAL MINING

Ownership of Coal Producing Companies

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company is engaged. Broad categories have been selected and are shown in parentheses after the coal company name. These designations apply where the parent company is not in itself a coal producer, and cover utility, steel, oil, chemical, and other. Where the firm is controlled by a coal company, it is so shown.

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Coal Operating Company

Addington Bros. Mining Inc.
Affinity Mining Co. (Other)
Alabama By-Products Corp. (Other)
Alexander Coal & Supply Inc.
Allegheny River Mining Co. (Other)
Aloe Coal Co. (Coal)
Alumbough Coal Co., Inc. (Other)
AMAX Coal Co. (Metals)
American Coal Co. (Utility)
Amherst Coal Co. (Coal)
Amige Smokeless Coal Co. (Other)
Apache Coal Co. (Coal)
Apache Mining Co.
Appalachian Contracting Co. (Other)
Arch Mineral Corp. (Oil)

Armo Steel Corp. (Steel)
Ashland Mining Corp. (Coal)
Avery Coal Co. Inc. (Other)
B & M Coal Co., Inc.
Badger Coal Co. (Other)
Bene Mining Co. (Coal)
Barbour Coal Co. (Coal)
Barnes & Tucker Co. (Chemical)
Baukol-Noonan, Inc. (Coal)
Boatice Pocahontas Co. (Oil, Steel) (Jointly owned Island Creek, Republic Steel)

Bedcor, Inc.
Belbe Coal Corp. (Oil)
Bell County Coal Corp.
Belva Coal Co. (Oil)
Benjamin Coal Co. (Coal)
Bergoo Coal Co.
Beth-Elkhorn Coal Corp. (Steel)
Bethlehem Mines Corp. (Steel)
Big Four Coal Corp.
Big Horn Coal Co. (Other)
Big Mountain Coal, Inc. (Steel)
Bill's Coal Co., Inc.
Bishop Coal Co. (Oil, Steel)
Black Beauty Mine
Black Creek Coal Sales Div. (Coal)
Blackwood Fuel Co., Inc.
Blair Fork Coal Co. (Coal)
Blue Diamond Mining (Coal)
Boone Trace Unlimited, Inc. (Other)

Parent or Controlling Company

Ashland Oil Co.
Eastern Associated Coal Corp.
Alabama By-Products Corp.
Filtrol Corp.
Arthur T. Walker Estate Corp.
Aloe Coal Co.
Donovan Companies, Inc.
AMAX, Inc.
Utah Power & Light Co.
Amherst Coal Co.
Pittston Co.
Flanary Coal & Land Co.
NewEra Resources, Inc.
Kanab Services, Inc.
Ashland Oil Co.; Hunt Petroleum Corp.; Hunt Indust.
Armco Steel Corp.
Sovereign Pocahontas Coal Co.
Bates Mfg., Inc.
Pocahontas Group, Inc.
Pittston Co.
Flanary Coal & Land Co.
Barbour Coal Co.
Aloe Standard Corp.
Baukol-Noonan, Inc.
Occidental Petroleum Co. and Republic Steel Corp.

ITT Corp.
Patrick Petroleum Co.
General Energy Corp.
Reading & Bates Offshore Drilling Co.
Benjamin Coal Co.
Unidyne, Inc.
Bethlehem Steel Co.
Bethlehem Steel Co.
McCulloch Consolidated Coal Co.
Peter Kiewit Sons Co.
Armco Steel Corp.
Cherokee Coal Co.
Continental Oil Co.; Inland Steel Co.
T. & T. Land Corp., Inc.
The Drummond Co.
Hawley Fuel Corp.
Blue Diamond Coal Co.
Blue Diamond Coal Co.
Foster & Creighton Co.

Coal Operating Company

Bradford Coal Co., Inc. (Coal)
Braztah Corp. (Oil)
Bridger Coal Co. (Utility)
Brown Badgett, Inc. (Oil)
Buckeye Coal Mining Co. (Steel)
Buffalo Mining Co. (Other)
Burgess Mining & Construction Corp. (Other)
CF&I Steel Corp. (Steel)
C & K Coal Co. (Chemical)
Cadco Coal Co.

Cal-Glo, Inc.
Call & Ramsey Coal Co. (Coal)
Cambria Coal Co. (Chemical)
Cammos Coal Mining Co. (Coal)
Canamex Coal Corp. (Coal)
Cannelton Industries, Inc. (Steel)
Canterbury Coal Co. (Other)
Carbon Fuel Co. (Other)
Carpentertown Coal & Coke Co.
Carter Mining Co. (Oil)
Carter-Roag Coal Co., Inc.
Cedar Coal Co. (Utility)
Central Appalachian Coal Co. (Utility)
Central Coal Co. (Utility)
Central Elkhorn Mining Co. (Coal)
Central Ohio Coal Co. (Utility)
Carticoals, Inc.
Charter Coal Corp. (Chemical)
Clamarron Coal Corp. (Coal)
Clifton Coal Co.
Climchfield Coal Div. (Other)
Climwood Mining Co. (Coal)
Coal Resources Corp. (Oil)
Coal Valley Corp.
Coalite Inc., Div. Brilliant Co. (Other)
Coastal States Energy Co.
Colorado Westmoreland Inc.
Colowyo Coal Co. (Other)
Consolidation Coal Co. (Oil)
Coteau Properties Co.
Cravat Coal Co. (Coal)
Cumberland Collieries (Coal)
DLM Coal Corp.
Decker Coal Co. (Utility)
Delta Coal Co.

Parent or Controlling Company

Bradford Coal Co., Inc.
McCulloch Oil Corp.
NERCO; Idaho Power Co.
Natoma Co.
Keller Steel Co.
Pittston Co.
Burgess Mining & Construction Corp.
CF&I Steel Corp.
Gulf Resources & Chemical Co.
Princess George Bank Run Gravel Corp.
Tampa Electric Co.
Elbo Coals, Inc.
Gulf Resources & Chemical Co.
Dexter-Carpenter Coal Sales Corp.
Canamex Commodity Corp.
Algoma Steel Corp. Ltd.
Westrans Industries
ITT Corp.
Sharon Steel
Exxon Corp.
ROAG Rohstoff und Verarbeitungs AG
American Electric Power Service Corp.
American Electric Power Service Corp.
American Electric Power Service Corp.
Black Star Coal Sales, Inc.
American Electric Power Service Corp.
ITT Corp.
Gulf Resources & Chemical Corp.
Clamarron Coal Corp.
Clifton Corporation
Pittston Co.
Sovereign Pocahontas Coal Corp.
Flying Diamond Oil Corp.
Dunavant Enterprises, Inc.
Great Northern Nekoosa Corp.
Coastal States Gas Corp.
Westmoreland Coal Co.
W. R. Grace Co.; Hanna Mining Co.
Continental Oil Co.
North American Coal Corp.
Cravat Coal Co.
Jewell Coal & Coke Co.
General Energy Co.
NERCO; Peter Kiewit Sons Co.
Cerro-Marmion

Ownership of Coal Producing Companies . . . Cont'd

Coal Operating Company

Diamond Coal Co., Inc.
Doverspike Bros. Coal Co.
Dresser Minerals Div. (Other)
H. E. Drummond Coal Div. (Other)
Dunavant Coal Co., Inc.
Duquesne Light Co. (Utility)
Eastern Associated Coal Corp. (Other)
Eastern Coal Corp. (Other)
Eastover Mining Co. (Utility)
Elbo Coals, Inc. (Coal)
Elkay Mining Co. (Other)
Elkhorn Processing Corp.
Emerald Mines Co. (Steel)
Empire Coke Co.
Empire Energy Corp.
Energy Development Co. (Utility)
Energy Development Corp.
Energy Producers, Inc.
English Coal Co., Inc.
Falcon Coal Co., Inc. (Other)
Falkirk Mining Co.
Fetterhoff Coal Co. (Metal)
Five Oaks Coal Co.
Florence Mining Co. (Coal)
Freeman United Coal Mining Corp. (Other)
Fresno Coal Corp. (Other)
G. M. & W. Coal Co., Inc.
Gabriel Valley Enterprises (Other)
Gateway Coal Co. (Steel)
Gibraltar Coal Corp. (Metal)
Glenn Coal Co.
Glenrock Coal Co.
Gowen Coal Co.
Greenwich Collieries Co. (Utility)
Greenwood Land & Mining Co.
H & F Mining, Inc.
Harian Fuel Co.
Harman Mining Corp. (Coal)
Harmer Coal Co. (Oil)
Helen Mining Co. (Coal)
Helvetia Coal Co. (Coal)
Home Creek Smokeless Coal Co.
Hub Coal Co.
Husky Industries
Ikard & Bandy Co., Inc. (Other)
Indian Head Mining Co.
Industrial Mining Co. (Steel)
Inland Steel Co. (Steel)
International Energy Corp.
International Harvester Co. (Other)
Island Creek Coal Co. (Oil)
Itmann Coal Co. (Oil)
Jewell Coal & Coke Co. (Coal)
Jewell Ridge Coal Corp. (Other)
Johns Creek Elkhorn Coal Corp.
Jones & Laughlin Steel Corp. (Steel)
Kaiser Steel Corp. (Steel)
Kellerman Mining Div. (Coal)
Kemmerer Coal Co. (Coal)
Kentland Elkhorn Coal Corp. (Other)
Kentucky Carbon Corp. (Coal)
Kentucky Coal Co.
Kerr-McGee Coal Corp. (Other)
King Knob Coal Co. (Coal)

Parent or Controlling Company

Transcontinental Oil Corp.
Zapata Corp.
Dresser Industries Inc.
The Drummond Co.
Dunavant Enterprises, Inc.
Duquesne Light Co.
Eastern Gas & Fuel Associates
Pittston Co.
Duke Power Co.
Elbo Coals, Inc.
Pittston Co.
NewEra Resources, Inc.
Lykes-Youngstown Corp.
McWane Cast Iron Pipe Co.
Houston Natural Gas Corp.
Iowa Public Service Co.
Ruhr-American Coal Corp.
United Coals Inc.
Instant Information & Advertising Inc.
Falcon Seaboard, Inc.
North American Coal Corp.
Cerro-Marmion
South Atlantic Coal Co.
North American Coal Corp.
General Dynamics Corp.
General Exploration Co.
Cerro-Marmion
CBK Agronomics Inc.
Jones & Laughlin Steel Corp.;
Wheeling-Pittsburgh Steel
AMAX Coal Co.; Peabody Coal Co.
Champion Coal Co., Inc.
NERCO
Yamulla Trk. & Exc. Co.
Pennsylvania Power & Light Co.
Shamrock Coal Co.
Hawley Fuel Corp.
Goldfield Corp.
Sovereign Pocahontas Coal Co.
Continental Oil Co.
North American Coal Corp.
Rochester & Pittsburgh Coal Co.
French Coal Co.
Pargas, Inc.
Husky Oil Co.
Kanab Services, Inc.
Pro-Land, Inc.
Keller Steel Co.
Inland Steel Co.
American Industries & Resources Corp.
International Harvester Co.
Occidental Petroleum Corp.
Continental Oil Co.
Jewell Coal & Coke Co.
Pittston Co.
General Energy Corp.
LTV Corp.
Kaiser Steel Corp.
The Drummond Co.
Lincoln Corp.
Pittston Co.
Carbon Fuel Co.
Nuclear Dynamics, Inc.
Kerr-McGee Corp.
King Knob Coal Co.

Coal Operating Company

Kitchikan Fuel Corp.
Knife River Coal Mining Co. (Utility)
Kodak Mining Co., Inc. (Coal)
Kristianson & Johnson Coal Co., Inc. (Other)
Laurel Run Mining Co.
Leckie Smokeless Coal Co.
Leeco Inc. (Other)
Lucas Coal Co.
Majestic Collieries Co. (Coal)
Majestic Mining, Inc.
Maple Meadow Mining Co. (Steel)
Margarita Fuels Inc. (Other)
Martiki Coal Corp. (Coal)
Martin County Coal Corp.
Marty Corporation (Coal)
Mary Helen Coal Co., Inc.
A. T. Massey Coal Co., Inc. (Metal)
Mathies Coal Co. (Oil)
McCoy Elkhorn Coal Corp. (Other)
Mead Coal (Other)
Mears Coal Co.
Meehan-Roag Coal Co., Inc.
Mettiki Coal Corp. (Coal)
Midland Coal Co. (Metal)
Midway Coal Co. (Other)
Missouri Mining Inc. (Other)
Monterey Coal Co. (Oil)
Morris Coal, Inc.
Mountain Clay Inc. (Other)
Mountain Drive Coal Co. (Coal)
Nacco Mining Co. (Other)
National Coal Mining Co. (Oil & Steel)
National Mines Corp. (Steel)
Natural Bridge Coal Div. (Coal)
Nemacolin Mines Corp.
New River Coal Co. (R.R.)
North American Coal Corp. (Coal)
Oakleaf Coal Co. (Other)
Oglebay Norton Co. (Other)
Ohio Coal & Construction Co. (Other)
Ohio Edison Co. (Utility)
Old Ben Coal Co. (Oil)
Olga Coal Co. (Steel)
Omar Mining Co. (Metal)
Onedia Mining Co.
Pacific Power & Light Co. (Utility)
Paramont Mining Corp.
Peabody Coal Co.
Peerless Eagle Coal Co. (Metal)
Penn United Energies Inc.
Perry County Coal Co. (Other)
Peter White Coal Mining Corp.
Plateau Mining Co. (Other)
Phillips Coal Inc. (Other)
Pickands Mather Co.
Pikeville Coal Co. (Steel)
Pittsburg & Midway Coal Mining Co. (Oil)
Plastic Universal Corp.
Pocahontas Red Ash Mining Co.
Pontiki Coal Corp. (Coal)
Pounding Mill Coal Co. (Coal)
Princess Susan Coal Co. (Other)
Quarto Mining Co. (Coal)

Parent or Controlling Company

Hawley Fuel Corp.
Montana Dakota Utilities Co.
Airco Coals, Inc.
Westrans Industries
Virginia Electric & Power Co.
International Carbon & Minerals
Kanab Services, Inc.
Amcord, Inc.
Sovereign Pocahontas Coal Co.
Perini Corp.
Cannalton Industries, Inc.
Trans-Air Inc.
Mapco, Inc.
St. Joe Minerals Inc.
Marty Corporation
Basic American Industries, Inc.
St. Joe Minerals Corp.
Continental Oil Co.
General Energy Corp.
Mead Corporation
Zapata Corp.
ROAG Rohstoff und Verarbeitungs AG
Mapco, Inc.
ASARCO, Inc.
Aloe Coal Co.
American Industries & Resources Corp.
Exxon Corp.
Ada Resources, Inc.
Kanab Services, Inc.
Mountain Drive Coal Co.
North American Coal Corp.
Occidental Petroleum Co.; National Steel Co.
National Steel Corp.
The Drummond Co.
Lykes Resources Inc.
Chessie System
North American Coal Corp.
Sherwood Leasing Corp.
Oglebay Norton Co.
American Industries and Resources Corp.
Ohio Edison Co.
Sohio Petroleum Co.
Lykes Resources, Inc.
St. Joe Minerals, Inc.
Pennsylvania Power & Light Co.
Pacific Power & Light Co.
Barber-Paramont Coal Corp.
Peabody Holding Co.; Newmont Mining Co.;
Williams Cos.; Bechtel Corp.; Fluor Corp.;
Equitable Life Assurance Society; Basing
Co.
St. Joe Minerals, Inc.
American Industries & Resources Corp.
Blue Diamond Coal Co.
Hawley Fuel Corp.
United Nuclear Corp.
Kanab Services, Inc.
Moore McCormack Resources
Steel Co. of Canada
Guif Oil Co.
Ada Resources, Inc.
Hawley Coal Mining Corp.
Mapco, Inc.
Elbo Coals Inc.
Central Penn Industries
North American Coal Corp.

Coal Operating Company

R & F Coal Co. (Oil)
 Race Fork Coal Corp.
 Ranger Fuel Corp. (Other)
 Raven Smokeless Coal Co.
 Reliable Coal Corp. (Coal)
 Republic Steel Corp. (Steel)
 River Coal Co. (Other)
 River Hill Coal Co., Inc.
 River Processing, Inc.
 Roeg-Kentucky Coal Co., Inc.
 Robinson Phillips Coal Co. (Metal)
 Rochester & Pittsburgh Coal Co. (Coal)
 Rockwood Coal Sales (Other)
 Royal Coal Co.
 Rushton Mining Co. (Utility)
 S.B.P. Coal Co.
 Sahara Coal Co. (Coal)
 Sanner Bros. Coal Co.
 Scotia Coal Co. (Coal)
 Somer Solvay Div. (Chemical)
 Sewell Coal Co. (Other)
 Shamrock Coal Co. (Coal)
 Shannan Coal Co.
 Slab Fork Coal Co. (Coal)
 Snap Creek Coal Co. (Other)
 Solar Fuel Co.
 Soldier Creek Coal Co.
 Southern Appalachian Coal Co. (Utility)
 Southern Energy Resources Co. (Other)
 Southern Ohio Coal Co. (Utility)
 Southeastern Illinois Coal Corp. (Oil)
 Sovereign Coal Corp. (Coal)
 Stehman Coal Co. (Chemical)
 Stensbury Coal Co. (Other)
 Stensbury & Co. Inc. (Other)
 Stearns Mining Co. (Coal)
 Stock Coal Co.
 Swisher Coal Co.
 Tesoro Coal Co. (Oil)
 Texas Pioneer Coal Co.
 Thunder Basin Coal Co.
 Tison Coal Co.
 Trace Fork Coal Co. (Metal)

Parent or Controlling Company

Shell Oil Co.
 W. R. Grace Co.
 Pittston Co.
 Gulf & Western
 Brook Coal Co.
 Republic Steel Corp.
 Pro-Land, Inc.
 Oil Shale Corp., Tosco Corp.
 Pargas, Inc.
 ROAG Rohstoff und Verarbeitungs AG
 St. Joe Minerals, Inc.
 Rochester & Pittsburgh Coal Co.
 Peter Kiewit Sons Co.
 United Pocahontas Coal Co.
 Pennsylvania Power & Light Co.
 Ringgold Coal Mining Co.
 Sahara Coal Co.
 Tosco Corp.
 Blue Diamond Coal Co.
 Allied Chemical Corp.
 Pittston Co.
 Jewell Coal & Coke Co.
 Gulf Resources & Chemical Co.
 Slab Fork Co.
 Pittston Co.
 Gulf & Western
 California Portland Cement Co.
 American Electric Power Service Corp.
 Marquette Co.
 American Electric Power Service Corp.
 Ashland Oil Co., Arch Mineral Corp.
 Sovereign Pocahontas Coal Co.
 Gulf Resources & Chemical Co.
 Ideal Basic Industries; Union Pacific Corp.
 Kanab Services, Inc.
 Blue Diamond Coal Co.
 Cerro-Mermon
 General Exploration Co.
 Tesoro Petroleum Corp.
 Pioneer Corporation
 Atlantic Richfield Co.
 T & C Coal Co., Inc.
 St. Joe Minerals, Inc.

Coal Operating Company

Triex Excavating Co.
 Tunnell Mining Co. (Utility)
 Twilight Industries, Inc. (Other)
 Union Carbide Corp. Metals Div. (Chemical)
 Universal Coal & Energy Co. Inc.
 United Electric Coal Cos. (Other)
 United Pocahontas Coal Co.
 United States Fuel Co. (Metal)
 United States Steel Corp. (Steel)
 Upshur Coals Inc. (Chemical)
 Utah International Inc. (Metal)
 VP-5 Mining
 Valley Camp Coal Co. (Oil)
 Valley Camp Utah (Oil)
 Valley Mining Co., Inc.
 Vantage Coal Corp. (Chemical)
 Virginia Iron Coal & Coke Co. (Other)
 Virginia Pocahontas Co. (Oil)
 W-P Coal Co.
 Walden Ridge Coal Co.
 Walker-Fayette Coal Co. (Oil)
 Jim Walter Resources, Inc.
 Washington Irrig. & Devel. Co. (Utility)
 Webster County Coal Corp. (Coal)
 Weebro, Inc.
 Wellmore Coal Corp.
 Westbury Development Corp.
 Western Coal Co.
 Western Energy Co. (Utility)
 Western Slope Carbon, Inc.
 Westmoreland Coal Co. (Coal)
 Westmoreland Resources (Other)
 West Virginia Energies, Inc.
 Wheeling-Pittsburgh Steel Corp. (Steel)
 Windsor Power House Coal Co. (Utility)
 Wolf Creek Collieries Co., Inc. (Metal)
 Wyodak Resources Devel. Corp. (Utility)
 Youghiogheny & Ohio Coal Co.
 Youngstown Mines Corp. (Steel)
 Zapata Coal Corp.
 Ziegler Coal Co. (Other)

Parent or Controlling Company

American Industries & Resources Corp.
 Pennsylvania Power & Light Co.
 U.S. Natural Resources Co.
 Union Carbide Corp.
 American Industries & Resources Corp.
 General Dynamics Corp.
 National Bulk Carriers, Inc.
 U.S. Smelting & Refining Co.
 United States Steel Corp.
 Alcoa Standard, Inc.
 General Electric Co.
 Occidental Petroleum Co.
 Quaker State Oil Refining Corp.
 Quaker State Oil Refining Corp.
 Valley Energy Resources, Inc.
 Gulf Resources & Chemical Co.
 Bates Mfg. Co., Inc.
 Occidental Petroleum Co.
 Consumers Mining Co.
 Squatchie Valley Coal Corp.
 Ashland Oil Co., Arch Mineral Corp.
 Jim Walter Corp.
 Pacific Pwr. & Lt.; Washington Wt. Pwr.
 Mapco Inc.
 Natomas Co.
 United Coal Companies
 Westbury Resources, Inc.
 Public Service Co. of New Mexico; Tucson
 Gas & Elec. Co.
 Montana Power Co.
 Northwest Coal Corp.
 Westmoreland Coal Co., Penn-Virginia Corp.
 Westmoreland Coal Co.; Penn-Virginia Corp.;
 Morrison-Knudsen Co.; Kewanee Industries,
 Inc.
 American Industries & Resources Corp.
 Wheeling-Pittsburgh Steel Corp.
 American Electric Power Service Corp.
 St. Joe Minerals, Inc.
 Black Hills Power & Light Co.
 Panhandle Eastern Pipeline Co.
 Lykes Resources, Inc.
 Zapata Corp.
 Houston Natural Gas Corp.

The Coal Reserves Picture: Estimated Tonnages Held by Individual Firms

As an additional service, KEYSTONE has compiled the following list of organizations owning, leasing or controlling over 102-billion tons of coal reserves in the United States and Canada.

The figures reported for each organization are estimated totals and do not differentiate between recoverable or in place reserves.

Organizations not appearing in this listing are invited to submit data for publication in future editions.

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Parent Company	Coal Operating Company	Reserves (Billion Tons)	Parent Company	Coal Operating Company	Reserves (Billion Tons)
Burlington Northern Inc.		11.400	Duke Power Co.	Eastover Land Co.	.250
- Continental Oil Co.	Consolidation Coal Co.*	10.800	Union Carbide Corp.	Union Carbide Ferroalloys Div.	.250
Union Pacific Corp.	Rocky Mountain Energy Co.	10.000	Gulf Resources & Chemicals Corp.	Charter Coal Corp.	.203
Kennecott Copper Corp.	Peabody Coal Co.	8.900	Allegheny River Mining Co.	Allegheny River Mining Co.	.200
- Exxon Corp.	Monterey Coal Co.	7.000			
North American Coal Corp.	North American Coal Corp.*	5.000	Bane Coal Corp.	Bane Coal Corp.	.200
American Metal Climax, Inc.	Amaz Coal Co.	4.900	Donan Joint Venture		.200
- Occidental Petroleum Co.	Island Creek Coal Co.*	4.430	Jones & Laughlin Steel Corp.	Jones & Laughlin Steel Corp.	.200
United States Steel Corp.	United States Steel Corp.	3.000	Kaiser Steel Corp.	Kaiser Steel Corp.	.200
Eastern Gas & Fuel Associates	Eastern Associated Coal Corp.	2.600	Kentucky River Coal Corp.	Kentucky River Coal Corp.	.200
			McAllester Fuel Co.		.200
- Gulf Oil Co.	Pittsburg & Midway Coal Mining Co.	2.600	New Mexico & Arizona Land Co.		.200
Pacific Power & Light Co.	Pacific Power & Light Co.	2.500	Palmer Coking Coal Co., Inc.	Palmer Coking Coal Co., Inc.	.200
- Atlantic Richfield Co.		2.200	Pinson Coal Co., Inc.	Pinson Coal Co., Inc.	.200
Bethlehem Steel Co.	Bethlehem Mines Corp.*	1.800	Solar Fuel Co.	Solar Fuel Co.	.200
- Texaco Inc.		1.650			
American Electric Power Corp.	Central Appalachian Coal Corp.*	1.500	Zapata Corp.	Zapata Coal Co.	.200
Kerr McGee Corp.	Kerr McGee Coal Corp.	1.500	Great Northern Nekoosa Corp.	Brilliant Coal Co.	.180
Pittston Co.	Clinchfield Coal Div.*	1.500	Public Service Co. of New Mexico	Western Coal Co.	.160
Norfolk & Western Ry.	Pocahontas Land Corp.	1.400	Red Ash Pocahontas Coal Co.	Red Ash Pocahontas Coal Co.	.153
CanPac Minerals Ltd.		1.300	NewEra Resources Inc.	NewEra Resources Inc.	.150
			Neely & Gibson Coal Co.	Neely & Gibson Coal Co.	.140
Utah International	Utah International	1.300	Allied Chemical Corp.	Semet-Solvay Div.	.100
Westmoreland Coal Co.	Westmoreland Coal Co.	1.200	American Smelting & Refining Co.	Midland Coal Co.	.100
Hillman Coal & Coke Co.		1.000	Carbon Fuel Co.	Carbon Fuel Co.*	.100
Houston Natural Gas Corp.	Ziegler Coal Co.	1.000	Mead Corp.	Woodward Co.	.100
Montana Power Co.	Western Energy Co.	1.000	Pennsylvania Power & Light Co.		.095
Greenwood Stripping Corp.	Greenwood Stripping Corp.	.735			
Cape Breton Development Corp.	Cape Breton Development Corp.	.724	Allegheny Power Service Corp.	Allegheny-Pittsburgh Coal Co.	.090
General Dynamics Corp.	Freeman Coal Mining Co.*	.600	Slab Fork Coal Co.	Slab Fork Coal Co.	.090
D. D. Stewart	Kentucky Home Coal Co.	.600	Wise Development Co., Inc.		.090
Armco Steel Co.	Armco Steel Co.	.400	Cambria Mining & Manufacturing Co.		.080
			The Corley Co.	The Corley Co.	.075
Southern Electric Generating Co.	Southern Electric Generating Co.	.400	Cedar Coal Co.	Cedar Coal Co.	.070
Reynolds Metals Co.		.350	Guaranty Gas Coal Co.		.070
Rochester & Pittsburgh Coal Co.	Rochester & Pittsburgh Coal Co.*	.300	Apollo Corp./Gysegum Inc.	Golden Rod Coal Co.	.065
Stearns Coal & Lumber Co.	Stearns Mining Co.	.300	Shannon Land & Mining Co.		.060
Virginia Iron Coal & Coke Co.	Virginia Iron Coal & Coke Co.	.300	Scholl & Wilcher Partnership	Coal Power Corp.	.057
Southern Railway System		.280			
Alco Standard Corp.	Barnes & Tucker Co.	.250	C.R.N. Mining Inc.	C.R.N. Mining Inc.	.050

The Coal Reserves Picture . . . Cont'd

Parent Company	Coal Operating Company	Reserves (Billion Tons)	Parent Company	Coal Operating Company	Reserves (Billion Tons)
General Energy Corp.	Buckhorn Hazard Coal Corp.	.050	Lovilla Coal Co.	Lovilla Coal Co.	.006
Public Service Co. of Indiana, Inc.		.050	North Cambria Fuel Co.	North Cambria Fuel Co.	.005
Lehigh Valley Anthracite Co.	Lehigh Valley Anthracite, Inc.	.048	Carter McCall Enterprises, Inc.		.005
Energy Development Co.	Energy Development Co.	.042	Ambrosia Coal & Construction Co.	Ambrosia Coal & Construction Co.	.004
Airco Coals, Inc.	Kodak Mining Co., Inc.	.040			
CDR Enterprises, Inc.	CDR Enterprises, Inc.	.040	Karst-Robbins Coal Co.	Karst-Robbins Coal Co.	.004
Lucas Coal Co.	Mineral Hill Corp.	.037	Belva Coal Co., Inc.	Belva Coal Co., Inc.	.003
Missouri, Kansas, Texas R.R.		.032	Bull Creek Coal & Dock Co.	Bull Creek Coal & Dock Co.	.003
Adventure Coal Corp.	Adventure Coal Corp.	.030	Markle-Bullers Coal Co.	Markle-Bullers Coal Co.	.003
Cairnes Coal Co., Inc.	Cairnes Coal Co., Inc.	.030	Moshannon Falls Mining Co.	Moshannon Falls Mining Co.	.003
			Perry Ross Coal Co.	Perry Ross Coal Co.	.003
Chicago & North Western Rwy.		.030	S & D Construction Co.	S & D Construction Co.	.003
Jeddo-Highland Coal Co.	Jeddo-Highland Coal Co.	.030	Smith & Stover Coal Co.	Smith & Stover Coal Co.	.003
PBS Company		.030	Industrial Mining Co.	Industrial Mining Co.	.003
Canon Coal Co.	Canon Coal Co.	.028	Associated Drilling, Inc.	Associated Drilling, Inc.	.002
Burford, Inc.	Burford, Inc.	.020			
Glen Burn Colliery, Inc.	Glen Burn Colliery, Inc.	.020	Boyle Coal Co., Inc.	Boyle Coal Co., Inc.	.002
Tarheel Coals, Inc.	Tarheel Coals, Inc.	.020	Jefferson County Coal Co.	Jefferson County Coal Co.	.002
Dexter-Carpenter Coal Corp.	D & C Mining Co.	.015	Dudek Coal Mining Co.	Dudek Coal Mining Co.	.002
Pullman, Inc.	Aloe Coal Co., Midway Coal Co.	.015	Monroe Coal Co.	Monroe Coal Co.	.002
Penn Allegheny Coal Co.	Penn Allegheny Coal Co.	.014	PIC Company	PIC Company	.002
			Zimnox Coal Co.	Zimnox Coal Co.	.002
Arcadia Co.	Arcadia Co.	.010	Apache Coal Co.	Apache Coal Co.	.002
Buckhannon River Co.		.010	S & D Trucking Co.	S & D Trucking Co.	.002
Cedarbrook Coal Co., Inc.	Cedarbrook Coal Co., Inc.	.010	Ralph Veon, Inc.	Ralph Veon, Inc.	.001
Great Basins Petroleum Co.		.010			
Green Brook Coal Co., Inc.	Green Brook Coal Co., Inc.	.010	Princess Coal Sales Co.		.001
Mineral Development Co.	Penn-Mar Coal Co.	.010			
Missouri Pacific R.R. Co.		.010	Alabama Electric Coop. Inc.	Abston Construction Co.	.001
Peggs Run Coal Co.	Peggs Run Coal Co.	.010	B. H. & H. Inc.	B. H. & H. Inc.	.001
Potter Coal Co.	Potter Coal Co.	.010	Empire Coke Co.	Empire Coke Co.	.001
Valley Coal Co.	Valley Coal Co.	.010	Joseph Godin Coal Co.	Joseph Godin Coal Co.	.001
			H. L. Kennedy Co.	H. L. Kennedy Co.	.001
Bane Mining Co.	Bane Mining Co.	.009	C. A. Ogden Coal Co.	C. A. Ogden Coal Co.	.001
Golden Glow Coals, Inc.	Golden Glow Coals, Inc.	.008			
Grove City Construction	Grove City Construction Co.	.008			
Longwall Mining, Inc.	Longwall Mining, Inc.	.008			
Boich Mining Co.	Boich Mining Co.	.008			
Caney Branch Coal Co., Inc.	Caney Branch Coal Co., Inc.	.007			

102.740

* See index for list of Associated Coal Producing Companies

The Coal Reserves Picture: Estimated Tonnages Held by Individual Firms

As an additional service, KEYSTONE has compiled the following list of organizations owning, leasing or controlling almost 141 billion tons of coal reserves in the United States and Canada.

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Organizations not appearing in this listing are invited to submit data for publication in future editions.

*See index for list of Associated Coal Producing Companies

Parent Company	Coal Operating Company	Reserves (Billion Tons)
Continental Oil Co.	Consolidation Coal Co.*	13.700
Burlington Northern Inc.		11.400
Union Pacific Corp.	Rocky Mountain Energy Co.	10.000
Newmont Mining Co.; Williams Companies; Bechtel Corp.; Fluor Corp.; Equitable Life Assur. Society of U.S.	Peabody Coal Co.	8.900
Exxon Corp.	Monterey Coal Co.	8.400
El Paso Natural Gas		5.200
North American Coal Corp.	North American Coal Corp.*	5.100
AMAX, INC.	AMAX Coal Co.	5.045
Occidental Petroleum Co.	Island Creek Coal Co.*	4.430
Mobil Corp.		3.500
United States Steel Corp.	United States Steel Corp.	3.000
Gulf Oil Co.	Pittsburg & Midway Coal Mining Co.	2.600
Atlantic Richfield Co.	Atlantic Richfield Co.	2.200
Sun Oil Co.		2.200
Phillips Petroleum		2.000
Bethlehem Steel Co.	Bethlehem Mines Corp.*	1.800
Pacific Power & Light Co.	NERCO, Inc.	1.700
Pittston Co.	Clinchfield Coal Div.*	1.700
Tenneco		1.700
Tenace Inc.		1.650
American Electric Power Corp.	Central Appalachian Coal Corp.*	1.500
Kerr McGee Corp.	Kerr McGee Coal Corp.	1.500
Shell Oil Co.	R & F Coal Co.	1.460
CanPac Minerals Ltd.		1.410
Norfolk & Western Ry.	Pocahontas Land Corp.	1.400
General Electric Co.	Utah International, Inc.	1.300
Westmoreland Resources; Penn-Virginia Corp.; Morrison-Knudsen Co.; Kewanee Industries	Westmoreland Resources	1.100
Eastern Gas & Fuel Associates	Eastern Associated Coal Corp.	1.058
Hillman Coal & Coke Co.		1.100
Houston Natural Gas Corp.	Ziglar Coal Co.	1.000
Montana Power Co.	Western Energy Co.	1.000
NICOR (Northern Ill. Gas Co.)		1.000
Westmoreland Coal Co.	Westmoreland Coal Co.	.849
Standard Oil Co. of Ohio	Old Ben Coal Co.	.825
Kentucky River Coal Corp.	Kentucky River Coal Corp.	.800
Kaneb Services		.750
Greenwood Stripping Corp.	Greenwood Stripping Corp.	.735
Cape Breton Development Corp.	Cape Breton Development Corp.	.724
Chevron Oil		.700
Ashland Oil, Inc.	Ashland Coal, Inc.; Arch Mineral Co.	.650
MAPCO, Inc.	Webster County Coal Corp.*	.650
St. Joe Minerals Corp.	A. T. Massey Coal Co., Inc.	.650

Parent Company	Coal Operating Company	Reserves (Billion Tons)
General Dynamics Corp.	Freeman United Coal Mining Co.*	.600
Montana Dakota Utilities Co.	Knife River Coal Mining Co.	.600
D. D. Stewart	Kentucky Home Coal Co.	.600
Belco Petroleum		.524
Morrison Knudsen Co.		.500
Panhandle Eastern Pipeline Co.	Youghiogheny & Ohio Coal Co.	.500
Columbia Gas System		.484
Quaker State Oil Refining Corp.	Valley Camp Coal Co.	.475
Consolidated Natural Gas Co.		.450
Alabama By-Products Corp.	Alabama By-Products Corp.	.445
Tennessee Valley Authority		.412
Armco Steel Co.	Armco Steel Co.	.400
Coastal States Gas Corp.	Coastal States Energy Co.	.400
Penn Pocahontas Coal Co.	Penn Pocahontas Coal Co.	.400
Southern Electric Generating Co.	Southern Electric Generating Co.	.400
Kentucky King Coal Co., Inc.	Kentucky King Coal Co., Inc.	.395
International Harvester Co.	Wisconsin Steel Div.	.370
Santa Fe Industries, Inc.		.370
Reynolds Metals Co.		.350
Jim Walter Corp.	Jim Walter Corp.	.350
Zapata Coal Co.	Zapata Coal Co.	.350
Mintech Corp.		.337
Bates Manufacturing Co.	Virginia Iron Coal & Coke Co.	.300
Southern Railway System		.280
Illinois Central Gulf R. R.	Madison Coal Corp.	.276
W. R. Grace & Co.; Hanna Mining Co.	Colowyo Coal Co.	.265
LTV Corp.	Allegheny River Mining Co.	.250
Allegheny River Mining Co.	Eastover Mining Co.	.250
Duke Power Co.	Stearns Mining Co.	.250
Blue Diamond Coal Co.	Barnes & Tucker Co.; Upshur Coals Corp.	.243
Alco Standard Corp.	Union Carbide Metals Div.	.235
Union Carbide Corp.		.221
Merchants Petroleum Co.	Bane Coal Corp.	.200
Bane Coal Corp.	Coalite Inc. Div. Brilliant Coal Co.	.200
Great Northern Nekoosa Co.	Jones & Laughlin Steel Corp.	.264
Kaiser Steel Corp.	Kaiser Steel Corp.	.200
McAlister Fuel Co.		.200
New Mexico & Arizona Land Co.		.200
Palmer Coking Coal Co., Inc.	Palmer Coking Coal Co., Inc.	.200
Public Service Co. of New Mexico;	Western Coal Co.	.200
Tucson Gas & Elec. Co.		
Ruhr-American Coal Corp.	Energy Development Corp.	.200
Solar Fuel Co.	Solar Fuel Co.	.200
Black Hills Power & Light Co.	Wyodak Resources Development Corp.	.188
Universal Minerals, Inc.		.180
Donan Joint Venture		.168

The Coal Reserves Picture . . . Cont'd

Parent Company	Coal Operating Company	Reserves (Billion Tons)	Parent Company	Coal Operating Company	Reserves (Billion Tons)
Old Home Manor Inc.	Old Home Manor Inc.	.168	T & C Coal Co. Inc.	Tizen Coal Co.	.039
Kentucky United Mining Co.	Kentucky United Mining Co.	.161	Lucas Coal Co.	Mineral Hill Corp.	.037
Lykes—Youngstown Corp.	Emerald Mines Corp.	.160	Burford, Inc.	Burford, Inc.	.036
Red Ash Pocahontas Coal Co.	Red Ash Pocahontas Coal Co.	.153	Jandy Coal Co. Inc.	Jandy Coal Co. Inc.	.035
California Portland Cement Co.	Soldier Creek Coal Co.	.150	Mercury Coal & Coke, Inc.		.035
NewEra Resources Inc.	NewEra Resources Inc.	.150	Westren Slope Carbon, Inc.	Western Slope Carbon, Inc.	.035
Gulf Resources & Chemical Corp.	C & K Coal Co.; Vantage Coal Co.; W. P. Stahlman; Cambria Coal Co.; Shannon Coal Co.	.148	W. R. Grace Co.	Race Fork Coal Corp.	.034
	Rochester & Pittsburgh Coal Co.*	.146	Missouri, Kansas, Texas R.R.		.032
Rochester & Pittsburgh Coal Co.	Neely & Gibson Coal Co.	.140	Mt. Victory Coal Co., Inc.	Mt. Victory Coal Co., Inc.	.031
Neely & Gibson Coal Co.	Semal-Solvay Div.	.125	Metco Mining Corp.	Metco Mining Corp.	.031
Allied Chemical Corp.	Allegheny River Mining Co.	.120	Adventure Coal Corp.	Adventure Coal Corp.	.030
Arthur T. Walker Estate Corp.	H. E. Drummond*	.110	Cairnes Coal Co., Inc.	Cairnes Coal Co., Inc.	.030
The Drummond Co.		.110	Chicago & North Western Rwy.		.030
Interstate Lumber Co.		.105	Douglas Pocahontas Coal Co.	Douglas Pocahontas Coal Co.	.030
Pennsylvania Power & Light Co.		.100	Hepburnia Coal Co.	Hepburnia Coal Co.	.030
ASARCO, Inc.	Midland Coal Co.	.100	Jeddo-Highland Coal Co.	Jeddo-Highland Coal Co.	.030
B & H Elkhorn Coal Co. Inc.	B & H Elkhorn Coal Co. Inc.	.100	Kentucky-Virginia Coal Corp.	Kentucky-Virginia Coal Corp.	.030
Carbon Fuel Co.	Carbon Fuel Co.*	.100	PBS Company		.030
Coal Ltd.		.100	Red Jacket Coal Co., Inc.	Red Jacket Coal Co., Inc.	.030
Adolph Coors Co.	Adolph Coors Co.	.100	Unidyne, Inc.	Bergoo Coal Co.	.030
Mead Corp.	Mead Coal	.100	Canon Coal Co.	Canon Coal Co.	.028
Shannon Land & Mining Co.	Bradford Coal Co., Inc.	.100	Cardinal Mining Co.	Cardinal Mining Co.	.027
Sigmon Enterprises	Sigmon Enterprises	.100	Iowa Public Service Co.	Energy Development Co.	.026
Elbo Coals Inc.	Elbo Coals Inc.; Call & Ramsey Coal Co.	.093	Canada Coal Co., Inc.	Canada Coal Co., Inc.	.025
			King Knob Coal Co.	King Knob Coal Co.	.025
Allegheny Power Service Corp.	Allegheny-Pittsburgh Coal Co.	.090	New River Co.	New River Co.	.025
Cerro Corp.	Fetterolf Coal Co., Inc.; M. F.	.090	South Atlantic Coal Co.	Five Oaks Coal Co.	.025
Titan Mining, Inc.	Titan Mining, Inc.	.090	Pro-Land Inc.	River Coal Co.; Indian Head Mining Co.	.023
Wise Development Co., Inc.		.090	Caney Branch Coal Co., Inc.	Caney Branch Coal Co., Inc.	.022
Southeast Coal Co.	Southeast Coal Co.	.082	Boden Mining Corp.	Boden Mining Corp.	.020
Cambria Mining & Manufacturing Co.		.080	Chapperal Coal Corp.	Chapperal Coal Corp.	.020
Washington Water Power Co.	Washington Irrigation & Devel. Co.	.080	Classic Mining Co.	Classic Mining Co.	.020
Rapoca Energy Corp.		.080	Glen Burn Colliery, Inc.	Glen Burn Colliery, Inc.	.020
Joseph Oriandi		.076	Kentucky Elkhorn Coals, Inc.	Kentucky Elkhorn Coals, Inc.	.020
The Corley Co.	The Corley Co.	.075	Penn Allegheny Coal Co.	Penn Allegheny Coal Co.	.020
Slab Fork Coal Co.	Slab Fork Coal Co.	.075	James Spur Coal Co.	James Spur Coal Co.	.020
United Nuclear Corp.	Plateau Mining Co.	.075	Tarheel Coals, Inc.	Tarheel Coals, Inc.	.020
Cedar Coal Co.	Cedar Coal Co.	.070	Penn West Fuels Inc.	Doverspike Bros. Coal Co.	.019
Falcon Seaboard, Inc.	Falcon Coal Co. Inc.	.070	Century Coals Ltd.	Century Coals Ltd.	.018
Guaranty Gas Coal Co.		.070	General Exploration Co.	Swisher Coal Co.	.018
Scholl & Witcher Partnership	Coal Power Corp.	.070	Lawson Hairs Inc.		.018
Solar Fuel Co.	Solar Fuel Co.	.070	Kerst-Robbins Coal Co.	Kerst-Robbins Coal Co.	.017
National Bulk Carriers Inc.	Royal Coal Co.; United Pocahontas Coal Co.	.067	American Coal Co.	American Coal Co.	.017
Apollis Corp./Gysagum Inc.	Golden Red Coal Co.	.065	Dixie Mining Co.	Dixie Mining Co.	.016
Paramont Minerals Corp.	Paramont Mining Corp.	.065	Transcontinental Oil Corp.	Diamond Coal Co. Inc.	.016
Paramount Elkhorn, Inc.	Paramount Elkhorn, Inc.	.060	Aloe Coal Co.	Aloe Coal Co.; Midway Coal Co.	.015
Shamrock Coal Co.	Shamrock Coal Co.	.060	Brook Coal Co.	Reliable Coal Corp.	.015
South Central Coal Co.	South Central Coal Co.	.060	Clifton Coal Co.	Clifton Coal Co.	.015
Carbon Fuel Co.	Carbon Fuel Co.	.056	Golden Glow Coals, Inc.	Golden Glow Coals, Inc.	.015
			Instant Information & Advertising Inc.	English Coal Co. Inc.	.015
Beltrami Enterprises Inc.	Beltrami Enterprises Inc. (Anth.)	.051	Johnstown Coal & Coke Co.	Johnstown Coal & Coke Co.	.015
Buckhannon River Co.		.050	Kentucky Prince Coal Corp.	Kentucky Prince Coal Corp.	.015
C-R-N Mining, Inc.	C-R-N Mining, Inc.	.050	Mary Helen Coal Co., Inc.	Mary Helen Coal Co., Inc.	.015
Cherokee Coal Co.	Bill's Coal Co.; Cherokee Coal Co.	.050	Middle States Coal Co. Inc.	Middle States Coal Co. Inc.	.015
S M Corporation	S M Corporation	.050	Perini Corp.	Majestic Mining Inc.	.015
General Energy Corp.	Buckhorn Hazard Coal Corp.	.050	Delta Mining Inc.	Delta Mining Inc.	.014
Lyncroft Associates	Dexter-Carpenter Coal Sales Corp.; D & C Mining Co. Inc.	.050	Herman Mining Corp.	Clintwood Mining Co.	.014
	Braztah Coal Co.	.050	Osborne Mining Corp.	Osborne Mining Corp.	.014
McCulloch Oil Corp.	Pinson Coal Co., Inc.	.050	Tenn-Tex Coal Corp.	Tenn-Tex Coal Corp.	.014
Pinson Coal Co., Inc.		.050	Moshannon Falls Mining Co.	Moshannon Falls Mining Co.	.013
Public Service Co. of Indiana, Inc.		.050	Chafin Coal Co.	Chafin Coal Co.	.012
Lehigh Valley Anthracite Co.	Lehigh Valley Anthracite, Inc.	.048	Durango Coal & Leasing Co., Inc.	Durango Coal & Leasing Co., Inc.	.012
Sunflower Energy Corp.	Sunflower Energy Corp.	.045	Leechburg Mining Co.	Leechburg Mining Co.	.012
Airco Coals, Inc.	Kodak Mining Co., Inc.	.040	R. G. Mining Co.	R. G. Mining Co.	.012
CDR Enterprises, Inc.	CDR Enterprises, Inc.	.040	Starford Coal Corp.	Starford Coal Corp.	.012
Manor Mining & Contracting Corp.		.040	Henry Clay Mining Co., Inc.	Henry Clay Mining Co., Inc.	.011

The Coal Reserves Picture . . . Cont'd

Parent Company	Coal Operating Company	Reserves (Billion Tons)
Arcadia Co.	Arcadia Co.	.010
Canamex Commodity Corp.	Canamex Coal Corp.	.010
Cedarbrook Coal Co., Inc.	Cedarbrook Coal Co., Inc.	.010
Cumberland River Coal Corp.	Cumberland River Coal Corp.	.010
Dunavant Enterprises, Inc.	Dunavant Coal Co.	.010
Great Basins Petroleum Co.		.010
Green Brook Coal Co., Inc.	Green Brook Coal Co., Inc.	.010
Guyan Eagle Mining Co., Inc.	Guyan Eagle Mining Co., Inc.	.010
LaRosa Fuel Co., Inc.	LaRosa Fuel Co., Inc.	.010
Louisiana Land & Exploration Co.	Louisiana Land & Exploration Co.	.010
Lucas Coal Co.	Lucas Coal Co.	.010
Marquette Co.		.010
Mineral Development Co.	Southern Energy Resources Co.	.010
Missouri Pacific R.R. Co.	Penn-Mar Coal Co.	.010
Peggs Run Coal Co.	Peggs Run Coal Co.	.010
Potter Coal Co.	Potter Coal Co.	.010
Pennsylvania Power & Light Co.	Tunnelton Mining Co.	.010
Robertson & Associates (III.) Inc.	Robertson & Associates (III.) Inc.	.010
T & H Coal Energy, Inc.	T & H Coal Energy, Inc.	.010
Valley Coal Co.	Valley Coal Co.	.010
Westover Coal Corp.	Westover Coal Corp.	.010
Bane Mining Co.	Bane Mining Co.	.009
Garbart Construction Co.	Garbart Construction Co.	.009
Multi-Land Corp.		.009
Peach Creek Processing Co.	Peach Creek Processing Co.	.009
Broecker, Norris, Raklos Coal Corp.	Broecker, Norris, Raklos Coal Corp.	.008
Case Coal Co.	Case Coal Co.	.008
Flanary Coal & Land Co.		.008
Glen Burn Colliery Inc.	Glen Burn Colliery Inc. (Anth.)	.008
Husky Industries	Husky Industries	.009
Bebe Coal Corp.	Bebe Coal Corp.	.008
Dixie Mining Co.	Dixie Mining Co.	.008
Grove City Construction	Grove City Construction Co.	.008
J. J. M. Y. Mining Corp.	J. J. M. Y. Mining Corp.	.008
Longwall Mining, Inc.	Longwall Mining, Inc.	.008
Boich Mining Co.	Boich Mining Co.	.008
Reclamation & Air Survey Inc.	Reclamation & Air Survey Inc.	.008
Swistock, Inc.		.008
Calvert & Marsh Coal Co. Inc.	Calvert & Marsh Coal Co. Inc.	.007
Hawk Contracting Inc.	Hawk Contracting Inc.	.007
United International Mining Corp.	United International Mining Corp.	.007
Dunkard Mining Co.	Dunkard Mining Co.	.006
Floyd Mining Co. Inc.	Floyd Mining Co. Inc.	.006
Ohio River Collieries Co.	Ohio River Collieries Co.	.006
R. E. M. Coal Co., Inc.	R. E. M. Coal Co., Inc.	.006
S & D Construction Co.	S & D Construction Co.	.006
South Hopkins Coal Co.	South Hopkins Coal Co.	.006
Carter McCall Enterprises, Inc.		.005
Breathitt Coal Sales, Inc.	Breathitt Coal Sales, Inc.	.005
Cheyenne Sales Co.	Cheyenne Sales Co.	.005
Energy Producers of America	Energy Producers of America	.005
Hardly Able Coal Co., Inc.	Hardly Able Coal Co., Inc.	.005
Helco Minerals Corp.	Helco Minerals Corp.	.005
Howard Enterprises	Howard Enterprises	.005
Jones & Bague Mining Co.	Jones & Bague Mining Co.	.005
Leon's Coal Co.	Leon's Coal Co.	.005
McDowell Enterprises, Inc.	Medlin Energy Corp.	.005
North Cambria Fuel Co.	North Cambria Fuel Co.	.005
Polls Creek Coal Co.	Polls Creek Coal Co.	.005
C. H. Snyder Co.	C. H. Snyder Co.	.005
Southern Pacific Transportation Co.		.005
Thompson Coal & Constr. Inc.	Thompson Coal & Constr. Inc.	.005
Wyoming Mining Co.	Wyoming Mining Co.	.005
Ambrosia Coal & Construction Co.	Ambrosia Coal & Construction Co.	.004
Brendo Faye Coal Sales	Brendo Faye Coal Sales	.004
Crescent Hills Coal Co.	Crescent Hills Coal Co.	.004

Parent Company	Coal Operating Company	Reserves (Billion Tons)
Great National Corp.	Great National Corp.	.004
Henry B. Coal Co. Inc.	Henry B. Coal Co. Inc.	.004
Leechburg Mining Co.	Leechburg Mining Co.	.004
Philip Reese Coal Co. Inc.	Philip Reese Coal Co. Inc.	.004
S. A. M. Coal Co.	S. A. M. Coal Co.	.004
Standard Marion Coal Co., Ltd.	Standard Marion Coal Co. Ltd.	.004
Ralph Veon, Inc.	Ralph Veon, Inc.	.004
Westbury Resources, Inc.	Westbury Development Corp.	.004
Bridgeview Coal Co.	Bridgeview Coal Co.	.003
Bull Creek Coal & Dock Co.	Bull Creek Coal & Dock Co.	.003
Congleton Bros., Inc.	Congleton Bros., Inc.	.003
Daset Mining Corp.	Daset Mining Corp.	.003
Donovan Companies	Alumbaugh Coal Corp.	.003
Farrell-Cooper Mining Co.	Farrell-Cooper Mining Co.	.003
Fran-Ru Enterprises, Inc.	Fran-Ru Enterprises, Inc.	.003
General Mines, Inc.	General Mines, Inc.	.003
Lechene Coal Co. Inc.	Lechene Coal Co. Inc.	.003
Keller Steel Co.	Industrial Mining Co.	.003
Markie-Bullers Coal Co.	Markie-Bullers Coal Co.	.003
Metropolitan International, Inc.	Metropolitan International, Inc.	.003
Moshannon Falls Mining Co.	Moshannon Falls Mining Co.	.003
Pennsylvania-Kentucky Mining Co.	Pennsylvania-Kentucky Mining Co.	.003
Perry Ross Coal Co.	Perry Ross Coal Co.	.003
Reading & Bates Offshore Oil Co.	Belve Coal Co., Inc.	.003
Royal Darby Coal Co.	Royal Darby Coal Co.	.003
Sharon Steel	Carpentertown Coal & Coke Co.	.003
Smith & Stover Coal Co.	Smith & Stover Coal Co.	.003
Tesone Coal Co.	Tesone Coal Co.	.003
Willowbrook Mining Co.	Willowbrook Mining Co.	.003
Anderson & Anderson Contractors Inc.	Anderson & Anderson Contractors Inc.	.002
Anthony Mining Co.	Anthony Mining Co.	.002
Apache Coal Co.	Apache Coal Co.	.002
Associated Drilling, Inc.	Associated Drilling, Inc.	.002
Boyle Coal Co., Inc.	Boyle Coal Co., Inc.	.002
Earl M. Brown	Earl M. Brown	.002
Champion Coal Co. Inc.	Champion Coal Co. Inc.	.002
Chase Eaton Co.	Jefferson County Coal Co.	.002
Coal Hill Contracting Co., Inc.	Coal Hill Contracting Co., Inc.	.002
Dudek Coal Mining Co.	Dudek Coal Mining Co.	.002
EFW Mining Co. Inc.	EFW Mining Co. Inc.	.002
Extractors, Inc.	Extractors, Inc.	.002
General Energy Corp.	General Energy Corp.	.002
General Minerals Corp.	General Minerals Corp.	.002
Gysegem Enterprises, Inc.	Gysegem Enterprises, Inc.	.002
H. & D. Mining Co.	H. & D. Coal Co.	.002
Industrial Mining Co.	Industrial Mining Co.	.002
Jader Fuel Co.	Jader Fuel Co.	.002
Keffler Rose Enterprises, Inc.	Keffler Rose Enterprises, Inc.	.002
Laurel Ridge Coal, Inc.	Manor Mining & Minerals Co.	.002
Lovilla Coal Co.	Lovilla Coal Co.	.002
Monroe Coal Sales, Co.	Monroe Coal Co.	.002
Natisco Co.	Natisco Co.	.002
Oil Shale Corp.	River Hill Coal Co. Inc.	.002
Pennsylvania Energy Corp.	Pennsylvania Energy Corp.	.002
PIC Company	PIC Company	.002
Pine Tree Corp.	Pine Tree Corp.	.002
S & D Construction Corp.	S & D Construction Corp.	.002
S & D Trucking Co.	S & D Trucking Co.	.002
Wasson Coal Mining Corp.	Wasson Coal Mining Corp.	.002
Zimnox Coal Co.	Zimnox Coal Co.	.002
Alabama Electric Coop., Inc.	Abston Construction Co.	.001
B. H. & H. Inc.	B. H. & H. Inc.	.001
Big Ben Coal Co.	Big Ben Coal Co.	.001
Boorhem Clark Coal Co.	Boorhem Clark Coal Co.	.001
Buckeye Coal Mining Co.	Buckeye Coal Mining Co.	.001
Carbonex Fuel Corp.	Carbonex Fuel Corp.	.001

The Coal Reserves Picture . . . Cont'd

Parent Company	Coal Operating Company	Reserves (Billion Tons)	Parent Company	Coal Operating Company	Reserves (Billion Tons)
Conoco Corp.	Congleton Bros., Inc.	.001	Regal Development Corp.	Regal Development Corp.	.001
E & B Coal Co.	E & B Coal Co.	.001	Squatchie Valley Coal Corp.	Squatchie Valley Coal Corp.	.001
Empire Coal Co.	Empire Coal Co.	.001	Schloppa Coal Co.	Schloppa Coal Co.	.001
Joseph Godin Coal Co.	Joseph Godin Coal Co.	.001	Trans-Alr Inc.	Margarita Fuels Inc.	.001
Kelley Enterprises Inc.	Kelley Enterprises Inc.	.001	United Coals, Inc.	United Coals, Inc.	.001
H. L. Kennedy Co.	H. L. Kennedy Co.	.001	West Lebanon Coal, Inc.	West Lebanon Coal, Inc.	.001
Krustack Inc.	Krustack Inc.	.001	Haynes R. Wood Coal Co., Inc.	Haynes R. Wood Co., Inc.	.001
McKim Coal Co.	McKim Coal Co.	.001			
C. A. Ogden Coal Co.	C. A. Ogden Coal Co.	.001			
Proton Energy Inc.		.001			
Princess Coal Sales Co.		.001			
					140 664

APPENDIX III

THE MEANING AND SIGNIFICANCE OF SELLER CONCENTRATION
IN THE COAL INDUSTRY

CRA #491

Final Report
THE MEANING AND SIGNIFICANCE OF SELLER
CONCENTRATION IN THE COAL INDUSTRY

Contract Number DE-AC01-79EI10603

Prepared for
U.S. Department of Energy
Energy Information Administration
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Chapter 1

EXECUTIVE SUMMARY

The following is a summary of the principal conclusions and recommendations from the study by Charles River Associates of conceptual issues related to the measurement of seller concentration in the coal industry. In analyzing issues of market definition and concentration measures, we closely examined four recent government studies on concentration and competition in the coal industry, reports by the Federal Trade Commission (1978), the Department of Justice (1978, 1979), and the General Accounting Office (1977).

I. Level of Seller Concentration

- The level of seller concentration is a useful statistic for competitive analysis, but users should be aware of its limitations. The competitive assessment of an industry requires, in addition, that other elements of market structure and also market behavior be considered.

II. Highlights Related to Coal Markets

- Since coal usually trades in markets which are distinct from the markets for oil, gas, and nuclear fuel, properly

defined coal markets constitute a meaningful entity for competitive analysis.

- Separate markets exist at present for high-grade bituminous metallurgical coal and for steam coal. The boundary lines of these markets are becoming less distinct, however, as electric utilities seek more low-sulfur coal and some low-rank bituminous coal is used in the production of coke.
- The market for metallurgical coal can be distinguished according to high or low volatility of the coal.
- Spot coal and contract coal trade in a single market, since their prices are closely interrelated by arbitrage.
- Metallurgical coal has two geographic markets: 1) the West; and 2) the East and Midwest. Within the latter, North and Central Appalachia emerges as a distinct submarket.
- Steam coal has three geographic markets: Appalachia, the Midwest, and the West. Some studies have further divided the West into the Northern Plains and Southwestern markets.
- Factors influencing competitive relationships are frequently changing in relevance and relative importance. Consequently the boundaries of each coal market are dynamic.

III. Measures of Concentration

- Information on concentration levels and trends in coal production, sales, and reserves will facilitate a competitive assessment of the coal industry.
- Sales or production is appropriate for measuring concentration only where coal reserves are abundant, so that a firm's future production levels are not constrained by the depletion of its current reserves.

- Measures of reserve concentration embody information on potential future changes in market structure.

IV. Data

- Publicly available data do not allow calculation of seller concentration in economically meaningful coal markets after 1974 because the data are not reported in categories that conform to product or geographical markets.
- The best available data are derived from the Federal Trade Commission's Special Report Survey covering the years 1964-1974. A separate survey of metallurgical coal data was performed subsequently by the Department of Justice. These data, however, are sufficient for calculating concentration ratios only in the following markets:
 - for steam coal: the Appalachian
Midwest
Western (Northern Plains, Southwest)
 - for metallurgical coal: North and Central Appalachia

Recommendations

- More research and analysis of the geographic boundaries of coal markets are needed, including the collection of more current data. We suggest that both the "few imports" and "few exports" test of the Elzinga-Hogarty technique be used as a starting point in delineating geographic boundaries of markets.
- So that government officials will have the data relevant to an analysis of competition in various coal markets, we recommend that all coal companies above a minimum size be required to report to the Department of Energy data on their annual production, sales, and brokerage activity by state (by county for Kentucky and Tennessee) for both

steam and metallurgical coal. Consistent definition of terms in accordance with generally accepted accounting principles should be used to permit comparison of concentration levels over time and to minimize the reporting burden on the companies. In addition, the Department of Energy should evaluate the feasibility and cost of an annual survey of reserve data. Such a survey would help insure that definitions and consequently reserve estimates are consistent within both the private and the public sector.

Chapter 2

COMPETITION, MARKETS, AND CONCENTRATION

Introduction: The Meaning of Competition

In a market economy competition plays a major role in allocating resources among alternative uses. As used in economic theory, the concept of competition has continued to evolve since Adam Smith emphasized its importance.* Competition, in modern economic theory, describes a market situation where the number of actual or potential sellers of a product or a group of homogeneous products is sufficiently large that the individual seller cannot appreciably affect the product's price. In the competitive model, price is determined by the forces of market demand and market supply, and participants recognize that the actions of any single seller have no perceptible impact on market price; in mathematical terms, price is a parameter to the seller (Scherer, 1980, p. 10). The key factor is that the market price is perceived by all to be beyond the influence of any individual seller or buyer.

*For a discussion of the concept of competition see Scherer (1980, pp. 9-12) and McNulty (1968).

Confusion is often introduced into public policy discussions concerning competition, however, because of the substitution of a popular concept of competition for the concept as used in economic theory. In the world of business, competition is often viewed as a process by which firms consciously engage in a struggle with each other for the expenditures of consumers. Economic theory describes this type of activity as rivalry and distinguishes it from the concept of competition. Rivalry occurs in situations where individual sellers clearly recognize that their actions do have a perceptible impact on price and market outcomes. In such situations, decision making among sellers involves a recognized interdependence, a condition that runs counter to the independent decision making and the perception of price as given that characterizes the economic concept of competition. As a result, there may be a high degree of rivalry in a market but weak competition, as the term is used in economic theory. The distinction is important, not only for purposes of clarity in discussion, but because public policy is concerned with competition rather than rivalry.

The following sections of this chapter discuss three major issues: 1) the definition of the product and geographical dimensions of an economic market; 2) the basis for measuring sellers' concentration in coal; and 3) the meaning and limitations of concentration measures in analyzing competition.

Defining Market Boundaries

Competition occurs within the context of a market. As a result, a comprehensive analysis of competition generally starts with a determination of the product and geographic dimensions of the market. When properly drawn, market boundaries will encompass all the forces of demand (buyers) and

supply (sellers) that determine the price of the product(s) being traded.* This perspective of a market is important because it highlights the purpose for which market boundaries are constructed and focuses attention on the need to maintain a close correspondence between the theoretical concept of a market and the definition of real-world markets.

The Substitutability Criterion

Economic theory provides some basic principles for defining markets. The basic criterion is the degree of economic substitutability between goods and between similar goods from different geographic areas. In simple terms, a properly defined market will include all products that are viewed as close substitutes among themselves and will exclude other products that are not good substitutes. The key to substitutability is what happens (how much substitution occurs) when price relationships change (Scherer, 1980, p. 60). However, the application of this principle is not a simple task. In fact, it can be quite difficult. Difficulty arises because economic theory, while suggesting the substitutability criterion, provides no guidance about how substitutable goods must be in order to belong to the same market.** There is also

*The impact of potential competition on price is analyzed in terms of the condition of entry to the market.

**If we think of substitutability as occurring along a continuum, economic theory tells us only that goods discretely different from others constitute a market, but does not tell us how large a gap in the continuum must be before products fall into separate markets.

the empirical difficulty of measuring the actual degree of substitutability between goods.*

At the practical level, the basic empirical problem in defining market boundaries involves identifying the range of alternatives to which users may reasonably turn. In a strict sense, all products are interrelated through exchange. However, many of these interrelationships are weak or negligible and of little importance to an analysis of competition. Such a wide grouping has little usefulness in analyzing competition. It is possible to identify gaps in the chain of alternatives that users face. The existence of such gaps indicates the dividing line between markets. Any effort to define actual boundaries of a market, however, is certain to involve an element of subjective judgment. While perfectly defined markets are extremely difficult, if not impossible, to identify, the careful analyst, following the guidelines of

*Attempts to measure the degree of substitution between goods in response to price changes often involve estimation of the cross-elasticity of demand, i.e., the percentage change in consumption of product A in response to changes in the price of product B. High values would indicate a high degree of substitution and low values suggest that the products are poor substitutes. A variety of interpretational and other problems seriously reduce the value of this measure in defining product boundaries of markets, however. For example, theory provides no guidance as to how high the cross-elasticity value must be to conclude the products belong in the same market. The technique also assumes that everything else, such as nonprice factors, remain constant. Moreover, substitution rates may be quite different across various price ranges. The use of cross-elasticity techniques does little, if anything, to reduce the subjective element in defining product boundaries of a market. For further discussion see Scherer (1980) and Needham (1978, pp. 109-114).

economic theory, can arrive at definitions that are reasonable approximations to the true market and are suitable for an analysis of competition.

Defining Market Boundaries:

Static and Dynamic Perspectives

To be valid competitive analysis must be based upon market definitions that are reasonable approximations to economically meaningful markets. In the past, many studies of competition have been deficient because they have viewed market boundaries as essentially static rather than as dynamic. With a static perspective, boundaries are perceived to be relatively constant and unchanging; with a dynamic perspective boundaries are seen as changing over time in response to a number of factors. In the case of certain products, a static perspective may be reasonable and perfectly adequate. In other cases, the static concept can result in a serious misrepresentation of reality and could easily lead the analyst to neglect certain critical factors influencing market boundaries and, by direct implication, to misinterpret the state of competition. Market boundaries of products such as coal, where competitive relationships are continually changing due to many factors, are clearly dynamic.*

*The definition of coal markets, even within a static concept, is necessarily imprecise. The coal industry simply does not organize itself into discrete categories. For example, transportation costs, which are a major determinant of geographical boundaries, are mainly a continuum. As a result, if a company were willing to absorb a portion of transportation costs, the company's coal shipments might flow beyond the conventional geographical boundaries of the market even when these boundaries are not changing.

We would argue strongly that, although the static approach makes the market definition task decidedly easier and the analysis apparently clear and precise, coal market boundaries are dynamic and their determination is clearly influenced by a variety of forces. With a static approach, boundaries are established on the basis of a set of transactions that occurred as a result of the relationship among a set of factors existing at a given point in time. Such relationships in the coal industry, however, are not fixed over time but often change. Some changes may have little impact on market boundaries but others are very important.

If one recognizes that market boundaries are dynamic and change in response to the changing environment, the task of defining market boundaries becomes more complicated. However, greater complication reflects the complex real-world situation and is not a basis for retreating to a static view of market boundaries. The real issue is whether the use of the static concept provides an adequate basis for policy analysis. Our contention is that the analyst concerned with competition is in some situations likely to be grossly misled by the use of a static concept of market boundaries. Such a situation clearly exists in the case of coal, where several highly dynamic factors, including institutional elements, operate in a manner that continuously affects market boundaries. The failure to recognize the dynamic nature of market boundaries creates the risk that any analysis that requires market boundaries to be drawn, such as analysis of competition utilizing concentration measures, is likely to produce misleading results or conclusions. Consequently, it is imperative that a dynamic concept of market boundaries be the basis of an analysis of competition in the case of products such as coal.

It is important that the task of defining market boundaries be placed in the proper perspective. The best that

can be done is to provide a reasonable approximation of the economically meaningful market as it exists at a particular moment in time and then to identify the factors that may cause boundaries, both product and geographic, to change over time. This task necessarily involves subjective judgment. For purposes of analyzing competition, reasonable levels of accuracy, rather than perfection, are sufficient, however.

Seller Concentration As a Determinant of Competition

The framework of the field of economics known as industrial organization serves as the basis for an analysis of market outcomes. This framework focuses on theoretical and empirical relationships between market structure, conduct, and performance or outcomes. Causation mainly flows from structure to conduct to performance, but the framework also recognizes the existence of important feedback loops, which allow causation to flow in the opposite direction.*

Market structure is a multidimensional concept.** Among its principal dimensions are the level of seller concentration, the level of buyer concentration, and conditions of entry into the market. The level of seller concentration has traditionally been used as one indicator of the extent of competition among sellers already operating in the market. Conditions of entry, which measure the advantages in cost or price which established sellers may enjoy over potential entrants, are an indicator of the constraint imposed on sellers

*The concepts and relationships addressed by industrial organization are described in Hay and Morris (1979), Needham (1978), Scherer (1980), and Shepherd (1979).

**For a comprehensive discussion of the various elements of market structure and their significance, see Scherer (1980).

by potential competition. The level of buyer concentration has been used as a measure of the ability of buyers to exercise influence over price, either as a countervailing force against seller concentration or as an exercise of monopsonistic power against numerous small sellers.

The level of seller concentration measures the number and size distribution of sellers in a market. Concentration measures are not direct indicators of the state of competition in a market, but are a surrogate measure of the degree of interdependency or "fewness" among sellers in a market.* High levels of concentration in a market are interpreted to represent a high degree of interdependency or "fewness" and, conversely, low concentration indicates a low degree of interdependency. Economic theory suggests that differences in the level of seller concentration can have important implications for competition.

The importance of seller concentration as a determinant of market outcomes arises from the prediction of theory of a positive relationship between the degree of interdependency among sellers in a market and the likelihood of those sellers engaging in cooperative behavior resulting in monopoly-like performance. Thus, high levels of concentration are likely to

*The degree of interdependency is inversely related to the number of sellers. "Fewness" describes the condition in which the number of sellers is sufficiently small that individual sellers recognize the impact of their actions on each other, i.e., a condition of interdependency exists. It should be emphasized that the condition of "fewness" does not conform, in a deterministic manner, to any specific number of sellers in a market. The emphasis of economic theory is on the condition of interdependency and not on the number of sellers per se.

cause market results to deviate substantially from competitive outcomes.*

Several aspects of the relationship between concentration and competition must be kept in mind during policy discussions. First, while a theoretical basis for the relationship exists, theory is limited to predicting whether the relationship is continuous or discrete and to indicating the level of concentration that separates monopoly and competition. Second, there are many other factors that influence seller behavior and market outcomes. The concentration-market outcome hypothesis assumes that these other factors remain constant. Since this is seldom the case, it is crucial that other factors (entry conditions, buyer concentration, etc.) affecting interdependency and seller behavior be identified and incorporated into any analysis of competition. Policy analysis must recognize that the competitive significance of a given level of concentration can vary importantly depending upon other structural factors and/or institutional characteristics of the market. Third, and perhaps most important of all, policy analysis based upon concentration measures has little meaning unless the concentration measures are based upon reasonably accurate definitions of market boundaries. Lacking accurate definitions of markets, the analyst is left with a number to interpret but no basis for an interpretation.

*The theoretical distinction is in qualitative terms and the concentration ratio is the quantitative measure. Because other factors affect the qualitative condition, the concentration measure is an incomplete measure of the qualitative condition. For an in-depth discussion of the relationship and the empirical evidence see Scherer (1980).

While a long discussion of the weaknesses and limitations of seller concentration measures in an analysis of competition could be presented, we have resisted such a temptation. The point of such a discussion is clear. Seller concentration measures must be used cautiously by the policy maker and in no sense can they be interpreted as indicative of a deterministic relationship with the state of competition in a given market. Their relationship with market outcomes is complex and dependent upon a number of other factors.

Thus, we have attempted to point out that, while indicators of market structure provide the analyst with a basis for assessing competition, their proper use requires an understanding of their strengths and weaknesses. Their use in a mechanical manner is neither warranted nor likely to yield meaningful results.

Market Definition: Identifying Product and Geographic Boundaries

The history of coal consumption indicates major changes in both the total level and the pattern of coal consumption. Since 1945, coal has disappeared from certain markets, such as home heating and railroads, and today coal basically serves two end uses: boiler fuel and steelmaking. In addition, the short-run competitiveness of coal is continually affected by numerous events, some of which affect all energy sources while the impact of others is limited to coal. It is clear that boundaries that encompass the forces of demand (buyers) and supply (sellers) that determine the market price of coal are constantly changing. As a result, the policy maker, in approaching the task of measuring and interpreting seller concentration in coal, must be aware of the dynamic nature of market boundaries. The adoption of a dynamic perspective,

while complicating any analysis of competition, recognizes that competitive relationships are constantly being altered by price and nonprice factors in real-world markets.* Most importantly, such a perspective is consistent with commercial reality.

Knowledgeable observers of coal markets are readily aware of the many factors that affect the competitive position of coal. These factors, extending far beyond the single issue of the relative price of coal, have a clear impact on the product and geographical boundaries of the market. It is the awareness of the individual factors that affect market boundaries and how they affect the meaning and interpretation of seller concentration that is crucial to sound analysis.

Boundaries that are sufficiently accurate to allow a meaningful analysis of competition can be identified, although their determination requires an element of judgment. The problems of market definition are difficult, but the definition of a market is fundamental to a comprehensive analysis of competition.

Product Boundaries

The product boundaries in the case of coal depend upon the degree of substitutability, based upon technical and economic factors, between coal and other energy sources and, given the

*Analysis based upon a static view of markets emphasizes the role of price on market boundaries and gives little attention to other factors that affect competitive relationships. In the case of products such as coal, the static framework is likely to involve too much abstraction from real-world markets and lead to incorrect measurement of structural indicators such as seller concentration. The result can easily be that the analyst's inferences about the competitiveness of the market structure are misleading.

wide variation in the characteristics of coal, between different types of coal in particular end uses. The demand for coal is a derived demand. As a boiler fuel, the demand is not for coal per se, but for the energy (and perhaps sulfur and ash) content of the coal. Similarly, the demand for coal in steelmaking is for the coking characteristics of certain coals. In both cases, there is some range of possibilities for economic substitution. This is readily seen in the case of coal used by utilities as a boiler fuel. In the case of coke production, opportunities for blending various types of coals do exist and are utilized. Thus, coal or a particular type of coal cannot be viewed as completely isolated from competition, actual or potential, from other sources of energy or other types of coal. As the degree of inter- or intrafuel substitution increases (decreases), the product boundaries of the market expand (contract).*

Chapter 3 contains our definition of the product dimensions of various coal markets. Here we seek only to illustrate the complex and dynamic nature of product boundaries. This is done by identifying specific factors that affect the competitive position of coal or specific types of coal.

Air Quality Standards

The electric utility's choice of a boiler fuel is based upon many factors in addition to relative prices. In recent years, air quality regulations have had a major influence on the choice of boiler fuel by electric utilities. These regulations can expand or contract the product boundary for

*Interfuel competition is not as strong today as it was when residual oil was relatively cheap and natural gas could be used as a boiler fuel.

coal in general or for specific types of coal: Coal is a heterogeneous product with substantial variations in certain characteristics, especially sulfur and ash content, which directly affect emissions and air quality. The imposition of regulations and the particular form of such regulations can have the effect of creating a separate market for coal with specific characteristics. For example, the EPA's performance standard for sulfur dioxide emissions could possibly eliminate competition between low- and high-sulfur coal in the utility boiler market (U.S. DOJ, 1979, pp. 9-11). Market definition is therefore sensitive to the form of the regulations.*

The above example illustrates the impact environmental regulations can have on the substitutability between various grades of coal and, by direct implication, on product boundaries. Some regulations could remove certain coals from the set of substitution possibilities the utility faces. Such regulations can have similar impacts on the competitive relationship between coal and other energy sources. However, the impact could be quite different depending on the particular energy source being considered. For example, certain environmental regulations might affect coal's competitive position relative to oil but have no impact on the coal-nuclear relationship.

Institutional Sources of Uncertainty

The dynamics of interfuel substitutability in the electric utility sector illustrate the crucial role of institutional factors. Coal's long-run competitive position relative to nuclear power is being enhanced by the uncertainties associated

*Environmental regulations have had the effect of causing competitive overlap between metallurgical coal and steam coal as a boiler fuel by electric utility sector. This changing relationship is discussed below (U.S. DOJ, 1979, pp. 34-35).

with public concern about the safety of nuclear plants and the disposal of nuclear wastes, and with the increasing delays in obtaining licenses for nuclear power plants. The length of the licensing process and the lack of standard plant designs are important sources of uncertainties. If the uncertainties and anxieties are reduced and standardized designs become the rule, the competitive relationship between coal and nuclear fuel might be substantially changed.

The Metallurgical Coal-Steam Coal Relationship

Metallurgical coal is used to produce coke for producing steel. Met coal has certain distinctive properties in terms of relatively low amounts of sulfur, phosphorus, and ash, which have historically caused it to sell at a substantially higher price than steam coal. Because of its distinctive attributes and the clear tendency of the market to place a high value on these attributes, met coal has generally been considered as trading in a different product market than steam coal.

The relationship between met coal and steam coal is not static and unchanging, however. In fact, the relationship is a prime example of the dynamic nature of the market boundaries. The distinction between met coal and steam coal has become blurred and there is evidence that, in certain instances, substitution has occurred. Because of increasingly strict emission standards, electric utilities in certain geographic areas have found it necessary to substitute met coal with low sulfur content for steam coal in their generating plants. In addition, since the production of coke can utilize a blend of different-rank coals, some low-rank bituminous coal, previously limited to use as a boiler fuel, has been used in the production of coke (U.S. DOJ, 1978, pp. 42-43). Thus, the increasing substitution between met and steam coal, while limited so far, illustrates that the competitive relationship

between products, previously regarded as distinctly different and belonging to different economic markets, can change. The evidence suggests that while two distinct markets probably still exist, their boundaries have become less distinct.

Technological Change

Technological change is probably the most important long-run determinant of the product boundaries of a market. The historical record clearly indicates that advances in technology have tended to increase the set of economically viable possibilities for substitution on the demand side of the market (Blair, 1972, pp. 95-98 and 114-151). As a result, product boundaries have tended to be pushed outward to encompass a wider set of substitution possibilities.

The effect of technological change is easily seen in the case of energy products such as coal. The nature of the competitive relationship between coal and other sources of energy is heavily influenced by the pace of technological developments of synthetic fuels. While forecasting the pace of technological change is very difficult, it is clear that such changes can have, in the long run, a major impact on product boundaries of markets, usually in the direction of bringing products that have tended to trade in separate markets into direct competition.

Long-Term Contracts

Long-term contracts are the predominant means used by utilities to procure coal. Gordon (1975) reports that over 75 percent of coal used by utilities is produced under contracts covering ten or more years and that the incidence of such contracts is significantly greater among larger utilities (CRA, 1977). While such contracts contain various clauses providing for price adjustments and cancellation, it seems clear the use

of such contracts tends to reduce to some extent the likelihood of a utility switching from coal to another fuel. In fact, Gordon's analysis indicates that utilities located in coal regions where shifting to another fuel would be unlikely tended to be quicker to use and more dependent on long-term contracts. The apparent explanation is that such utilities, by adopting long-term contracts, were not effectively reducing their options regarding fuel use but were increasing the security of supply.

Summary

The several points discussed above were presented not in an attempt to delineate specific market boundaries, but to illustrate the sensitivity of market boundaries to a variety of factors. Some of the factors, such as technological change, affect boundaries over a long period of time while others, such as the imposition of or changes in the form of emission standards, can affect boundaries in the short run. Our list is clearly not exhaustive. The point is relatively simple: market distinctions between products are sensitive to a variety of forces extending far beyond relative prices.

The dynamic nature of coal markets is only one of several reasons why it is difficult to delineate market boundaries. Competitive relationships are necessarily complex, especially in the case of a product such as coal with significant variations in qualities, the geographic distribution of these qualities, and mining methods and costs. The overlay of a matrix of government regulation and the resulting uncertainty serves to multiply the complexity of these relationships and to make it more difficult to delineate boundaries. However, reasonable market boundaries can be established and are valuable to policy makers concerned with competition.

Geographic Boundaries

The second dimension of a coal market is the extent of the geographic area encompassing the demand and supply forces of the product. Markets may be regional, national, or international in scope. Distinct regional markets are likely where transportation costs are high relative to the value of a product. Cement is a product clearly trading in distinct (noncompeting) regional markets.

As in the case of defining product boundaries, economic theory can provide guidelines for determining geographic boundaries. The criterion is the degree of interregional substitution of the products in the market. When properly drawn, a regional market will include all firms whose products are good substitutes to a common set of buyers. Products supplied by firms located outside of the region will not be economic substitutes for products supplied within the region.

If the region is defined too narrowly, some supply forces (producers) will be omitted from the market. In a similar manner, an overly broad definition will include producers whose products are not ready substitutes. In either case, the market definition would deviate from an economically meaningful market and create a situation where any concentration measures based upon the incorrect definition could be misleading. Whether the concentration measures would be too high or too low depends upon the size distribution of the firms included or excluded from the geographic market relative to the firms in the correctly defined market.

The trading area of a product depends upon the importance of transportation costs. The distance that coal from a particular coal basin can be shipped and remain competitive with coal from basins located elsewhere is heavily affected by transportation costs. Other factors are also important in determining the geographic trading patterns of coal. The combination of various types of coal and different needs of

coal users, along with regional differences in mining costs, cause geographic boundaries to be determined by a complex set of factors. And, most importantly, the factors and their individual forces are frequently changing. Thus, geographic markets, while being based upon coal basins, are constantly being affected by a variety of factors that change the competitiveness of coal from one region with coal from other regions.

Transportation Costs

The geographic trading pattern of a product reflects a given state of technology and the current condition of a number of economic and noneconomic factors. In the case of coal, technological advances leading to lower transportation costs have acted to expand greatly the geographic trading areas of coal mined at a particular location. Introduction of unit trains reduced transportation costs and, as a result, expanded geographic trading patterns. Future changes in transportation, such as greater use of slurry pipelines, are likely to lead to similar changes in geographic boundaries.* As transportation costs change, market boundaries shift, leading to consequent changes in the alternatives buyers face and in the level of seller concentration.

Government Regulation

Government regulation can have a major impact on the geographical size of a market. In the case of coal, regulation is a major factor affecting trading patterns. While the price of coal is unregulated, the competitive position of coal in general and of specific types of coal in particular is

*In a study for the Coal and Electric Power Analysis Division of DOE, CRA will conduct tests of the sensitivity of interregional flows of coal to changes in transportation costs.

heavily influenced by regulations involving environmental and land-use policies, leasing policies for federal lands, railroad rates, and occupational and safety issues.

The impact of various government regulations on geographic market boundaries can vary from one region to another. This results from the fact that the characteristics of coal vary greatly across regions. For example, certain regulatory policies, such as land-use policies, have a differential impact on the competitiveness of strip coal versus deep-mined coal. Since strip-mining operations are primarily located in Western regions and deep-mining production in the East and Midwest, regulations affecting strip mining can, by affecting mining costs and/or production levels, influence the distance that Western coal can be transported and still be competitive with Midwestern coal. Alternatively, government regulations requiring the use of scrubbing devices in coal-fired electric power plants would increase the competitive position of local coal with a higher sulfur content in relation to distant coal with a lower sulfur content.

Our discussion of the issue of determining the geographical boundaries of a market emphasizes the volatile nature of these boundaries. A similar emphasis was made in our discussion of the product boundaries of a market. In the case of a heterogeneous product such as coal, the volatility of boundaries -- product and geographic --- is much greater than in cases involving basically homogeneous products. However, reasonable estimates of geographic boundaries can be made by the analyst in spite of the inherent difficulty of the task.

An Improved Technique of Defining Geographic Boundaries

Empirical estimation of geographic boundaries can be expected to provide only an approximation to the true

geographic dimensions of a market. The task of actually defining a geographic market has been addressed by Professors Elzinga and Hogarty (1973), who have proposed an analytical technique that captures both the demand and supply elements operating in the market. In this sense, it represents an improvement over many past efforts to define markets.

Briefly, their technique is based upon analysis of the geographic distribution of trade in the relevant product(s) and utilizes two criteria: the little in from outside (LIFO) criterion and the little out from inside (LOFI) criterion. The LIFO element measures the extent to which a supply of the product(s) flows into a geographic region from the outside (imports) and the LOFI element measures the extent to which demand forces cause the product to flow out of the region (exports). In a distinct geographic market, there would be few imports and few exports.

Application of the Elzinga and Hogarty technique involves initially identifying a product's major producing area and subsequently, using shipments data, determining the geographic area (number of states) required to meet an agreed-upon value for the LOFI and LIFO criteria. One of the weaknesses of this technique is economic theory's inability to indicate the critical value for LOFI and LIFO that the analyst should adopt. Elzinga and Hogarty use a "strong test" of 90 percent, meaning that a geographic area would be considered to be a distinct market if at least 90 percent of what is consumed in the area is also produced within the area (indicating a low LIFO value) and if at least 90 percent of production within the area was also consumed within the area (indicating a low LOFI value). A region simultaneously satisfying both criteria would be viewed as representing a reasonable approximation of a true geographic market. If an area fails to meet both criteria, the

geographic dimensions of the region are expanded until the criteria are met.*

The Elzinga and Hogarty technique, while representing an analytical improvement, nonetheless contains certain limitations. First, as indicated previously, economic theory provides no guidance to the analyst as to the critical value that should be assigned to the LOFI and LIFO criteria. In practice, analysts have focused on values ranging between 90 and 75 percent. A difficulty, however, is that different values obviously lead to different conclusions about whether a region is a distinct market. Second, the technique requires the availability of disaggregate data on the geographical distribution of the product. Such data are either not available or where available are collected at too high a level of aggregation.

In addition, application of the Elzinga-Hogarty technique involves some ambiguity in cases where there are important regional differences in the production costs of a commodity. Such a situation exists in the case of Western strip-mined coal and Midwestern deep-mined coal. As a result of lower mining costs, Western coal can flow to the Midwest but Midwestern coal is too costly to ship to the West. In this situation, Midwestern producers face competition from Western mines, but western producers do not face competition from Midwestern mines.

Perhaps the most important criticisms of the Elzinga-Hogarty technique are that it does not capture the extent of potential competition and that it is slow to detect changes in market boundaries. The Elzinga-Hogarty technique is based on existing or past patterns of product shipments and

*For an application of this technique to coal see Hogarty (1975). The authors also use a "weak test" of 75 percent.

does not reflect the extent to which shipment patterns might change in response to changes in the price of the product or in transportation costs. This is not a serious limitation, however, as long as the importance of potential competition is taken into account through an analysis of entry conditions in the market. Also, it is not clear that there is a practical way of drawing geographical boundaries to encompass potential competitors in a market.

A more serious limitation of the Elzinga-Hogarty technique is that it is slow in recognizing changes in market boundaries. For example, as soon as a new railroad or slurry pipeline is constructed, coal producers and users face expanded alternatives and the geographic boundaries of the market may change substantially. It may be some time, however, before there is a large enough change in actual shipment patterns for a new market to be discerned by the Elzinga-Hogarty technique.

Despite some limitations, the Elzinga-Hogarty technique is analytically sound and provides valuable guidance to the analyst. Although it is a useful starting point, it should not be used in a mechanical manner. Its use does not reduce the value of intimate knowledge of the coal industry; rather it is best used as a means of organizing such knowledge and data in the manner necessary for analyzing competition.

Summary

The task of defining the product and geographic dimensions of a market is complicated by several factors. First, market boundaries are the end result of the impact of many factors influencing competitive relationships. Second, the factors frequently change in relevance and relative importance, so that market boundaries are dynamic. Third, economic theory, while providing the substitutability criterion as the basis for defining markets, is quite limited in its ability to provide

further assistance to the analyst. Fourth, empirical measurement of the degree of substitutability is extremely difficult. In the face of these limitations, the task of defining actual market boundaries requires an element of judgment. The policy analyst need not shrink from the task of defining markets, however, but should be constantly aware of the complexities of the analysis.

Measuring Seller Concentration

Measures of seller concentration reflect the number and the size distribution of firms in a market. They represent the share of the economic activity controlled by a given number of the largest firms. Calculation of concentration measures is an easy task in the textbook context of homogeneous goods and perfectly drawn market boundaries. In practice, the task can be quite difficult.

Defining Economic Activity:

Current versus Future Indicators

A major issue in constructing concentration measures is the proper definition of the industry's economic activity. The issue is whether measures of current activity, such as sales or production, are adequate or whether measures of future productive ability, such as ownership of reserves, are more meaningful. The importance of this issue is greatest in the case of a product like coal with a depletable base. With a depletable resource, it is possible that a company's large market share in terms of current activity might be a poor indicator of the firm's future position in the industry, if the firm's reserve position were small relative to its current production. Thus, an important question is whether concentration measures based upon current activity are

adequate, or whether concentration should be measured by indicators of future importance in the market.

It has been argued that coal sales or production are not adequate measures of either the current or future ability of individual firms to supply coal to the market (U.S. DOJ, 1978, pp. 56-62). The inadequacy results from the extensive use of long-term supply contracts and the fact that coal is a depletable resource. As an alternative, the use of coal reserves, preferably uncommitted reserves, is often suggested.

In a strict sense, the argument that a firm's share of economic activity measured in terms of sales or production does not necessarily indicate that the firm's future share of activity is correct, given the depletable nature of coal. A large producer of coal today may not be a producer at all or as important a producer in the future. The firm's future position depends critically on the amount of reserves it possesses, and on its ability to maintain a reserve position. Alternatively, a firm may have little current production but large reserves which it is just beginning to develop. Consequently, a reserve-based measure of the coal universe and of individual firm shares of the total is, in a strict sense, a better indicator of the firm's future importance in the industry.

However, a clear preference for a reserve-based measure rests upon an assumption of disproportionately high or low ratios of total coal reserves to current and planned production. For example, with a low ratio, a firm's relative importance in the industry could change drastically as a high production rate depletes its reserves. However, given a high value of the ratio, there is no reason why the depletable nature of coal will necessarily lead to a reduction in the firm's share of the market.*

*It should be noted that, in the face of a high ratio of reserves to production, a firm's market share could still decline for a variety of other reasons.

A coal producer clearly has a strong incentive to maintain a reserve position sufficient to provide for future production. While the optimal size of the reserve will rise or fall in response to several factors, future production levels are not likely to be seriously constrained by depletion of reserves, especially for the dominant producers. Given the relative abundance of total coal reserves in existence and the ability of firms to discover new reserves or to purchase known reserves in the market, production-based measures of economic activity can be adequate indicators of firm's future importance in the industry. Thus, the possibility that production could deplete a firm's reserve base is not sufficient by itself to generally diminish the value of using measures of current activity to construct concentration measures.* In using such measures, however, the analyst, aware of the importance of the assumption of a high reserve to production ratio, must be alert for information, public or private, that indicates the inappropriateness of the assumption in the case of a specific firm. On the other hand, where a firm or group of firms has a high ratio of reserves to current production, relative to the

*Even if one were to grant that reserve-based measures are always to be preferred, the likelihood of developing such measures is quite low for several reasons. First, coal reserves are heterogeneous along several dimensions which have varying importance across different end uses. Second, the accessibility of coal reserves differs to an important degree. Some reserves simply may not be sufficiently accessible to compete with other, relatively accessible, reserves. Third, identification of the quality and quantity of coal reserves is a difficult task and interpretations of geological tests can vary widely from one firm to another (Fenili, 1979).

industry average, one can anticipate an increase in their relative importance in the industry.*

Captive Production and Long-Term Contracts

The measurement of concentration levels in coal is further complicated by the extensive use of long-term supply contracts and the presence of "captive" mining operations. Arguments have been made on both sides of the issue of whether coal production or reserves accounted for by long-term contracts or "captive" operations should be included in any measure of the total economic activity in coal (Duchesneau, 1975; FTC, 1978; U.S. DOJ, 1978). In our judgment, however, both reserves committed under long-term contract and captive production ought to be included in the relevant coal universes. Both represent potential competition. If other sellers were to act jointly and elevate price, the higher price could induce a supply response from both "committed reserves" and captive production. Long-term contracts often contain clauses allowing cancellation by either party within a reasonable period, usually one year. In the case of captive production, such production is often able to enter the open market in response to favorable price movements. In fact, there is historical evidence to indicate that this has taken place in the coal industry.** In addition, captive production is part of total demand and total supply and plays a role in price determination. Thus, such coal cannot be viewed as totally isolated from the market.

*Such appears to be the case, for example, with major oil companies in the coal industry.

**See Charles River Associates (1977). In addition to affecting coal prices via potential competition, prices under long-term contracts are affected by competitive conditions. Such prices are often renegotiated when demand and supply conditions change dramatically.

In summary, there are several important issues measuring seller concentration in coal. The issues arise mainly from the depletable nature of coal and specific institutional features of the coal industry. It is our judgment that measures of current economic activity, such as sales or production, can be properly used to measure concentration. The argument in favor of using only reserve-based measures is based on the assumption that producers allow current production to deplete their reserve base. The likelihood of such a situation is greatest in the case of a firm's strategic decision to exit from coal production, in which case the decision is likely to be well known and the analyst should be able to make the necessary adjustments to current production data.

Chapter 3

DELINEATION OF COAL MARKETS

Introduction

Chapter 2 develops a conceptual framework for defining markets and measuring seller concentration in them. This framework is applied in Chapter 3 to a delineation of coal markets. Appendix B is a summary table which lays out, for visual reference, the product and geographic market definitions identified in Chapter 3.

A competitive analysis of industry structure requires that one or more markets be delineated in terms of both product and geographic boundaries. Market boundaries are determined by the degree of substitutability within a range of product attributes or geographic areas. Economic theory provides two measures of the degree of substitutability between products or between the same product in different regions. Cross-elasticity of demand -- the ratio of the percentage change in the demand for Y to the percentage change in the price of X -- measures the extent to which an increase (decrease) in the price of X leads consumers to shift to (from) Y. Correspondingly,

cross-elasticity of supply -- the ratio of the percentage change in the quantity of Y supplied to the percentage change in the price of X -- measures the extent to which suppliers of Y shift their capacity to (from) the production of X as the price of X increases (decreases).

In the case of coal, there is a diversity of coal attributes relative to end use, and a continuum of transport costs. Coal transactions are variable and not infrequently cross market boundaries, even if the boundaries can be fixed. Unlike other sources of energy, such as oil and nuclear fuel, sufficiently discriminating data are simply not available on coal prices and quantities demanded, across attributes and within different geographic areas, to enable the calculation of reliable cross-elasticities.* Therefore, in empirical analysis, delineation of coal market boundaries requires subjective judgments about the degree of substitutability and approximate estimates of the costs of substituting among different attributes and between different locations. Practical indicia, which analysts use in defining markets, include price patterns and responses, supply patterns, transportation costs, attributes of the products, and industry recognition of distinct products or geographical areas.

To further complicate the task of defining coal markets, market boundaries are dynamic and in flux. They change in response to technological developments, changes in transport costs, alterations in use pattern, and institutional or legal requirements, especially environmental regulation. Our task here is not to provide definitive delineations of either the product or the geographic boundaries of coal markets, but rather to inform policy makers of the complexity of the issues

*See Chapter 2, on The Substitutability Criterion, p. 2-3.

with which they must be concerned in evaluating the competitiveness of the coal industry.

Product Markets

The term "coal" used in this study refers to the broad categories of bituminous, subbituminous, and lignite coals classified according to carbon content.* Definition of product markets involves analysis at two levels: 1) determining the degree of economic substitutability between coal and other energy sources; and 2) given the wide variation in the characteristics of coal, the competition among different types of coal.

Interfuel Substitutability

Even though all fuels serve basically the same technical function and certain fuels may substitute for coal in some instances, coal normally trades in a market that is distinct from the markets for other fuels. In commercial practice, the extent to which coal competes in a broader fuel market is a complicated question, depending in large part on the time dimension involved, the proximity of demanders to alternative fuel sources, pollution emission standards, and other factors.

The primary sources of energy that are most frequently identified as potential substitutes for coal are nuclear fuel, oil, and gas. Both coal and nuclear fuel are used primarily by electric utilities. Competition between these fuels is long-run and occurs as the utilities decide what type of generating system they should use for new or replacement "baseload" power. There is some diversity of opinion, however,

*This usage is consistent with the DOJ (1978, 1979), FTC (1978), and GAO (1977) reports on coal.

as to whether this kind and degree of competition forms a basis for including coal and nuclear fuel within the same product market. A 1975 study on competition in the energy sector quotes a 1972 FTC report, stating that, "For the entire U.S., the evidence indicates that coal, oil, natural gas, and uranium are sufficiently substitutable in their use by electric utilities to support the conclusion that they trade in the same economic market" (Duchesneau, 1975, p. 24). This conclusion rests in part on the projection that by 1979 nuclear fuel would be used in 59.2 percent of new generating capacity within the electric power industry.* In contrast to this, a Department of Justice study (1978, p. 32) concludes that in the long run, substitutability between coal and nuclear fuel is diluted by "indirectness of competition." Such indirectness stems from the fact that each fuel accounts for only a fraction of lifetime plant costs. Over shorter periods of time, coal and nuclear fuels are somewhat poor substitutes, since no coal plant can be converted economically to use nuclear fuel, nor vice versa. Hence, due to limited short-term competition and only indirect long-run competition, attributes of coal and nuclear fuel are sufficiently distinct that in most cases they trade in separate markets. Under present economic and technological conditions, therefore, it is meaningful to calculate concentration ratios for coal alone.

In the case of oil and gas, there is also some disagreement about whether these fuels are competitive with coal. As evidenced by the 1972 FTC report (Duchesneau, 1972),

*The author of the study in which the FTC report is mentioned states at one point that the FTC data may be biased upward in estimating the multifuel capabilities of utilities. He himself goes only so far as to say that fossil fuels and nuclear fuel are competitive (Duchesneau, 1975, pp. 23-24).

some believe that oil and gas are (or were) indeed competitive with coal, at least in their use by utilities. The DOJ study, however, states that in the long run, and even more so in the short run, these types of fuel cannot be viewed as economic substitutes. High OPEC prices, the limited availability of natural gas, and government policies prohibiting or discouraging the use of oil and gas as boiler fuels, have effectively eliminated new baseload plants fired by oil or gas as an option for electric utilities. In the industrial sector, especially the steel industry, the cost of substitution generally precludes the use of oil or gas in place of coal.

In the household and commercial sectors of the coal industry, fuel patterns show that since 1947 coal has been almost entirely replaced by oil and gas. Similarly, in the transportation sector, diesel fuel, electricity, and petroleum have replaced coal. In the long run it may be that liquefaction and gasification will increase at least the indirect use of coal in these sectors, but this will only occur in response to large increases in the relative prices of the currently used sources. Furthermore, the DOJ study estimates that liquefaction and gasification will not be an economically feasible replacement of present fuels before the turn of the century.

Again, the degree of substitution between coal and either oil or gas is sufficiently limited that coal can be regarded as trading in a distinct product market.

Whatever the extent of substitutability among coal, oil, gas, and nuclear fuel for use in the generation of electric power in 1972 when the FTC report was written, interfuel competition is clearly weaker today. The future of nuclear power is uncertain, residual oil is no longer cheap, and natural gas is no longer available as a boiler fuel.

Steam Versus Metallurgical Coal

Industry participants recognize a clear distinction between the market for high-quality bituminous metallurgical coal and the market for steam coal. The steel industry puts a premium on coal with distinctive coking properties such as low content of sulfur, ash, and phosphorus. These relatively unique characteristics have made metallurgical coal a distinct product market. Historically, and still to a large extent today, the distinctive characteristics of metallurgical coal have been reflected in its price, which as of late 1974 was more than double the delivered spot price of steam coal (\$63.30 per ton as compared to \$31.10 per ton) (Executive Office of the President, Council on Wage and Price Stability, 1976).

Although price differentials still indicate the existence of distinct markets between steam and metallurgical coal, mounting evidence points to increasing substitution by users of both, and to some blurring in the boundaries between these two products. Technological improvements in the blending of coals and other hydrocarbons have permitted much wider usage of lower-rank coals in the manufacture of coke. According to the FTC report, because of proximity to steel plants, coal with weak coking characteristics from the Illinois Basin as well as the Western region has been used for metallurgical purposes, as higher-grade coals are becoming depleted (FTC, 1978, p. 22).

Substitution is taking place on the part of steam coal users as well. For example, increasingly strict emissions standards are inducing electric utilities in certain geographic areas to substitute in their generating plants some low-sulfur metallurgical coal for some steam coal with a high-sulfur content.

Except at extreme ranges of coal attributes, customers can blend coals to achieve almost any quality level they desire, and blending techniques are increasingly popular and

inexpensive. Such practice is already fairly common among both metallurgical and steam coal users. Thus, the lines between the two markets are becoming somewhat blurred by the movement of coal across traditional boundaries in response to changes in technology and price.

According to the 1979 DOJ study, within the product market of metallurgical coal there are several submarkets based on volatility. Strong blast furnace coke requires that some low or medium volatile coke be used in the blend, and thus defines low and medium volatile prime (containing less than 1 percent sulfur) coking coal as a distinct market. Low volatile prime coking coal is also a distinct market since foundry coke makers have a unique demand for this coal. In addition, a distinct market may also exist for high volatile prime coking coal, which has the property of forming stronger, more homogeneous coke and whose prices are significantly lower than those in other categories of volatility. Although a medium volatile coal will produce coke, most metallurgical coke is produced from a blend containing 15 to 30 percent low volatile coal and 70 to 85 percent high volatile bituminous coal (Averitt, 1974, pp. 52-54).

Spot Versus Long-Term Contract Coal

The DOJ report mentions that the steam coal market may further be segmented into the long-term contract and spot coal markets. However, this distinction deals less with product content than with the time dimension of the market, and appears to be more a behavioral than explicitly structural factor of the market. It can be argued that the two categories are in fact part of the same broad market, since buyers and sellers can and do arbitrage between the spot and contract markets. Contracts in the coal industry impose fewer restrictions on behavior than in some other industries.

Most utilities buy a mix of spot and long-term contract coal. Each buyer has a "portfolio" of coal supply arrangements, ranging from long through intermediate term, to "evergreen,"* to spot. Proportions of purchase are adjusted in relation to expected costs, and while the expected level of spot prices over the long run is close to the contract level, spot market prices do boom occasionally with increases in demand. When spot prices are at a premium, some suppliers of long-term contract coal reduce the quality and quantity of deliveries under their contracts in order to move more coal into the spot market. Even in the West, where contracts are not easily broken, terms are renegotiated in light of changes in spot prices. Therefore, since the prices of spot and contract coal are closely interrelated, the two types of transactions should be considered as taking place in a single broad market..

Geographic Markets

As in the case of product boundaries, geographic markets depend on the degree of interregional substitution, or the costs involved for users of a product in one area to import the product from alternative sources of supply outside the area.

Transportation costs, which affect the distance that coal from a given region can be shipped and still remain competitive with coal produced in other regions, are an extremely important determinant of geographic trading patterns. Transport costs, however, form a continuum and frequently change in response to technological advances and other factors. Specifications of

*The term "evergreen" refers to contracts with indefinite time limits in which the price is renegotiated annually.

product markets, or the combination of different types of coal and different needs of coal users, along with regional differences in mining costs, also determine the extent and shape of geographic markets. Since these also form a complex of ever-changing forces, especially in response to government regulation, geographic boundaries, while based primarily upon coal-producing basins, are frequently being transgressed, and are undergoing shifts and distortions.

The coal resources of the United States are distributed among eight major coal basins. Due to the regional insulation created by high transport costs, the basins have traditionally been associated with coherent regional coal markets. In recent years, greater use of unit trains, increased costs of mining, and the higher price of coal have lessened the ratio of coal transport costs to the delivered price of coal. Consequently, the insularity of the regional coal basins has also diminished.

Transport costs are still high enough, however, that coal is bought and sold in regional markets rather than a single national market. At the same time, there has been recognition that the boundaries of geographic markets, however they are delineated, do not capture the magnitude and effectiveness of potential competition between markets. Hence, the extraregional forces are still important, especially since observations of the industry all point to a trend of diminished regional insulation. For example, the DOJ report points out concentration ratios for the nation as a whole provide an indication of the relative positions of firms with the proven ability to "package," contract, and deliver long-term coal supplies, unconstrained by the boundaries of regional coal markets.

Steam Coal

The three recent government reports on competition in the coal industry disagree in defining geographic market boundaries for steam coal. The FTC study (1978) has grouped the eight producing regions into three geographic markets for steam coal: the Appalachian, the Midwestern, and the Western regions. The Justice Department's study (1978) has identified four distinct markets by separating the Western market into a Northern Plains market and a Southwestern market. The GAO report (1977) contains yet another geographical configuration: three markets are also identified, but with slightly different boundaries than in the FTC report.

Since none of the reports gives an adequate explanation or presentation of the methodology employed in deriving these geographic markets, it is difficult to ascertain the empirical rigor of their market-defining processes. The FTC report states that "regional markets [were] drawn on the basis of product flows, using Bureau of Mines coal distribution data." A footnote on the general techniques of geographic market definition refers to a methodology developed by Leonard Weiss, as well as the Elzinga-Hogarty technique* with its "substantial limitations." The FTC staff apparently used the Elzinga-Hogarty test supplemented by subjective judgment.

The Justice report provides greater detail about the process of its market definition. At the conceptual level, the

*The Elzinga-Hogarty test, devised for determining geographic market boundaries, is based on observations of interregional shipments data. It requires that to qualify as a market, an area must simultaneously satisfy two conditions: a product must be locally produced and locally consumed so that there are few "imports" and few "exports." See Elzinga and Hogarty (1973).

Justice report rejects the "few exports" component of the Elzinga-Hogarty technique and argues that the "few imports" test alone is sufficient for defining the geographical boundaries of markets. Although there is not a clear indication of precisely how the "few imports" test was applied (perhaps in conjunction with other factors) to arrive at particular definitions of the geographic market, the report does mention checking the validity of the geographic boundaries it found. Rough estimates were made of transport costs, shipping distances, and minemouth prices so that calculations could be made of how boundaries shifted in response to change in minemouth price, or where the delivered price for coal from the core of each production center would equal those from adjoining markets (DOJ, 1978, pp. 46-47).

The authors of the government reports also disagree on the degree of "blending" that characterizes their market boundaries. While they are in accord on the continued existence of a distinct Eastern market consisting of states around the Appalachian coal basin,* the FTC study notes that the Midwestern and Western regions are fusing into one market, from the perspective of the Midwestern consumer. Several factors in the early 1970s, such as the Clean Air Amendments of 1970, have caused increasing amounts of low-sulfur Western coal to flow into the Midwest. Because of the lower production costs of strip-mined coal, Western coal could compete favorably with the low-sulfur, underground coal of the Midwest. Rising oil prices in the early 1970s diminished the importance of

*The states are in two groups: 1) the Northern Appalachian Basin: Pennsylvania, Ohio, West Virginia, Maryland; and 2) the Southern Appalachian Basin: Virginia, Tennessee, North Carolina, Georgia, Alabama, and Eastern Kentucky. See Averitt (1974, pp. 34-36).

transportation costs relative to the value of coal, and in conjunction with cost-reducing transport innovations like the unit train, Western coal became increasingly competitive in more distant Midwestern consumption areas. Midwestern coal, because of its higher production cost, however, cannot compete in Western consumption centers. Therefore, beginning from 1971, the FTC recommends analyzing survey data in terms of the Appalachian, Western, and Midwest and West regions.

It should be noted, however, that the trend of Western coal flowing into the Midwest is also being slowed by subsequent legislation, such as the Clean Air Act Amendments of 1977, which require the use of high-sulfur local coal to minimize local economic disruption or unemployment, and the Surface Mining Control and Reclamation Act of 1977, which narrows the production cost gap between strip and underground mining.

The DOJ study (1978, p. 45), however, does not agree with the hypothesis that "coal markets west of Appalachia are dissolving into a simple Central-Western market."* The authors argue that the Elzinga-Hogarty test condition, which forms the basis of such a hypothesis, overstates the size of regional markets by simultaneously imposing the "few imports" and "few exports" test. Imposition of the latter pushes the market's proposed boundaries too far and fails to capture the power of a monopolist in an exporting region to charge noncompetitive

*This appears to be an unfair characterization of the FTC hypothesis. As discussed above, the two markets are merging only from the Midwestern consumer's perspective, and the product flow is only in one direction. Therefore, more than one market characterizes the area west of Appalachia.

prices in that region.* Indeed, the Justice study discusses each of its four markets primarily in terms of how well it meets the "few imports" test. The Justice authors, therefore, prefer to retain the narrower market definitions, especially since acceptable data on the smaller markets are available.

This difference in geographical market definition between the Department of Justice and the FTC is based ultimately on a difference in the reasons for defining the geographical boundaries of a market, as indicated by its criterion for determining whether a group of firms within a region by joint action has the power to raise prices above the competition level. In this limited type of inquiry exports from the region are unimportant. The key question is whether noncompetitive pricing would attract or increase imports into the region; that is, what alternatives are there for consumers located in the region?

This type of inquiry, however, is more germane to a later step in a competitive analysis, namely, the determination of whether one or more firms within the market possess market power, than it is to defining the geographical boundaries of a market. According to traditional economic analysis, a market is defined as part of the analytical process of explaining price determination. The market, therefore, should encompass all the forces of both demand and supply whose interaction determines price. The "few imports" test looks only at the demand side of the market and the alternatives buyers face. But supply forces also play a role in determining price. If

*The charge that the Elzinga-Hogarty test criteria may overstate the size of regional markets varies from general criticisms that the technique could lead to too narrowly defined markets due to ignoring potential competition. See FTC (1978, p. 24).

there are significant exports from a region, then demand from other regions will affect price and the market is properly defined as interregional.* For example, increased demand from other regions, by increasing market demand, will increase the price paid by local consumers, just as a decline in exports will lower the prices paid by local consumers.

Furthermore, it is not clear that the "few imports" standard, by itself, is an adequate basis for assessing whether producers in a region enjoy market power. Even if all producers of a good are located in Region A, if there are significant exports to Region B, arbitrage will serve to keep prices the same in the two markets, apart from transportation costs. The relevant question in assessing market power is the alternatives of consumers generally within the market, not the alternatives of only some of them.

We believe that both the "few imports" and the "few exports" tests should be used in defining geographical markets.

Metallurgical Coal

Regarding geographical boundaries for metallurgical coking coal, the FTC study claims that "there are no separate producing/consuming geographic market areas as in the case of utility coal, but one national market" (FTC, 1978, p. 60). The national market is perceived as being centered in the Appalachian region.

While the 1978 DOJ study states that the market for metallurgical coal is national or international in scope, the 1979 update identifies the West, and the East and Midwest as clearly distinct markets for coking coal. Within the East and

*For a more detailed critique of the "few imports" approach, see Management Analysis Center (1979, pp. 14-17).

Midwest region the authors identify Northern and Central Appalachia as a distinct market for coking coal, since this region is advantageously located near the steel industry. The 1979 DOJ report identified Alabama as a distinct geographic market for low and medium volatile prime coking coal. We think that, thus far, the 1979 DOJ study most carefully defines the geographical boundaries of the market for metallurgical coal and that the West, East, and Midwest ought to be tentatively accepted as distinct geographical markets for metallurgical coal.

We also conclude, however, that past attempts to define the geographical boundaries of the markets for both steam and metallurgical coal have had sufficient problems in their methodology or their data that a definitive study of market boundaries remains to be done. We recommend that the Department of Energy give serious consideration to performing a study of the geographical boundaries of coal markets, including collecting the necessary data.

Exports

While none of the recent government studies of competition in the coal industry argues that the boundaries of coal markets are international, as opposed to regional or national, there is evidence that coal markets may be in the process of widening their boundaries beyond the United States. According to a recent article in Business Week (1/28/80, pp. 35-36), the rapidly rising prices of oil are increasing exports from U.S. coal mines. Exports of metallurgical coal, always substantial, are expected to reach 60 million tons this year. The greatest increase in coal exports should come from steam coal, however. Exports of steam coal are expected to grow from 2 million tons in 1979, to 7.5 million tons in 1980, to as much as 80 million

tons by 1990. Correspondingly, the prices U.S. users pay for coal will become more sensitive to international demand.

If these expectations materialize, markets for both metallurgical and steam coal may be international by the end of this decade.

Chapter 4

MEASURES OF CONCENTRATION

Introduction

In Chapter 4 we discuss appropriate measures of concentration in the coal markets delineated in Chapter 3. Aside from analyzing the theoretical aspects of measuring current versus future activity in the coal industry, we also examine the levels of concentration as revealed by the concentration ratios for the top four and eight firms in the United States and regional coal markets calculated in the four recent government studies.

Measures of seller concentration denote the share of total market activity controlled by some number of the largest firms in an industry, often the top four, eight, or twenty. The data required for such a measure include the activity of individual firms and a total for the industry. The total, or "universe," is used as the basis for estimating the degree to which the largest firms can dominate the marketplace if they were to act together.

A major problem in constructing concentration measures is the proper definition of the industry's economic activity. In the case of coal, the appropriate phase of activity to be examined becomes especially significant, due to the depletable nature of the resource and the prevalence of long-term supply contracts in market practices. As previously discussed in Chapter 2 (pp. 2-23 to 2-26), should concentration measures reflect current activity, as captured in production and sales figures, or should they reflect future capacity, such as ownership of reserves, either total or committed?

In the FTC and DOJ studies, seller concentration is measured in terms of both current and future activity. Figures are presented for production, sales, shipments to electric utilities, shipments of metallurgical coal, total reserves, uncommitted reserves, and uncommitted nonfederal reserves. Except for metallurgical coal sales, for which data exist only for the national market, all the measures are for markets at both the national and regional levels.

The production figures presented in the FTC (1978) study treat all coal as homogeneous, while reserve data differentiate among coal types: bituminous, subbituminous, lignite, low-sulfur, and surface minable. Aside from metallurgical coal sales and shipments to utilities, none of the other production or reserve measures distinguishes between metallurgical and steam coal. Since the FTC study had already delineated two separate markets for steam and metallurgical coal, the inconsistency between market definition and concentration measure constitutes a significant weakness of the study.

Measures of Current Activity

Production, sales, and shipment figures are all measures of current economic activity. Some economists contend that to

the extent brokerage activity takes place, production data may not be as accurate as sales data in measuring the level of concentration in the market. Large firms occasionally purchase coal from small firms, which they then resell on the market.

Our investigations on this issue are in accordance with the findings of the GAO study, which revealed that brokerage sales took place infrequently and apparently not in sufficient quantities to significantly affect concentration ratios based on sales data.*

Sales data presented in dollar figures also have the advantage of capturing differences in quality (heating value, sulfur, and ash content) among coal, while production data do not.

Another issue is whether captive mine production (or reserves) should be included in the market. Captive mine ownership has been prevalent among metallurgical coal consumers and is becoming increasingly so among electric utilities.** The FTC, DOJ, and GAO studies all include captive mine production in calculating concentration ratios, and we agree with their position. As in the case of long-term contracts,

*We compared production and sales data for the top eight producing groups in 1978, based on figures from the Keystone Coal Industry Manual (1979, p. 664) and 1978 Annual Reports. None of these documents mentioned brokering activity, let alone how important it may be. Data for both production and sales could be found for only three firms. For none of these companies did production and sales tonnage differ by more than 4 percent, and part or all of this difference may be attributable to factors other than brokering.

**Captive production by utilities supplied about 12 percent of utility coal consumption in 1975, according to the Keystone Coal Industry Manual (1976, p. 436).

captive production is part of both total demand and total supply, and is often able to enter the open market in response to favorable price movements. This movement may occur even across market boundaries, such as between the metallurgical and steam coal markets. According to the GAO report (1977, p. VI-3), in 1974 shortages of spot coal resulted in the diversion of captive coking coal to utility boilers. State utility commissions and the Securities and Exchange Commission have sometimes restricted the ability of utilities to transact in the open market, but apparently their interpretation of captive coal operations is not inviolable. According to a report by the Federal Power Commission (1977, p. 13), "A utility commission could conceivably allow the coal operation to sell coal on the open market with the appropriate ratemaking adjustments to take into consideration the revenues earned from those transactions. A separate mining subsidiary usually would not be bound by those restrictions." Since coal could be self-produced at lower costs, the availability of alternatives created by captive mines restricts the ability of coal producers to raise prices above the average costs of production. Since the production and reserves of captive mines play a significant role in determining coal prices, they should be included in calculated concentration ratios.

Measures of Future Activity

As measures of current economic activity, production, sales, and shipment figures reflect bygone market interactions and are useful indicators of the past competitive status of an industry. If a firm's reserve position were small relative to its production activity, however, then its currently large market share may not be an appropriate indicator of the firm's future position in the industry. The firm's potential

influence on future prices depends critically on the amount of reserves it controls, and on its ability to maintain a reserve portfolio. Hence, it can be argued that under conditions of a low reserves-to-production ratio, a reserve-based measure is a better indicator of industry competitiveness. These conditions are actually infrequent, however, as most major producers keep up their inventory, and the likelihood of their reserves being eroded by production is small.

The next logical step, then, would be to define a measure of reserves that most accurately reflects future productive capacity. Here the degree to which a measure of concentration can be refined and judgment about the ultimate utility of doing so depend on the availability and reliability of data. About 80 percent of coal in the commercial market is transacted through contracts of five to thirty years' duration (Executive Office of the President, 1976, p. 26). Because of the prevalence of such long-term arrangements, with large blocks of reserves and mining services committed to sale, it has been argued that total coal reserves may not be as valid a measure of a firm's future competitive capability as are "uncommitted" reserves. To what degree, however, are "committed" reserves in fact committed? Long-term contracts contain clauses covering price and price adjustments, conditions under which contract provisions can be broken or the contract renegotiated, and penalties associated with various breaches of contract provisions (CRA, 1977, p. 3-17), usually within a reasonable period of time. Thus, reserves that have been committed can, and have been, diverted to the open market in response to price changes. In our judgment reserves committed under long-term contracts still represent an element of potential competition and therefore should be included in the reserve universe just as uncommitted reserves are.

A second issue relating to reserves is whether coal on unleased federal and Indian lands should be included. Due to the leasing moratorium imposed by the Interior Department since 1973, the four government studies (FTC, 1978; U.S. DOJ, 1978 and 1979; and GAO, 1977) have all calculated a reserve measure that would exclude unleased federal reserves and reserves on Indian land.* The FTC constructed a universe consisting of the total demonstrated reserve base excluding estimated unleased federal reserves. Since the federal government occupies a key position in the reserve ownership, especially in the West,** this adjustment turns out to be very significant in calculating concentration ratios. The potential effects of federal coal leasing policies upon the Northern Plains market and Southwestern market (as defined by the DOJ) are evidenced by the spread between the four-firm concentration of uncommitted federal reserves and total uncommitted reserves in these regions. In the Northern Plains, the four-firm concentration ratio for uncommitted nonfederal reserves is 46.9 percent, while the figure for all uncommitted reserves is only 13.7 percent. In the Southwestern market the comparable figures are 66.3 percent versus 25.4 percent (U.S. DOJ, 1978).

In June 1979, however, the federal leasing moratorium was lifted, and the Environmental Impact Statement regulating federal leasing of coal reserves went into effect. According to sources in the Office of Leasing Policy Development at the Department of Energy, a schedule of geographical leasing

*The common rationale was that the decisions on leasing coal on these lands would be determined primarily by political considerations and not in response to economic forces.

**Of the 1975 reserve base, 55 percent belongs to the federal government, largely in the West. See Charles River Associates (1977, p. 3-17).

targets has been drawn up, showing what federal reserves will be available for leasing and what production is expected to take place in the near future. For example, reserves in Southern Wyoming and Northern Colorado are expected to be leased by early 1981, while Central Utah reserves will be leased by the middle of that year. With the resumption of leasing, exclusion of unleased federal reserves from the total universe base is no longer appropriate. However, under land-use planning criteria and various environmental regulations, some reserves will continue to be barred from leasing. Consideration has to be given to how these "not-for-lease" reserves may be estimated and excluded in attempts to refine the measure of total reserves as a universe base.

In summary, we find that measures of both current and future economic activity are significant in the calculation of concentration. Current measures can be adequate indicators not only of a firm's present status, but also its future importance as well, especially if future production levels of firms are not seriously constrained by the depletion of reserves. Given the abundance of total coal reserves and discoverable new reserves, major firms usually maintain their reserve profiles. Where reserve concentration is significantly higher or lower than concentration of production or sales, however, the data suggest that concentration of production or sales will increase or decrease, respectively, in the future.

Data on reserve concentration are useful because they embody more information on what groups of companies are likely to become important producers in the future, and how the future character of the industry might change. According to the FTC study, because of the acquisition of several large independent coal companies by petroleum companies and conglomerates, the percentage of coal production as well as reserve holdings

accounted for by these firms has increased dramatically in the period from 1967 to 1974. As stated in an article in Business Week (9/24/79, p. 104), "Thanks to a careful acquisition strategy that began 15 years ago, 11 oil companies now own 25 percent of all the coal in the industry..." Also, "From a modest 22 percent production share in 1978, oil companies have embarked on an ambitious expansion program that will put their share of national production at almost 50 percent by 1985." Consequently, the article predicts that the type of competition will change in the coal industry as oil company money, technology, and management skills increasingly set the pace for coal's growth. The focus of production will also shift away from the smaller underground mines of Appalachia to the large strip mines in the West (Business Week, 9/24/79, p. 106).

In evaluating the advantages and limitations of these various concentration measures, the policy maker should remember that no one is superior to the others for all purposes. The measures that conceptually are the most refined and permit the narrowest interpretation of existing market concentration also rely on data that have undergone the most ad hoc adjustments and thus are probably the least accurate. Also, the incremental benefits of greater precision in the data have to be weighed against the additional costs of obtaining or achieving such accuracy. The policy maker will have to assess the costs and benefits of such a tradeoff.

Levels of Concentration

In calculating concentration ratios, whether for production or for reserves, the best available data are derived from the Federal Trade Commission's Special Report Survey covering the years 1964-1974. Separate data on metallurgical coal are obtained by the Department of Justice. Chapter 5

discusses in more detail the serious limitations of utilizing these sources to calculate concentration in all economically meaningful product and geographic markets, as well as the need for more comprehensive data. This section takes the concentration ratios that have been calculated by the four recent government studies, and examines them briefly in light of their levels, the trends they indicate, and the generalizations policy makers have made thus far.

Table C-1 in Appendix C presents the concentration ratios for bituminous and lignite coal, for both the national and regional markets, based on Federal Trade Commission data obtained through the Special Survey. Table C-2 presents four-firm concentration ratios of prime coking (metallurgical) coal for the North and Central Appalachian market. Tables C-3 and C-4 present share figures held by oil/gas companies and large conglomerates of coal production and reserves.

In terms of bituminous and lignite coal production, concentration was low to moderate throughout the 1964-1974 period both nationally and for the Appalachian region, where four-firm concentration in 1974 was 25 and 22.3 percent, respectively. Concentration in the Midwestern region was higher (56.1 percent in 1974) due to large-scale, low-cost surface mining and the prevalence of large production units. If the Western market of the FTC study were broken up into the Northern Plains market and the Southwestern market of the DOJ study, then the Southwestern market is characterized by an increasing four-firm concentration ratio, from 48.2 percent in 1964 to 64.1 percent in 1974. This apparently results in part from the increasingly large size of new production units and the utilities' preference for large, single-source supply contracts. There is no evidence that the bidding for contracts was other than competitive, however.

On the national level and in all the regional markets except the Southwestern, there is the apparent trend of

declining concentration in production since 1970. The FTC report attributes the decrease to shift from underground to surface mining in response to legislative changes and the major coal strikes of 1971 and 1974 in which larger companies were affected. Factors that have widened market boundaries, such as the transportation innovations and sulfur emissions regulations resulting in increased shipments of Western coal into the Midwestern region since 1970, have also contributed to the decrease in production concentration.

Looking to the future, the downward trend of production concentration should continue for the nation as a whole, and for the Appalachian and Midwestern markets as well. The 1974 four-firm ratio for U.S. coal reserves is 13.3 percent. Excluding the 120 billion tons of demonstrated reserves controlled by the federal government, the uncommitted nonfederal reserve concentration ratio increases to 25.5 percent. As for the Appalachian and Midwestern markets, the figures for concentration of uncommitted nonfederal reserves and total uncommitted reserves make clear the potential effects of federal coal leasing policies upon that market's competitiveness.

Similar conclusions may be drawn about the Southwestern market, in which concentrations of uncommitted nonfederal reserves (66.3 percent) and total uncommitted reserves (25.4 percent) are 40.9 percentage points apart. This region also presents dramatic potential for federal leasing to affect the structure of the market.

Since the great bulk of coking coal in the larger East and Midwest market is located in North and Central Appalachia, concentration figures for North and Central Appalachia are indicative of those in the larger geographic markets (see Table C-2, Appendix C). According to the Justice Report (1979, p. 65), the Department has found "relatively low levels of

concentration in the North and Central Appalachian markets." Unfortunately, available data do not permit even a gross estimate of concentration ratios in the less significant Western markets or the low and medium volatile market in Alabama.

Concentration of metallurgical coal sales (measured on a national scale in the FTC study) was moderate throughout the 1964-1974 period. The four-firm concentration was 41 percent in 1974, while that of eight-firm was 54 percent. Metallurgical coal, while not facing significant competition from alternative fuels, increasingly faces competition from blends of other grades of fuel.

Concentration ratios of coal shipments to electric utilities were measured on a national basis, since data were not readily available on a geographic basis corresponding to geographic market boundaries. Four-firm concentration of shipments to electric utilities was higher than production concentration from 1964-1974, reaching a high of 37.7 percent in 1970, then decreasing to 32.5 percent in 1974. The decrease may have resulted from the increasing share accounted for by smaller (unsurveyed) coal producers and the significant work stoppages in 1971 and 1974.

The FTC study also recorded share figures held by oil/gas companies and large conglomerates of coal production, shipments to electric utilities, and coal resources on both a national and regional basis (see Tables C-3 and C-4). On a national basis, for 1967-1974 the 36 surveyed oil companies' share of total production grew from 10.8 to 19.1 percent. Share of coal shipments to electric utilities grew from 13.7 to 22 percent. In 1974, the oil/gas companies owned 14.5 percent of U.S. demonstrated reserve base and between 20.5 and 42 percent of privately held coal reserves.

Regionally, oil/gas company share of production was highest in the Midwest, while their share of the demonstrated reserve base was 9.7 percent in Appalachia, 19 percent in the Midwestern region, and 14.6 percent in the Western region (35 percent when unleased federal reserves are excluded).

After measuring concentration, all four government studies, and especially the Justice study, emphasize the fact that without evaluation of other structural factors and the nature of the competitive process itself simple concentration ratios do not present sufficient information upon which to base any judgments of competitiveness.

Chapter 5

DATA BASES

Data Requirements

Our analysis of product and geographic markets in Chapter 3 indicates that it is necessary to have data for each geographic market on reserves, production, and sales for each of the leading firms and for the market as a whole in order to calculate seller concentration in the coal industry and to interpret the competitive significance of the concentration ratios. Furthermore, this information should reflect uniform methods of reporting and standard definitions of the products and geographical regions involved. Reserves, for instance, should measure either in-place or recoverable coal, and data on the two types of reserves should not be mixed.* Also, firm and universe data must be consistent with each other so that they can be used together. Since it is too costly to survey every

*We recommend that recoverable reserves be used since it is from these reserves rather than in-place reserves that production will change in response to a change in price.

firm in the country to sum to a unique figure, a government estimate of the universe figure will probably have to be used. Firm data should therefore be reported in a way consistent with the universe data.

Use of coal production by firm to calculate seller concentration is relatively straightforward, and needs no additional comment. Sales data, however, are slightly more complex. In calculating sales data one must be aware of the brokerage activity between firms to properly attribute the sales. If, for example, Company A sells to Company B, which in turn sells to coal consumers, such sales ought to be included in B's market share rather than A's.

An important point to be made about data requirements is that to accommodate changing definitions of the product and geographic markets, such data should be reported according to the finest categories that are practical and economical. It is essential that data be reported at a level of detail that will permit them to be aggregated into markets as they exist today and as they are likely to exist in the future. Thus data should be reported separately for steam coal and metallurgical coal.* Similarly, data should be reported by state, and for Kentucky and Tennessee by county, since these two states have been divided into two distinct geographical markets.**

*In certain instances it may be useful to further divide the market for metallurgical coal according to volatility. However, it is important to recognize that the finer the distinction, the more difficult and costly will be the acquisition of data.

**The GAO study includes only eastern Kentucky within its eastern Appalachian market. Both the DOJ and FTC studies place eastern Kentucky in an Appalachian market, and western Kentucky in the Midwest markets. The DOJ study similarly divides Tennessee into these two markets.

Once the data have been reported at this level of detail, one should be able to determine, for any geographical market, the total amount of either metallurgical or steam coal that the region sells, produces, or holds in reserve. Similarly, one should be able to identify the leading firms in the region, and find the amount of metallurgical or steam coal that each firm sells, produces, or holds in reserve in that market. From these numbers a concentration ratio can be easily calculated.

Available Data

The most serious problem in determining the level of seller concentration in coal markets is the unavailability of the necessary data in public sources. Recognizing the dynamic nature of the boundaries of coal markets, one must be wary of using data for incorrect or bygone product or geographical market boundaries. Also, depending on how one chooses to measure concentration of reserves, production, or sales of coal, the necessary statistics may simply not exist in a manner allowing meaningful comparability across firms.

Suppose one wanted to calculate concentration of reserves in economically meaningful coal markets. Data on reserves are reported in the Keystone Coal Industry Manual and occasionally in the annual reports of coal companies. The latter sources, however, are unsatisfactory since the reporting of reserves in annual reports is optional. Not all coal firms report reserves, and not all reporting companies follow the same definition of reserves.

The Keystone Manual publishes annual data on the total estimated reserves of coal held by most firms in the United States and Canada. Although more informative than what it found in company annual reports, these data too are inadequate for determining concentration ratios. For instance, there is no means of determining how the company's total reserves are

distributed by geographical markets. Thus, the largest holder of reserves, Consolidation Coal Company, has an estimated 13.7 billion tons of coal resources. Consolidation Coal, however, has associated companies in West Virginia, Tennessee, Illinois, Ohio, Pennsylvania, North Dakota, and Canada. The percentage of Consolidation Coal reserves held in each of these regions is not indicated, rendering it impossible to determine the company's share of reserves except for the North American continent (which no one has yet suggested constitutes an economically meaningful market for coal).

Available reserve data similarly fail with regard to the product market. The Keystone Manual publishes statistics only on total reserves, with no breakdown into the distinct markets for steam and metallurgical coal. Although substitution between the two types of coal exists, all of the studies previously mentioned in this report agree that steam coal and metallurgical coal now constitute separate markets. We concur with this consensus, and therefore see little value in using the Keystone data to estimate concentration in the coal industry.

Finally, Keystone reports estimated total reserves without differentiating between recoverable and in-place reserves. Presumably some companies report recoverable reserves while others report in-place reserves. Like net sales and gross sales, figures on these two kinds of reserves cannot be meaningfully added or compared.

Production and sales data, used to measure current levels of concentration, are similarly deficient. Sales data in dollars, important because they capture differences in the quality of coal, which are not reflected in tonnage figures, are simply not easy to find. Although annual reports often provide the company's sales of coal, there is generally no breakdown of these sales into sales of metallurgical coal and sales of steam coal.

Production data are also not without problems of their own. In the Keystone Manual production is published by company by state, thereby allowing closely defined and changing geographic markets. It is even possible to derive production according to county since Keystone lists the counties in which the individual companies' mines are located. Unfortunately, Keystone's data on production do not always distinguish between steam and metallurgical coal. In the section on production by company by state, the percentages of metallurgical coal and steam coal are reported for a few companies, but not for most. Furthermore, one cannot attempt to fill in the missing data from the Keystone list of coking coal since a coking seam can also produce steam coal.

Recommendations

Using publicly available data, there is insufficient comparability across firms and continuity in time such that policy makers or analysts can calculate seller concentration in all the various economically meaningful coal markets. Since seller concentration is an important variable in an analysis of the competitiveness of coal markets, it is desirable that the data needed to calculate concentration ratios become available to policy makers. To this end, we recommend that all coal companies above a minimal size be required to report to the Department of Energy each year their recoverable reserves, production, brokerage activity, and sales by state (by county for Kentucky and Tennessee) of both steam coal and metallurgical coal. Form EIA-28 of the Financial Reporting System is a step toward meeting the need for satisfactory coal data, although the reserve data reported there will be noncomparable across firms since each reporting company is allowed to use the reserve definitions and classifications currently followed in its internal records.

Given the lack of uniformity in the reserves data, the problem of consistent measurement and interfirm comparability becomes especially acute for the policy maker. Ideally, recoverable reserves should be clearly defined so that all companies are reporting comparable reserve data, and these data are, in turn, comparable with government estimates of total reserves, by state, of both steam and metallurgical coal. Problems may still abound, however, since interpretation of geological test results and the amount of coal believed mineable at various prices may differ among firms, according to their respective views of the future (Fenili, 1979). Simply requiring companies to report the amount of demonstrated coal reserves they control by specifying the use of Bureau of Mines seam thickness and depth standards does not overcome these problems. Also, the amount of information a firm possesses about its coal deposits depends on what the firm views as optimal for its decision-making process, and how future events would affect the price of coal. Each firm has to weigh the costs of acquiring more information against the benefits of additional information. Given the large variance in the types of information firms possess regarding their coal deposits, the lack of uniformity continues to pose a challenging problem for policy makers.

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Appendix A
THE RELATIONSHIP OF CONCENTRATION TO
PROFITS AND INNOVATION

Concentration and Profits

Examination of an industry's structure is an important element in a competitive assessment of an industry and its performance: whether the industry approximates a competitive ideal, or whether firms can tacitly or overtly collude to restrict output and raise prices. Economic theory suggests that when one or a few firms (monopoly or oligopoly) control most of an industry's output, or when concentration is high, undesirable market performance may result. Indeed, a central proposition of traditional industrial organization economics is that the size distribution of sellers is an important determinant of an industry's profitability.*

*The theory also points out that barriers to entry are necessary if an industry is to persistently earn profits above a competitive level.

Although economists have devised several schemes for classifying industries according to their level of concentration and have conducted empirical tests of some concentration-profits hypotheses, economic theory gives no guidance about the level of concentration required to generate above-normal profits in an industry. It should be noted, in addition, that these schemes are all based on manufacturing industries, and thus their relevance to an exhaustible natural resource such as coal is still being investigated.

The market concentration ratio, the most commonly used measure of an industry's structure, is usually calculated as the percentage of total industry sales accounted for by the leading four, eight, or twenty firms. Bain (1968, pp. 137-147) classifies an industry as being significantly oligopolistic when the four largest producers account for 50 percent or more of total output and eight firms account for at least 70 percent. Kaysen and Turner (1959, pp. 295-297) classify an industry as "concentrated" if the top eight firms hold a share of 50 percent or more. Scherer (1980, p. 67) suggests that "[w]hen the leading four firms control 40 percent or more of the total market, it is fair to assume that oligopoly is beginning to rear its head."

Once four-firm concentration reaches the 40 to 50 percent level, oligopoly often appears and profits may rise. Empirical studies have found that industries in which the four-firm concentration is at or above 45 to 55 percent, or where eight firms control 80 percent of total output, tend to have higher profits than less concentrated industries. According to Weiss (1974), the relationship between concentration and profits has been one of the most thoroughly tested hypotheses in economics. Data for a large number of industries became available after World War II. Concentration ratios measuring the output of the top four, eight, twenty, and fifty companies for the Standard

Industrial Classification's 4- and 5-digit codes have been computed by the Bureau of Census for the years 1947, 1954, 1958, 1963, 1967, and 1972.

According to Weiss (1974) there are considerable conceptual and measurement problems with the available data, related to factors such as size of firms, growth rates of industries, risk, measures of firm efficiency, product differentiation, advertising, and R&D activities. Errors in the concentration indices as well as in profit measures tend to reduce the observable correlation between concentration and profits and bias the estimated relationships toward zero. This leads Weiss (1974, p. 201) to conclude that any positive relationship that does appear tends to be understated, and even if no relationship is detected, one may still exist.

A general consensus exists that there is at least a weak positive correlation between concentration and profits, especially as evidenced by the earlier empirical studies. One exception is the test performed by Stigler in 1963, in which the relationship was found to be insignificant. Weiss (1974, p. 220) points out that the test covered periods of strong inflation, a time when the concentration-profit relationship is expected to be weak. During periods of price control or strong inflation, prices of concentrated industries rise with more of a lag than competitive industries, since the former are the self-conscious decisions of leading firms. As Weiss (1974, p. 221) states, "the upshot of these studies is that the concentration-profits hypothesis is only strongly supported for normal years of relatively stable price and/or a recession -- 1953-1967."

Some more recent studies, however, have questioned the consensus on the concentration-profits relationship. Yale Brozen's work in 1970 and 1971 attempted to carry forward in time observations of a cross-section of industries studied

earlier by Bain, Mann, and Stigler (Weiss, 1974, p. 221). He found no confirmation of the persistence of the earlier correlation. An enlarged sample of Bain's original industries also failed to reveal significant positive correlation between concentration and profits. Brozen attributed the declining relationship over time to the fact that the concentrated industries were in excess-demand disequilibrium when observed by Bain and Stigler (Weiss, 1974, p. 221). With the process of adjustment, profits fell to a normal level over time.

It is clear that the bulk of empirical studies reveals a positive correlation between profits and concentration. However, the existence of some nonsignificant correlations precludes drawing definitive conclusions. Questions have been posed about both sets of findings with regard to quality of data, assignment of firms to proper industries, time frames observed, and other specifications of the statistical tests.

Data from other countries are being utilized increasingly to further test these relationships. Although the data are not strictly comparable because of differences in industry boundaries or concentration measures, certain interesting patterns are emerging. There is similarity in the degree of concentration among the leading firms across similar industries, and the positive effect of concentration on profitability is also present.

Even if the positive correlation between concentration and profits is confirmed, what can be inferred from such a relationship? First of all, the conventional concentration ratio suffers strong basic deficiencies as a good measure of firm-size distribution. Theoretically, such an arbitrary statistic as the simple summation of four or eight largest shares fails to establish the exact number, relative importance, and necessary size of the largest firms in determining industry performance. With regard to this issue,

John Kwoka (1979) in recent work utilized individual market share data for 1972. By examining market share correlates of industry performance, the study was able to shed more light on what features of industries are important, how important they are in total and what their relative importance is. Kwoka concludes that the two largest firms are of equal importance in determining industry price-cost margins, while a sufficiently large third share would exercise a depressing effect, due to problems of coordination. Once output control by one or two firms reaches 25 to 35 percent, industry margins begin to increase. Beyond "some point," however, performance is no longer affected by further increases in concentration (Kwoka, 1979, p. 108).

Kwoka was also able to isolate the effects of several other independent variables from the market power effects of large shares, especially scale economies. It seems that the cost disadvantages of small-scale entry, as well as minimum efficient plant size, are relevant. The implication is that scale economies play a role in explaining margins, but only in industries where minimum efficient scale is substantial and suboptimal size is costly (Kwoka, 1979, pp. 103 and 108).

A second important question revolves around interpretation of the findings. Dispute centers on the direction of causality in the concentration-profits relationship. The conventional view holds that the existence of a small number of firms in an industry facilitates collusion, thus resulting in higher profits. The competing view states that rather than being regarded as a departure from competition, a high profit level in an industry is a measure of its health. Industries become concentrated for technological and efficiency reasons. The largest firms are the most efficient and earn the highest profits. Thus, a positive concentration-profit relationship denotes superior efficiency.

The study by Demsetz (1974) highlights the efficiency view. The study is based on the hypothesis that if firms in highly concentrated industries engage in collusive behavior, then the fruits of such collusion, namely higher profits, should be enjoyed by the smaller firms as well. Thus in highly concentrated industries the profit rates of small firms should be positively correlated with concentration. The results of his study showed that this was not the case and on this basis Demsetz rejects the collusion hypothesis.

The study goes a step further to regress differences between the rates of return of large and small firms against concentration. The resulting positive relationship is interpreted by Demsetz to mean that superior efficiency of the largest firms can explain the positive association between concentration and profitability (Demsetz, 1974, pp. 176-177).

A paper by Bond and Greenberg (1976) criticizes the analysis of Demsetz in several respects. One is the failure to consider all of the various reasons which might explain differences in profitability among firms in the same industry. The paper points out that large firms may enjoy higher profits due to ability to price discriminate, or because of product differentiation. Indeed, with regard to product differentiation, there exists a body of related literature on the positive association of concentration, advertising intensity, and profitability. However, the exact cause and effect linkages among these variables are at present also unclear, and empirical work on this subject has not advanced very far (Mann, 1974, p. 155). Bond and Greenberg tested the efficiency hypothesis by regressing differences in rates of return upon an industry advertising-to-sales variable. Results revealed that the advertising-to-sales ratio, rather than the concentration ratio, is significantly associated with differences in profit rates. In other words, the higher

profitability of large firms may be more explained by their product differentiation and the ability to raise prices, rather than the ability to lower costs due to superior efficiency (Bond and Greenberg, 1976, p. 204).

The controversy of the concentration-profits relationship will not be easily settled, since the existence of competing hypotheses preclude any clear-cut interpretations of empirical tests. Problems with the data and the concept of concentration ratios mean that empirical constructs do not always measure the relevant theoretical concepts. The policy maker, then, ought not to treat the findings that emerge from concentration statistics and their use in various empirical works as conclusive evidence in an analysis of competition.

Again, the concentration ratio is only one indicator of market structure, and the same numerical figure in different industries may indicate different levels of concentration. The impact of the concentration ratio upon profits depends on its relationship to other market structure indicators, such as entry barriers and performance.

Concentration and Technological Change

The concept of technological change is broader than that of profits, encompassing the introduction of new products, product features, or processes of production. Historically, technological change has played a major role in the economic growth and prosperity of U.S. firms and industries. It is estimated that the contribution of technological change to

economic growth has been at least as important as that of capital formation, population growth, and increased education.*

In contrast to profits, technological change is difficult to quantify. Indeed, the term is so abstract that the relationship between seller concentration and technological change can be perceived only through secondary measures of the latter. Some of the most commonly used are expenditures on research and development, the number of personnel hired for R&D purposes, the number of significant innovations, or invention patents received, and estimates of sales associated with new patents introduced (Scherer, 1980, p. 418). Even with such a selection of alternative measures, however, conclusions drawn from studies concerning technological change and seller concentration are usually tentative and subject to qualification.

Technological change can be viewed, according to Scherer (1980, p. 411), as the outcome of the innovation process, encompassing four essential functions: invention, entrepreneurship, investment, and development. At the stage of invention, a new and promising technical possibility is recognized and worked out in its most rudimentary form. The concept is then tested, modified, and perfected through development. Entrepreneurship involves the organizational and financial efforts supporting the commercial utilization of the invention, and investment is the act of risking funds for the venture.

Assessments of innovation commonly refer to the relationship between innovation and market structure, or

*Denison (1974), for instance, has estimated that technological change accounted for 30 percent of the growth in the national income of the United States between 1948 and 1969.

concentration, and the relationship between innovation and firm size. In the latter case, discussion of firm size as it relates to innovation may be helpful in clarifying some of the complexities of the concentration-technological change issue. Some economists argue that large firms have an advantage over their smaller counterparts with regard to at least some stages of technological change. A larger firm can realize economies of scale that are beyond the reach of medium and small firms. For example, a large firm can afford and effectively utilize expensive testing equipment and highly skilled scientists. It can also attract capital at a lower cost to finance expensive R&D projects, and can realize greater savings from process innovations. Additionally, large firms can spread their risks by financing several projects simultaneously and averaging out their losses and gains. J. K. Galbraith goes so far as to say that technology is too far advanced for all but large firms to bear the risks of technological change. By his own genius, the lone inventor has lost his place to the large corporation.

Amid such discouraging pronouncements, the small businessman and the ambitious tinkerer can take heart in the knowledge that not all economists share these beliefs. Large firms are often recognized as having certain disadvantages with respect to at least certain stages of technological change. Perhaps the most obvious drawback is the abundance of red tape that almost inevitably wraps itself around a large company. In instances where R&D groups find themselves so bound, they tend to suffer from bureaucratic restraints and inhibitions at the expense of creativity (Scherer, 1980, p. 414). Contrary to the previous arguments, then, it would seem that large firms may not be able to attract the most imaginative inventors. They are, rather, at a distinct disadvantage. Further fallacy may be uncovered in the argument that large firms have an advantage in spreading their risk. Some maintain that in such companies

individual managers make R&D decisions without consulting a risk portfolio. With such decentralization, risk may not be intelligently assessed in order to minimize losses. Thus, it may not always be the case that such firms use risk to their benefit. Additionally, some economists maintain that even if they did, the consequences would be relatively minor since risks are not as great as they may appear. Most projects are small, and do not require large sums of money. Furthermore, businesses generally will not begin new product or process development until technical uncertainties have been eliminated through inexpensive preliminary research (Scherer, 1980, pp. 415-416).

Empirical evidence shows that small firms, academicians, and independent inventors continue to create new products and processes, but that big firms are often responsible for developing innovations and introducing them in the market. Usually, however, development costs are not so high that small and medium-size companies cannot afford them. Indeed, studies in the past dozen years indicate that although there are some advantages that can be exploited by large firms, R&D is done more efficiently in small and medium size companies (Kamien and Schwartz, 1975, p. 9).

In exploring the links between firm size and the innovation process, three main generalizations can be made from the available evidence. First, independent inventors and smaller firms continue to play an important role in generating initial ideas and novel concepts. Second, while the cost of developing these ideas requires significant resources, they are not beyond the capability of small and medium firms. Third, there remain a few advances which require such heavy private developmental investment that they should be undertaken by very large corporations, or medium-sized corporations with high tolerance for risk (Scherer, 1980, pp. 417-418).

From the above generalizations, it can be seen that no one particular firm size is more conducive to technological change than others. Different sized firms possess different areas of comparative advantage with regard to the stages of technological change. A policy for optimal technological change, then, may be to require a diversity of firm size in industry, each with its own advantages and disadvantages.

As in the case of firm size, there is much dispute over the relationship between technological change and concentration. Some argue that highly concentrated industries are a more effective instrument for innovation. Proponents of this theory, notably J. Schumpeter, claim that it is the implicit goal of innovating firms to achieve monopoly power. Once the firm has established itself in such a position it will continue to innovate in order to maintain its power. Additionally, it is argued that the gains in new technology, which only monopolies or concentrated industries will produce, more than offset the losses suffered by a lack of perfect competition (Kamien and Schwartz, 1975, p. 15). A related theory states that innovation leads to concentration. Since learning costs are high, the successful innovator immediately finds himself in a position of superiority. Further progress becomes increasingly easier for the initially successful firm, and at the same time becomes harder for others. The result is that successful surveying firms tend to be large, and industry concentration tends to be high (Kamien and Schwartz, 1975, p. 13).

Yet another theory linking high seller concentration and innovation focuses upon the notion that innovation can be costly and risky. By profitably exploiting its market position a firm with monopoly power, or a high market share, can obtain the necessary funds to risk investing in new technology. Also, since a firm in a highly concentrated industry is insulated

from the short-run pressures of competition, investment plans concerning R&D can be well thought out and methodically pursued. Under these circumstances, an industry will also have more incentive to innovate since it can internalize most of the benefits from innovation, rather than confer external economies on potential imitators (Scherer, 1980, p. 424).

On the other side of the issue are those who claim that monopoly power and the high market shares associated with high concentration lead to complacency on the part of firms. Since such companies face little or no threat to their position, they prefer to preserve the status quo rather than to innovate. In contrast to this, industries with many sellers and small market shares are likely to try to increase their power through innovation. Once an individual becomes successful, the shares of his rivals are threatened, provoking them to introduce new processes and products at an earlier date (Scherer, 1980, p. 428).

Although the existence of many firms provide more opportunities for R&D, and numerous incentives to innovate, the question arises as to whether there can be so many firms in an industry that innovation is inhibited. If the number of imitators is likely to be large, sellers may not choose to develop a new product or process since they may not be able to maintain monopoly power long enough to cover the costs of innovation. According to Scherer (1980, p. 429), "[t]he smaller the new product market's total profit potential is in relation to any single firm's development costs, all things being equal, the more the presence of a significant number of rivals is apt to discourage early innovation." Scherer suggests that the decision to innovate will depend on five variables: the size of the overall market profit potential, the number of actual or potential rivals competing to share that potential, the speed at which rivals are expected to react

and imitate, the degree to which being first confers a permanent product differentiation advantage, and the size of anticipated R&D costs. Clearly, according to this hypothesis, there is no one absolute level of seller concentration that promotes or inhibits innovations.

Empirical evidence, in accordance with Scherer, suggests that innovation as it relates to concentration does depend on numerous factors. Although the work is admittedly fragile, it appears that when the technological opportunities are great, and the knowledge base is expanding, fear of rivals is less likely to deter innovation than when opportunities are few. Furthermore, if the profit potential is small in relation to the development costs for a new product or process, development may not take place unless the number of potential imitators is low. In this instance, highly concentrated industries favor innovation. Similarly, in fields where there is little technical opportunity, a modest degree of oligopoly may be favorable to innovation. An alternative way of interpreting the evidence is to view low opportunity fields as so unprofitable that only if concentration is high will firms have strong incentives to undertake innovation. Where opportunity is high, firms will compete to innovate regardless of the level of concentration (Scherer, 1980, pp. 436-437).

Appendix B
PRODUCT AND GEOGRAPHIC MARKET DEFINITIONS

PRODUCT AND GEOGRAPHIC MARKET DEFINITIONS

JUSTICE

FTC*

GAO

PRODUCT MARKETS

STEAM COAL

{ Industrial
retail
utility

{ spot
contract

{ undeveloped
fully packaged
long-term supply

METALLURGICAL
COAL

{ low volatile
low and medium
volatile

STEAM COAL

{ Bituminous

{ Subbituminous

METALLURGICAL
COAL

{ Lignite

{ Low Sulfur

SALES TO
ELECTRIC
UTILITIES

{ Surface Mineable

Bituminous

Subbituminous

Lignite

Low Sulfur

Surface Mineable

GEOGRAPHIC MARKETS (distinguished by products)

STEAM

{ Appalachian
Midwest
Northern Plains
Southwest

METALLURGICAL

{ West
East and Midwest (North and
Central Appalachia)

LOW AND MEDIUM
VOLATILE

Alabama

STEAM

{ Appalachian
Midwestern
Western

METALLURGICAL

Appalachian
(national
market)

Eastern
Appalachian

Central Western

Southwestern

*FTC does not differentiate between metallurgical and steam coal, though they recognize the separate markets. Same with electric utilities.

Appendix C

CONCENTRATION RATIOS BY GEOGRAPHIC
MARKETS FOR BITUMINOUS, LIGNITE,
AND PRIME COKING COAL; AND

OIL GAS COMPANIES' SHARE OF COAL
PRODUCTION AND RESERVES

Table C-1
CONCENTRATION RATIOS FOR BITUMINOUS AND LIGNITE COAL

Concentration Measure	Appalachia		Midwest		Western		Midwest and Western		Northern Plains		Southwest		United States	
	4-firm	8-firm	4-firm	8-firm	4-firm	8-firm	4-firm	8-firm	4-firm	8-firm	4-firm	8-firm	4-firm	8-firm
Production (1964)	20.1	29.4	58.1	77.1	33.1	50.9	--	--	63.1	100.0	48.2	49.0 ¹	23.8	33.8
Production (1969)	25.7	37.3	60.7	82.7	33.6	55.8	--	--	56.7	77.5	53.8	58.4 ¹	28.2	38.2
Production (1974)	22.3	32.5	56.1	72.7	34.3	51.3	44.3	57.6	37.7	62.9	64.1	75.4 ¹	25.0	34.0
Total Reserves (1974)	15.2	22.8	22.0	28.6	13.9	20.1	15.4	20.5	14.3	22.1	29.7	39.8	13.3	18.3
Uncommitted Reserves (1974)	19.3	25.7	25.6	31.7	13.5	19.0	15.8	21.1	13.7	20.5	25.4	34.7	14.8	20.8
Total Non-Federal Reserves (1974)	15.2	22.8	22.0	28.6	NA	NA	NA	NA	42.8	66.0	67.9	91.0	20.0	27.0
Uncommitted Non-Federal Reserves (1974)	19.3	25.7	25.6	31.7	NA	NA	NA	NA	46.9	70.2	66.3	90.6	25.5	30.5

¹Only five firms in 1964 and six in 1969 and 1974 included in FTC Survey.

SOURCE: FTC data: Bureau of Mines, Department of Interior, *Minerals Yearbook*.

Table compiled from: Federal Trade Commission, *The Structure of the Nation's Coal Industry*, Bureau of Economics, November 1978, pp. 38, 40, 41, 42, 45, 81-84, 89; and Department of Justice, *Competition in the Coal Industry*, May 1978, p. 63.

Table C-2

FOUR-FIRM CONCENTRATION RATIOS OF PRIME COKING COAL
IN THE NORTH AND CENTRAL APPALACHIAN MARKET

<u>Universe</u>	<u>Low Volume</u>	<u>Low and Medium Volume</u>	<u>High Volume</u>	<u>Total</u>
Total	33.6	38.7	18.3	22.8
Total Uncommitted	35.7	44.2	19.5	25.7

SOURCE: Department of Justice Survey. Table from: Department of Justice,
Competition in the Coal Industry, May 1979, p. 59.

Table C-3

PERCENTAGE OF TOTAL COAL PRODUCTION ACCOUNTED FOR BY VARIOUS SURVEYED COMPANY GROUPS IN 1967 AND 1974 AND PERCENTAGE CHANGE, 1967-1974

Region and Year	Oil/Gas Companies			Independent Coal Companies	Steel Companies	Electric Utilities	"Other" Companies
	Top 8	Top 20	36 ¹				
Total United States							
1967	1.6	10.4	10.1	32.0	10.7	2.3	10.1
1974	1.6	12.7	19.1	9.5	8.9	4.0	22.4
Percentage Change ²	1.5	22.1	76.0	-70.2	-16.8	71.7	122.5
Appalachian Region							
1967	0.0	10.3	10.8	21.2	14.2	2.5	9.7
1974	0.0	13.7	14.8	12.4	12.6	2.6	11.4
Percentage Change ²	--	33.9	36.4	-41.5	-11.3	4.4	17.7
Midwestern Region							
1967	5.8	11.9	11.9	66.8	0.1	0.0	10.3
1974	5.5	15.5	29.9	1.5	1.6	3.6	50.6
Percentage Change ²	-4.6	31.0	151.7	-97.8	1,893.2	--	390.5
Western Region							
1967	4.7	4.7	4.7	9.2	14.3	14.1	14.4
1974	2.2	2.2	19.1	11.2	4.8	11.8	21.0
Percentage Change ²	-53.5	-53.5	308.1	21.6	-66.4	-16.1	45.9
Midwest & West Region							
1967	5.6	10.9	10.9	58.8	2.1	2.0	10.9
1974	4.4	11.1	26.3	4.7	2.7	6.4	40.7
Percentage Change ²	-21.8	1.9	141.8	-91.9	30.7	223.9	274.0

¹36 surveyed companies classified as oil/gas companies.

²Percentage changes were calculated using unrounded data.

SOURCE: Federal Trade Commission, Structure of the Nation's Coal Industry, November 1978, p. 101.

Table C-4
OIL AND GAS COMPANIES' SHARES OF COAL RESERVES AS OF
JANUARY 1, 1974

Region Reserve base	Percentage of Reserves Controlled by Surveyed Oil/Gas Companies			Reserve Universe (Million Tons)
	Top 8	Top 20	36 Surveyed	
<u>Total United States</u>				
Demonstrated coal reserve base ¹				
Total Coal	6.1	12.2	14.5	429,341
Surface mineable coal	6.4	12.2	15.4	136,795
Uncommitted coal*				
Estimate I	6.4	12.3	14.3	393,140
Estimate II	7.2	13.9	16.0	350,052
Demonstrated coal reserve base excluding estimated unleased federal coal ²				
Total coal	8.6	17.2	20.5	303,453
Surface mineable coal	9.9	19.0	23.9	87,902
Uncommitted coal*				
Estimate I	9.5	18.2	21.0	267,252
Estimate II	11.3	21.6	25.0	224,164
Estimated private coal reserves ³				
Total coal	17.6	35.3	42.0	148,049
Surface mineable coal	NA	NA	NA	NA
Uncommitted coal*				
Estimate I	22.7	43.4	50.2	111,848
Estimate II	23.2	44.4	51.3	109,365
<u>Appalachian Region⁴</u>				
Demonstrated coal reserve base ¹				
Total coal	0.3	9.4	9.7	106,025
Surface mineable coal	0.0	4.0	4.6	15,736
Uncommitted coal*				
Estimate I	0.4	8.6	8.7	88,362
Estimate II	0.6	13.9	14.2	54,234
<u>Midwestern Region⁵</u>				
Demonstrated coal reserve base ¹				
Total coal	9.1	14.9	19.0	107,807
Surface mineable coal	0.2	1.3	2.4	26,572
Uncommitted coal*				
Estimate I	9.6	15.4	19.2	100,930
Estimate II	11.1	17.8	22.2	87,632

Table continued on following page.

Table C-4 (Continued)

OIL AND GAS COMPANIES' SHARES OF COAL RESERVES AS OF
JANUARY 1, 1974

Region	Percentage of Reserves Controlled by Surveyed Oil/Gas Companies			Reserve Universe (Million Tons)
	Top 8	Top 20	36 Surveyed	
Reserve base				
<u>Western Region</u>				
Demonstrated coal reserve base ¹				
Total Coal	7.4	12.2	14.6	215,391
Surface mineable coal	9.2	16.6	20.8	94,486
Uncommitted coal*				
Estimate I	7.5	12.5	14.2	203,725
Estimate II	7.7	12.7	14.5	199,484
Demonstrated coal reserve base excluding estimated unleased federal coal ²				
Total coal	17.8	29.3	35.2	89,518
Surface mineable coal	19.1	34.5	43.0	45,608
Uncommitted coal*				
Estimate I	19.7	32.6	37.3	77,852
Estimate II	20.8	34.5	39.4	73,611
<u>Midwest & West Region</u>				
Demonstrated coal reserve base ¹				
Total Coal	8.0	13.1	16.1	323,198
Surface mineable coal	7.2	13.3	16.8	121,058
Uncommitted coal*				
Estimate I	8.2	13.5	15.9	304,655
Estimate II	8.7	14.3	16.9	287,466
Demonstrated coal reserve base excluding estimated unleased federal coal ²				
Total coal	13.0	21.4	26.4	197,310
Surface mineable coal	12.1	22.2	28.1	72,165
Uncommitted coal*				
Estimate I	14.0	22.9	27.1	178,767
Estimate II	15.5	25.4	30.0	161,578

*Estimate I universes were calculated by assuming that all unsurveyed reserves were uncommitted. Estimate II universes were calculated by assuming that the unsurveyed reserves (other than those held by the federal government) were committed in the same proportion as those held by the surveyed companies in the relevant region and for the applicable coal type.

NA = Not available.

Footnotes and source on following page.

Table C-4 (Continued)
OIL AND GAS COMPANIES' SHARES OF COAL RESERVES AS OF
JANUARY 1, 1974

¹Calculated from data of U.S. Department of the Interior, Bureau of Mines, Demonstrated Coal Reserve Base of the United States, by Sulfur Category, on January 1, 1974 (Mineral Industry Surveys, May 1975). See text for data limitations.

²See Appendix 3-B of the FTC report for a description of the methodology and data sources employed for the calculation of estimated unleased federal coal reserves.

³The estimated private coal reserve universe is the survey universe (138,547 million tons) plus individual company reserves not covered by the FTC Survey but reported in the 1974 Keystone Coal Industry Manual (McGraw-Hill), pp. 621-622. The Keystone data were not available by geographic region or by coal type. See text for a discussion of the relative unreliability and downward bias of this private coal reserve universe estimate.

⁴The source for federal coal reserves estimates reported no federal reserves in the Appalachian Region. However, the U.S. Department of the Interior, Annual Report On Coal-Fiscal Year 1977, p. 40, indicates that there is an unquantified amount of federally owned coal in a four-county area of north-central Alabama.

⁵The estimated 15 million tons of unleased federal coal reserves in the Midwestern Region had no significant effect on the company group shares when excluded from the demonstrated coal reserve base.

SOURCE: FTC, The Structure of the Nation's Coal Industry, November 1978, pp. 109-112.

APPENDIX II

A STATISTICAL PROFILE OF MAJOR COAL-PRODUCING FIRMS, 1978

Prepared by
Oak Ridge Associated
Universities

Prepared for
Energy Information
Administration
U.S. Department of
Energy

A STATISTICAL PROFILE OF MAJOR COAL-PRODUCING FIRMS, 1978

Joe G. Baker
Rachel C. Bishop

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Available from the National Technical Information Service, U.S. Department of Commerce, Springfield, Virginia 22161. Please direct all price inquiries to NTIS.

**A STATISTICAL PROFILE OF
MAJOR COAL-PRODUCING
FIRMS, 1978**

**Joe G. Baker
Rachel C. Bishop**

Prepared by

**Labor and Policy Studies Program
Manpower Education, Research, and Training Division
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September 1980

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ABSTRACT

This report examines major coal-producing groups, which are firms controlling output of 3 million or more tons annually. Characteristics of the major producing groups—such as their percentage of U.S. output, their ownership by companies in coal, steel, oil, etc., and their regional concentration—are compared using 1966 and 1978 data. On the basis of mine-level data for 1978, a cross-section of mines controlled by major producers is compared to one of mines controlled by smaller firms for differences in markets, coal prices, transportation, distribution of output, technology, and other characteristics. Finally, such measures of efficiency as output per miner-shift and scale characteristics by market type (such as captive versus open), consumer (steam or steel), and controlling group are examined.

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INTRODUCTION

The National Energy Act (NEA) was passed in 1978 with a basic goal of reducing U.S. dependency upon imported oil. The NEA, which is actually composed of five separate acts, will accomplish this goal by increasing the use and development of domestic energy resources and reducing energy demand through conservation.

The Powerplant and Industrial Fuel Use Act (PL 95-620) of the NEA is aimed directly at increasing the use of coal, our most abundant fossil fuel. While projections of future coal use vary, the President's Commission on Coal estimates that 1985 tonnage will range from 932 million tons to 1036 million tons, an increase from 28 percent to 35 percent over estimated 1979 tonnage of 770 million tons.¹ Given these massive increases in tonnage, the ability of the coal industry to meet output goals becomes an important national concern.

This concern has resulted in an investigation of performance and competition in the U.S. coal industry. The purpose of this study is to examine production and market characteristics of major coal-producing firms. The results will supply input into the broader Fuel Use Act research. Thus, this study is descriptive, providing a detailed statistical profile of the coal industry and the major producing companies. Most of the data are presented in tables or frequency distributions, although statistical significance tests are used in many cases. The reliability of these data is tested by the extent of coverage of output and mines.

Although the data reported here were gathered from a variety of sources, most of the analysis is based upon the Energy Information Administration Form 7, "Bituminous Coal and Lignite Production and Mine Operation" (see Appendix D for a sample of the EIA-7 form). This form is sent to all mines with 1000 or more tons of coal output during the year. The data in EIA-7 are collected under mandatory authorities of PL 93-275, so coverage is approximately 90 percent of total tonnage. Covered in these annual surveys is such basic information as production, employment, mining methods, markets, prices, and coal beds mined during the year.

For the purposes of this analysis, these data were segregated into two groups: mines that fell under the control or ownership of major coal-producing groups (firms that in 1978 produced or controlled 3 million or

more tons of output as defined by *Keystone*²); and all other mines. These mines were identified in the EIA-7 data tape by individual mine company codes. Each mine on the tape was placed into either the major or the non-major group by examining the company code. To assess characteristics of the majors and the role they play in the coal industry, most of the analysis in this report compares markets, mine types, mining techniques, and other characteristics of the majors to the rest of the industry.

A variety of other data was used to develop the information contained in this report. McGraw-Hill publications such as the *Keystone Coal Industry Manual* and *Coal Mine Directory* for various years were significant sources of data. *Moody's Industrial Manual* and *Moody's Public Utility Manual* for various years provided information on mine ownership. Other information was obtained through the Bituminous Coal Operators Association, various state industrial commission and mining division reports, and selected federal government publications.

NOTES

¹The President's Commission on Coal, *Staff Findings* (Washington, D.C.: U.S. Government Printing Office, 1980), p. 14.

²These coal-producing groups will be discussed in detail in Chapter 1.

CHAPTER 1. THE MAJOR COAL-PRODUCING GROUPS, 1966 and 1978

DEFINITION

Major coal-producing groups (called "major producers" or simply "majors") are companies or parent groups that control or own a mine or group of mines with an aggregate annual output of 3 million tons or more. These majors may own mines outright or control them in that the output of mines controlled goes directly to the major through some sort of agreement. For example, Consolidation Coal operates a number of mines it owns directly; it also controls some smaller companies such as Mathies, Bishop, Itmann, and Harmar coal companies. In some cases, a mine or mine company may be owned by more than one company (e.g., Decker Coal Company in 1978) with tonnage split between the majors.

In the winter of 1977-78, the coal industry experienced a major strike lasting 109 days from December 6, 1977, to March 3, 1978. This strike contributed to the 9.4 million worker-days lost to work stoppages in 1978, which was 4.9 percent of the total working time available. In 1966, the industry lost only 1.9 percent of total working time to work stoppages, with a 17-day strike over a new contract being the major walkout. It is not known how time lost to work stoppages influenced the statistics reported here.

CHARACTERISTICS

Table 1-1 details ownership of the major coal-producing groups. Together, the major producers accounted for 56.6 percent of total domestic production in 1978, producing 369.8 million tons of the total of 653.8 million tons. This compares to 54.9 percent of domestic production controlled by the major producers in 1966. Although the percentage has changed little, the total tonnage accounted for in 1966 by major producers was 293.5 million compared to 369.8 million in 1978.

Table 1-2 details the 1966 major producers. In 1978 there were 39 firms classified as major producers; in 1966 only 26 firms were classified as major producers.

Table 1-1. Ownership of Major Coal Producers, 1978

Coal Company	Tonnage	Controlling Company	
		Name	Type
1. Peabody Coal Co.		Peabody Holding Co.; New-	—
(Ill.) (4,650,273 Strip)	10,474,555	mont Mining Co.; Williams	
(Mo.) (2,185,906 Strip) (10,969 Auger)	2,196,875	Co.; Bechtel Corp.; Fluor	
(Okla.) (Strip)	1,112,363	Corp.; Equitable Life Assur-	
(Ind.) (7,822,914 Strip)	8,146,981	ance Society; Boeing Co.	
(Ky.W.) (6,558,331 Strip)	14,450,924		
(Ohio) (1,180,805 Strip) (199,425			
Auger)	3,189,200		
(Colo.) (Strip)	1,474,644		
(Mont.) (Strip)	2,064,886		
(Ariz.) (Strip)	9,287,588		
(Ark.) (Strip)	59,875		
Total	52,457,891		
2. Consolidation Coal Co.		Continental Oil Co.	Oil
Eastern Region			
Allegheny (Pa.)	803,000		
Washington (Pa.)	1,708,000		
Moundsville (W.Va.)	4,133,000		
Subtotal	6,644,000		
Northern W.Va. Region			
Morgantown (W.Va.) (650,000 Strip)	4,782,000		
Blacksville (W.Va.)	2,118,000		
Fairmont (W.Va.) (825,000 Strip)	4,660,000		
Subtotal	11,560,000		
Southern Appalachia Region			
Bluefield (W.Va.) (380,000 Strip)	1,333,000		
Beckley (W.Va.)	568,000		
Tazewell (W.Va.)	95,000		
Tazewell (Tenn.)	643,000		
Subtotal	2,639,000		

Table 1-1. Ownership of Major Coal Producers, 1978 (Cont'd.)

Coal Company	Tonnage	Controlling Company	
		Name	Type
Midwestern Region			
Underground (Ohio)	1,596,000		
Underground (Ill.)	1,546,000		
Ohio Surface (Ohio) (Strip)	2,770,000		
Illinois Surface (Ill.) (Strip)	6,410,000		
Subtotal	12,322,000		
Western Region			
(N.D.) (Strip) ^a	3,976,000		
Canada (Strip) ^a	1,081,000		
Utah	414,000		
Subtotal	5,471,000		
Associated Companies			
Harmar Coal Co. (Pa.)	340,000		
Mathies Coal Co. (Pa.)	1,182,000		
Bishop Coal Co. (W.Va.)	802,000		
Itmann Coal Co. (W.Va.)	861,000		
Subtotal	3,185,000		
Total for Consolidation	41,821,000		
3. AMAX Coal Co.		AMAX, Inc. 20.6% owned	Metal, oil
(Ill.) (3,412,695 Strip)	4,778,147	by Standard Oil of Cali-	
(Ind.) (Strip)	5,164,665	fornia)	
(Ky.W.) (Strip)	1,536,368		
(Wyo.) (Strip)	18,306,790		
Gibraltar Coal Co. (Ky.W.) (Strip)			
(closed 1978)	1,315		
Total	29,787,285		

^aConsolidation's Canadian output is excluded from other tables.

Table 1-1. Ownership of Major Coal Producers, 1978 (Cont'd.)

Coal Company	Tonnage	Controlling Company	
		Name	Type
4. Texas Utilities (Tex.) (Strip) (Est.)	16,000,000	Independent	Utility
5. Island Creek Coal Co.		Occidental Petroleum Corp.	Oil
Island Creek Div. (W.Va.)	1,733,864		
Island Creek Div. (Ky.E.)	2,894,376		
Northern Div. (Pa.)	413,276		
Northern Div. (W.Va.)	2,285,221		
Northern Div. (Ohio)	0		
West Kentucky Div. (Ky.W.)	4,296,036		
Va. Pocahontas Div. (Va.)	1,297,238		
Beatrice Pocahontas Co. (Va.)	362,450		
VP-5 Mining (Va.)	108,773		
Virginia Pocahontas Co. (Va.)	198,355		
Total	13,589,589		
6. Arch Mineral Corp. (Wyo.) (Strip)	8,356,128	Ashland Oil Co.; Hunt	Oil
Southwestern Illinois Coal Corp. (Ill.)		Petroleum Corp.; Hunt	
(Strip)	364,220	Industries	
Walker-Fayette Coal Co. (Ala.) (Strip)	4,195,161		
Total	12,915,509		
7. Glenrock Coal Co. (Wyo.) (Strip)	3,358,899	NERCO, Inc.; Pacific	Utility
Bridger Coal Co. (Wyo.) (Strip) ^b	3,450,360	Power Light	
Decker Coal Co. (Mont.) (Strip) ^c	4,536,796		
Bankhead Mining Co. Inc. (Ala.) (Strip)	68,800		
Total	11,414,855		
8. Pittston Co.		Independent	Coal
Clinchfield Coal Div. (Va. & W.Va.)			
(856,687 Strip)	5,217,469		
Amigo Smokeless Coal Co. (W.Va.)	77,954		
Kentland Elkhorn Coal Corp. (W.Va.)	285,994		

^bTotal tonnage.

^cNERCO share of ownership 50%, remainder reported by Peter Kiewit Sons Co.

Table 1-1. Ownership of Major Coal Producers, 1978 (Cont'd.)

Coal Company	Tonnage	Controlling Company	
		Name	Type
Jewell Ridge Coal Corp. (Va.) (108,821 Strip)	1,207,450		
Badger Coal Co. (W.Va.) (254,810 Strip)	670,465		
Sewell Coal Co. (W.Va.) (133,123 Strip)	1,075,791		
Eastern Coal Corp. (Ky.E.)	388,596		
Buffalo Mining Co. (W.Va.) (370,107 Strip)	929,398		
Ranger Fuel Corp. (W.Va.) (18,802 Strip)	338,269		
Elkay Mining Co. (W.Va.) (278,678 Strip)	764,672		
Total	10,956,058		
9. Western Energy Co. (Mont.) (Strip)	10,576,000	Montana Power Co.	Utility
10. United States Steel Corp.		U.S. Steel	Steel
(Ky.E.)	1,986,000		
(W.Va.)	2,538,000		
(Pa.)	3,913,000		
Southern Dist. (Ala.)	985,000		
Western Dist. (Utah)	307,000		
Western Dist. (Colo.)	650,000		
Total	10,379,000		
11. Big Horn Coal Co. (Wyo.) (Strip)	2,838,862		
Rosebud Coal Sales Co. (Wyo.) (Strip)	2,868,048		
Decker Coal Co. (Mont.) (Strip) ^d	4,536,848		
Total	10,243,758		
12. Bethlehem Mines Corp.		Bethlehem Steel	Steel
(Pa.)	4,138,981		
(W.Va.) (1,222,847 Strip)	3,269,235		

^dOwned 50% by Peter Kiewit and 50% by NERCO, reported separately.

Table 1-1. Ownership of Major Coal Producers, 1978 (Cont'd.)

Coal Company	Tonnage	Controlling Company	
		Name	Type
Beth-Elkhorn Corp. (Ky.E.) (16,919 Strip) (11,709 Auger)	2,044,601		
Total	9,452,817		
13. Central Ohio Coal Co. (Ohio) (Strip)	2,525,651	American Electric Power	Utility
Central Appalachian Coal Co. (W.Va.) (179,000 Strip)	558,909		
Windsor Power House Coal Co. (W.Va.)	527,935		
Southern Ohio Coal Co. Meigs Div. (Ohio)	2,115,135		
Martinka Div. (W.Va.)	647,012		
Braztah Mines (Utah)	846,601		
Southern Appalachian Coal Co. (W.Va.) (377,311 Strip)	834,256		
Cedar Coal Co. (W.Va.) (625,769 Strip)	1,233,610		
Total	9,289,109		
14. Pittsburg & Midway Coal Mining Co. (Ky.W.) (1,471,515 Strip)	2,400,379	Gulf Oil Co.	Oil
(Colo.) (Strip)	962,943		
(N.M.) (Strip)	2,992,958		
(Mo.) (Strip)	1,504,437		
Total	7,860,717		
15. Old Ben Coal Co. (Ill.)	3,825,734	Sohio Petroleum Co.	Oil
Old Ben Coal Co. (Ind.) (Strip)	3,915,304		
Total	7,741,038		
16. North American Coal Corp.		Independent	Coal
Western Div. (N.D.) (Strip)	911,743		
Central Div. (Ohio)	1,839,133		
Eastern Div. (Pa.)	450,892		
Florence Mining Co. (Pa.)	1,355,835		
Helen Mining Co. (Pa.)	611,639		
Nacco Mining Co. (Ohio)	1,044,193		

Table 1-1. Ownership of Major Coal Producers, 1978 (Cont'd.)

Coal Company	Tonnage	Controlling Company	
		Name	Type
Quarto Mining Co. (Ohio)	1,250,663		
Falkirk Mining Co. (N.D.) (Strip)	142,308		
Total	7,606,406		
17. Utah International Inc.		General Electric Co.	Electrical equipment
(N.M.) (Strip)	6,207,000		
(Colo.) (Strip)	893,000		
Total	7,100,000		
18. Westmoreland Coal Co.		Westmoreland, Penn-Va. Corp.	Coal
Hampton Div. (W.Va.)	735,000		
Winding Gulf Div. (W.Va.)	667,000		
Imperial Smokeless Div. (W.Va.)	446,000		
Stonega Div. (Va.) (Part Strip & Auger)	3,834,000		
Colorado Westmoreland, Inc. (Colo.)	435,000		
Total	6,117,000		
19. C & K Coal Co. (Pa.) (Strip)	2,116,000	Gulf Resources & Chemical Co.	Chemical
Vantage Coal Corp. (Pa.) (Strip)	581,000		
Shannon Coal Co. (Pa.) (Strip)	1,492,000		
Stahlman Coal Co. (Pa.) (Strip)	917,000		
Cambria Coal Co. (Pa.) (Strip)	758,000		
Total	5,864,000		
20. Freeman United Coal Mining Co. (Ill.)		General Dynamics Corp.	Electronics, defense
(1,726,086 Strip)	5,837,485		
21. Eastern Associated Coal Co.		Eastern Gas & Fuel Associates	Gas
(Pa.)	9,689		
(W.Va.)	5,491,490		
Affinity Mining Co. (W.Va.)	215,597		
Total	5,716,776		
22. Drummond Coal Co. (Ala.) (Strip)	5,500,000	The Drummond Co.	Coal

Table 1-1. Ownership of Major Coal Producers, 1978 (Cont'd.)

Coal Company	Tonnage	Controlling Company	
		Name	Type
23. Carter Oil Co. Monterey Coal Co. (Ill.) Carter Mining Co. (Wyo.) (Strip)	2,426,511 2,769,107	Exxon Corp.	Oil
Total	5,195,618		
24. United Coal Cos. Va. Coal Div. (Va.) United Coal Cos. Tri-State Div. (Ky.E.) Sharples Coal Corp. (W.Va.) (50,000 Strip)	3,184,000 1,493,000 450,000	United Coal Companies	Coal
Total	5,127,000		
25. Knife River Coal Mining Co. (N.D.) (Strip) (Mont.) (Strip)	4,759,106 300,001	Montana Dakota Utilities Co.	Utility
Total	5,059,107		
26. Keystone Coal Mining Corp. (Pa.) Helvetia Coal Co. (Pa.) Kent Coal Mining Co. (Pa.) (Strip)	2,637,183 1,526,675 783,116	Rochester & Pittsburgh Coal Co.	Coal
Total	4,946,974		
27. Martiki Coal Corp. (Ky.E.) (Strip) Webster County Coal Corp. (Ky.W.) Pontiki Coal Corp. (Ky.E.) Mettiki Coal Corp. (Md.)	2,000,000 2,117,785 662,250 102,396	Mapco, Inc.	Oil, gas, liquid natural gas, pipelines, coal
Total	4,882,431		
28. Washington Irrigation & Development Co. (Wash.) (Strip)	4,700,000	Pacific Power & Light Washington Water Power	Utility
29. Zeigler Coal Co. (Ill.) (Ky.W.) Empire Energy Corp. (Colo.) (242,096 Strip)	3,221,037 485,254 860,776	Houston Natural Gas Corp.	Gas
Total	4,567,067		

Table 1-1. Ownership of Major Coal Producers, 1978 (Cont'd.)

Coal Company	Tonnage	Controlling Company	
		Name	Type
30. Westmoreland Resources (Mont.) (Strip)	4,554,201	Westmoreland Coal; Penn.-Va. Corp.; Morrison-Knudsen Co.; Kewanee Industries, Inc.	Coal, gas
31. Falcon Coal Co. Inc. (Ky.E.) (3,904,150 Strip)	4,008,999	Diamond Shamrock Corp.	Chemicals, oil gas
Hawkeye Coal Co. (Ky.E.) (Strip)	280,000		
Total	4,288,999		
32. Kemmerer Coal Co. (Wyo.) (Strip)	4,061,794	Lincoln Corp.	Coal
33. Baukol-Noonan, Inc. (N.D.) (Strip)	3,874,428	Independent	Coal
34. Ashland Coal, Inc. (Ky.E.) (Strip)	3,850,000	Ashland Oil, Inc.	Oil
35. Sunoco Energy Development Co. (Wyo.) (Strip)	3,800,000	Sun Company, Inc.	Oil
36. Jones & Laughlin Steel Corp.		LTV Corp.	Steel
Vesta-Nemacolin Group (Pa.)	1,457,165		
Emerald-Shannopin-Gateway Group (Pa.)	1,509,139		
Olga-Dehue Group (W.Va.)	673,333		
Total	3,639,637		
37. International Energy Corp. (Ala. & Mo.) (Strip)	171,754	American Industries & Resources Corp.	Other
Missouri Mining Inc. (Mo.) (Strip)	983,090		
Ohio Coal & Construction Corp. (Ohio) (Strip)	1,391,350		
Penn United Energies Inc. (Pa.) (Strip)	100,000		
Triex Excavating Co. (Ky.) (Strip)	60,000		
Universal Coal & Energy Co. Inc. (Mo. & Ohio) (Strip)	636,061		
West Va. Energies, Inc. (W.Va.) (Strip)	222,000		
Total	3,564,255		

Table 1-1. Ownership of Major Coal Producers, 1978 (Cont'd.)

Coal Company	Tonnage	Controlling Company	
		Name	Type
38. Energy Fuels Corp. (Colo.) (Strip)	3,505,308	Independent	Coal
39. Alabama By-Products Corp. (Ala.) (109,317 Strip)	<u>3,023,918</u>	Independent	Coal, chemicals
Grand total	370,867,030		

Sources: *Moody's Industrial Manual, 1979.*
Keystone Coal Mine Directory, 1978.
Keystone Coal Industry Manual, 1979.

Table 1-2. Ownership of Major Coal Producers, 1966

Coal Company	Tonnage	Controlling Company	
		Name	Type
1. Peabody Coal Co.		Independent	Coal
(Ill.) (12,458,144 Strip)	18,543,503		
(Mo.) (Strip)	3,404,875		
(Okla.) (Strip)	225,921		
(Ind.) (Strip)	8,033,512		
(Ky.W.) (15,929,049 Strip)	16,714,552		
(Ohio) (313,804 Deep & Auger; 281,133 Auger; 3,494,242 Strip)	4,553,109		
(Ala.) (Strip)	943,705		
(Colo.) (Strip)	568,798		
Gibraltar Coal Corp. (Ky.W) (Strip) ^a	1,053,043		
Total	54,041,018		
2. Consolidation Coal Co.		Purchased by Continental	Oil
Pittsburgh Coal Co., Div. (Pa.)		Oil Sept. 15, 1966	
(155,000 Strip)	3,877,000		
Mountaineer Coal Co., Div. (W.Va.)	7,798,000		
Christopher Coal Co., Div. (W.Va.)	7,502,000		
Mathies Coal Co. (Pa.)	2,167,000		
Hanna Coal Co. Div.			
(Ohio) (6,714,000 Strip)	8,798,000		
(W.Va.)	2,046,000		
Harmar Coal Co. (Pa.)	1,657,000		
Pocahontas Fuel Co. Div.			
(Tenn.)	594,000		
(W.Va.)	4,000,000		
Bishop Coal Co. (W.Va.)	1,809,000		
Truax-Traer Coal Co. Div.			
(Ill.) (5,845,000 Strip)	6,862,000		
(N.D.) (Strip)	1,482,000		
Itmann Coal Co. (W.Va.)	2,757,000		
Miscellaneous Production	51,000		
Total	51,400,000		

^aOwned jointly with Ayrshire Collieries Corp.

Table 1-2. Ownership of Major Coal Producers, 1966 (Cont'd.)

Coal Company	Tonnage	Controlling Company	
		Name	Type
3. Island Creek Coal Co. Island Creek Div. (W.Va.) (Va.) Evans Elkhorn Div. (Ky.E.) West Kentucky Div. (Ky.W.) (782,928 Strip) National Coal Mining Co. (W.Va.) Beatrice Pocahontas Co. (Va.) Total	9,068,102 30,012 3,151,981 8,161,292 2,060,464 1,180,541 23,652,392	Independent	Coal
4. United States Steel Corp. (Ky.E.) (W.Va.) (466,000 Strip & 44,000 Auger) (Pa.) Southern District (Ala.) Western District (Utah) Western District (Colo.) Total	2,259,000 5,796,000 6,386,000 2,064,000 998,000 504,000 18,007,000	Independent	Steel
5. The Pittston Co. Clinchfield Coal Div. Pittston Co. (Va.) Amigo Smokeless Coal Co. (W.Va.) Clinchfield Coal Div. Pittston Co., Compass Operation (W.Va.) Kentland Elkhorn Coal Corp. (Ky.) Jewell Ridge Coal Corp. (Va.) Total	9,958,030 938,092 2,406,292 1,433,185 804,013 15,539,612	Independent	Coal
6. Freeman Coal Mining Corp. (Ill.) United Electric Coal Cos. (Ill.) (Strip) Total	7,706,710 5,854,938 13,561,648	General Dynamics Corp.	Electronics, defense

Table 1-2. Ownership of Major Coal Producers, 1966 (Cont'd.)

Coal Company	Tonnage	Controlling Company	
		Name	Type
7. Eastern Associated Coal Corp. (Pa.) (W. Va.) Total	 1,686,298 <u>10,429,995</u> 12,116,293	Eastern Gas & Fuel	Gas
8. Bethlehem Mines Corp. (Pa.) (W. Va.) Beth-Elkhorn Corp. (Ky.E.) Total	 6,163,497 3,622,655 <u>1,402,274</u> 11,188,426	Bethlehem Steel	Steel
9. Old Ben Coal Corp. (Ill.) Coal Processing Corp. (Va.) (108,275 Strip & 77,554 Auger) Kings Station Coal Corp. (Ind.) Enos Coal Corp. (Ind.) Total	 6,060,071 750,102 78,546 <u>3,005,006</u> 9,893,725	Old Ben Corp. Independent	Coal
10. Pittsburg & Midway Coal Mining Co. (Kan.) (Strip) (Ky.W.) (3,832,574 Strip) (Colo.) (Strip) (N.M.) (Strip) Total	 840,562 7,047,478 613,181 <u>339,080</u> 8,840,301	Gulf Oil	Oil
11. Ayrshire Collieries Corp. (Ill.) (Strip) (Ind.) (Strip) Thunderbird Collieries Corp. (Ind.) (1,174,545 Strip) (Ill.) (Strip) Gibraltar Coal Corp. (Ky.W.) (Strip) ^b Total	 777,792 2,725,099 2,431,002 1,549,043 <u>1,052,838</u> 8,535,774	Ayrshire, Independent	Coal

^b Owned jointly with Peabody Coal Co.

Table 1-2. Ownership of Major Coal Producers, 1966 (Cont'd.)

Coal Company	Tonnage	Controlling Company	
		Name	Type
12. North American Coal Corp.		Independent	Coal
North American Coal Corp.			
Southern Div. (W.Va.) (Auger)	384,186		
Lignite Div. (N.D.) (Strip)	276,866		
Ohio Div. (Ohio)	5,450,786		
Pennsylvania Div. (Pa.)	1,320,223		
Total	7,432,061		
13. Southwestern Illinois Coal Corp.			
(Ill.)	6,786,797		
14. Westmoreland Coal Co.		41% of stock owned by	Coal
(W.Va.)	2,665,921	Virginia Coal and Iron	
(Va.) (Part Strip & Auger)	3,481,708		
Total	6,147,629		
15. Republic Steel Corp.		Independent	Steel
(Ala.) (Part Strip)	468,246		
(Pa.)	3,492,249		
(Ky.E.)	848,463		
Total	4,808,958		
16. Valley Camp Coal Co.		Independent	Coal
(W.Va.)	4,349,039		
(Pa.)	417,478		
Total	4,766,517		
17. Winding Gulf Coals, Ind. (W.Va.)	4,252,000	Winding Gulf Coals,	Coal
Cliffstop Smokeless Coal Co. (W.Va.)	414,900	Independent	
Total	4,666,900		

Table 1-2. Ownership of Major Coal Producers, 1966 (Cont'd.)

Coal Company	Tonnage	Controlling Company	
		Name	Type
18. Bell & Zoller Coal Co. (Ill.) (Ky.W.) Zeigler Coal & Coke Co. (Ill.) Total	2,439,354 917,980 826,485 <u>4,183,819</u>	Zeigler Coal & Coke, Independent	Coal
19. Central Ohio Coal Co. (Ohio) (Strip) Central Appalachian Coal Co. (W.Va.) Total	3,453,999 617,765 <u>4,071,764</u>	Appalachian Electric Power	Utility
20. Carbon Fuel Co. (W.Va.) (114,504 Auger) Kentucky Carbon Corp. (Ky.E.) Total	3,078,956 764,125 <u>3,843,081</u>	Independent	Coal
21. Rochester & Pittsburgh Coal Co. (Pa.) (W.Va.) Wildwood Coal Co. Div. (Pa.) Total	1,451,188 1,898,654 330,516 <u>3,680,358</u>	Independent	Coal
22. Oglebay Norton Co. (W.Va.) (Ohio) Total	1,811,900 1,716,000 <u>3,527,900</u>	Independent	Coal
23. Amherst Coal Co. (W.Va.)	3,483,121	Independent	Coal
24. Youghiogheny & Ohio Coal Co. (Ohio) (W.Va.) Total	2,436,797 740,347 <u>3,177,144</u>	Independent	Coal

Table 1-2. Ownership of Major Coal Producers, 1966 (Cont'd.)

Coal Company	Tonnage	Controlling Company	
		Name	Type
25. Ranger Fuel Corp. (W.Va.) (1,302,799 Strip & 700,610 Auger)	3,125,374	Independent	Coal
26. Jones & Laughlin Steel Corp. (Pa.)	<u>3,005,000</u>	Independent	Steel
Grand total	293,482,612		

Sources: *Moody's Industrial Manual*, June 1967.
Keystone Coal Mine Directory, 1966.

Size Distribution, 1966 and 1978

Charts 1-1 and 1-2 compare the size distribution of major coal producers in 1978 and 1966 respectively. The majority of majors were concentrated in the range of 3 million to 10 million tons per year (77 percent in 1978 and 73 percent in 1966), with smaller numbers of majors having more than 10 million tons of output per year. In both years, the major producers can be virtually split between a small number of gigantic producers and all other majors. In 1966, Peabody Coal Company and Consolidation Coal Company dwarfed the rest of the majors, together accounting for 36 percent of the output of all 26 majors. Both Peabody and Consolidation were twice as big in terms of output as the number three producer, Island Creek Coal Company.

Peabody and Consolidation were joined by AMAX Coal in 1978 as the elite of the majors. Together these three majors accounted for 123 million tons of output, which equaled 33 percent of the major's output and 18.8 percent of total U.S. output in 1978. Table 1-3 contains summary statistics for the major producers in 1966 and 1978. Although the mean size of major producers was larger in 1966 than in 1978, the difference is not significantly large. The smaller mean and median statistics for 1978 compared to 1966 indicate that most of the growth in major producing groups has been in the smaller end of the distribution.

Table 1-3. Summary Statistics of Major Producers, 1966 and 1978

Year	N	Millions of Tons		
		Mean	Median	Standard Deviation
1966	26	11.29	6.47	13.27
1978	39	9.51	5.84	10.18

Sources: Tables 1-1 and 1-2.

Ownership, 1966 and 1978

Table 1-4 details ownership of major producers in 1966 and 1978 by product type. The two major shifts in ownership occurring over this 12-year period have been a decrease in tonnage controlled by coal and steel

Chart 1-1. Size Distribution of Major Coal Producers, 1978

Chart 1-2. Size Distribution of Major Coal Producers, 1966

companies only and an increase in tonnage controlled by oil, utilities, and "other" companies. In 1966, only two producers were controlled by oil companies (see Table 1-2). Pittsburg and Midway Coal Mining, with output of 8.8 million tons and ranked tenth in 1966, was (and still is) controlled by Gulf Oil. The entrance of oil companies into coal mining was set in motion by the purchase of the giant Consolidation Coal Company by Continental Oil Company (Conoco) in 1966. Since then, virtually every major oil producer has entered the coal business with Occidental Petroleum, Ashland Oil, Hunt Petroleum, Standard Oil of Ohio (Sohio) Petroleum, Exxon, Standard Oil of California, and Sun Oil Company (Sunoco) joining the ranks of the majors.

Table 1-4. Percent Produced by Major Producers Classified
by Product Types, 1966 and 1978

Type of Product	1966			1978		
	Number of Companies	Tons of Output	Percent ^a of Total	Number of Companies	Tons of Output	Percent ^a of Total
Coal	15	159,472,201	54.3	10	56,577,399	15.3
Steel	4	37,009,384	12.6	3	23,471,454	6.3
Oil ^b	2	60,240,301	20.5	9	101,062,470	27.25
Utility	1	4,071,764	1.4	6	57,039,071	15.4
Other ^c (metal, gas, etc.)	4	32,688,962	11.1	11	132,716,636	35.78
Total	26	293,482,612	100.0	39	370,867,080	100.00

^aTotals may not add to 100 due to rounding.

^bIncludes Consolidation in 1966, which was acquired by Conoco in September of that year.

^cIncludes AMAX in 1978, 20.6 percent of which was owned by Standard Oil of California.

Sources: *Keystone Coal Industry Manual*, various years.
Keystone Coal Mine Directory, various years.

Utility companies became substantially more involved in coal during this period, increasing output from only 1.4 percent of all major tonnage in 1966 to 15.4 percent in 1978. This is not surprising, given that utility consumption of coal increased from 54 percent of all coal consumed in the U.S. in 1966 to 77 percent in 1977.¹

The involvement of both coal and steel companies decreased between 1966 and 1978. Independent coal companies accounted for over half of all output from the major producers in 1966 and only 15.3 percent in 1978. The 1966 figure is somewhat misleading because the purchase of Consolidation by Conoco in September meant that its output was counted as oil company controlled for the whole year. If Consolidation were counted as an independent coal producer in 1966, the percent of major coal output by independent coal companies would increase to almost 78 percent. The decrease in steel company involvement in the majors (12.6 percent of major producer output in 1966; 6.3 percent in 1978) follows generally the decrease in coal usage by steel companies over this period (96 million tons consumed in 1966 versus 77 million consumed in 1977).²

Concentration in the Coal Industry, 1966 and 1978

Table 1-5 details output concentration of the coal industry in 1966 and 1978. In 1978, the top four producing groups accounted for 21.3 percent of total U.S. output, down from 27.6 percent controlled by the top four firms in 1966. The eight-firm concentration ratios have decreased also, falling from 37.4 percent of total output in 1966 to 28.7 percent in 1978. Both the 1978 and 1966 figures include captive tonnage, and estimates of the amount of captive tonnage in 1978 were made using the EIA-7 data. One could argue that captive tonnage should be removed from measures of concentration because it does not move in conventional markets and therefore, does not affect price and quantity. However, one could also argue that the potential for influence exists, for an increase or decrease in captive output would decrease or increase the demand for coal from noncaptive sources, *ceteris paribus*.

Tables 1-6 through 1-8 detail output concentration by region (Appalachian, Interior, and West). The states included in these regions are listed in the introduction to Chapter 3.

As was the case with the U.S. totals, concentration has decreased in the Appalachian region from 1966 to 1978 (Table 1-6). The four-firm ratio

Table 1-5. Output Concentration of Major Producers, 1966 and 1978

Year	Producing Company	Output (10 ³ tons)	Percentage of U.S. Total
1978	1. Peabody Coal Co.	52,458	
	2. Consolidation Coal Co.	40,740	
	3. AMAX Coal Co.	29,787	
	4. Texas Utilities (est.)	16,000	
	Subtotal (4 firms)	138,985 ^a	21.3%
	5. Island Creek Coal Co.	13,590	
	6. Ashland Oil	12,916	
	7. NERCO, Inc.	11,415	
	8. Pittston Co.	10,956	
	Total (8 firms) (est.)	187,861 ^b	28.7%
	Total U.S. production (est.)	653,800	
1966	1. Peabody Coal Co.	54,041	
	2. Consolidation Coal Co.	51,400	
	3. Island Creek Coal Co.	23,652	
	4. U.S. Steel	18,007	
	Subtotal (4 firms)	147,100	27.6%
	5. Pittston Co.	15,540	
	6. General Dynamics Corp.	13,562	
	7. Eastern Associated Coal	12,116	
	8. Bethlehem Steel	11,118	
	Total (8 firms)	199,436	37.4%
	Total U.S. production	533,881	

^aIncludes an estimated 16.4 million tons of captive output.

^bIncludes an estimated 24.5 million tons of captive output.

Source: *Keystone Coal Mine Directory*, 1966 and 1978.

Table 1-6. Appalachian Coal Output Concentration, 1978 and 1966

Year	Producing Company	Output (10 ³ tons)	Percentage of Appalachian Total
1978	1. Consolidation Coal Co.	28,394	
	2. Pittston Co.	10,956	
	3. Bethlehem Steel	9,453	
	4. U.S. Steel	9,422	
	Subtotal (4 firms)	58,225	16.2%
	5. Island Creek Coal Co.	9,294	
	6. American Electric Power	8,443	
	7. North American Coal Corp.	6,552	
	8. Gulf Resources	5,864	
	Total (8 firms)	88,377	24.5%
	Total Appalachian production	360,191	
1966	1. Consolidation Coal Co.	43,056	
	2. U.S. Steel Co.	16,505	
	3. Island Creek Coal Co.	15,491	
	4. Pittston Co.	15,540	
	Subtotal (4 firms)	90,592	23.7%
	5. Eastern Associated Coal	12,116	
	6. Bethlehem Steel	11,188	
	7. North American Coal Corp.	7,155	
	8. Westmoreland Coal Co.	6,148	
	Total (8 firms)	127,199	33.2%
	Total Appalachian production	382,982	

Source: *Keystone Coal Mine Directory*, 1966 and 1978.

Table 1-7. Interior Coal Output Concentration, 1978 and 1966

Year	Producing Company	Output (10 ³ tons)	Percentage of Interior Total
1978	1. Peabody Coal Co.	36,443	
	2. Texas Utilities	16,000	
	3. AMAX Coal Co.	11,481	
	4. Consolidation Coal Co.	7,956	
	Subtotal (4 firms)	71,879	48.1%
	5. Old Ben Coal Co.	7,741	
	6. Freeman United Coal Mining	5,838	
	7. Island Creek Coal Co.	4,296	
	8. Pittsburg and Midway Coal Mining Co.	3,905	
	Total (8 firms)	93,659	62.7%
	Total Interior production	149,321	
1966	1. Peabody Coal Co.	47,975	
	2. Freeman United Coal Mining	13,561	
	3. Old Ben Coal Co.	9,144	
	4. Ayrshire	8,536	
	Subtotal (4 firms)	79,216	61.1%
	5. Island Creek Coal Co.	8,161	
	6. Pittsburg and Midway Coal Mining Co.	7,888	
	7. Consolidation Coal Co.	6,862	
	8. Southwestern Illinois	6,787	
	Total (8 firms)	108,914	84.0%
	Total Interior production	129,659	

Source: *Keystone Coal Mine Directory*, 1966 and 1978.

Table 1-8. Western Coal Output Concentration, 1978 and 1966

Year	Producing Company	Output (10 ³ tons)	Percentage of Western Total
1978	1. AMAX Coal Co.	18,307	
	2. Peabody Coal Co.	12,827	
	3. NERCO, Inc.	11,346	
	4. Western Energy	10,576	
	Subtotal (4 firms)	53,056	37.3%
	5. Peter Kiewit Sons Co.	10,244	
	6. Arch Mineral Corp.	8,356	
	7. Utah International, Inc.	7,100	
	8. Knife River Coal Mining	5,059	
	Total (8 firms)	83,815	58.9%
	Total West production	142,390	
1966	1. Utah Construction	2,012	
	2. Pacific Power and Light	1,562	
	3. Knife River Coal Mining	1,546	
	4. Kaiser Steel	1,524	
	Subtotal (4 firms)	6,644	31.3%
	5. U.S. Steel	1,502	
	6. Consolidation Coal Co.	1,482	
	7. Pittsburg and Midway Coal Mining Co.	952	
	8. Kemmerer Coal Co.	838	
	Total (8 firms)	11,418	53.8%
	Total West production	21,240	

Source: *Keystone Coal Mine Directory*, 1966 and 1978.

has decreased from 23.7 percent in 1966 to 16.2 percent in 1978; the eight-firm ratio has decreased from 33.2 percent in 1966 to 24.5 percent in 1978. In both years, Appalachian concentration was less than the U.S. as a whole.

Table 1-7 details concentration of output in the Interior region. As was the case in Appalachia and the U.S., concentration fell from 1966 to 1978. The four-firm ratio fell from 61.1 percent to 48.1 percent, and the eight-firm ratio fell from 84.0 percent to 62.7 percent of total regional output. Concentration is still greater in the Interior region than in any other region and is substantially higher than in the U.S. as a whole.

Table 1-8 details concentration in the West. Movement of major producing firms (3 million tons per year or more) into the western region is a recent occurrence; in 1966 only 5 of the 26 majors had output originating in western mines, amounting to a total of less than 5 million tons. Of the top 8 western firms in 1978, only Peabody existed as a major in 1966 (see Table 1-10).

Unlike the other regions examined, concentration increased in the West from 1966 to 1978. The four-firm ratio rose from 31.3 percent in 1966 to 37.3 percent in 1978, and the eight-firm ratio from 53.8 percent in 1966 to 58.9 percent in 1978. From 1966 to 1978 the West experienced considerable growth in coal output, from 21 million tons to over 142 million tons.

Some economists have argued that concentration of reserves is the appropriate measure of competition in the coal industry. However, good data on firm-level reserve holdings are unavailable. Table 1-9 contains firm-level reserve information reported in *Keystone*.

Table 1-9. 1978 Coal Reserves of the Major Coal-Producing Companies

Producing Company	Coal Reserves (10 ⁶ tons)	Controlling Company	
		Name	Type
Peabody Coal	8,900	Peabody Coal	—
Consolidation Coal	13,700	Continental Oil	Oil
AMAX Coal	5,045	AMAX	Metal, oil
Texas Utilities	NA	Texas Utilities	Utility
Island Creek Coal	4,430	Occidental Petroleum	Oil
Arch Mineral	650	Ashland Oil	Oil
Glenrock Coal	1,700	NERCO, Inc./Pacific Power & Light	Utility
Pittston	1,700	Pittston	Coal
Western Energy	1,000	Montana Power	Utility
U.S. Steel	3,080	U.S. Steel	Steel
Big Horn Coal	NA	Peter Kiewit Sons	—
Bethlehem Mines	1,800	Bethlehem Steel	Steel
Central Ohio Coal	NA	American Electric Power	Utility
Pittsburg & Midway Coal Mining	2,600	Gulf Oil Co.	Oil
Old Ben Coal	825	Standard Oil of Ohio	Oil
North American Coal	5,100	North American Coal	Coal
Utah International	1,300	General Electric	Electricity, equipment
Westmoreland Coal	849	Westmoreland Coal	Coal
C & K Coal	148	Gulf Resources & Chemical	Chemical
Freeman United Coal Mining	600	General Dynamics	Defense
Eastern Associated Coal	1,058	Eastern Gas & Fuel Assoc.	Gas
Drummond Coal	110	Drummond Coal	Coal
Carter Oil	8,400	Exxon	Oil
United Coal	10	United Coal Cos.	Coal
Knife River Coal Mining	600	Montana Dakota Utilities	Utility
Keystone Coal Mining	146	Rochester & Pittsburgh Coal	Coal
Martiki Coal	404	Mapco, Inc.	Coal
Washington Irrigation & Development	80	Washington Irrigation & Development	Utility
Zeigler Coal	1,000	Houston Natural Gas	Gas
Westmoreland Resources	1,100	Westmoreland Resources	Coal, gas
Falcon Coal	NA	Diamond Shamrock	Chemicals, oil, gas
Kemmerer Coal	NA	Lincoln	Coal
Baukol-Noonan	500	Baukol-Noonan	Coal
Ashland Oil	650	Ashland Oil	Oil
Sunoco Energy Div.	NA	Sun Co.	Oil
Jones & Laughlin Steel	264	LTV	Steel
International Energy	NA	American Industries and Resources	—
Energy Fuels	NA	—	—
Alabama By-Products	NA	—	—

NA = No information available.

Source: *Keystone Coal Industry Manual*, 1979.

Turnover among the Major Producers, 1966, 1973, and 1978

Table 1-10 shows the rank of 1978 major producers in 1973 and 1966. The producers listed in this table are coal companies, and ownership or control of the company could have changed between the periods listed (e.g., Old Ben Coal was an independent coal company in 1966; in the 1973 and 1978 rankings, it is a subsidiary of Standard Oil of Ohio).

Of the 39 major producers in 1978, 25 (64.1 percent) were listed as major producers in 1973 and 15 (38.5 percent) were major producers in 1966. Of the top 15 producers in 1978, the survival rate is much higher, with 13 of the top 15 classified as majors in 1973 and 9 of the top 15 classified as majors in 1966. Of the 39 major producers in 1978, 13 were not classified as majors in 1973.

Half of the top 10 coal producers in the U.S. in 1978 did not exist in 1966. These producers (AMAX, Texas Utilities, Arch Mineral, NERCO, and Western Energy) all control predominantly gigantic surface mines (only AMAX runs a single deep mine operation that accounts for less than 5 percent of its total production). AMAX and Arch Mineral have oil interests (AMAX is 20.6 percent owned by Standard Oil of California); the others are controlled by utilities. These new giants have replaced traditionally top coal producers such as Bethlehem, Old Ben, and U.S. Steel. Peabody, Consolidation Coal, and Island Creek have seen very little change in their status as major producers from 1966 to 1978, although all three have changed ownership or control during this period.

Unionization among the Major Producers, 1978

Table 1-11 contains the union status of the major coal producers in 1978. Virtually all of the major producers are unionized, the exceptions being Gulf Resources, United Coal, Mapco, Diamond Shamrock, and Sunoco Energy Development Company. The appearance of large surface operations in the major producing groups has led to several of the companies being organized by the operating engineers. Large surface mines are similar to heavy road construction, using earth moving machinery and employing operating engineers.

Table 1-10. Turnover among Major Coal Producers, 1966, 1973, 1978

Major Producers in 1978	Rank in 1978	Rank in 1973	Rank in 1966
Peabody Coal Co.	1	1	1
Consolidation Coal Co.	2	2	2
AMAX Coal Co.	3	5	*
Texas Utilities	4	*	*
Island Creek Coal Co.	5	3	3
Ashland Oil Co. (Arch Mineral Corp.)	6	8	*
NERCO, Inc./Pacific Power & Light (Glenrock Coal)	7	*	*
Pittston Co.	8	4	5
Western Energy Co.	9	19	*
U.S. Steel	10	6	4
Peter Kiewit Sons Co. (Big Horn Coal)	11	17	*
Bethlehem Mines Corp.	12	7	8
American Electric Power (Central Ohio Coal)	13	16	19
Pittsburg & Midway Coal Mining Co.	14	14	10
Old Ben Coal Co.	15	10	9
North American Coal Co.	16	9	12
Utah International Inc.	17	15	*
Westmoreland Coal Co.	18	12	14
Gulf Resources & Chemical Co. (C & K Coal)	19	*	*
Freeman United Coal Mining Co.	20	13	6
Eastern Associated Coal Co.	21	11	7
Drummond Coal Co.	22	*	*
Exxon Corp. (Carter Oil Co.)	23	*	*
United Coal Cos.	24	*	*
Knife River Coal Mining Co.	25	*	*
Rochester & Pittsburgh Coal Co. (Keystone)	26	18	*
Mapco, Inc. (Martiki; Webster)	27	*	*
Washington Irrigation & Development Co.	28	28	*
Zeigler Coal Co.	29	20	18
Westmoreland Resources	30	*	*
Falcon Coal Co.	31	23	*
Kemmerer Coal Co.	32	31	*
Baukol-Noonan, Inc.	33	*	*
Ashland Coal	34	*	*
Sunoco Energy Div.	35	*	*
Jones & Laughlin Steel Corp.	36	24	26
American Industries & Resources Corp. (Ohio Coal)	37	*	*
Energy Fuels Corp.	38	*	*
Alabama By-Products Corp.	39	26	*

* = Not listed as major producer.

Sources: *Keystone Coal Industry Manual*, various years.
Keystone Coal Mine Directory, various years.

Table 1-11. Union Status of Major Coal-Producing
Companies Work Forces, 1978

Company	Union Status
1. Peabody	All mines UMWA (United Mine Workers of America)/ BCWA (Bituminous Coal Wage Agreement of 1978) except surface operations in Montana, Colorado and Arizona which are UMWA/WSA (Western Surface Agreement).
2. Consolidation	All mines UMWA/BCWA except North Dakota surface operations which are UMWA/WSA.
3. AMAX	All mines UMWA/BCWA except Wyoming surface operations; these are nonunion.
4. Texas Utilities	IBEW (International Brotherhood of Electrical Workers)
5. Island Creek	All mines UMWA/BCWA
6. Arch Mineral	Wyoming surface operations are PMW (Progressive Mine Workers); all other operations are UMWA/BCWA.
7. NERCO	Glenrock Coal (Wyoming surface) is UMWA/WSA; Bankhead Mining (Alabama surface) is UMWA/BCWA; Bridger Coal (Wyoming surface) is AFL-CIO; and Decker Coal (Montana surface) is PMW.
8. Pittston	All mines UMWA/BCWA.
9. Western Energy	IUOE (International Union of Operating Engineers).
10. United States Steel	All mines UMWA/BCWA.
11. Peter Kiewit Sons	Big Horn Coal (Wyoming surface) is UMWA/WSA; Rosebud Coal (Wyoming surface) is IUOE; Decker Coal (Montana surface) is PMW.
12. Bethlehem	All mines UMWA/BCWA.
13. American Electric Power	All Mines UMWA/BCWA.
14. Pittsburgh and Midway Coal	All mines UMWA/BCWA except Colorado and New Mexico surface operations which are UMWA/WSA.
15. Old Ben Coal	All mines UMWA/BCWA.
16. North American Coal	All mines UMWA/BCWA except North Dakota surface operations which are UMWA/WSA.

Table 1-11. Union Status of Major Coal-Producing
Companies Work Forces, 1978 (Cont'd.)

Company	Union Status
17. Utah International	All mines IUOE.
18. Westmoreland Coal Co.	All mines UMWA/BCWA.
19. Gulf Resources	All mines nonunion.
20. Freeman United	All mines UMWA/BCWA.
21. Eastern Associated	All mines UMWA/BCWA.
22. Drummond	All mines UMWA/BCWA.
23. Carter Oil	Monterey Coal (Illinois) is UMWA/BCWA; Carter Mining (Wyoming surface) is nonunion.
24. United Coal	All mines nonunion.
25. Knife River Mining	All mines PMW.
26. Rochester and Pittsburgh Coal	All mines UMWA/BCWA.
27. Mapco, Inc.	All mines nonunion.
28. Washington Irrigation and Development	All mines IUOE.
29. Zeigler Coal	All mines UMWA/BCWA.
30. Westmoreland Resources	All mines IUOE.
31. Diamond Shamrock	All mines nonunion.
32. Kemmerer Coal Co.	All mines UMWA/WSA.
33. Baukol-Noonan	Center mine is IBEW, Noonan mine is nonunion.
34. Ashland Coal	All mines nonunion.
35. Sunoco Energy Development	Nonunion mine.
36. Jones and Laughlin Steel	All mines UMWA/BCWA
37. American Industries Resources Corp.	All mines controlled by AIR have independent unions

Table 1-11. Union Status of Major Coal-Producing
Companies Work Force, 1978 (Cont'd.)

Company	Union Status
38. Energy Fuels	All mines UMWA/WSA.
39. Alabama By-Products	All mines UMWA/BCWA.

NOTE: UMWA = United Mine Workers of America

BCWA = Bituminous Coal Wage Agreement of 1978

IBEW = International Brotherhood of Electrical Workers

IUOE = International Union of Operating Engineers

PMW = Progressive Mine Workers

WSA = Western Surface Agreement

Sources: Information collected from U.S. Department of Energy, Energy Information Administration; *Bituminous Coal Wage Agreement of 1978*; Bituminous Coal Operators Association; 1979 *Keystone Coal Industry Manual*, and telephone conversations with individual companies.

SUMMARY

Although the ranks of the majors have grown since 1966, their proportion of total U.S. output has remained about the same. The average major in 1966 was larger than in 1978. The eight-firm concentration ratio and the four-firm ratio fell from 1966 to 1978. In both years concentration of output was minimal.

There has been considerable change in the composition of the majors from 1966 to 1978. Changes in control or ownership or entrance of new major producers have resulted in a significant growth in the number of oil-controlled and utility-controlled majors; those controlled by steel and independent coal companies have declined. The entrance of new producers controlled by oil and utilities has altered the ranking of firms within the major producing class; half of the top 10 producers in 1978 did not exist in 1966. Unionization is common among the major producers with a variety of unions represented.

NOTES

¹The President's Commission on Coal, *Coal: A Data Book* (Washington, D.C.: U.S. Government Printing Office, 1979), p. 29. 1978 figures unavailable.

²Ibid.

CHAPTER 2. STATISTICAL PROFILE OF THE MAJOR PRODUCING GROUPS, 1978

INTRODUCTION

This chapter examines production, technology, transportation, markets, and other characteristics of the major coal-producing groups and compares them to nonmajor coal producers.

The Department of Energy preliminary estimates indicate that 653.8 million tons were produced in 1978; the EIA-7 data account for 621.6 million tons or a coverage of 95.1 percent of the tonnage produced. The DOE 1978 estimated mine population is 6075; the EIA-7 data account for 5580 mines or 91.9 percent of the estimated population. The greater coverage of tonnage than of mine population suggests that those mines for which records were not received or for which data are missing are small producers (estimated mean annual output of 65,000 tons versus 110,000 tons for the mines for which data are available). The results, then, are biased in favor of larger producers.

The total tonnage of the major producers in 1978 was estimated as 369.8 million by *Keystone*; the total tonnage of major producers identified on the EIA-7 tape was 336.6 million or 91.0 percent of the estimated *Keystone* tonnage. Several factors have been identified as reasons for the differences between the EIA-7 major tonnage and the *Keystone* estimate:

1. The 1978 EIA-7 tape used was an early edition; therefore, it excluded some of the questionnaires that were late in arriving or that were obtained through follow-up surveys.

2. The accuracy of the *Keystone* data are unknown. However, discrepancies between *Keystone* and the EIA-7 data in the reported tonnage of the individual mines indicate that for some mines and companies these differences can be large. Because the EIA-7 data are collected under law and knowingly providing false information is a criminal offense, one would place greater confidence in the EIA estimates.

3. Due to sales arrangements of some major producers, identification of individual mines falling under their control is difficult. Some majors operate cleaning plant and/or tipples that purchase or sell the coal of a large number of small producers. Other majors own reserves and lease them to small independent operators to mine but receive the tonnage from the leased reserves and count it as controlled tonnage. In both instances,

those mines that have a marketing arrangement with a major may list themselves as independent on the EIA-7 form. For some of these mines, the *Keystone Coal Industry Manual* only publishes the summary statistics at the cleaning plant and tipple; therefore, identification of these small controlled mines is difficult. Thus, some of the nonmajor mines in the following tables are small independents who have marketing arrangements with majors. Given the coverage of major producer tonnage and the similarity between these "missing" majors and the nonmajor sector of the industry, the expected bias resulting from this identification problem is presumed to be insignificant.

Most of the following tabulations are broken into three coal-producing regions:

<u>Appalachian</u>	<u>Interior</u>	<u>West</u>
Alabama	Arkansas	Arizona
East Kentucky	Illinois	Colorado
Maryland	Indiana	Montana
Ohio	Iowa	New Mexico
Pennsylvania	Kansas	North Dakota
Tennessee	West Kentucky	Utah
Virginia	Missouri	Washington
West Virginia	Oklahoma	Wyoming
	Texas	

All of the statistics and distributions here are based on samples, not on complete populations. Therefore, any observed differences in variable means or distribution between major and nonmajor producer samples either may represent true differences between major and nonmajor producer populations or may occur simply by chance--based on the sampling process. To determine which is more likely, statistical tests of significance are used to measure the probability that a difference between the two samples is due strictly to chance.

Student's t test examines differences in sample means; the chi-square test measures differences in frequency distributions. The larger the calculated t or chi-square value, the greater its associated "level of significance." The level of significance is the probability that a t or chi-square value of a particular magnitude would occur simply by chance. For example, a t or chi-square statistic that is significant at the .01 level is so large that it would occur in only 1 of 100 random samples from the population. A sample difference of this size has only a 1 percent probability of being caused by chance; therefore, it probably represents a real difference between the two groups.

PRODUCTION CHARACTERISTICS, 1978

Production Technique

Tables 2-1, 2-2, and 2-3 show the number of major and nonmajor mines by type (deep, surface, and other) in 1978 for the Appalachian, Interior, and West regions. The chi-square statistic for each of these tables indicates that there is a statistically significant difference (at the .01 level) in the types of mines controlled by the majors versus the rest of the industry.

In Appalachia, the major groups control predominantly deep mines while the nonmajors control more surface mines than deep mines. Both majors and nonmajors control more surface mines than deep mines in the Interior region; however, the nonmajors are weighted heavily in favor of surface mines. In the West, more deep mines than surface mines are controlled by nonmajors; the major groups control predominantly surface mines.

Table 2-1. Mine Type: All Mines, Appalachian Region, 1978

Mine Type	Nonmajor		Major		Total	
	N	%	N	%	N	%
Deep	1,962	42.6	315	75.2	2,277	45.4
Surface	2,645	57.4	103	24.6	2,748	54.6
Other	1	0.0	1	0.2	2	0.0
Total	4,608	100.0	419	100.0	5,027	100.0

χ^2 probability = .0001

Source: EIA-7.

Table 2-2. Mine Type: All Mines, Interior Region, 1978

Mine Type	Nonmajor		Major		Total	
	N	%	N	%	N	%
Deep	23	6.8	43	43.0	66	15.1
Surface	313	93.2	57	57.0	370	84.9
Other	0		0		0	
Total	336	100.0	100	100.0	436	100.0

χ^2 probability = .0001

Source: EIA-7.

Table 2-3. Mine Type: All Mines, Western Region, 1978

Mine Type	Nonmajor		Major		Total	
	N	%	N	%	N	%
Deep	44	62.9	10	20.0	54	45.0
Surface	26	37.1	40	80.0	66	55.0
Other	0		0		0	
Total	70	100.0	50	100.0	120	100.0

χ^2 probability = .0001

Source: EIA-7.

Table 2-4 reports the deep mine technology used by firm type for the three regions. These numbers are only for those deep mines that reported using a single technology; mines that employ more than one method (such as conventional and continuous) are excluded. This restriction limits the coverage in Appalachia to 92.2 percent of all deep mines; in the Interior region, 80.0 percent of deep mines are represented; and in the West, 75.9 percent of deep mines are reported. Some of those mines not included had missing data on technology employed.

Table 2-4. Technology Employed: Deep Mines Reporting Only One Technology, 1978

Technique	Number of Mines											
	Appalachian				Interior				West			
	Nonmajor		Major		Nonmajor		Major		Nonmajor		Major	
	N	%	N	%	N	%	N	%	N	%	N	%
Conventional	840	45.4	29	11.6	13	76.5	22	61.1	3	9.4	0	0.0
Continuous	572	30.9	215	86.3	4	23.5	14	38.9	29	90.6	9	100.0
Hand-cut	438	23.7	5	2.0	0	0.0	0	0.0	0	0.0	0	0.0
Total	1,850	100.0	249	100.0	17	100.0	36	100.0	32	100.0	9	100.0
χ^2 probability	.0001				.270				.340			

Source: EIA-7.

The Interior and West regions did not have statistically significant differences in deep mine technology. Most western deep mines use continuous mining and most Interior mines use conventional mining, regardless of who controls the mine. In Appalachia, mine technology did differ with ownership: nonmajor producers used more conventional and hand-cut mining, while most deep mines controlled by the major producers used continuous mining.

Location of Production

Table 2-5 shows the distribution of major and nonmajor tonnage in 1978 by mine type and region. The biggest difference between the location of production by type of controlling firm is the dominance of the nonmajor production in the Appalachian region and the dominance of major group mines in the Interior and the West. Major group controlled output is fairly evenly divided between the three regions, while 80.5 percent of nonmajor tonnage originates in the Appalachian region.

Thus, 68.7 percent of total Appalachian output originates from nonmajor mines, while only 26.3 percent of Interior output and 13.7 of Western output originate from nonmajor mines.

Tables 2-6, 2-7, and 2-8 report tonnage by firm and mine type for the Appalachia, Interior, and West regions, respectively. As these tables show, only in the Interior region is major and nonmajor production distributed between deep and surface output in similar proportions. In Appalachia, nonmajor production is mostly surface output (60.9 percent) and major production is mostly deep (77.3 percent); in the West, 97.4 percent of major output is from surface mines, while 37.3 percent of nonmajor output is from surface mines.

Table 2-5. Distribution of Tonnage: All Mines by Region, 1978
(10³ tons)

Region	Nonmajor ^a					
	Deep		Surface		Total	
	N	%	N	%	N	%
Appalachia	92,236.0	83.7	144,030.8	78.6	236,266.8	80.5
Interior	5,670.2	5.1	31,922.1	17.4	37,592.3	12.8
West	12,260.9	11.1	7,279.6	4.0	19,540.5	6.7
Total	110,167.1	100.0	183,232.5	100.0	293,399.6	100.0

Region	Major ^a					
	Deep		Surface		Total	
	N	%	N	%	N	%
Appalachia	83,589.4	67.1	23,935.6	11.3	107,525.0	32.0
Interior	37,823.9	30.3	67,544.6	32.0	105,368.5	31.4
West	3,233.9	2.6	119,876.7	56.7	123,110.6	36.6
Total	124,647.2	100.0	211,356.9	100.0	336,004.1	100.0

^aExcludes tonnage not classified as deep or surface.

Source: EIA-7.

Table 2-6. Tonnage All Mines, Appalachian
Region, 1978 (10³ tons)

Mine Type	Company Type					
	Nonmajor		Major		Total	
	N	%	N	%	N	%
Deep	92,236.0	39.0	83,589.4	77.3	175,825.4	51.0
Surface	144,030.8	60.9	23,935.6	22.1	167,966.4	48.8
Other	190.0	0.1	632.0	0.6	822.0	0.2
Total	236,456.8	100.0	108,157.0	100.0	344,613.8	100.0

Source: EIA-7.

Table 2-7. Tonnage All Mines, Interior
Region, 1978 (10³ tons)

Mine Type	Company Type				Total	
	Nonmajor		Major			
	N	%	N	%	N	%
Deep	5,670.2	15.0	37,823.9	35.9	43,494.1	30.6
Surface	31,922.1	85.0	67,544.6	64.1	99,466.7	69.4
Other	0.0	0.0	0.0	0.0	0.0	0.0
Total	37,592.3	100.0	105,368.5	100.0	142,960.8	100.0

Source: EIA-7.

Table 2-8. Tonnage All Mines, Western
Region, 1978 (10³ tons)

Mine Type	Company Type					
	Nonmajor		Major		Total	
	N	%	N	%	N	%
Deep	12,260.9	62.7	3,233.9	2.6	15,434.8	10.8
Surface	7,279.6	37.3	119,876.7	97.4	127,156.3	89.2
Other	0.0	0.0	0.0	0.0	0.0	0.0
Total	19,540.5	100.0	123,110.6	100.0	142,591.1	100.0

Source: EIA-7.

Mine Age and Size Distribution

Tables 2-9 through 2-11 detail the age distribution of surface and deep mines by size of mine, region, and controlling group. The age distribution of mines reveals information about market viability of a group of mines: generally, concentration of mines in young age categories implies high rates of entry and exit from the industry, i.e., turnover. Mines seldom survive to a mature age, thus the concentration in younger age groups. If a region is undergoing rapid growth, the mine age distribution again would have a larger than expected number of young mines.

Mine age distribution is also affected by type of mines. Surface mines do not require the investment that deep mines do, so they are easier to open and more likely to cease operations if demand falls. Mine size also has the same influence; smaller mines can enter and leave the industry more easily than large mines due to differences in initial investment required to open a mine. For these reasons, the following tables control for type of mine (surface or deep) and mine size.

Table 2-9 shows the age distribution of small (less than 100,000 tons annually) surface and deep mines in Appalachia. As one would expect, both small surface and small deep mines are concentrated in young age categories (less than 3 years old), implying high turnover. There is little difference in age distribution of surface mines by controlling group; however, small deep mines controlled by major firms survive longer than those controlled by nonmajors: 58.4 percent of major deep mines survived past 3 years, while only 17.7 percent of nonmajor deep mines survived past 3 years.

The small number of mines in the Interior and West prohibits meaningful results when mine ownership and age are controlled for. Tables 2-10 and 2-11 contain the age distribution by region and ownership of large (more than 100,000 tons annually) deep and surface mines.

As shown in Table 2-10, the age distribution of major- compared to nonmajor-controlled deep mines varied by region. In the Appalachian region, 43.2 percent of the nonmajor deep mines were less than 3 years old, while only 15.2 percent of the majors were less than 3 years old. The chi-square statistic indicates that this difference is significant at the .001 level. In the Interior, nonmajors again had a much higher percentage of young mines, with 58.4 percent less than 3 years old compared to only 22.3 percent of major-controlled deep mines. Overall, however, the difference in the

Table 2-9. Age Distribution of Appalachian Mines with Less Than 100,000 Tons Annual Output, 1978

Mine Age (years)	Surface				Deep			
	Nonmajor		Major		Nonmajor		Major	
	N	%	N	%	N	%	N	%
Age < 1	947	47.4	14	34.1	777	49.5	18	19.1
1 ≤ Age < 3	659	33.0	13	31.7	515	32.8	21	22.3
3 ≤ Age < 7	254	12.7	11	26.8	173	11.0	30	31.9
7 ≤ Age < 10	75	3.8	2	4.9	68	4.3	11	11.7
10 ≤ Age < 20	47	2.4	1	2.4	27	1.7	4	4.2
Age ≥ 20	14	0.7	0	0.0	11	0.7	10	10.6
Total	1,996	100.0	41	100.0	1,571	100.0	94	100.0
χ^2 probability	.151				.001			
Percent of mines covered	87.3		80.4		90.1		79.0	

Source: EIA-7.

Table 2-10. Age Distribution of Deep Mines With 100,000
Tons or More Annual Output, 1978

Mine Age (years)	Number of Mines											
	Appalachia				Interior				West			
	Nonmajor		Major		Nonmajor		Major		Nonmajor		Major	
	N	%	N	%	N	%	N	%	N	%	N	%
Age < 1	25	14.6	9	6.2	2	16.7	2	5.6	0	0.0	0	0.0
1 ≤ Age < 3	49	28.6	13	9.0	5	41.7	6	16.7	2	10.0	3	42.9
3 ≤ Age < 7	30	17.5	11	7.6	0	0.0	6	16.7	4	20.0	2	28.6
7 ≤ Age < 10	22	12.9	23	15.8	2	16.7	7	19.4	2	10.0	0	0.0
10 ≤ Age < 20	24	14.0	38	26.2	3	25.0	8	22.2	2	10.0	1	14.3
Age ≥ 20	21	12.2	51	35.2	0	0.0	7	19.4	10	50.0	1	14.3
Total	171	100.0	145	100.0	12	100.0	36	100.0	20	100.0	7	100.0
χ ² probability	.001				.146				.231			
Percent of mines covered	77.7		74.0		92.3		83.7		74.1		77.7	

Source: EIA-7.

distributions was not statistically significant. In the West, the small number of observations and the lower response rate make interpretation of the results difficult; however, the three deep mines less than 3 years old controlled by majors are new mine openings most likely due to growth rather than replacement.

Table 2-11 details the age distribution of large (100,000 or more tons annually) surface mines. In both the Appalachia and Interior regions, mines controlled by nonmajors are concentrated in the young (less than 3 years) age category, while major-controlled surface mines are more mature. There is little difference between majors and nonmajors in the age distribution of large western surface mines.

Tables 2-12 and 2-13 show the size distribution of deep and surface mines, respectively. In all regions, nonmajors' deep mines are concentrated in small size classes (less than 100,000 tons annually) while deep mines controlled by majors are concentrated in the 200,000-plus tonnage categories.

As shown by Table 2-13, in the West and Interior surface mines grouped by ownership exhibit much the same pattern, with the majority of nonmajors in small size classes and the majority of major-controlled mines producing 200,000-plus tons annually. In Appalachia this same general trend exists; however, much larger portions of both major-controlled and nonmajor-controlled mines are in the smaller classes.

Markets and Prices

Table 2-14 displays the distribution of tonnage by controlling group among various market uses by region. Because many mines sell coal in more than one market (e.g., coke and export), one mine's output can be distributed among several end uses. The "All other" category in Table 2-14 contains tonnage for which mines listed markets; the "Unknown" category contains tonnage for which end use information was unavailable (this was significant only in nonmajor Appalachian mines). The response rate was high across all regions and controlling groups.

The major difference in the market uses of major output as opposed to nonmajor output in Appalachia is in coking coal. Over one-fourth of major producers tonnage is metallurgical grade coal; while only 8.2 percent of nonmajor output is consumed in this market. However, the undistributed tonnage in the nonmajor "Unknown" category could affect this percentage. The steam market is the major consumer of coal from both types of controlling groups in all three regions.

Table 2-11. Age Distribution of Surface Mines with
100,000 or More Tons Annual Output, 1978

Mine Age (years)	Number of Mines											
	Appalachia				Interior				West			
	Nonmajor		Major		Nonmajor		Major		Nonmajor		Major	
	N	%	N	%	N	%	N	%	N	%	N	%
Age < 1	45	17.3	6	16.7	11	14.7	1	2.5	0	0.0	2	7.1
1 ≤ Age < 3	101	38.8	11	30.6	37	49.3	5	12.5	2	33.3	4	14.3
3 ≤ Age < 7	56	21.5	7	19.4	13	17.3	8	20.0	1	16.7	8	28.6
7 ≤ Age < 10	33	12.7	4	11.1	7	9.3	7	17.5	1	16.7	5	17.9
10 ≤ Age < 20	15	5.8	6	16.7	2	2.7	5	12.5	0	0.0	6	21.4
Age ≥ 20	10	3.8	2	5.6	5	6.7	14	35.0	2	33.3	3	10.7
Total	260	100.0	36	100.0	75	100.0	40	100.0	6	100.0	28	100.0
χ ² probability	.284				.001				a			
Percent of mines covered	72.4		69.2		93.8		74.1		77.8		70.0	

^aLack of observations prevents χ^2 analysis.

Source: EIA-7.

Table 2-12. Deep Mine Size Distribution by Region
and Controlling Group, 1978

Mine Size (10 ³ tons)	Number of Mines											
	Appalachia				Interior				West			
	Nonmajor		Major		Nonmajor		Major		Nonmajor		Major	
	N	%	N	%	N	%	N	%	N	%	N	%
Less than 10	648	33.0	16	5.1	4	17.4	0	0.0	2	4.55	0	0.0
10-49.9	835	42.6	45	14.3	3	13.0	0	0.0	7	15.9	0	0.0
50-99.9	259	13.2	58	18.4	3	13.0	0	0.0	8	18.2	1	10.0
100-199.9	135	6.9	73	23.2	5	21.7	1	2.3	6	13.6	3	30.0
200-499.9	71	3.6	65	20.6	5	21.7	8	18.6	15	34.1	5	50.0
500 or more	14	0.7	58	18.4	3	13.0	34	79.1	6	13.6	1	10.0
Total	1,962	100.0	315	100.0	23	100.0	43	100.0	44	100.0	10	100.0
χ^2 probability	.001				.001				.504			

Source: EIA-7.

Table 2-13. Surface Mine Size Distribution by
Region and Controlling Group, 1978

Mine Size (in 10 ³ tons)	Number of Mines											
	Appalachia				Interior				West			
	Nonmajor		Major		Nonmajor		Major		Nonmajor		Major	
	N	%	N	%	N	%	N	%	N	%	N	%
Less than 10	661	25.0	10	9.7	77	24.6	1	1.8	10	38.5	0	0.0
10-49.9	1,167	44.1	23	22.33	102	32.6	0	0.0	5	19.2	0	0.0
50-99.9	458	17.3	18	17.5	54	17.3	2	3.5	2	7.7	0	0.0
100-199.9	209	7.9	20	19.4	43	13.7	1	1.8	3	11.5	2	5.0
200-499.9	132	5.0	20	19.4	29	9.3	14	24.6	1	3.8	6	15.0
500 or more	18	0.7	12	11.7	8	2.6	39	68.4	5	19.2	32	80.0
Total	2,645	100.0	103	100.0	313	100.0	57	100.0	26	100.0	40	100.0
χ^2 probability			.001				.001				.001	

Source: EIA-7.

Table 2-14. Market Uses, All Mines by Region
and Controlling Group, 1978
(10³ tons)

Market	Appalachia				Interior			
	Nonmajor		Major		Nonmajor		Major	
	N	%	N	%	N	%	N	%
Utilities	93,656.3	41.7	56,477.1	54.5	41,238.7	78.4	91,743.6	91.3
Coke and gas	18,339.4	8.2	26,601.0	25.6	1,649.3	3.1	977.9	1.0
Other industrial	24,074.0	10.7	4,981.3	4.8	3,901.8	7.4	5,665.5	5.6
Export	7,661.9	3.4	11,355.0	11.0	162.4	0.3	24.0	0.0
All other	10,797.1	4.8	2,431.9	2.3	1,014.5	1.9	1,436.6	1.4
Unknown	69,919.2	31.2	1,847.6	1.8	4,605.4	8.8	642.2	0.6
Total	224,447.9	100.0	103,693.9	100.0	52,572.1	100.0	100,489.8	100.0
Number of mines	4,438		406		315		96	
Percent of mines covered		96.3		96.9		93.8		95.0
χ^2 probability		.001				.0001		

Market	West			
	Nonmajor		Major	
	N	%	N	%
Utilities	10,336.5	55.8	109,170.6	93.9
Coke and gas	3,249.6	17.5	987.2	0.8
Other industrial	3,192.7	17.2	5,543.0	4.8
Export	a		a	
All other	1,508.2	8.1	449.3	0.4
Unknown	236.6	1.3	100.8	0.1
Total	18,523.6	100.0	116,250.9	100.0
Number of mines	68		48	
Percent of mines covered		97.2		95.9
χ^2 probability		.0001		

^aNo tonnage reported.

Source: EIA-7.

The chi-square statistics for the output uses in the Interior and West regions by controlling group were significant at least at the .01 level, indicating that the markets of nonmajors were significantly different from those of the major producers. Both of the regions are dominated by steam coal production, with over 90 percent of major-controlled mine output in this market. In the Interior and West regions, nonmajor-controlled mines are more involved in the metallurgical coal markets than are the majors by contrast to the Appalachian region where majors dominate the metallurgical market.

Table 2-15 details captive and noncaptive output by region, mine size, and controlling group. Captive output does not move in commercial markets; noncaptive output moves in commercial markets (including buyers with long-term contracts). The Appalachian region is the only region where major producers have a higher portion of their output captive than nonmajors. In every region and for every controlling group, captive output is concentrated in large mines.

Table 2-16 compares mean coal prices of noncaptive sales by coal rank, region, and controlling group. Prices in these tables were computed by dividing total value of coal produced by total tonnage produced. The "N" in this table is the number of mines. The coal ranks are classified by the American Society for Testing and Materials. Ranks 20-22 (low to medium volatile bituminous) and ranks 23-29 (high volatile bituminous) can be used for both metallurgical and steam markets. Ranks 30-33 (subbituminous) and 40-42 (lignite) are used mainly for the steam coal market, and are virtually nonexistent in the Appalachia and Interior regions. As one moves from the high quality bituminous ranks to lignite, average price falls. It should be noted that coal rank leaves out many coal characteristics that can potentially affect price such as ash content and sulfur content. The extent of coal cleaning can also affect prices.

In Appalachia, major firms' coal prices are significantly higher (at the .01 level) than nonmajors' prices for all ranks. In the Interior majors' prices are significantly higher (at least at the .05 level) for all coal ranks than nonmajors' prices. In the West, the only coal rank with statistically significant differences between major and nonmajor prices is high volatile bituminous (ranks 23-29), where nonmajors command a higher price. When coal rank is not controlled for, nonmajors' coal prices are significantly higher (.01 level) than are majors'.

**Table 2-15. Captive and Noncaptive Production, All
Mines by Region, Size, and Controlling Group, 1978**
(10³ tons)

Mine Size and Market Type	Appalachia				Interior			
	Nonmajor		Major		Nonmajor		Major	
	N	%	N	%	N	%	N	%
Tons < 100,000								
Captive	2,052.5	1.9	1,239.9	16.1	3.1	0.0	0	0.0
Noncaptive	104,783.5	98.1	6,475.3	83.9	7,218.9	100.0	138.8	100.0
Total	106,836.0	100.0	7,715.2	100.0	7,222.0	100.0	138.8	100.0
Tons > 100,000								
Captive	13,135.2	10.1	27,805.3	27.4	7,124.9	23.4	14,471.8	13.8
Noncaptive	116,805.3	89.9	73,801.2	72.6	23,279.3	76.6	90,757.9	86.2
Total	129,940.5	100.0	101,606.5	100.0	30,404.2	100.0	105,229.7	100.0
Total tonnage								
Captive	15,187.7	6.4	29,045.2	26.6	7,128.0	18.9	14,471.8	13.7
Noncaptive	221,583.8	93.6	80,276.5	73.4	30,498.2	81.1	90,896.7	86.3
Total	236,776.5	100.0	109,321.7	100.0	37,626.2	100.0	105,368.5	100.0

Mine Size and Market Type	West			
	Nonmajor		Major	
	N	%	N	%
Tons < 100,000				
Captive	24.2	9.0	0	0.0
Noncaptive	959.2	91.0	57	100.0
Total	983.4	100.0	57	100.0
Tons > 100,000				
Captive	9,804.8	54.1	24,142.8	19.6
Noncaptive	8,294.1	45.8	98,910.8	80.4
Total	18,098.9	100.0	123,053.6	100.0
Total tonnage				
Captive	9,829.0	51.5	24,142.8	19.6
Noncaptive	9,253.3	48.5	98,967.8	80.4
Total	19,082.3	100.0	123,110.6	100.0

Source: EIA-7.

Table 2-16. Mean Coal Prices, All Mines Selling in Open Market by Region and Coal Rank, 1978

Coal Rank	Price per Ton, f.o.b. Mine					
	Appalachia		Interior		West	
	Nonmajor	Major	Nonmajor	Major	Nonmajor	Major
20-22 ^a	N = 724	N = 112	N = 30	f	N = 5	e
Mean	\$25.23	\$47.31	\$29.03		\$26.90	
Standard deviation	11.59	11.61	7.79		.003	
t	18.7**					
23-29 ^b	N = 3,714	N = 293	N = 283	N = 91	N = 50	N = 19
Mean	22.20	34.32	18.50	20.38	19.54	15.44
Standard deviation	7.63	9.09	5.07	4.86	6.50	5.15
t	25.77**		3.10**		2.43**	
30-35 ^c	e	e	e	e	N = 9	N = 20
Mean					13.59	9.58
t					1.85	
40-42 ^d	e	f	e	e	N = 4	N = 9
Mean					7.44	6.43
Standard deviation					4.35	2.24
t					0.51	
All ranks	N = 4,438	N = 406	N = 315	N = 96	N = 68	N = 48
Mean	22.81	38.11	19.11	20.74	18.89	10.89
Standard deviation	8.65	11.59	5.79	5.80	7.36	5.31
t	33.02**		2.41*		6.40**	
Percent of mines covered	92.2	96.7	93.8	96.0	97.1	96.0

^aLow to medium volatile bituminous.

*Significant at .05 level.

^bHigh volatile bituminous.

**Significant at .01 level.

^cSubbituminous.

^dLignite.

^eNo mines reported.

^fOne mine--data suppressed.

Source: EIA-7.

Transportation

Table 2-17 details the distribution of tonnage from majors and nonmajors by transportation mode controlling for region and mine size. Rail transportation is the dominant form of transport in all size classes and regions; rail transportation is also used more by majors than by nonmajors. Small mines controlled by both major and nonmajor groups transport a larger percentage of their coal by trucks than do large mines. Large mines controlled by both majors and nonmajors have significant portions of their tonnage consumed at the mine mouth; for small mines mine-mouth consumption is negligible.

Chi-square statistics were generated to test for significant differences in the distribution of transportation mode. The difference was significant (.0001 level) in all regions and size groups.

Operating Constraints

If a mine does not reach its highest level of output (under realistic assumptions) in the fourth quarter of the operating year, the EIA-7 form queries the mine as to the causes of this shortfall. The reasons that were listed as most important--tabulated by region, mine type, and controlling group--appear in Tables 2-18 through 2-23.

Table 2-18 shows operating constraints affecting deep mines in Appalachia. Although many of the constraints were important to both mines controlled by majors and nonmajors, the order of importance differed. For major deep mines, strikes were the most important constraint, followed by railroad car shortages, absenteeism, and lack of coal demand. For nonmajor deep mines, lack of coal demand was the major operating constraint followed by strikes, railroad car shortages, and environmental regulations.

Table 2-19 shows the operating constraints reported for Appalachian surface mines. Both nonmajor- and major-controlled surface mines list environmental regulations as the primary constraint for the largest number of mines. For nonmajors, this is followed by lack of demand, strikes, and railroad car shortages. For major's environmental regulations are followed by strikes and coal demand. None of the other constraints had over 5 percent of the nonmajor total.

Tables 2-20 and 2-21 list the operating constraints in the Interior region for deep and surface mines. For deep mines, major producers listed

Table 2-17. Transportation Characteristics, All Mines
by Region, Mine Size, and Controlling Group, 1978
(10³ tons)

Transportation Mode	Appalachia				Interior			
	Nonmajor		Major		Nonmajor		Major	
	N	%	N	%	N	%	N	%
Mines producing								
≤ 100,000 tons								
Rail	65,598.5	61.4	6,827.1	88.6	3,495.2	48.4	136.2	98.2
Truck	38,188.4	35.8	566.4	7.3	3,495.5	48.4	0.5	0.4
Mine mouth	403.5	0.4	151.8	2.0	13.5	0.2	a	0.0
Other	2,624.3	2.4	164.0	2.1	212.6	2.9	2.0	1.4
Total	106,814.7	100.0	7,709.3	100.0	7,216.8	100.0	138.7	100.0
χ ² probability			.0001				.0001	
Mines producing								
> 100,000 tons								
Rail ^b	90,529.2	69.7	79,848.6	78.6	17,968.1	59.1	72,224.5	68.6
Truck	34,520.2	26.6	3,347.3	3.3	6,556.1	21.6	8,826.4	8.4
Mine mouth	1,970.8	1.5	17,814.8	17.5	5,585.7	18.4	23,677.1	22.5
Other	2,798.4	2.2	595.7	0.6	294.5	1.0	535.3	0.5
Total	129,818.6	100.0	101,606.4	100.0	30,404.4	100.0	105,263.3	100.0
χ ² probability			.0001				.0001	
West								
Transportation Mode	Nonmajor		Major					
	N	%	N	%				
Mines producing								
≤ 100,000 tons								
Rail	701	58.3	57.0	100.0				
Truck	373.2	31.1	a	0.0				
Mine mouth	53.1	4.4	a	0.0				
Other	74.1	6.2	a	0.0				
Total	1,201.4	100.0	57.0	100.0				
Mines producing								
> 100,000 tons								
Rail ^b	10,908.2	59.5	86,381.4	70.2				
Truck	1,868.7	10.2	1,164.5	0.9				
Mine mouth	4,610.1	25.1	32,436.4	26.4				
Other	952.0	5.2	3,071.3	2.5				
Total	18,339.0	100.0	123,053.6	100.0				
χ ² probability			.0001					

^aNo tonnage reported.

^bIncludes barge.

Source: EIA-7.

Table 2-18. Primary Operating Constraints,
Appalachian Deep Mines, 1978

Primary Operating Constraint	Number of Mines				
	Nonmajor		Major		Total
	N	%	N	%	N
Manpower shortage	8	1.1	0	0.0	8
Absenteeism	56	7.78	36	14.1	92
Railroad car shortage	114	15.8	46	18.0	160
Shortages of materials or supplies	5	0.7	1	0.4	6
Environmental regulations	91	12.6	10	3.9	101
Lack of coal demand	202	28.1	40	15.7	242
Strike	151	21.0	94	36.9	245
Repairs	18	2.5	12	4.7	30
Lack of adequate reserves	4	0.6	2	0.8	6
Mining Enforcement and Safety Administration (MESA) regula- tions and enforcement	13	1.8	3	1.2	16
Lack of equipment	0	0.0	0	0.0	0
Mining conditions	6	0.8	1	0.4	7
Weather	8	1.1	0	0.0	8
Permit approval	1	0.1	0	0.0	1
Price of coal	1	0.1	0	0.0	1
Personal preference	0	0.0	0	0.0	0
Barge shortage	2	0.3	2	0.8	4
Red tape	1	0.1	0	0.0	1
Other	38	5.2	9	3.5	47
Total	720	100.0	257	100.0	977

Source: EIA-7.

Table 2-19. Primary Operating Constraints,
Appalachian Surface Mines, 1978

Primary Operating Constraint	Number of Mines				
	Nonmajor		Major		Total
	N	%	N	%	N
Manpower shortage	10	1.1	0	0.0	10
Absenteeism	2	0.2	2	4.4	4
Railroad car shortage	83	9.0	3	6.7	86
Shortage of materials or supplies	3	0.3	0	0.0	3
Environmental regulations	405	44.1	28	62.2	433
Lack of coal demand	196	21.3	4	8.9	200
Strike	99	10.8	7	15.6	106
Repairs	41	4.5	0	0.0	41
Lack of adequate reserves	5	0.5	0	0.0	5
Mining Enforcement and Safety Administration (MESA) regula- tions and enforcement	8	0.9	0	0.0	8
Lack of equipment	1	0.1	0	0.0	1
Mining conditions	5	0.5	0	0.0	5
Weather	17	1.9	0	0.0	17
Permit approval	2	0.2	0	0.0	2
Price of coal	0	0.0	0	0.0	0
Personal preference	1	0.1	0	0.0	1
Barge shortage	0	0.0	0	0.0	0
Red tape	1	0.1	0	0.0	1
Other	<u>40</u>	<u>4.3</u>	<u>1</u>	<u>2.2</u>	<u>41</u>
Total	919	100.0	45	100.0	964

Source: EIA-7.

Table 2-20.. Primary Operating Constraints,
Interior Deep Mines, 1978

Primary Operating Constraint	Number of Mines				
	Nonmajor		Major		Total
	N	%	N	%	N
Manpower shortage	1	7.1	0	0.0	1
Absenteeism	4	28.6	6	15.0	10
Railroad car shortage	0	0.0	4	10.0	4
Shortages of materials or supplies	0	0.0	0	0.0	0
Environmental regulations	3	21.4	14	35.0	17
Lack of coal demand	0	0.0	2	5.0	2
Strike	1	7.1	10	25.0	11
Repairs	0	0.0	0	0.0	0
Lack of adequate reserves	0	0.0	0	0.0	0
Mining Enforcement and Safety Administration (MESA) regula- tions and enforcement	1	7.1	0	0.0	1
Lack of equipment	0	0.0	0	0.0	0
Mining conditions	1	7.1	2	5.0	3
Weather	0	0.0	0	0.0	0
Permit approval	0	0.0	0	0.0	0
Red tape	0	0.0	0	0.0	0
Other	3	21.4	2	5.0	5
Total	14	100.0	40	100.0	54

Source: EIA-7.

Table 2-21. Primary Operating Constraints,
Interior Surface Mines, 1978

Primary Operating Constraint	Number of Mines				
	Nonmajor		Major		Total
	N	%	N	%	N
Manpower shortage	1	0.8	0	0.0	1
Absenteeism	1	0.8	4	12.5	5
Railroad car shortage	5	3.9	5	15.6	10
Shortage of materials or supplies	1	0.8	0	0.0	1
Environmental regulations	40	30.8	3	9.4	43
Lack of coal demand	33	25.4	6	18.8	39
Strike	16	12.3	5	15.6	21
Repairs	8	6.2	2	6.3	10
Lack of adequate reserves	1	0.8	0	0.0	1
Mining Enforcement and Safety Administration (MESA) regula- tions and enforcement	0	0.0	0	0.0	0
Lack of equipment	0	0.0	1	3.1	1
Mining conditions	4	3.1	2	6.3	6
Weather	6	4.6	0	0.0	6
Permit approval	1	0.8	0	0.0	1
Red tape	0	0.0	0	0.0	0
Other	13	10.0	4	12.5	17
Total	130	100.0	32	100.0	162

Source: EIA-7.

environmental regulations, strikes, absenteeism, and railroad car shortages most frequently. Unlike those in Appalachia, few Interior deep mines were constrained by lack of coal demand.

Surprisingly, environmental regulations were not the most frequently cited constraint by major-controlled surface mines in the Interior region (see Table 2-21). Lack of demand, strikes, and rail car shortages were the primary constraints for majors (excluding "other" reasons); while environmental regulations, lack of demand, and strikes were important for nonmajors.

Table 2-22 lists operating constraints for western deep mines. Of the three major deep mines reporting constraints, two listed lack of coal demand as the cause and one experienced strike problems. For nonmajor deep mines, the most frequently cited cause of production constraints was manpower shortages followed by mining conditions and strikes.

Table 2-23 lists operating constraints of western surface mines. Operations of major- and nonmajor-controlled surface mines were constrained most frequently by railroad car shortages and lack of coal demand. Also mentioned as primary constraints to output by both majors and nonmajors were environmental regulations.

Shifts Worked

Tables 2-24 and 2-25 detail the mean number of shifts worked daily for deep and surface mines controlling for region, major/nonmajor group, and mine size. The average number of shifts per day was computed by dividing total worker-shifts by employment and then dividing the quotient by days active.

The lack of small, major-controlled deep mines in the Interior and West makes a comparison between majors and nonmajors in those regions meaningless (see Table 2-24). However, in Appalachia, the number of shifts worked by small mines differed significantly between majors and nonmajors, with major-controlled mines working more shifts per day. This was also true for large deep mines in both the West and in Appalachia. In the Interior, there was no significant difference in the shifts of major-controlled and nonmajor-controlled deep mines.

Table 2-25 details shifts worked for small and large surface mines. In Appalachia, there was no significant difference by controlling group in small mine shifts. Comparisons were not possible for small surface mines in the Interior and West.

Table 2-22. Primary Operating Constraints,
Western Deep Mines, 1978

Primary Operating Constraint	Number of Mines				
	Nonmajor		Major		Total
	N	%	N	%	N
Manpower shortage	6	26.1	0	0.0	6
Absenteeism	2	8.7	0	0.0	2
Railroad car shortage	1	4.4	0	0.0	1
Environmental regulations	2	8.7	0	0.0	2
Lack of coal demand	1	4.4	2	66.7	3
Strike	3	13.0	1	33.3	4
Repairs	1	4.4	0	0.0	1
Mining conditions	4	17.4	0	0.0	4
Permit approval	1	4.4	0	0.0	1
Red tape	1	4.4	0	0.0	1
Other	<u>1</u>	<u>4.4</u>	<u>0</u>	<u>0.0</u>	<u>1</u>
Total	23	100.0	3	100.0	26

Source: EIA-7.

Table 2-23. Primary Operating Constraints,
Western Surface Mines, 1978

Primary Operating Constraint	Number of Mines				
	Nonmajor		Major		Total
	N	%	N	%	N
Manpower shortage	0	0.0	0	0.0	0
Railroad car shortage	2	15.4	10	40.0	12
Environmental regulations	2	15.4	3	12.0	5
Lack of coal demand	4	30.8	6	24.0	10
Strike	1	7.7	0	0.0	1
Repairs	1	7.7	2	8.0	3
Lack of adequate reserves	1	7.7	0	0.0	1
Mining conditions	0	0.0	0	0.0	0
Weather	1	7.7	0	0.0	1
Permit approval	0	0.0	0	0.0	0
Red tape	0	0.0	2	8.0	2
Other	1	7.7	2	8.0	3
Total	13	100.0	25	100.0	38

Source: EIA-7.

Table 2-24. Average Shifts per Day, Deep Mines by Size, Region, and Controlling Group, 1978

Mean Number of Shifts per Day	Number of Mines											
	Appalachia				Interior				West			
	Nonmajor		Major		Nonmajor		Major		Nonmajor		Major	
	N	%	N	%	N	%	N	%	N	%	N	%
<u>Output ≤ 100 tons/year</u>												
Shifts < 1.5	872	60.2	10	10.0	5	50.0	0	0.0	4	25.0	0	0.0
1.5 < Shifts < 2.5	544	37.6	83	83.0	5	50.0	0	0.0	11	68.0	0	0.0
2.5 < Shifts < 3	32	2.2	7	7.0	0	0.0	0	0.0	1	6.3	0	0.0
Total	1,448	100.0	100	100.0	10	100.0	0	0.0	16	100.0	0	0.0
χ ² probability	.0001				a				a			
<u>Output > 100 tons/year</u>												
Shifts < 1.5	52	27.0	6	3.7	0	0.0	0	0.0	3	10.7	0	0.0
1.5 < Shifts < 2.5	128	66.7	138	84.1	11	91.7	41	95.3	23	82.1	8	88.9
2.5 < Shifts < 3	12	6.3	20	12.2	1	8.3	2	4.7	2	7.2	1	11.1
Total	192	100.0	164	100.0	12	100.0	43	100.0	28	100.0	9	100.0
χ ² probability	.0001				.619				.567			
Percent of mines covered	83.6		83.8		95.6		100.0		100.0		90.0	

^aData insufficient for χ^2 computation.

Source: EIA-7.

Table 2-25. Shifts per Day, Surface Mines by Size,
Region and Controlling Group, 1978

Mean Number of Shifts per Day	Number of Mines											
	Appalachia				Interior				West			
	Nonmajor		Major		Nonmajor		Major		Nonmajor		Major	
	N	%	N	%	N	%	N	%	N	%	N	%
<u>Output ≤ 100 tons/year</u>												
Shifts < 1.5	861	59.1	14	33.3	102	61.8	2	100.0	6	42.9	0	0.0
1.5 < Shifts < 2.5	560	34.4	28	66.7	58	35.2	0	0.0	7	50.0	0	0.0
2.5 < Shifts < 3	37	2.5	0	0.0	5	3.0	0	0.0	1	7.1	0	0.0
Total	1,458	100.0	42	100.0	165	100.0	2	100.0	14	100.0	0	0.0
χ ² probability	.001				a				a			
<u>Output > 100 tons/year</u>												
Shifts < 1.5	94	34.9	16	36.4	17	26.6	1	2.0	0	0.0	3	7.9
1.5 < Shifts < 2.5	167	62.1	25	56.8	46	71.9	45	38.2	6	75.0	33	86.8
2.5 < Shifts < 3	8	3.0	3	6.8	1	1.6	5	9.8	2	25.0	2	5.3
Total	269	100.0	44	100.0	64	100.0	51	100.0	8	100.0	38	100.0
χ ² probability	.410				.0001				.880			
Percent of mines covered	65.3		83.5		73.2		93.0		85.2		94.9	

^aData insufficient for χ^2 computation.

Source: EIA-7.

For large surface mines, shifts worked for major-controlled and nonmajor-controlled mines differed significantly only in the Interior (.05 level), with major-controlled mines having a higher percentage of mines with two and three shifts.

Employment

Table 2-26 shows the average number of miners working daily by mine type, region, and controlling group. These employment figures are compiled in the same manner that the Department of Energy compiles coal industry employment and, therefore, do not make adjustments for days worked. These employment figures include all workers engaged in production, preparation (cleaning plant), development work, and maintenance and repair work. They also include supervisory and technical personnel.

As shown in Table 2-26, nonmajor employment in both deep and surface mines is concentrated in the Appalachian region, with over 90 percent of the miners employed. Employment of the major-controlled mines is more dispersed regionally. The Interior region contains 43.9 percent of all employment in majors' surface mines, with the remaining surface workers equally divided between the West and Appalachia. Over three-fourths of the employment in major groups' deep mines is concentrated in Appalachia; the West region contains only 2 percent of major deep employment with the remaining 22.5 percent in the Interior region.

Employment in mines controlled by nonmajors dominates in the Appalachian region, with 55.4 percent of all deep mine workers and 91.4 percent of all surface mine workers. In the Interior, nonmajor workers comprise only 11.1 percent of deep mine employment and 38.1 percent of surface employment. The West region deep mine employment is 78.0 percent nonmajor, while surface mine employment is only 6.7 percent nonmajor. Overall, total deep mine employment is fairly evenly divided between majors and nonmajors with 50.9 percent of the workers employed in nonmajor-controlled mines. In surface mining, the 72,120 workers in nonmajor Appalachian mines swamp the employment in other regions with the result that nationally 76.0 percent of surface mine workers are employed in nonmajor controlled mines.

Table 2-26. Average Number of Miners Working Daily, by
Controlling Group, Mine Type, and Region, 1973

Region	Surface				Deep				Total			
	Nonmajor		Major		Nonmajor		Major		Nonmajor		Major	
	N	%	N	%	N	%	N	%	N	%	N	%
Appalachia	72,120	90.8	6,810	27.1	67,850	90.4	54,560	75.5	139,970	90.6	61,370	63.0
Interior	6,770	8.5	11,020	43.9	2,040	2.7	16,270	22.5	8,810	5.7	27,290	28.0
West	520	0.7	7,270	29.0	5,150	6.9	1,450	2.0	5,670	3.7	8,720	9.0
Total	79,410	100.0	25,100	100.0	75,040	100.0	72,280	100.0	154,450	100.0	97,380	100.0
Percent of mines covered		77.9		94.5		94.7		91.0		84.5		92.3

Source: EIA-7.

Capital Characteristics

Tables 2-27 through 2-31 detail the distribution of surface mine draglines and power shovels by mine size class and ownership. These tables are included to test for a difference between major and nonmajor surface mine equipment, i.e., within a given size mine, do major controlled mines use bigger (and presumably more efficient) equipment than nonmajor surface mines? To answer this question, these tables exhibit the relative distribution of machines by machine size for majors and nonmajors by size of mine.

The mine size class groupings are as follows (all in 10^3 tons annually):

Class 1 (less than 10)	Class 4 (100 to less than 200)
Class 2 (10 to less than 50)	Class 5 (200 to less than 500)
Class 3 (50 to less than 100)	Class 6 (500 or more)

Table 2-27 examines the size distribution of power shovels in Appalachian surface mines. The small number of responses of major-controlled mines in size classes 1, 2, and 3 did not allow a comparison between majors and nonmajors. For mine size classes 4, 5, and 6, the chi-square probabilities indicate that there is a significant difference (at least at the .065 level) between majors and nonmajors, with the majors having a higher percentage of large power shovels within a given size class.

Table 2-28 examines the size distribution of draglines in Appalachian surface mines. As was the case with power shovels, the major-controlled surface mines tend to employ larger capacity draglines in each mine size class. The difference in machine sizes is statistically significant (.10 level) in each size class for which a significance test is possible.

Table 2-29 examines the size distribution of power shovels in Interior surface mines by mine ownership. Lack of observations limited the tabulation to size classes 4, 5, and 6; although size class 4 only has nonmajor mine information. There is no significant difference in machine size between majors and nonmajors in mine size class 5; the difference is significant in mine size class 6. In size class 6, nonmajors have a higher proportion of machines with capacity of less than 6 cubic yards; they also have a higher portion of machines with greater than 50 cubic yards capacity.

Table 2-30 details the size distribution of draglines in Interior surface mines for mine size classes 4, 5, and 6. While no significance test was possible for class 4, the chi-square statistic indicates that there is no significant difference in the size of draglines used by major- and nonmajor-controlled surface mines of classes 5 and 6.

Table 2-27. Power Shovel Size Distribution in Appalachian Surface Mines by Mine Size and Ownership, 1978

Number of Power Shovels by Power Shovel Size in Cubic Yards						χ^2 probability
Mine Size Class	< 6	6-15	16-50	> 50	Total	
<u>Class 1</u>						
Nonmajor						
Number	98	6	0	0	104	
Percent	94.2	5.8	0.0	0.0	100.0	a
Major						
Number	0	0	0	0	0	
Percent	0.0	0.0	0.0	0.0	0.0	
<u>Class 2</u>						
Nonmajor						
Number	210	15	2	0	227	
Percent	92.5	6.6	0.9	0.0	100.0	a
Major						
Number	1	0	0	0	1	
Percent	100.0	0.0	0.0	0.0	100.0	
<u>Class 3</u>						
Nonmajor						
Number	90	22	3	0	115	
Percent	78.3	19.1	2.6	0.0	100.0	a
Major						
Number	0	1	1	0	2	
Percent	0.0	50.0	50.0	0.0	100.0	
<u>Class 4</u>						
Nonmajor						
Number	48	9	4	0	61	
Percent	78.7	14.8	6.6	0.0	100.0	.002
Major						
Number	0	3	1	0	4	
Percent	0.0	75.0	25.0	0.0	100.0	
<u>Class 5</u>						
Nonmajor						
Number	39	25	7	0	71	
Percent	54.9	35.2	9.9	0.0	100.0	.006
Major						
Number	1	5	0	0	6	
Percent	16.7	83.3	0.0	0.0	100.0	

Table 2-27. Power Shovel Size Distribution in Appalachian Surface Mines by Mine Size and Ownership, 1978 (Cont'd.)

	Number of Power Shovels by Power Shovel Size in Cubic Yards					
Mine Class	6	6-15	16-50	> 50	Total	χ^2 probability
Class						
<u>Class 6</u>						
Nonmajor						
Number	5	3	1	1	10	
Percent	50.0	30.0	10.0	10.0	100.0	.006
Major						
Number	1	15	9	4	29	
Percent	3.4	51.7	31.0	13.8	100.0	

^aEmpty cells do not allow χ^2 computation.

Source: EIA-7.

Table 2-28. Dragline Size Distribution in Appalachian
Surface Mines by Mine Size and Ownership, 1978.

Number of Power Shovels by Power Shovel Size in Cubic Yards:						χ^2 probability	
Mine Size Class	< 6	6-15	16-50	> 50	Total		
Class 1							
Nonmajor						a	
Number	28	11	1	0	40		
Percent	70.0	27.5	2.5	0.0	100.0		
Major							
Number	0	1	1	0	2		
Percent	0.0	50.0	50.0	0.0	100.0		
Class 2							
Nonmajor							.001
Number	105	89	3	0	197		
Percent	53.3	45.7	1.5	0.0	100.0		
Major							
Number	1	1	2	0	4		
Percent	25.0	25.0	50.0	0.0	100.0		
Class 3							
Nonmajor							.002
Number	60	119	4	0	183		
Percent	32.8	65.0	2.2	0.0	100.0		
Major							
Number	1	6	2	0	9		
Percent	11.1	66.7	22.2	0.0	100.0		
Class 4							
Nonmajor							.001
Number	55	110	6	0	171		
Percent	32.2	64.3	3.5	0.0	100.0		
Major							
Number	1	10	6	0	17		
Percent	5.6	58.8	35.3	0.0	100.0		
Class 5							
Nonmajor							.001
Number	27	101	6	0	134		
Percent	20.1	75.4	4.5	0.0	100.0		
Major							
Number	12	6	3	5	26		
Percent	46.2	23.1	11.5	19.2	100.0		

Table 2-28. Dragline Size Distribution in Appalachian Surface Mines by Mine Size and Ownership, 1978 (Cont'd.)

	Number of Power Shovels by Power Shovel Size in Cubic Yards					
Mine Size Class	< 6	6-15	16-50	> 50	Total	χ^2 probability
Class 6						
Nonmajor						
Number	4	37	1	0	42	
Percent	9.5	88.1	2.4	0.0	100.0	
Major						.071
Number	1	31	4	3	39	
Percent	2.6	79.5	10.3	7.7	100.0	

^aEmpty cells do not allow χ^2 computation.

Source: EIA-7.

Table 2-29. Power Shovel Size Distribution in Interior
Surface Mines by Size Class and Ownership, 1978

Cubic Yards	Number of Power Shovels											
	Mine Size Class ^a											
	4				5				6			
	Nonmajor		Major		Nonmajor		Major		Nonmajor		Major	
	N	%	N	%	N	%	N	%	N	%	N	%
< 6	7	70.0	0	0.0	8	47.1	7	33.3	6	30.0	4	3.3
6-15	3	30.0	0	0.0	9	52.9	8	38.1	5	25.0	70	57.9
16-50	0	0.0	0	0.0	0	0.0	2	9.5	4	20.0	28	23.1
> 50	0	0.0	0	0.0	0	0.0	4	19.0	5	25.0	19	15.7
Total	10	100.0	0	0.0	17	100.0	21	100.0	20	100.0	121	100.0
χ^2 probability	b				.123				.001			

^aLack of major producers in small size classes restricted table to larger mines.

^bEmpty cells do not allow χ^2 computation.

Source: EIA-7.

Table 2-30. Dragline Size Distribution in Interior
Surface Mines by Size Class and Ownership, 1978

Cubic Yards	Number of Draglines											
	Mine Size Class ^a											
	4				5				6			
	Nonmajor		Major		Nonmajor		Major		Nonmajor		Major	
	N	%	N	%	N	%	N	%	N	%	N	%
< 6	12	36.4	0	0.0	12	30.0	5	20.8	3	18.8	18	18.8
6-15	21	63.6	1	100.0	22	55.0	9	37.5	5	37.5	31	32.3
16-50	0	0.0	0	0.0	4	10.0	7	29.2	3	18.8	17	17.7
> 50	0	0.0	0	0.0	2	5.0	3	12.5	4	25.0	30	31.3
Total	33	100.0	1	100.0	40	100.0	24	100.0	16	100.0	96	100.0
χ^2 probability	b				.127				.703			

^aLack of major producers in small size classes restricted table to larger mines.

^bEmpty cells do not allow χ^2 computation.

Source: EIA-7.

Table 2-31 shows the size distribution of power shovels and draglines in Western surface mines with annual output of 200,000 tons or more. For both types of machines, there is a statistically significant difference between majors and nonmajors in machine size employed (at least at the .017 level). The nonmajors tend to have a higher percentage of machines in the small bucket sizes, with over 40 percent of both draglines and power shovels having capacities of less than 6 cubic yards.

To examine the capital characteristics of deep mines, a crude index of their capital-labor ratio was computed in the following manner. First, all deep mines were segregated into groups that used either conventional mining or continuous mining only (observations for other deep techniques, such as longwall, were too small to generate meaningful results). For each of these mines, the average number of cutting machine-shifts (conventional mining) or continuous-mining machine-shifts (continuous mining) was calculated by multiplying the number of machines by the average number of daily shifts (see Tables 2-24 and 2-25). The average number of miners working daily was then divided by the average number of machine shifts daily to get the average number of workers per machine-shift.

The average number of workers per machine-shift in a mine is influenced by a variety of factors. Some mines hold machines in reserve for repair or to use when other machines are down. Although these reserve machines are not used for mining, they will increase the average number of daily machine-shifts as calculated above and reduce the number of workers per machine shift, *ceteris paribus*. The average number of workers per machine-shift will also be influenced by mine staffing. If a mine has a cleaning plant and a large number of support workers (safety officers, maintenance and repair, supervisors), this will increase the workers per machine-shift. For small deep mines, the workers may perform several tasks (e.g., maintenance, operation, and supervision) thus reducing the number of workers per machine-shift. Also, if a mine is increasing or decreasing output or mine capacity, the number of workers involved in development or construction of new sections will influence the worker-machine ratio. In the case of mines reducing output, the relative rate of work force versus machine reductions will influence the worker-machine ratio.

Tables 2-32 through 2-36 examine workers per machine-shift by mine size for the three regions of Appalachia, the Interior, and West. When possible, a t test is employed to discover any statistically significant difference

Table 2-31. Power Shovel and Dragline Size Distribution in
Western Surface Mines with 200,000 Tons or More
Annual Output^a by Ownership Type, 1978

Cubic Yards	Number of Power Shovels				Number of Draglines			
	Nonmajor		Major		Nonmajor		Major	
	N	%	N	%	N	%	N	%
< 6	2	50.0	5	8.1	3	42.9	5	7.0
6-15	2	50.0	25	40.3	1	14.3	18	25.4
16-50	0	0.0	32	51.6	3	42.9	29	40.8
> 50	0	0.0	0	0.0	0	0.0	19	26.8
Total	4	100.0	62	100.0	7	100.0	71	100.0
χ^2 probability	.015				.017			

^aMine size classes 5 and 6 were combined to provide sufficient observations.

Source: EIA-7.

Table 2-32. Workers per Cutting Machine-Shift, Appalachian Deep Mines by Size Class and Ownership, 1978

Mine Size Class	Workers per Cutting Machine-Shift						t
	Nonmajor			Major			
	Mean	Standard Deviation	N	Mean	Standard Deviation	N	
1	9.28	5.46	273	9.00	1.83	4	0.10
2	14.12	14.36	426	27.09	16.61	11	2.93 ^b
3	23.50	18.64	73	56.80	41.24	5	3.41 ^b
4	36.54	18.93	26	56.44	13.53	3	1.70
5	36.64	23.82	6	72.00	21.21	2	1.61
6	a	a	0	77.67	31.32	3	c
Total	14.22	14.18	804	41.58	31.32	28	9.42 ^b

^aNo observations.

^bSignificant at .01 level.

^cOnly one observation.

Source: EIA-7.

Table 2-33. Workers per Continuous Machine-Shift, Appalachian Deep Mines by Size Class and Ownership, 1978

Mine Size Class	Workers per Continuous Machine-Shift						
	Nonmajor			Major			
	Mean	Standard Deviation	N	Mean	Standard Deviation	N	t
1	14.05	10.76	62	20.17	11.18	6	1.31
2	22.86	36.95	201	32.63	18.39	31	1.44
3	29.51	43.30	137	47.22	24.90	46	2.62 ^a
4	51.86	59.93	84	40.53	17.00	54	1.34
5	62.17	51.74	45	39.05	12.61	33	2.48 ^a
6	40.05	15.50	7	49.68	31.07	18	0.75
Total	31.61	44.61	536	40.83	21.14	188	2.72 ^a

^aSignificant at .01 level.

Source: EIA-7.

Table 2-34. Workers per Cutting Machine-Shift, Interior Deep Mines by Size Class^a and Ownership, 1978

Mine Size Class	Workers per Cutting Machine-Shift						
	Nonmajor			Major			t
	Mean	Standard Deviation	N	Mean	Standard Deviation	N	
4	36.33	23.28	3	48.00	^c	1	.50
5	31.50	19.09	2	67.44	19.48	6	1.96 ^d
6	51.00	0.00	2	58.81	11.45	15	0.90
Total ^b	30.54	19.85	13	60.68	14.18	22	5.07 ^e

^aLack of responses limited analysis to larger size classes.

^bTotal includes all size classes.

^cOnly one observation.

^dSignificant at .10 level.

^eSignificant at .01 level.

Source: EIA-7.

Table 2-35. Workers per Continuous Machine-Shift, Interior Deep Mines by Size Class^a and Ownership, 1978

Mine Size Class	Workers per Continuous Machine-Shift						
	Nonmajor			Major			t
	Mean	Standard Deviation	N	Mean	Standard Deviation	N	
5	^c	^c	0	35.52	11.28	2	^d
6	49.15	^d	1	53.01	14.68	12	0.26
Total ^b	18.40	21.34	4	50.51	15.25	14	3.18 ^e

^aLack of responses limited analysis to larger size classes.

^bTotal includes all size classes.

^cNo mines reported.

^dOnly one observation.

^eSignificant at .01 level.

Source: EIA-7.

Table 2-36. Workers per Continuous Machine-Shift, Western
Deep Mines by Size Class and Ownership, 1978

Workers per Continuous Machine-Shift							
Mine Size Class	Nonmajor			Major			t
	Mean	Standard Deviation	N	Mean	Standard Deviation	N	
1	5.00	a	1	b	b	b	c
2	27.62	21.70	4	b	b	b	c
3	25.70	12.82	5	b	b	b	c
4	39.17	31.16	5	55.50	26.02	3	0.66
5	46.50	28.19	12	44.55	22.44	4	0.12
6	43.78	18.04	3	31.60	a	1	0.67
Total	37.64	25.32	30	47.04	21.85	8	0.93

^aOnly one observation.

^bNo mines reporting.

^cNo comparison possible.

Source: EIA-7.

between majors and nonmajors in workers per machine shift. When one does not control for mine size, the worker-machine ratio of nonmajors is significantly different (.01 level) from major in all regions and for all mine techniques (conventional and continuous) except in the West. When one controls for mine size, the results are somewhat mixed by region and mining technique. In most cases, the variance in worker-machine ratio is so great that the means of major and nonmajor groups do not differ significantly.

SUMMARY

This chapter examined a number of production, marketing, and transportation characteristics of mines controlled by both major and nonmajor producers. A significant difference was found between majors and nonmajors in the types of mines controlled (mix between surface and deep). In Appalachian deep mines, major producers used continuous mining to a greater degree than did nonmajor producers; no difference in deep mine production technique between majors and nonmajors was found in the other regions.

In terms of total tonnage produced, Appalachia is the only region where nonmajor output is greater than major output. Major tonnage is spread fairly evenly among the three regions, while over 80 percent of nonmajor tonnage originates in Appalachia. Nonmajor surface and deep mines also tended to have a higher percentage of mines in young age groups and small size classes.

A significant difference was found between majors and nonmajors in the end uses of the coal produced. In Appalachia, a much higher percentage of major coal is used for steel production than of nonmajor coal. In the West and Interior regions, most major-produced coal is used to produce electricity, while nonmajor output is more distributed among the types of markets. The amount of captive coal produced by majors and nonmajors varied by region and mine size.

In examining average price received, a crude control of coal quality (rank) was used. In most regions and rank groups, there was a statistically significant difference between coal prices of majors and nonmajors, although in the West the nonmajors received a higher price.

A statistically significant difference was found between major producers and nonmajor producers by type of transportation. Generally speaking, more major controlled coal is consumed at the mine mouth or moved by rail and less is moved by truck than nonmajor coal.

The operating constraints listed by majors and nonmajors showed little difference, although nonmajors tended to blame lack of coal demand more often than majors. Major-controlled mines also tended to work more shifts per day than did nonmajors.

The EIA-7 data indicated that 154,450 miners were employed in nonmajor mines and 97,380 in major-controlled mines. Of the nonmajor miners, 90.6 percent were employed in deep mines as opposed to only 63.0 percent of miners in all major-controlled mines.

Several measures of capital employed in major and nonmajor deep and surface mines were examined. The results did not produce clear evidence of significant differences in equipment used across all regions and mine types.

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CHAPTER 3. RELATIVE EFFICIENCY AND SCALE CHARACTERISTICS OF THE MAJOR FIRMS AND THE INDUSTRY

INTRODUCTION

This chapter examines measures of production efficiency of major-controlled mines and nonmajor-controlled mines by type of mine, mine size, and market type. Two ratio measures of production efficiency are used:

1. Output per miner shift. Output per miner-shift is the most common measure of production efficiency in coal mining and is calculated by dividing the total tonnage reported by a mine by the total number of worker-shifts. This measure does not control for length of shift (data on worker-hours were missing from a large number of the observations), so part of the variation in output per miner-shift could be due to differences in the length of the shift. Moreover, output per miner-shift does not control for the cleaning of coal. If a mine cleans its output, part of the tonnage removed from the face is discarded as waste, reducing tons per miner-shift. Cleaning also requires additional workers who are not producing coal, further reducing tons per miner-shift. To the extent that major-controlled mines are more likely to clean output than are nonmajors, coal prices and labor productivity will vary due to coal cleaning (see Appendix C).

2. Output per machine-shift. Output per machine-shift is calculated by first separating all deep mines into mines that used exclusively conventional mining and those that only used continuous mining. Within each of these two groups, the total numbers of cutting machine-shifts (conventional mining) and continuous machine-shifts (continuous mining) were calculated by multiplying the number of machines by the total number of shifts. Output per machine-shift was arrived at by dividing total annual tonnage by total machine-shifts. One problem with using output per machine-shift as a measure of efficiency is that some mines keep spare machines as backup for breakdowns, overhaul, etc., of the working machines. These backup machines are counted in determining total machine-shifts even though they are not mining coal. To the extent that different mines hold varying amounts of reserve machinery, output per machine-shift will vary although output per machine-shift for only the machines used in mining may be identical.

OUTPUT PER MINER-SHIFT BY MINE SIZE

Table 3-1 through 3-6 detail output per miner-shift controlling for region, mine type, mine size, and types of ownership. In all tables, a

t test is employed to test for statistically significant differences between mean output per miner-shift in major-controlled mines and the mean for nonmajor-controlled mines. The "N" value in these tables is the number of mines in the sample.

Output per miner-shift for Appalachian deep mines appears in Table 3-1. For both major- and nonmajor-controlled mines, there is no clear evidence of increasing output per miner as mine size increases. There is a statistically significant difference in output per miner-shift between majors and nonmajors for size classes 2 through 4 and for all mines, with nonmajor mines having higher productivity in each case. This may be due to the concentration of the major-controlled mines in the metallurgical coal market in Appalachia, where high coal prices allow mines to exploit less fertile reserves. This point will be examined later in the chapter.

Table 3-2 examines output per miner-shift for Appalachian surface mines. As with deep mines, there are no clear economies of scale in output per worker as mine size increases. Only size classes 1 and 5 had significant differences between the output per miner-shift of major versus nonmajor producers.

Table 3-3 shows worker-output ratios for Interior deep mines. The major producers had no small deep mines in the Interior region; and the output per miner-shift of large majors was not significantly different from that of nonmajor producers. However, there is a much more pronounced scale relationship evident for the nonmajor producers, with output per miner-shift growing from size class 1 to size class 5 (note, however, that size class 3 may contain a data miscode).

Output per miner-shift of Interior surface mines is shown in Table 3-4. There is no difference in the worker-output ratios of major firms versus others in all sizes except the smallest (the one major mine in size group 1 may just be beginning production and grow to a larger size). However, for both majors and nonmajors, there is clearly a scale relationship between mine size and output per miner-shift.

Table 3-5 contains worker output ratios for Western deep mines. For those size classes for which major-controlled deep mines exist in the West, there is no statistically significant difference in output per miner-shift between majors and nonmajors. Economies of scale may be influencing the nonmajor deep mine worker-output ratios. It is interesting to note that in all three regions, deep mines of size class 3 (50-100 thousand tons annually) are the most efficient of all nonmajor mines.

Table 3-1. Output per Miner-Shift, Appalachian
Deep Mines by Size Class and Ownership, 1978

Mine Size Class	Tons per Miner-Shift						t
	Nonmajor			Major			
	Mean	Standard Deviation	N	Mean	Standard Deviation	N	
1	14.88	33.88	545	9.83	5.11	12	0.51
2	15.84	11.57	716	9.26	7.94	44	3.71 ^a
3	17.37	11.94	235	7.11	4.12	55	6.26 ^a
4	15.06	16.76	121	8.82	4.99	66	2.93 ^a
5	14.62	16.28	65	8.95	4.50	55	2.48 ^b
6	11.69	11.65	11	11.22	9.32	48	0.14
Total	15.62	21.84	1,693	9.03	6.32	280	5.01 ^a
Percent of mines covered			86.3			88.9	

^aSignificant at .01 level.

^bSignificant at .02 level.

Source: EIA-7.

Table 3-2. Output per Miner-Shift, Appalachian
Surface Mines by Size Class and Ownership, 1978

Tons per Miner-Shift							
Mine Size Class	Nonmajor			Major			t
	Mean	Standard Deviation	N	Mean	Standard Deviation	N	
1	16.96	18.61	380	44.92	80.39	7	3.42 ^a
2	25.26	37.13	807	24.94	22.61	22	0.04
3	27.27	24.04	323	17.38	7.83	15	1.58
4	23.11	13.72	163	18.49	10.57	17	1.33
5	23.71	14.43	99	45.67	106.11	17	1.93 ^b
6	25.22	7.44	14	31.28	16.16	10	1.18
Total	23.58	29.02	1,786	28.72	52.13	88	1.53
Percent of mines covered			67.5			85.4	

^aSignificant at .01 level.

^bSignificant at .10 level.

Source: EIA-7.

Table 3-3. Output per Miner-Shift, Interior Deep Mines by Size Class and Ownership, 1978

Mine Size Class	Tons per Miner-Shift						t
	Nonmajor			Major			
	Mean	Standard Deviation	N	Mean	Standard Deviation	N	
1	3.26	2.26	4	a	a	0	
2	8.49	4.92	3	a	a	0	
3	38.23	23.24	3	a	a	0	
4	13.08	7.21	5	13.55	b	1	0.15
5	18.61	10.24	4	12.43	3.56	8	1.40
6	18.53	5.93	3	13.13	5.30	34	1.62
Total	15.84	14.06	22	13.00	12.20	43	0.83
Percent of mines covered			95.6			100.0	

^aNo observations.

^bOnly one observation.

Source: EIA-7.

Table 3-4. Output per Miner-Shift, Interior Surface Mines by Size Class and Ownership, 1978

Mine Size Class	Tons per Miner-Shift						t
	Nonmajor			Major			
	Mean	Standard Deviation	N	Mean	Standard Deviation	N	
1	20.69	33.65	50	0.15	a	1	4.32 ^c
2	22.48	16.08	76	b	b	0	
3	23.89	15.05	46	13.32	16.18	2	0.95
4	30.13	35.18	33	19.61	a	1	1.71
5	24.87	20.39	24	29.27	42.31	13	0.41
6	37.75	21.12	8	29.82	13.01	39	1.36
Total	24.20	24.43	237	28.39	23.19	56	1.16
Percent of mines covered			75.7			98.2	

^aOnly one observation.

^bNo observations.

^cSignificant at .01 level.

Source: EIA-7.

Table 3-5. Output per Miner-Shift, Western Deep Mines by Size Class and Ownership, 1978

Mine Size Class	Tons per Miner-Shift						t
	Nonmajor			Major			
	Mean	Standard Deviation	N	Mean	Standard Deviation	N	
1	2.94	1.56	2	a	a	0	
2	9.80	8.71	7	a	a	0	
3	16.26	8.89	8	a	a	0	
4	13.39	8.12	6	8.92	3.61	3	0.80
5	13.96	7.44	15	14.35	5.45	5	0.10
6	17.15	10.64	6	14.38	b	1	0.64
Total	13.57	8.55	44	12.54	5.05	9	0.34

Percent of mines covered 100.0 90.0

^aNo observations.

^bOnly one observation.

Source: EIA-7.

Table 3-6. Output per Miner-Shift, Western Surface Mines by Size Class and Ownership, 1978

Mine Size Class	Tons per Miner-Shift						t
	Nonmajor			Major			
	Mean	Standard Deviation	N	Mean	Standard Deviation	N	
1	14.74	13.47	7	a	a	0	
2	22.91	18.92	5	a	a	0	
3	10.06	2.53	2	a	a	0	
4	70.63	43.76	2	31.14	11.99	2	0.87
5	24.50	b	1	36.01	26.69	5	0.96
6	97.06	86.84	5	69.02	48.87	31	1.01
Total	40.40	53.78	22	62.68	46.91	38	1.65 ^c

Percent of mines covered 100.0 100.0

^aNo observations.

^bOnly one observation.

^cSignificant at .10 level.

Source: EIA-7.

Table 3-6 contains output per miner-shift of Western major and non-major surface mines. As with deep mines, there were no major-controlled mines in the smaller size classes. When one controls for mine size, major and nonmajor surface mines show no statistically significant difference in output per miner-shift. There is also strong evidence of economies of scale: the largest size class for surface mines of both majors and non-majors had a clear advantage over other mine size groups in worker-output ratio.

In summary, the scale efficiency information is mixed, with clear scale effects in some regions and mine types and no scale effects in others. In most cases, there are no statistically significant differences in output per miner-shift between major-controlled mines and nonmajor mines. The most notable exception is Appalachian deep mines; here the difference may be due to markets and type of coal (metallurgical versus steam coal).

OUTPUT PER MACHINE-SHIFT BY MINE SIZE

Tables 3-7 through 3-10 detail output per machine-shift by mine size and ownership for deep mines by region. Lack of observations in the Interior restricted the examination to cutting machines only; lack of observations in the West restricted the examination to continuous machines only.

Table 3-7 shows output per cutting machine-shift in Appalachia. The standard deviation of both majors and nonmajors is high; this results in no statistically significant differences by type of ownership in machine output per shift. For both majors and nonmajors, there are definite economy of scale factors with output per cutting machine-shift rising fairly steadily with mine size class.

Output per continuous mining machine-shift by mine size and ownership in Appalachia is displayed in Table 3-8. Although machine-output ratios are significantly different between majors and nonmajors in size classes 4 and 5, in the other size classes and overall the differences are not significant. With the exception of nonmajor mines in size class 6, there is strong evidence of economies of scale for both majors and nonmajors.

Table 3-9 examines output per cutting machine-shift in Interior deep mines. The lack of small, major deep mines prohibits comparison in small size groups. For the larger size classes, machine-output ratios differ significantly between majors and nonmajors in size classes 4 and 6. For the non-major mines, the effects of economies of scale are evident from the data.

Table 3-7. Output per Cutting Machine-Shift, Appalachian
Deep Mines by Mine Size and Ownership, 1978

Mine Size Class	Tons per Machine-Shift						
	Nonmajor			Major			t
	Mean	Standard Deviation	N	Mean	Standard Deviation	N	
1	93.63	68.51	41	66.03	41.11	3	0.67
2	323.25	926.26	139	187.05	59.80	9	0.44
3	366.25	195.29	45	386.67	107.96	5	0.23
4	1,059.68	2,303.29	19	376.26	164.22	3	0.49
5	543.87	186.65	4	828.33	480.16	2	0.85
6	a	a	0	1,014.96	559.00	3	
Total	353.07	961.58	248	385.81	366.85	25	0.17

Source: EIA-7.

Table 3-8. Output per Continuous Machine-Shift, Appalachian
Deep Mines by Mine Size and Ownership, 1978

Mine Size Class	Tons per Machine-Shift						
	Nonmajor			Major			t
	Mean	Standard Deviation	N	Mean	Standard Deviation	N	
1	118.76	123.40	30	193.21	172.32	5	1.14
2	212.46	138.78	136	228.80	144.58	27	0.55
3	433.41	672.46	102	311.88	182.40	40	1.11
4	620.13	1,099.86	65	322.82	174.67	51	1.90 ^a
5	644.74	634.03	41	318.89	134.32	33	2.86 ^b
6	328.53	73.40	6	433.86	217.92	17	1.11
Total	382.58	639.57	380	312.03	176.20	173	1.42

^aSignificant at .10 level.

^bSignificant at .01 level.

Source: EIA-7.

Table 3-9. Output per Cutting Machine-Shift, Interior
Deep Mines by Mine Size and Ownership, 1978

Mine Size Class	Tons per Machine-Shift						
	Nonmajor			Major			t
	Mean	Standard Deviation	N	Mean	Standard Deviation	N	
1	52.68	22.36	2	a	a	0	
2	199.09	b	1	a	a	0	
3	275.72	b	1	a	a	0	
4	393.19	66.75	3	736.31	b	1	8.90 ^c
5	559.51	425.17	2	741.21	407.49	6	0.47
6	1,275.86	342.92	2	708.39	260.44	15	2.61 ^d
Total	493.68	457.56	11	718.61	291.53	22	1.66

^aNo observations.

^bOnly one observation.

^cSignificant at .01 level.

^dSignificant at .02 level.

Source: EIA-7.

Table 3-10. Output per Continuous Machine-Shift, Western
Deep Mines by Mine Size and Ownership, 1978

Mine Size Class	Tons per Machine-Shift						
	Nonmajor			Major			t
	Mean	Standard Deviation	N	Mean	Standard Deviation	N	
1	22.74	b	1	a	a	0	
2	181.94	100.01	4	a	a	0	
3	481.23	304.90	4	a	a	0	
4	538.17	283.36	5	392.73	107.80	3	0.74
5	737.25	536.35	9	587.96	289.45	4	0.48
6	753.04	221.07	3	421.71	b	1	2.11
Total	548.49	416.36	26	493.97	222.29	8	0.34

^aNo observations.

^bOnly one observation.

Source: EIA-7.

Table 3-10 details output per continuous machine-shift in western deep mines. For those mine size groups for which a comparison is possible, there is no statistically significant difference in output per machine-shift between major producers and nonmajor producers. As was the case in other regions, deep mines in the West exhibit strong evidence of economies of scale in output per machine-shift.

EFFICIENCY BY CONSUMER GROUP

To determine if producer efficiency varies by the type of coal sold, Tables 3-11 through 3-14 examine output per miner-shift by major consumer group (steam coal or metallurgical coal) by region, mine type, and ownership.

Table 3-11 examines output per miner-shift of steam deep mines and met in Appalachia. There is a significant difference in worker-output ratios between steam coal mines and met coal mines in size classes 2, 4, and 5, and for the groups uncontrolled for mine size. In every mine size class, average output per miner-shift is greater in steam coal mines than in met coal mines. This fact may explain the difference between the worker-output rates of Appalachian major deep mines and others since major deep mines are more heavily concentrated in the met coal market (25.6 percent of total major Appalachian output) than are nonmajors (8.2 percent of total nonmajor Appalachian output).

This difference raises the question of how major firm efficiency compares to nonmajor efficiency within a market group. Table 3-12 examines output per miner-shift in Appalachian deep mines selling the majority of their output to utilities (steam coal), by ownership and mine size. In all but the largest and smallest mines, the difference in output per miner-shift is significant between majors and nonmajors, and in each of these instances the output ratios of the nonmajors are higher. Overall, nonmajor deep mines in Appalachia produce an unweighted average of 16.19 tons per miner-shift while the major-controlled deep mine produce 9.85 tons.

Table 3-13 compares Appalachian deep mines controlled by majors and nonmajors selling the majority of their output in the met coal market. Here the results are rather mixed, with no clear difference in output per miner-shift for majors versus nonmajors. Thus, it seems that a portion of the overall difference between majors and nonmajors in worker-output rates in Appalachian deep mines is explained by the consumer group (a higher proportion

Table 3-11. Comparison of Output per Miner-Shift, Appalachian Deep Mines Selling Metallurgical and Steam Coal, by Mine Size, 1978

Mine Size Class	Tons per Worker-Shift						
	Utilities			Steel			
	Mean	Standard Deviation	N	Mean	Standard Deviation	N	t
1	11.12	6.82	43	8.11	4.79	13	1.46
2	15.54	13.02	118	11.50	8.47	57	2.12 ^a
3	13.79	7.04	87	12.68	18.36	59	0.51
4	16.86	19.66	68	7.18	3.99	48	3.33 ^b
5	13.75	9.91	53	7.07	3.66	41	4.06 ^b
6	11.72	10.13	40	7.56	2.91	11	1.32
Total	14.31	12.37	409	9.73	10.80	229	4.60 ^b

^aSignificant at .05 level.

^bSignificant at .01 level.

Source: EIA-7.

Table 3-12. Output per Miner-Shift, Appalachian Deep Mines with Majority of Output Consumed by Utilities, by Mine Size and Ownership, 1978

Mine Size Class	Tons per Worker-Shift						
	Nonmajor			Major			
	Mean	Standard Deviation	N	Mean	Standard Deviation	N	t
1	11.66	6.90	39	5.85	2.51	4	1.63
2	16.24	13.35	108	7.96	4.14	10	1.93 ^a
3	15.64	6.92	66	7.97	3.28	21	4.85 ^b
4	22.84	24.93	37	9.71	4.50	31	2.85 ^b
5	16.06	11.26	33	9.93	5.51	20	2.23 ^c
6	9.37	3.79	5	12.06	10.78	35	0.53
Total	16.19	13.61	288	9.85	6.97	121	4.85 ^b

^aSignificant at .10 level.

^bSignificant at .01 level.

^cSignificant at .05 level.

Source: EIA-7.

Table 3-13. Output per Miner-Shift, Appalachian Deep Mines with Majority of Coal Consumed by Steel Companies, by Mine Size and Ownership, 1978

Mine Size Class	Tons per Worker-Shift						
	Nonmajor			Major			
	Mean	Standard Deviation	N	Mean	Standard Deviation	N	t
1	8.05	5.06	11	8.46	4.46	2	0.09
2	12.32	8.87	42	9.24	7.04	15	1.19
3	16.94	22.07	37	5.53	3.23	22	2.37 ^a
4	6.46	3.06	29	8.28	4.99	19	1.53 ^b
5	5.24	2.32	18	8.51	3.91	23	3.06 ^b
6	6.03	1.83	4	8.43	3.17	7	1.25
Total	10.91	13.13	141	7.83	4.72	88	2.11 ^c

^aSignificant at .02 level.

^bSignificant at .01 level.

^cSignificant at .05 level.

Source: EIA-7.

Table 3-14. Output per Miner-Shift, Appalachian Surface Mines with Majority of Output Consumed by Utilities, by Mine Size and Ownership, 1978

Mine Size Class	Tons per Worker-Shift						t
	Nonmajor			Major			
	Mean	Standard Deviation	N	Mean	Standard Deviation	N	
1	18.71	22.66	54	8.79	12.64	4	0.85
2	28.78	59.95	209	22.09	19.33	11	0.37
3	26.55	20.12	127	21.41	9.65	7	0.67
4	22.22	9.49	84	20.40	11.84	12	0.59
5	21.30	10.83	65	17.74	8.14	13	1.11
6	25.34	7.73	13	32.25	16.83	9	1.23
Total	25.34	39.28	552	21.32	14.30	56	0.74

Source: EIA-7.

of mines in the met market), and part of the difference is simply lower productivity within a group (steam market).

Table 3-14 examines Appalachian surface mines selling the majority of their output in the steam market. Majors and nonmajors show no statistically significant difference in worker-output ratios, like Appalachian surface mines when market type is not controlled (Table 3-2). Because most mines in the West and Interior regions are in the steam coal market, worker-output ratios by market type for these regions are not reproduced here.

EFFICIENCY BY MARKETING ARRANGEMENT

The recent growth in captive mine production and the entry of utilities into the major producing group have raised some questions about the relative efficiency of captive mines, given that these mines are somewhat "insulated" from the forces of competition.

Table 3-15 compares captive to open market output per worker for deep and surface mines by region. The results are somewhat mixed with no clear pattern emerging. In Appalachia, open market deep mines are more productive than captive deep mines, but surface mines exhibit no statistically significant difference. The difference in deep mine worker-output rates may be due more to captive met coal mines than to less efficiency in mine operation. In the West, while there is no difference in deep mine productivity for surface mines, the productivity of captive mines differs significantly from that of open market mines. However, in both the West and the Interior regions, captive surface mines are more productive than open market mines.

To examine captive versus open market productivity controlling for mine size, Appalachian deep and surface mines were divided into size class groups and compared in Tables 3-16 and 3-17. Controlling for the size distribution of mines made no difference in the results of Table 3-15, with the majority of deep mines by size class showing significant difference in productivity for captive versus open market (Table 3-16) and only the smallest group in surface mines showing a significant difference (Table 3-17).

Table 3-15. Output per Miner-Shift, by Mine Type,
Region and Marketing Arrangement, 1978

Region/Mine Type	Tons per Miner-Shift						
	Captive			Open Market			t
	Mean	Standard Deviation	N	Mean	Standard Deviation	N	
Appalachia							
Deep	8.84	4.64	70	15.15	21.12	1,840	2.49 ^b
Surface	16.25	8.97	15	23.93	30.74	1,850	0.96
Total	10.15	6.26	85	19.55	26.75	3,690	3.23 ^c
West							
Deep	10.23	3.51	8	13.87	8.65	36	1.14
Surface	96.95	87.63	5	50.49	46.30	47	1.87 ^d
Total	43.56	67.04	13	34.61	39.60	83	0.67
Interior							
Deep	0.45	^a	1	14.46	9.30	59	11.57 ^c
Surface	48.84	23.89	7	24.55	24.14	281	2.62 ^c
Total	42.79	27.95	8	22.80	22.60	340	2.45 ^b

^aOnly one observation.

^bSignificant at .02 level.

^cSignificant at .01 level.

^dSignificant at .10 level.

Source: EIA-7.

Table 3-16. Output per Miner-Shift, Captive and Open Market
Appalachian Deep Mines by Size Class, 1978

Mine Size Class	Tons per Miner-Shift						
	Captive			Open Market			
	Mean	Standard Deviation	N	Mean	Standard Deviation	N	t
1	11.61	a	1	14.78	33.56	556	2.22 ^c
2	11.09	5.73	20	15.64	11.60	735	1.74 ^b
3	9.91	3.78	13	16.18	11.83	265	1.89 ^b
4	7.38	4.58	9	13.90	15.09	157	1.28
5	6.43	2.75	16	14.01	14.51	84	2.06 ^c
6	8.80	4.30	11	12.17	11.01	43	0.97
Total	8.84	4.64	70	15.15	21.12	1,840	2.49 ^d

^aOnly one observation.

^bSignificant at .10 level.

^cSignificant at .05 level.

^dSignificant at .02 level.

Source: EIA-7.

Table 3-17. Output per Miner-Shift, Captive and Open Market
Appalachian Surface Mines by Size Class, 1978

Mine Size Class	Tons per Miner-Shift						
	Captive			Open Market			
	Mean	Standard Deviation	N	Mean	Standard Deviation	N	t
1	0.68	a	1	17.51	21.33	386	15.5 ^b
2	13.59	18.85	2	25.28	36.84	827	0.44
3	19.60	5.96	5	27.05	23.82	331	0.70
4	18.60	6.13	4	23.13	13.69	169	0.65
5	9.77	6.22	2	27.23	42.79	114	0.57
6	23.94	a	1	27.91	12.19	23	1.56
Total	16.25	8.97	15	23.93	30.74	1,850	0.96

^aOnly one observation.

^bSignificant at .01 level.

Source: EIA-7.

SUMMARY

This chapter examined two measures of efficiency (output per miner-shift and output per machine-shift) of major- and nonmajor-controlled mines. When mine size class is controlled, in most cases no statistically significant difference was found in average labor productivity between majors and nonmajors. While there was little evidence of scale economies in Appalachia, they affect both deep and surface mines in the Interior and the West.

When output per machine-shift is used as a measure of efficiency, the results are somewhat mixed. For some regions and mine types the difference between majors and nonmajors in average machine productivity is significant, and in other regions no difference was found. Almost all regions and mine types showed evidence of scale economies.

When average labor productivity was examined by consumer group, Appalachian deep mines selling metallurgical coal were found to have lower productivity than Appalachian steam coal mines. Examining only deep mines selling in the steam market revealed that in most cases nonmajor mines had higher average labor productivity. Examining only deep mines in the metallurgical coal market did not reveal a clear advantage of nonmajors over majors in average labor productivity. There was no statistically significant difference in average labor productivity between major-controlled surface mines and nonmajor surface mines selling in the steam coal market.

To examine how efficiency varies by marketing arrangement, mines were divided into captive mines and mines selling in the open market and their average labor productivity compared. No clear pattern emerged (i.e., productivity was significantly different between captive and deep for some regions and mine types). However, in the West captive mines were more productive than open market mines; while in Appalachia the opposite was true.

Future Research Needs

1. Capital Measures. The measures of capital used in this report were in physical units--continuous mining machines, cutting machines, draglines, etc. These measures are incomplete in that they only account for movable equipment and do not control for machine quality (age and model of machine). Although a better measure would be the net value of total equipment at a mine, collecting data of this sort would present problems.

2. Measures of Efficiency. Two measures of economies of scale and efficiency were used in this report: output per worker-shift and output per machine-shift. Problems with these measures arise from the extent of coal cleaning the amount of backup equipment. A better way to test for differences among mine types in worker output would apply multiple regression analysis to the 1978 cross-sectional data to control for as many of these "contaminants" of efficiency measures as possible.

It should also be noted that any output measure of productivity measures output--not efficiency. Once one controls for type of seam, market, coal cleaning, and other factors, some very efficient producers could have low output rates.

3. Concentration. Measures of concentration (or conversely, of competition) are chock-full of difficulties. The crude aggregate measures employed in this report convey information about how coal output concentration has changed since 1966, but the question of competition is not adequately addressed.

Several steps could be taken to improve the output concentration measures employed in this report. The obvious first step (and perhaps the most difficult) would be to define the market areas in which to measure concentration. At a minimum these markets would have to be defined by coal type (met, steam, etc.) and geographical region. Within these markets, one would have to consider the number of long-term contracts, the quantity of captive production, and how these variables influence competitiveness.

The other side of the coin in competitive analysis is buyer concentration. A priori, one would expect that buyer concentration in the coal industry is high because approximately 80 percent of U.S. coal production goes to utilities, which are granted public monopolies over large geographical regions. Any study of coal industry competitiveness would have to deal with the market power of coal purchasers.

Finally, strong arguments have been advanced for the use of the extent of reserves controlled as a measure of concentration. At present, reserve information is not adequate for this task, although those data available could provide useful information.

APPENDIX A - CONTROL AND OWNERSHIP OF MAJOR PRODUCERS, 1973-1977

Table A-1. Ownership of Major Coal Producers, 1973

Coal Company	Tonnage	Controlling Company	
		Name	Type
1. Peabody Coal Co.		Kennecott Copper Corp.	Metal
(Ill.) (5,880,145 Strip)	15,104,108		
(Mo.) (Strip)	3,072,464		
(Okla.) (Strip)	1,557,010		
(Ind.) (Strip)	12,316,135		
(Ky.W.) (15,746,555 Strip)	24,605,740		
(Ohio) (1,865,930 Strip)	4,780,921		
(Ala.) (1,342,238 Strip) (83,624 Auger)	1,425,862		
(Colo.) (Strip)	737,175		
(Mont.) (Strip)	1,971,643		
(Ariz.) (Strip)	3,246,500		
(Utah)	489,887		
(Ark.) (Strip)	103,876		
Gibraltar Coal Corp. (Ky.W.) (Strip) ^a	507,466		
Total	69,918,787		
2. Consolidation Coal Co.		Continental Oil	Oil
Pittsburgh Coal Co., Div. (Pa.)	3,805,622		
Mountaineer Coal Co., Div. (W.Va.) (1,127,164 Strip)	7,370,516		
Christopher Coal Co., Div. (W.Va.) (957,133 Strip)	8,640,875		
Mathies Coal Co. (Pa.)	2,035,869		
Central Div. (Ohio) (7,620,057) (Strip)	10,721,452		
Harmar Coal Co. (Pa.)	730,470		
Pocahontas Fuel Co. Div. (W.Va.) (948,545 Strip)	5,066,159		
Tennessee Div. (Tenn.)	1,344,052		
Bishop Coal Co. (W.Va.)	1,302,785		
Midwestern Div. (Ill.) (4,182,511 Strip)	6,504,308		
Western Div. (N.D. Strip)	2,427,255		
Itmann Coal Co. (W.Va.)	1,986,996		

^aOwned jointly with AMAX Coal Co.

Table A-1. Ownership of Major Coal Producers, 1973 (Cont'd.)

Coal Company	Tonnage	Controlling Company	
		Name	Type
Ohio Valley Div. (W.Va.)	5,451,356		
Rowland Div. (W.Va.) (225,745 Strip)	815,411		
Blacksville Div. (W.Va.)	2,274,237		
Total	60,477,363		
3. Island Creek Coal Co.		Occidental Petroleum Corp.	Oil
Island Creek Div. (W.Va.)	4,192,421		
Island Creek Div. (E.Ky.)	3,496,294		
West Ky. Div. (W.Ky.)	6,980,832		
Va. Pocahontas Div. (Va.)	1,863,819		
Va. Pocahontas Co. (Va.)	367,351		
Beatrice Pocahontas Co. (W.Va.)	1,160,654		
National Coal Mining Co. (W.Va.)	792,594		
Northern Div. (Pa.)	816,383		
Northern Div. (W.Va.)	3,208,972		
Total	22,879,320		
4. Pittston Co.		Independent	Coal
Clinchfield Coal Div. (Va.)	8,094,832		
Amigo Smokeless Coal Co. (W.Va.)	514,122		
Kentland Elkhorn Coal Corp.	1,292,630		
Jewell Ridge Coal Corp. (Va.)	2,457,153		
Badger Coal Co. (W.Va.)	1,107,203		
Sewell Coal Co. (W.Va.)	1,468,416		
Eastern Coal Corp. (Ky.E.)	1,022,971		
Buffalo Mining Co. (W.Va.)	1,306,663		
Ranger Fuel Corp. (W.Va.)	748,884		
Elkay Mining Co. (W.Va.)	617,083		
Snap Creek Coal Co. (W.Va.)	166,348		
Total	18,796,305		
5. AMAX Coal Co.		American Metal Climax, Inc.	Metal
(Ill.) (4,695,681 Strip)	4,733,534		
(Ind.) (Strip)	6,659,524		
(Ky.W.) (Strip)	3,859,061		

Table A-1. Ownership of Major Coal Producers, 1973 (Cont'd.)

Coal Company	Tonnage	Controlling Company	
		Name	Type
(Wyo.) (Strip)	897,507		
Gibraltar Coal Corp. (Ky.W.) (Strip) ^b	507,466		
Total	16,657,552		
6. United States Steel Corp.		U.S. Steel	Steel
(Ky.E.) (35,000 Auger)	3,286,000		
(W.Va.)	4,777,000		
(Pa.)	5,172,275		
Southern Dist. (Ala.)	1,581,763		
Western Dist. (Utah)	749,000		
Western Dist. (Colo.)	656,000		
Total	16,222,038		
7. Bethlehem Mines Corp.		Bethlehem Steel	Steel
(Pa.)	6,472,634		
(W.Va.) (1,771,397 Strip) (103,357 Auger)	4,278,364		
Beth-Elkhorn Corp. (Ky.E.)			
(674,081 Strip) (274,212 Auger)	3,378,002		
Total	14,129,000		
8. Arch Mineral Corp. (Wyo.) (Strip)	4,362,775	Ashland Oil Co.	Oil
Arch Coal Co. (Ala.) (Strip)	863,497		
Eads Coal Co. (Ill.) (Strip)	663,195		
Southwestern Illinois Coal Corp.			
(Ill.) (Strip)	5,897,046		
Walker-Fayette Coal Co. (Ala.) (Strip)	752,118		
Total	12,538,631		

^b Owned jointly with Peabody Coal Co.

Table A-1. Ownership of Major Coal Producers, 1973 (Cont'd.)

Coal Company	Tonnage	Controlling Company	
		Name	Type
9. North American Coal Corp. (Lignite Div., N.D.) (Strip) (Ohio Div.) (Ohio) (Pennsylvania Div.) (Pa.) Florence Mining Co. (Pa.) Helen Mining Co. (Pa.) Oneida Mining Co. (Pa.) Nacco Mining Co. (Ohio) Quarto Mining Co. (Ohio) Total	1,090,144 4,214,424 726,348 3,217,348 770,674 458,448 1,141,989 881,941 12,501,316	Independent	Coal
10. Old Ben Coal Co. (Ill.) Old Ben Coal Co. (Va.) Old Ben Coal Co. (Ind.) (Strip) Total	6,482,077 472,947 3,891,660 10,846,684	Standard Oil Co. (of Ohio)	Oil
11. Eastern Associated Coal Corp. (Pa.) (W.Va.) Total	661,271 9,978,792 10,640,063	Eastern Gas and Fuel Associates	Gas
12. Westmoreland Coal Co. Hampton Div. (W.Va.) Winding Gulf Div. (W.Va.) Imperial Smokeless Div. (W.Va.) Stonega Div. (Va.) Total	1,547,950 1,938,943 830,244 4,491,514 8,808,651	Westmoreland Coal; Penn- Virginia Corp. (formerly Va. Coal & Iron)	Coal
13. Freeman Coal Mining Corp. (Ill.) United Electric Coal Cos. (Ill.) (Strip) Total	5,296,122 3,373,799 8,669,921	General Dynamics Corp.	Electronics, defense

Table A-1. Ownership of Major Coal Producers, 1973 (Cont'd.)

Coal Company	Tonnage	Controlling Company	
		Name	Type
14. Pittsburgh & Midway Coal Mining Co. (Kan.) (Strip) (Ky.W.) (2,629,189 Strip) (Colo.) (Strip) (N.M.) (Strip) (Mo.) (Strip) Total	 725,451 4,229,621 1,076,120 463,289 1,569,608 8,064,089	Gulf Oil Co.	Oil
15. Utah International Inc. (N.M.) (Strip)	7,389,321	Independent	Metal
16. Central Ohio Coal Co. (Ohio) (Strip) Central Appalachian Coal Co. (W.Va.) Windsor Power House Coal Co. (W.Va.) Central Coal Co. (W.Va.) Southern Ohio Coal Co. (Ohio) Southern Appalachian Coal Co. (W.Va.) Total	 3,667,844 535,255 520,101 354,927 357,710 1,127,357 6,563,194	American Electric Power	Utility
17. Rosebud Coal Sales Co. (Wyo.) (Strip) Big Horn Coal Co. (Wyo.) (Strip) Decker Coal Co. (Mont.) (Strip) Total	 1,509,736 444,545 4,159,287 6,113,568	Peter Kiewit Sons Co.	Construction
18. Rochester & Pittsburgh Coal Co. (Pa.) Helvetia Coal Co. (Pa.) Total	 3,425,241 1,241,147 4,666,388	Rochester & Pittsburgh, Independent	Coal

Table A-1. Ownership of Major Coal Producers, 1973 (Cont'd.)

Coal Company	Tonnage	Controlling Company	
		Name	Type
19. Western Energy Co. (Mont.) (Strip)	4,600,000	Montana Power Co.	Utility
20. Zeigler Coal Co. (Ill.)	2,798,041	Houston Natural Gas Corp.	Gas
(Ky.W.)	1,474,540		
Total	4,272,581		
21. Valley Camp Coal Co. (W.Va.) (154,344 Strip) (51,019 Auger)	4,092,054	Independent	Coal
22. Industrial Generating Co. (Tex.) (Strip) (Est.)	4,000,000	Texas Utilities	Utility
23. Falcon Coal Co. Inc. (Ky.E.) (Strip)	3,746,000	Independent	Coal
24. Jones & Laughlin Steel Corp. (Pa.) Gateway Coal Co. (Pa.)	2,145,234 1,430,000	Jones & Laughlin, Independent	Steel
Total	3,575,234		
25. Breathitt County Coal Co. (Ky.E.) (Strip & Auger)	3,491,487	Falcon Seaboard, Inc.	Coal, oil, gas
26. Alabama By-Products Corp. (Ala.)	3,467,864	Independent	Chemicals, coal
27. Republic Steel Corp. (Pa.)	2,478,032	Independent	Steel
(Ky.E.)	803,900		
Total	3,281,932		
28. Washington Irrigation & Development Co. (Wash.) (Strip)	3,229,176	Pacific Power & Light; Washington Water Power	Utility

Table A-1. Ownership of Major Coal Producers, 1973 (Cont'd.)

Coal Company	Tonnage	Controlling Company	
		Name	Type
29. Youngstown Sheet & Tube Buckeye Coal Co. (Pa.) Youngstown Mines Corp. (W.Va.) Olga Coal Co. (W.Va.) Total	 1,114,100 779,000 1,277,000 3,170,100	Youngstown Sheet & Tube, Independent	Steel
30. Jewell Coal & Coke Co. (Va.) Shamrock Coal Co. (Ky.E.) Cumberland Collieries (Va.) Total	 1,376,140 1,171,266 615,200 3,162,606	Jewell Coal & Coke,	Coal
31. Kemmerer Coal Co. (Wyo.) (Strip) Gunn-Quealy Coal Co. (Wyo.) Total	 2,946,676 103,470 3,050,146	Kemmerer Coal Co.	Coal

Source: *Moody's Industrial Manual*, 1974.
Moody's Public Utility Manual, 1974.
Keystone Coal Mine Directory, 1973.
Keystone Coal Industry Manual, 1974.

Table A-2. Ownership of Major Coal Producers, 1974

Coal Company	Tonnage	Controlling Company	
		Name	Type
1. Peabody Coal Co.		Kennecott Copper Corp.	Metal
(Ill.) (5,591,476 Strip)	14,772,705		
(Mo.) (Strip)	2,858,066		
(Okla.) (Strip)	1,540,957		
(Ind.) (Strip)	10,584,128		
(Ky.W.) (13,226,606 Strip)	23,286,930		
(Ohio) (1,309,868 Strip)	2,048,351		
(Ala.) (1,309,868 Strip) (56,718 Auger)	1,452,160		
(Colo.) (Strip)	563,415		
(Mont.) (Strip)	2,228,524		
(Ariz.) (Strip)	6,448,410		
(Utah)	1,047,671		
(Ark.) (Strip)	565,650		
Gibraltar Coal Corp. (Ky.W.) (Strip) ^a	707,109		
Total	68,104,076		
2. Consolidation Coal Co.		Continental Oil Company	Oil
Pittsburgh Coal Co., Div. (Pa.)	2,975,471		
Mountaineer Coal Co., Div. (W.Va.) (831,644 Strip)	6,393,605		
Christopher Coal Co., Div. (W.Va.) (861,875 Strip)	7,227,215		
Mathies Coal Co. (Pa.)	1,808,538		
Central Div. (Ohio) (6,137,129 Strip)	8,753,244		
Harmar Coal Co. (Pa.)	631,991		
Pocahontas Fuel Co. Div. (Tenn., W.Va.) (1,143,573 Strip)	5,819,178		
Bishop Coal Co. (W.Va.)	976,579		
Mid-Western Div. (Ill.) (4,788,191 Strip)	6,428,296		
Western Div. (N.D.) (2,096,474 Strip) (Can. 399,967 Strip)	2,496,441		

^aOwned jointly with AMAX Coal Co.

Table A-2. Ownership of Major Coal Producers, 1974 (Cont'd.)

Coal Company	Tonnage	Controlling Company	
		Name	Type
Itmann Coal Co. (W.Va.)	1,292,065		
Ohio Valley Div. (W.Va.)	4,398,338		
Blacksville Div. (W.Va.)	2,552,972		
Total	51,753,933		
3. Island Creek Coal Co.		Occidental Petroleum Corp.	Oil
Island Creek Div. (W.Va.)	3,286,313		
Island Creek Div. (Ky.E.)	3,882,443		
Northern Div. (Pa.)	507,004		
Northern Div. (W.Va.)	2,933,151		
West Kentucky Div. (Ky.W.)	6,513,103		
Va. Pocahontas Div. (Va.)	1,976,938		
Beatrice Pocahontas Co. (Va.)	870,316		
Virginia Pocahontas Co. (Va.)	312,694		
National Coal Mining Co. (W.Va.)	566,055		
Total	20,848,017		
4. AMAX Coal Co.		AMAX, Inc.	Metal
(Ill.) (4,327,037 Strip)	5,070,573		
(Ind.) (Strip)	7,749,883		
(Ky.W.) (Strip)	3,108,448		
(Wyo.) (Strip)	3,312,858		
Gibraltar Coal Corp. (Ky.W.) (Strip) ^b	707,109		
Total	19,948,871		
5. Pittston Co.		Independent	Coal
Clinchfield Coal Div. (Va.)	7,677,827		
Amigo Smokeless Coal Co. (W.Va.)	365,611		
Kentland Elkhorn Coal Copr. (Ky.E.)	998,051		
Jewell Ridge Coal Corp. (Va.)	2,386,392		
Badger Coal Co. (W.Va.)	878,191		

^b Owned jointly with Peabody Coal Co.

Table A-2. Ownership of Major Coal Producers, 1974 (Cont'd.)

Coal Company	Tonnage	Controlling Company	
		Name	Type
Sewell Coal Co. (W.Va.)	1,402,528		
Eastern Coal Corp. (Ky.E.)	822,844		
Buffalo Mining Co. (W.Va.)	1,193,132		
Ranger Fuel Corp. (W.Va.)	650,863		
Elkay Mining Co. (W.Va.)	863,829		
Snap Creek Coal Co. (W.Va.)	142,643		
Total	17,381,911		
6. United States Steel Corp.		U.S. Steel	Steel
(Ky.E.) (13,000 Auger)	3,161,000		
(W.Va.) (66,000 Strip)	4,334,000		
(Pa.)	5,127,000		
Southern Dist. (Ala.)	1,432,000		
Western Dist. (Utah)	685,000		
Western Dist. (Colo.)	869,000		
Processed Coal	781,000		
Total	16,389,000		
7. Arch Mineral Corp. (Wyo.) (Strip)	5,732,152	Ashland Oil Co.	Oil
Arch Coal Co. (Ala.) (Strip) ^C	541,059		
Eads Coal Co. (Ill.) (Strip) ^C	413,101		
Southwestern Illinois Coal Corp. (Ill.) (Strip)	6,562,353		
Walker-Fayette Coal Co. (Ala.) (Strip)	629,874		
Total	13,878,539		
8. Bethlehem Mines Corp.		Bethlehem Steel	Steel
(Pa.)	6,086,565		
(W.Va.) (1,587,328 Strip) (165,601 Auger)	3,830,559		
Beth-Elkhorn Corp. (Ky.E.) (888,508 Strip) (165,601 Auger)	3,430,501		
Total	13,347,625		

^CRobertson & Assoc., Inc., successor.

Table A-2. Ownership of Major Coal Producers, 1974 (Cont'd.)

Coal Company	Tonnage	Controlling Company	
		Name	Type
9. North American Coal Corp. (Lignite Div., N.D.) (Strip) (Ohio Div.) (Ohio) (Pennsylvania Div.) (Pa.) Florence Mining Co. (Pa.) Helen Mining Co. (Pa.) Oneida Mining Co. (Pa.) Nacco Mining Co. (Ohio) Quarto Mining Co. (Ohio) Total	1,270,254 3,533,994 667,267 1,383,320 657,819 395,878 1,039,060 823,971 9,771,563	Independent	Coal
10. Big Horn Coal Co. (Wyo.) (Strip) Rosebud Coal Sales Co. (Wyo.) (Strip) Decker Coal Co. (Mont.) (Strip) Total	994,000 1,917,000 6,786,000 9,697,000	Peter Kiewit Sons Co.	Construction
11. Old Ben Coal Co. (Ill.) Old Ben Coal Co. (Va.) Old Ben Coal Co. (Ind.) (Strip) Total	5,369,480 385,851 3,696,549 9,451,880	Standard Oil Co. (of Ohio)	Oil
12. Eastern Associated Coal Corp. (Pa.) (W.Va.) Total	520,930 7,176,893 7,697,823	Eastern Gas and Fuel Associates	Gas
13. Westmoreland Coal Co. Hampton Div. (W.Va.) Winding Gulf Div. (W.Va.) Imperial Smokeless Div. (W.Va.) Stonega Div. (Va.) Total	1,143,094 1,654,191 619,391 4,163,899 7,580,575	Westmoreland Coal; Penn- Virginia Corp.	Coal

Table A-2. Ownership of Major Coal Producers, 1974 (Cont'd.)

Coal Company	Tonnage	Controlling Company	
		Name	Type
14. Pittsburgh & Midway Coal Mining Co. (Kan.) (Strip) 134,138 (Ky.W.) (2,535,574 Strip) 4,009,018 (Colo.) (Strip) 1,134,068 (N.M.) (Strip) 509,416 (Mo.) (Strip) 1,741,534 Total 7,528,174		Gulf Oil Co.	Oil
15. Utah International Inc. (N.M.) (Strip) 6,955,000		Independent	Metal
16. Freeman Coal Mining Corp. (Ill.) 4,557,684 United Electric Coal Co. (Ill.) (Strip) 2,392,389 Total 6,950,073		General Dynamics Corp.	Electronics, defense
17. Industrial Generating Co. (Tex.) (Strip) (Est.) 6,500,000		Texas Utilities	Utility
18. Central Ohio Coal Co. (Ohio) (Strip) 3,367,486 Central Appalachian Coal Co. (W.Va.) 458,451 Windsor Power House Coal Co. (W.Va.) 514,364 Central Coal Co. (W.Va.) 132,595 Southern Ohio Coal Co. (Ohio) 980,540 Southern Appalachian Coal Co. (W.Va.) 348,649 Cedar Coal Co. (Since 4/74) (363,891 Strip) (W.Va.) 576,546 Total 6,378,631		American Electric Power Service Corp.	Utility
19. Rochester & Pittsburgh Coal Co. (Pa.) (934,986 Strip) (4,136 Auger) 3,544,183 Helvetia Coal Co. (Pa.) 1,064,609 Total 4,608,792		Rochester & Pittsburgh; Independent	Coal

Table A-2. Ownership of Major Coal Producers, 1974 (Cont'd.)

	Coal Company	Tonnage	Controlling Company	
			Name	Type
20.	A.T. Massey Coal Co., Inc. Properties Wolf Creek Collieries Co. (Ky.E.) Robinson-Phillips Coal Co. (W.Va.) (44,000 Strip) Omar Mining Co. (W.Va.) (92,807 Strip) Trace Fork Coal Co. (W.Va.) (92,807 (Strip) Peerless Eagle Coal Co. (W.Va.) Total	2,335,000 457,812 561,956 503,810 444,779 4,303,357	St. Joe Minerals Corp.	Metal
21.	Zeigler Coal Co. (Ill.) (Ky.W.) Total	3,147,937 864,872 4,012,809	Houston Natural Gas Corp.	Gas
22.	C & K Coal Co. (Pa.) (Strip)	4,000,000	Gulf Resources & Chemical Co.	Chemical
23.	Washington Irrigation & Development Co. (Wash.) (Strip)	3,890,437	Pacific Power & Light; Washington Water Power	Utility
24.	Kemmerer Coal Co. (Wyo.) (Strip) Gunn-Quealy Coal Co. (Wyo.) Total	3,353,157 103,019 3,456,176	Kemmerer Coal, Independent	Coal
25.	Falcon Coal Co. Inc. (Ky.E.) (Strip)	3,441,878	Falcon Seaboard, Inc.	Coal, oil, gas
26.	Alabama By-Products Corp. (Ala.)	3,430,697	Independent	Coal, chemicals
27.	Pacific Power & Light (Wyo.) (Strip) Bridger Coal Co. (Wyo.) (Strip) Total	2,687,045 735,349 3,422,394	Pacific Power & Light; Independent	Utility
28.	Valley Camp Coal Co. (W.Va.) (107,431 Strip) Valley Camp of Utah, Inc. (Utah) Total	3,288,605 6,524 3,295,129	Independent	Coal

Table A-2. Ownership of Major Coal Producers, 1974 (Cont'd.)

Coal Company	Tonnage	Controlling Company	
		Name	Type
29. Western Energy Co. (Mont.) (Strip)	3,213,000	Montana Power Co.	Utility
30. R & F Coal Co. (Ohio) (Strip)	3,200,000	Independent	Coal
31. Jewell Coal & Coke Co. (Va.) (Est.)	1,300,000	Jewell Coal & Coke,	Coal
Shamrock Coal Co. (Ky.E.) (Est.)	1,100,000	Independent	
Cumberland Collieries (Va.) (Est.)	600,000		
Total	3,000,000		

Sources: *Keystone Coal Mine Directory*, 1974.
Keystone Coal Industry Manual, 1975.

Table A-3. Ownership of Major Coal Producers, 1975

Coal Company	Tonnage	Controlling Company	
		Name	Type
1. Peabody Coal Co.		Kennecott Copper Corp.	Metal
(Ill.) (5,726,727 Strip)	15,213,336		
(Mo.) (Strip)	2,983,476		
(Okla.) (Strip)	1,425,746		
(Ind.) (10,138,462 Strip)	10,237,778		
(Ky.W.) (13,746,414 Strip)	25,864,471		
(Ohio) (1,604,851 Strip)	4,425,285		
(Ala.) (Strip)	1,058,798		
(Colo.) (Strip)	754,592		
(Mont.) (Strip)	2,103,110		
(Ariz.) (Strip)	6,985,793		
(Utah)	1,155,501		
(Ark.) (Strip)	95,337		
Gibraltar Coal Corp. (Ky.W.) (Strip) ^a	747,311		
Total	73,050,534		
2. Consolidation Coal Co.		Continental Oil Co.	Oil
Eastern Region			
Allegheny (Pa.)	709,248		
Washington (Pa.)	2,362,187		
Moundsville (W.Va.)	4,841,466		
Subtotal	7,912,901		
Northern W. Va. Region			
Morgantown (W.Va.) (847,851 Strip)	7,445,587		
Blacksville (W.Va.)	2,565,012		
Fairmont (W.Va.) (886,219 Strip)	6,482,512		
Subtotal	16,493,111		
Southern Appalachia Region			
Bluefield (W.Va.) (575,925 Strip)	3,681,716		
Beckley (W.Va.) (254,990 Strip)	1,212,777		

^aOwned jointly with AMAX Coal Co.

Table A-3. Ownership of Major Coal Producers, 1975 (Cont'd.)

Coal Company	Tonnage	Controlling Company	
		Name	Type
Tazewell (W.Va.)	298,809		
Tazewell (Tenn.)	925,085		
Subtotal	6,118,387		
Midwestern Region			
Underground (Ohio)	2,596,296		
Underground (Ill.)	1,802,434		
Ohio Surface (Ohio) (Strip)	5,624,059		
Illinois Surface (Ill.) (Strip)	5,469,427		
Subtotal	15,492,216		
Western Region			
United States (N.D.) (Strip)	2,345,638		
Canada (Can.) (Strip)	719,892		
Subtotal	3,065,530		
Associated Companies:			
Harmar Coal Co. (Pa.)	703,693		
Mathies Coal Co. (Pa.)	2,019,777		
Bishop Coal Co. (W.Va.)	1,242,621		
Itmann Coal Co. (W.Va.) (72,489 Strip)	1,649,727		
Laurel Mine (Pa.)	110,570		
Development Tonnage	110,669		
Subtotal	5,837,057		
Total	54,919,202		
3. AMAX Coal Co.		AMAX, Inc.	Metal, oil
(Ill.) (4,690,236 Strip)	5,956,578		
(Ind.) (Strip)	8,675,080		
(Ky.W.) (Strip)	3,172,847		
(Wyo.) (Strip)	3,288,079		
Gibraltar Coal Corp. (Ky.W.) (Strip) ^b	747,311		
Total	21,839,895		

^bOwned jointly with Peabody Coal Co.

Table A-3. Ownership of Major Coal Producers, 1975 (Cont'd.)

Coal Company	Tonnage	Controlling Company	
		Name	Type
4. Island Creek Coal Co.		Occidental Petroleum Corp.	Oil
Island Creek Div. (W.Va.)	2,669,068		
Island Creek Div. (Ky.E.)	3,693,390		
Northern Div. (Pa.)	733,979		
Northern Div. (W.Va.)	2,929,799		
Northern Div. (Ohio)	28,777		
West Kentucky Div. (Ky.W.)	6,250,004		
Va. Pocahontas Div. (Va.)	1,573,829		
Beatrice Pocahontas Co. (Va.)	715,348		
Virginia Pocahontas Co. (Va.)	308,825		
National Coal Mining Co. (W.Va.)	518,102		
Total	19,421,121		
5. Pittston Co.		Independent	Coal
Clinchfield Coal Div. (Va.) (1,600,154 Strip)	7,424,218		
Clinchfield Coal Div. (W.Va.)	143,381		
Amigo Smokeless Coal Co. (W.Va.)	355,679		
Kentland Elkhorn Coal Corp. (Ky.E.)	814,826		
Jewell Ridge Coal Corp. (Va.) (59,594 Strip)	2,717,046		
Badger Coal Co. (W.Va.) (169,867 Strip)	840,655		
Sewell Coal Co. (W.Va.) (152,915 Strip)	1,590,863		
Eastern Coal Corp. (Ky.E.)	1,145,950		
Buffalo Mining Co. (W.Va.) (274,353 Strip)	1,401,367		
Ranger Fuel Corp. (W.Va.) (208,168 Strip)	763,138		
Elkay Mining Co. (W.Va.) (115,584 Strip)	1,044,906		
Snap Creek Coal Co. (W.Va.) (160,919 Strip)	312,273		
Total	18,554,302		

Table A-3. Ownership of Major Coal Producers, 1975 (Cont'd.)

Coal Company	Tonnage	Controlling Company	
		Name	Type
6. United States Steel Corp. (Ky.E.) (W.Va.) (198,334 Strip) (Pa.) (49,162 Strip) Southern Dist. (Ala.) Western Dist. (Utah & Colo.) Total	3,135,458 5,189,312 5,650,544 1,434,671 1,705,888 17,115,873	U.S. Steel	Steel
7. Arch Mineral Corp. (Wyo.) (Strip) Southwestern Illinois Coal Corp. (Ill.) (Strip) Walker-Fayette Coal Co. (Ala.) (Strip) Total	7,953,192 4,943,407 571,168 13,467,767	Ashland Oil Co.; Hunt Petroleum Corp.; Hunt Industries	Oil
8. Bethlehem Mines Corp. (Pa.) (W.Va.) (1,582,345 Strip) (29,795 Auger) Beth-Elkhorn Corp. (Ky.E.) (563,933 Strip) (34,239 Auger) Total	6,236,802 4,092,600 3,025,709 13,355,111	Bethlehem Steel	Steel
9. Big Horn Coal Co. (Wyo.) (Strip) Rosebud Coal Sales Co. (Wyo.) (Strip) Decker Coal Co. (Mont.) (Strip) Total	777,432 1,772,870 9,174,634 11,724,936	Peter Kiewit Sons Co.	Construction
10. North American Coal Corp. (Lignite Div., N.D.) (Strip) (Ohio Div.) (Ohio) (Pennsylvania Div.) (Pa.) Florence Mining Co. (Pa.) Helen Mining Co. (Pa.)	826,193 3,323,867 751,049 1,250,019 809,240	Independent	Coal

Table A-3. Ownership of Major Coal Producers, 1975 (Cont'd.)

Coal Company	Tonnage	Controlling Company	
		Name	Type
Oneida Mining Co. (Pa.)	355,942		
Nacco Mining Co. (Ohio)	1,152,669		
Quarto Mining Co. (Ohio)	1,125,702		
Total	9,594,681		
11. Old Ben Coal Co. (Ill.)	5,033,519	Standard Oil Company (of Ohio)	Oil
Old Ben Coal Co. (Va.)	366,279		
Old Ben Coal Co. (Ind.) (Strip)	3,857,917		
Total	9,257,715		
12. Central Ohio Coal Co. (Strip)	2,772,000	American Electric Power	Utility
Central Appalachian Coal Co. (W.Va.)	388,000		
Windsor Power House Coal Co. (W.Va.)	598,000		
Central Coal Co. (W.Va.)	182,000		
Southern Ohio Coal Co. (Ohio)	2,036,000		
Southern Appalachian Coal Co. (W.Va.) (763,000 Strip)	1,181,000		
Cedar Coal Co. (601,000 Strip) (W.Va.)	1,108,000		
Total	8,265,000		
13. Westmoreland Coal Co.		Westmoreland Coal; Penn- Virginia Corp.	Coal
Hampton Div. (W.Va.) (100,000 Strip & Auger)	1,300,000		
Winding Gulf Div. (W.Va.)	1,600,000		
Imperial Smokeless Div. (W.Va.) (100,000 Strip & Auger)	600,000		
Stonega Div. (Va.) (1,200,000 Strip & Auger)	4,400,000		
Total	7,900,000		

Table A-3. Ownership of Major Coal Producers, 1975 (Cont'd.)

Coal Company	Tonnage	Controlling Company	
		Name	Type
14. Eastern Associated Coal Co. (Pa.) (W.Va.) Affinity Mining Co. (W.Va.) Total	456,441 7,161,432 222,402 7,840,275	Eastern Gas and Fuel Associates	Gas
15. Pittsburgh & Midway Coal Mining Co. (Ky.W.) (2,458,000 Strip) (Colo.) (Strip) (N.M.) (Strip) (Mo.) (Strip) Total	4,027,000 760,000 468,000 2,039,000 7,294,000	Gulf Oil Co.	Oil
16. Freeman-United Coal Mining Co. (Ill.) (2,311,522 Strip)	6,510,458	General Dynamics Corp.	Electronics, defense
17. Western Energy Co. (Mont.) (Strip)	6,407,307	Montana Power Co.	Utility
18. Utah International Inc. (N.M.) (Strip)	6,073,000	Independent	Metal
19. Industrial Generating Co. (Tex.) (Strip) (Est.)	6,000,000	Texas Utilities	Utility
20. Rochester & Pittsburgh Coal Co. (Pa.) (882,648 Strip) Helvetia Coal Co. (Pa.) Total	3,942,562 1,378,873 5,321,435	Rochester & Pittsburgh; Independent	Coal
21. Pacific Power & Light (Wyo.) (Strip) Bridger Coal Co. (Wyo.) (Strip) Total	3,231,649 1,862,125 5,093,774	Pacific Power & Light; Independent	Utility

Table A-3. Ownership of Major Coal Producers, 1975 (Cont'd.)

	Coal Company	Tonnage	Controlling Company	
			Name	Type
22.	C & K Coal Co. (Pa.) (Strip)	2,279,836	Gulf Resources and Chemical Co.	Chemical
	Vantage Coal Corp. (Pa.) (Strip)	138,713		
	Shannon Coal Co. (Pa.) (Strip)	1,796,000		
	Stahlman Coal Co. (Pa.) (Strip)	368,517		
	Cambria Coal Co. (Pa.) (Strip)	408,708		
	Total	4,991,774		
23.	Zeigler Coal Co.		Houston Natural Gas Corp.	Gas
	(Ill.)	4,037,053		
	(Ky.W.)	547,236		
	Total	4,584,289		
24.	Falcon Coal Co., Inc. (Ky.E.)		Falcon Seaboard, Inc.	Coal, oil, gas
	(Strip)	4,506,251		
25.	Alabama By-Products Corp. (Ala.)		Independent	Coal, chemicals
	(66,910 Strip)	4,213,123		
26.	Jewell Coal & Coke Co. (Va.)	1,478,000	Jewell Coal & Coke; Independent	Coal
	Shamrock Coal Co. (Ky.E.)	1,278,000		
	Cumberland Collieries Inc. (Va.)	1,295,000		
	Total	4,051,000		
27.	Westmoreland Resources (Mont.) (Strip)	4,048,082	Westmoreland Coal; Penn-Va. Corp.; Morrison-Knudsen Co.; Kewanee Oil Co.	Coal, oil
28.	Knife River Coal Mining Co.		Montana Dakota Utilities Co.	Utility
	(N.D.) (Strip)	3,295,879		
	(Mont.) (Strip)	300,053		
	Total	3,595,932		
29.	Washington Irrigation & Development Co. (Wash.) (Strip)	3,415,934	Pacific Power & Light; Washington Water Power	Utility

Table A-3. Ownership of Major Coal Producers, 1975 (Cont'd.)

Coal Company	Tonnage	Controlling Company	
		Name	Type
30. Valley Camp Coal Co. (W.Va.) (103,381 Strip) Valley Camp of Utah, Inc. (Utah) Total	3,176,731 201,493 3,378,224	Quaker State Oil Refining Co.	Oil
31. H.E. Drummond Coal Div. (Ala.) (Strip)	3,325,347	The Drummond Co.	Coal
32. Pennsylvania Mines Corp. Greenwich Collieries Co. (Pa.) Rushton Mining Co. (Pa.) Tunnelton Mining Co. (Pa.) Total	2,296,098 575,886 413,332 3,285,316	Pennsylvania Power & Light Co.	Utility
33. Martiki Coal Corp. (Ky.E.) (Strip) Webster County Coal Corp. (Ky.W.) Total	450,491 2,758,032 3,208,523	Mapco, Inc.	Oil
34. Republic Steel Corp. (Pa.) (Ky.E.) (Ala.) Total	2,334,806 397,794 426,117 3,158,717	Republic Steel Corp.	Steel
35. Virginia Iron Coal & Coke Co. (Va.) (977,520 Strip) Avery Coal Co. (Pa.) (Strip) Total	1,644,140 1,371,900 3,016,040	Bates Manufacturing, Inc.	Textiles

Sources: *Keystone Coal Mine Directory*, 1975.
Keystone Coal Industry Manual, 1976.
Moody's Industrial Manual, 1976.

Table A-4. Ownership of Major Coal Producers, 1976

Coal Company	Tonnage	Controlling Company	
		Name	Type
1. Peabody Coal Co.		Peabody Holding Co.;	—
(Ill.) (4,448,939 Strip)	12,893,452	Newmont Mining Co.;	
(Mo.) (2,988,696 Strip) (46,869		Williams Cos.; Bechtel	
Auger)	3,035,565	Corp.; Fluor Corp.; Equi-	
(Okla.) (Strip)	1,616,040	table Life Assurance Soci-	
(Ind.) (9,855,990 Strip)	10,170,575	ety; Boeing Co.	
(Ky.W.) (11,260,717 Strip)	22,070,544		
(Ohio) (1,379,445 Strip) (145,227			
Auger)	3,968,218		
(Ala.) (Strip)	327,077		
(Colo.) (Strip)	1,623,233		
(Mont.) (Strip)	2,397,348		
(Ariz.) (Strip)	10,226,167		
(Utah)	1,064,433		
(Ark.) (Strip)	94,805		
Gibraltar Coal Corp. (Ky.W.) (Strip) ^a	1,055,000		
Total	70,542,457		
2. Consolidation Coal Co.		Continental Oil Co.	Oil
Eastern Region			
Allegheny (Pa.)	748,000		
Washington (Pa.)	2,361,000		
Moundsville, (W.Va.)	4,697,000		
Subtotal	7,806,000		
Northern W. Va. Region			
Morgantown (W.Va.)	5,774,000		
Blacksville (W.Va.)	2,682,000		
Fairmont (W.Va.)	6,110,000		
Contract (Strip)	1,824,000		
Subtotal	16,390,000		

^aOwned jointly with AMAX Coal Co.

Table A-4. Ownership of Major Coal Producers, 1976 (Cont'd.)

Coal Company	Tonnage	Controlling Company	
		Name	Type
Southern Appalachia Region			
Bluefield (W.Va.)	2,247,000		
Beckley (W.Va.)	1,223,000		
Tazewell (W.Va.)	234,000		
Tazewell (Tenn.)	844,000		
Contract (Strip)	700,000		
Subtotal	5,248,000		
Midwestern Region			
Underground (Ohio)	2,568,000		
Underground (Ill.)	1,785,000		
Ohio Surface (Ohio) (Strip)	5,571,000		
Illinois Surface (Ill.) (Strip)	6,186,000		
Subtotal	16,110,000		
Western Region			
United States (N.D.) (Strip)	4,049,000		
Canada (Can.) (Strip)	947,000		
Utah	80,000		
Subtotal	5,076,000		
Associated Companies:			
Harmar Coal Co. (Pa.)	537,000		
Mathies Coal Co. (Pa.)	2,027,000		
Bishop Coal Co. (W.Va.)	1,250,000		
Itmann Coal Co. (W.Va.)	1,444,000		
Subtotal	5,258,000		
Total	55,888,000		
3. AMAX Coal Co.			
(Ill.) (4,138,000 Strip)	5,960,000	AMAX, Inc. (20.6% owned	Metal, oil
(Ind.) (Strip)	6,487,000	by Standard Oil, Califor-	
(Ky.W.) (Strip)	2,204,000	nia)	

Table A-4. Ownership of Major Coal Producers, 1976 (Cont'd.)

Coal Company	Tonnage	Controlling Company	
		Name	Type
(Wyo.) (Strip)	7,355,000		
Gibraltar Coal Corp. (Ky.W) (Strip) ^b	1,055,000		
Total	23,061,000		
4. Island Creek Coal Co.		Occidental Petroleum Corp.	Oil
Island Creek Div. (W.Va.)	2,312,336		
Island Creek Div. (Ky.E.)	2,466,245		
Northern Div. (Pa.)	549,465		
Northern Div. (W.Va.)	2,629,690		
Northern Div. (Ohio)	6,151		
West Kentucky Div. (Ky.W.)	6,236,358		
Va. Pocahontas Div. (Va.)	2,143,471		
Beatrice Pocahontas Co. (Va.)	747,178		
Virginia Pocahontas Co. (Va.)	206,413		
National Coal Mining Co. (W.Va.)	315,097		
Total	14,612,404		
5. Pittston Co.		Independent	Coal
Clinchfield Coal Div. (Va. & W.Va.)			
(1,851,670 Strip)	7,692,554		
Amigo Smokeless Coal Co. (W.Va.)	344,202		
Kentland Elkhorn Coal Corp.	519,304		
Jewell Ridge Coal Corp. (Va.) (95,639 Strip)	2,555,434		
Badger Coal Co. (W.Va.) (174,837 Strip)	646,495		
Sewell Coal Co. (W.Va.) (169,441 Strip)	1,556,672		
Eastern Coal Corp. (Ky.E.)	892,629		
Buffalo Mining Co. (W.Va.) (305,826 Strip)	1,237,205		
Ranger Fuel Corp. (W.Va.) (61,185 Strip)	526,862		

^b Owned jointly with Peabody Coal Co.

Table A-4. Ownership of Major Coal Producers, 1976 (Cont'd.)

Coal Company	Tonnage	Controlling Company	
		Name	Type
Elkay Mining Co. (W.Va.) (281,481 Strip)	881,350		
Snap Creek Coal Co. (W.Va.) (116,519 Strip)	248,922		
Total	17,101,629		
6. United States Steel Corp.		U.S. Steel	Steel
(Ky.E.)	2,763,618		
(W.Va.) (165,000 Strip)	4,878,776		
(Pa.) (96,000 Strip)	5,528,668		
Southern Dist. (Ala.)	1,253,038		
Western Dist. (Colo.)	953,200		
Western Dist. (Utah)	604,700		
Total	15,982,000		
7. Bethlehem Mines Corp.		Bethlehem Steel	Steel
(Pa.)	6,318,231		
(W.Va.) (1,720,423 Strip) (33,750 Auger)	4,247,934		
Beth-Elkhorn Corp. (Ky.E.)			
(572,218 Strip) (135,630 Auger)	3,488,873		
Total	14,055,038		
8. Arch Mineral Corp. (Wyo.) (Strip)	8,100,000	Ashland Oil Co.; Hunt	Oil
Southwestern Illinois Coal Corp. (Ill.) (Strip)	5,000,000	Petroleum Corp.; Hunt	
Walker-Fayette Coal Co. (Ala.) (Strip)	500,000	Industries	
Total	13,600,000		
9. Pacific Power & Light Properties		Pacific Power & Light Co.;	Utility
Pacific Power & Light Co. (Wyo.) (Strip)	2,714,322	Independent	

Table A-4. Ownership of Major Coal Producers, 1976 (Cont'd.)

Coal Company	Tonnage	Controlling Company	
		Name	Type
Bridger Coal Co. (Wyo.) (Strip) ^c	2,286,042		
Decker Coal Co. (Mont.) (Strip) ^d	5,103,824		
Washington Irrigation & Development Co. (Wash.) (Strip) ^e	2,042,123		
Total	12,146,311		
10. North American Coal Corp.		Independent	Coal
(Western Div., N.D.) (Strip)	1,122,980		
(Central Div.) (Ohio)	3,529,816		
(Eastern Div.) (Pa.)	798,729		
Florence Mining Co. (Pa.)	1,580,348		
Helen Mining Co. (Pa.)	758,694		
Oneida Mining Co. (Pa.) (Sold)	78,295		
Nacco Mining Co. (Ohio)	1,385,379		
Quarto Mining Co. (Ohio)	1,425,351		
Total	10,679,592		
11. Central Ohio Coal Co. (Ohio)		American Electric Power	Utility
(3,270,476) (Strip)	3,295,379		
Central Appalachian Coal Co. (W.Va.)			
(169,288 Strip)	597,478		
Windsor Power House Coal Co. (W.Va.)	731,745		
Southern Ohio Coal Co. (Ohio)	2,942,446		
Southern Appalachian Coal Co.			
(W.Va.) (527,006 Strip)	1,437,018		
Cedar Coal Co. (601,000 Strip) (W.Va.)	1,500,085		
Total	10,504,151		

^cPPL share of ownership 66 2/3%, remainder owned by Idaho Power Co. and reported separately.

^dPPL share of ownership 50%, remainder reported by Peter Kiewit Sons Co.

^ePPL share of ownership 50%, remainder owned by Washington Water Power Co. and reported separately.

Table A-4. Ownership of Major Coal Producers, 1976 (Cont'd.)

Coal Company	Tonnage	Controlling Company	
		Name	Type
12. Old Ben Coal Co. (Ill.)	4,927,676	Sohio Petroleum Corp.	Oil
Old Ben Coal Co. (Va.)	241,446		
Old Ben Coal Co. (Ind.) (Strip)	4,346,284		
Total	9,515,406		
13. Western Energy Co. (Mont.) (Strip)	9,264,700	Montana Power Co.	Utility
14. Westmoreland Coal Co.		Westmoreland Coal; Penn- Virginia Corp.	Coal
Hampton Div. (W.Va.) (200,000 Strip & Auger)	1,400,000		
Winding Gulf Div. (W.Va.)	1,400,000		
Imperial Smokeless Div. (W.Va.) (100,000 Strip & Auger)	700,000		
Stonega Div. (Va.) (1,200,000 Strip & Auger)	4,600,000		
Total	8,100,000		
15. Big Horn Coal Co. (Wyo.) (Strip)	751,634	Peter Kiewit Sons Co.	Construction
Rosebud Coal Sales Co. (Wyo.) (Strip)	2,182,945		
Decker Coal Co. (Mont.) (Strip) ^f	5,103,824		
Total	8,038,403		
16. Eastern Associated Coal Co.		Eastern Gas & Fuel Associates	Gas
(Pa.)	358,050		
(W.Va.)	7,358,261		
Affinity Mining Co. (W.Va.)	242,439		
Total	7,958,750		
17. Pittsburg & Midway Coal Mining Co.		Gulf Oil Co.	Oil
(Ky.W.) (2,557,920 Strip)	3,930,480		
(Colo.) (Strip)	1,140,177		

^f Owned 50% by Peter Kiewit and 50% by Pacific Power & Light Co., reported separately.

Table A-4. Ownership of Major Coal Producers, 1976 (Cont'd.)

Coal Company	Tonnage	Controlling Company	
		Name	Type
(N.M.) (Strip)	842,339		
(Mo.) (Strip)	<u>2,010,820</u>		
Total	7,923,816		
18. Utah International Inc. (N.M.) (Strip)	6,465,000	General Electric Co.	Electrical equipment
19. Freeman United Coal Mining Co. (Ill.) (2,147,772 Strip)	6,126,444	General Dynamics Corp.	Electronics, defense
20. Industrial Generating Co. (Tex.) (Strip) (Est.)	6,000,000	Texas Utilities	Utility
21. Rochester & Pittsburgh Coal Co. (Pa.) (1,000,076 Strip)	4,187,627	Rochester & Pittsburgh; Independent	Coal
Helvetia Coal Co. (Pa.)	<u>1,610,371</u>		
Total	5,797,998		
22. Falcon Coal Co. Inc. (Ky.E.) (5,141,823 Strip)	5,194,295	Falcon Seaboard, Inc.	Coal, oil, gas
23. Zeigler Coal Co. (Ill.)	4,094,000	Houston Natural Gas Corp.	Gas
(Ky.W.)	575,000		
Empire Energy Corp. (Colo.) (125,000 Strip)	<u>507,000</u>		
Total	5,176,000		
24. C & K Coal Co. (Pa.) (Strip)	2,302,000	Gulf Resources & Chemical Corp.	Chemical
Vantage Coal Corp. (Pa.) (Strip)	644,000		
Shannon Coal Co. (Pa.) (Strip)	1,074,000		
Stahlman Coal Co. (Pa.) (Strip)	502,000		
Cambria Coal Co. (Pa.) (Strip)	<u>509,000</u>		
Total	5,031,000		

Table A-4. Ownership of Major Coal Producers, 1976 (Cont'd.)

Coal Company	Tonnage	Controlling Company	
		Name	Type
25. Jewell Coal & Coke Co. (Va.)	1,570,000	Jewell Coal & Coke;	Coal
Shamrock Coal Co. (Ky.E.)	1,586,000	Independent	
Cumberland Collieries Inc. (Va.) (Strip)	1,210,000		
Total	4,366,000		
26. Alabama By-Products Corp. (Ala.)		Independent	Coal, chemicals
(160,000 Strip)	4,247,000		
27. Kemmerer Coal Co. (Wyo.) (Strip)	4,122,457	Lincoln Corp.	Coal
28. Knife River Coal Mining Co.		Montana Dakota Utilities	Utility
(N.D.) (Strip)	3,794,665	Co.	
(Mont.) (Strip)	314,814		
Total	4,109,479		
29. Westmoreland Resources (Mont.) (Strip)	4,083,894	Westmoreland Coal; Penn- Virginia Corp.; Morrison- Knudsen Co.; Kewanee Industries, Inc.	Coal, oil
30. Martiki Coal Corp. (Ky.E.) (Strip)	1,150,354	Mapco, Inc.	Oil
Webster County Coal Corp. (Ky.W.)	2,696,641		
Pontiki Coal Corp. (Ky.E.)	68,726		
Total	3,915,721		
31. Valley Camp Coal Co. (W.Va.) (123,845 Strip)	3,270,754	Quaker State Oil Refining	Oil
Valley Camp of Utah Inc. (Utah)	346,724	Corp.	
Total	3,617,478		
32. Republic Steel Corp.		Republic Steel	Steel
(Pa.)	2,083,208		
(Ky.E.)	408,570		
(Ala.)	735,784		
Total	3,227,562		

Table A-4. Ownership of Major Coal Producers, 1976 (Cont'd.)

Coal Company	Tonnage	Controlling Company	
		Name	Type
33. H. E. Drummord Coal Div. (Ala.) (Strip)	3,193,087	The Drummond Co.	Coal
34. Energy Fuels Corp. (Colo.) (Strip)	3,007,314	Energy Fuels Corp.	Uranium, coal

Sources: *Keystone Coal Mine Directory*, 1976.
Keystone Coal Industry Manual, 1977.

Table A-5. Ownership of Major Coal Producers, 1977

Coal Company	Tonnage	Controlling Company	
		Name	Type
1. Peabody Coal Co.		Peabody Holding Co.; New-	—
(Ill.) (3,807,783 Strip)	11,448,671	mont Mining Co.; Williams	
(Mo.) (Strip)	2,814,419	Cos.; Bechtel Corp; Fluor	
(Okla.) (Strip)	1,586,506	Corp.; Equitable Life	
(Ind.) (9,408,920 Strip)	9,817,812	Assurance Society; Boeing	
(Ky.W.) (10,626,583 Strip)	20,151,488	Co.	
(Ohio) (1,341,751 Strip) (190,617			
Auger)	3,581,558		
(Ala.) (Strip) (Closed)	50,097		
(Colo.) (Strip)	1,406,334		
(Mont.) (Strip)	2,343,877		
(Ariz.) (Strip)	11,325,282		
(Utah) (Sold)	363,542		
(Ark.) (Strip)	91,689		
Gibraltar Coal Corp. (Ky.W.) (Strip) ^a	744,113		
Total	65,725,388		
2. Consolidation Coal Co.		Continental Oil Co.	Oil
Eastern Region			
Allegheny (Pa.)	1,032,000		
Washington (Pa.)	2,017,000		
Moundsville (W.Va.)	4,186,000		
Subtotal	7,235,000		
Northern W. Va. Region			
Morgantown (W.Va.) (664,000 Strip)	5,860,000		
Blacksville (W.Va.)	2,443,000		
Fairmont (W.Va.) (675,000 Strip)	5,624,000		
Subtotal	13,927,000		

^aOwned jointly with AMAX Coal Co.

Table A-5. Ownership of Major Coal Producers, 1977 (Cont'd.)

Coal Company	Tonnage	Controlling Company	
		Name	Type
Southern Appalachia Region			
Bluefield (W.Va.) (772,000 Strip)	2,322,000		
Beckley (W.Va.)	954,000		
Tazewell (W.Va.)	190,000		
Tazewell (Tenn.)	706,000		
Subtotal	4,172,000		
Midwestern Region			
Underground (Ohio)	1,957,000		
Underground (Ill.)	1,854,000		
Ohio Surface (Ohio) (Strip)	3,672,000		
Illinois Surface (Ill.) (Strip)	6,371,000		
Subtotal	13,854,000		
Western Region			
United States (N.D.) (Strip)	3,701,000		
Canada (Can.) (Strip)	842,000		
Utah	264,000		
Subtotal	4,807,000		
Associated Companies:			
Harmar Coal Co. (Pa.)	429,000		
Mathies Coal Co. (Pa.)	1,524,000		
Bishop Coal Co. (W.Va.)	954,000		
Itmann Coal Co. (W.Va.)	1,092,000		
Subtotal	3,999,000		
Total	47,994,000		
3. AMAX Coal Co.			
(Ill.) (3,355,893 Strip)	5,073,578	AMAX, Inc. (20.6% owned by Standard Oil, California)	Metal, oil
(Ind.) (Strip)	6,854,806		
(Ky.W.) (Strip)	2,122,820		
(Wyo.) (Strip)	13,331,844		
Gibraltar Coal Corp. (Ky.W.) (Strip) ^b	744,113		
Total	28,127,161		

^b Owned jointly with Peabody Coal Co.

Table A-5. Ownership of Major Coal Producers, 1977 (Cont'd.)

Coal Company	Tonnage	Controlling Company	
		Name	Type
4. Island Creek Coal Co.		Occidental Petroleum Corp.	Oil
Island Creek Div. (W.Va.)	1,635,562		
Island Creek Div. (Ky.E.)	3,166,737		
Northern Div. (Pa.)	428,663		
Northern Div. (W.Va.)	2,541,525		
Northern Div. (Ohio)	0		
West Kentucky Div. (Ky.W.)	5,851,942		
Va. Pocahontas Div. (Va.)	1,969,357		
Beatrice Pocahontas Co. (Va.)	571,928		
VP-5 Mining (Va.)	68,220		
Virginia Pocahontas Co. (Va.)	322,054		
National Coal Mining Co. (W.Va.)	193,871		
Total	16,749,859		
5. Pittston Co.		Independent	Coal
Clinchfield Coal Div. (Va. & W.Va.)			
(1,583,555 Strip)	6,715,691		
Amigo Smokeless Coal Co. (W.Va.)	265,938		
Kentland Elkhorn Coal Corp. (Ky.E.)	327,743		
Jewell Ridge Coal Corp. (Va.) (149,285 Strip)	2,187,862		
Badger Coal Co. (W.Va.) (236,854 Strip)	653,098		
Sewell Coal Co. (W.Va.) (124,439 Strip)	1,189,802		
Eastern Coal Corp. (Ky.E.)	527,840		
Buffalo Mining Co. (W.Va.) (297,715 Strip)	945,140		
Ranger Fuel Corp. (W.Va.) (80,642 Strip)	521,093		
Elkay Mining Co. (W.Va.) (389,875 Strip)	919,366		
Snap Creek Coal Co. (W.Va.)	55,476		
Total	14,309,049		

Table A-5. Ownership of Major Coal Producers, 1977 (Cont'd.)

Coal Company	Tonnage	Controlling Company	
		Name	Type
6. United States Steel Corp. (Ky.E.) (W.Va.) (154,000 Strip) (Pa.) (14,000 Strip) Southern Dist. (Ala.) Western Dist. (Colo.) Western Dist. (Utah) Total	 2,381,000 3,543,000 5,462,000 1,154,000 914,000 505,000 13,959,000	U.S. Steel	Steel
7. Arch Mineral Corp. (Wyo.) (Strip) Southwestern Illinois Coal Corp. (Ill.) (Strip) Walker-Fayette Coal Co. (Ala.) (Strip) Total	 7,900,000 4,200,000 500,000 12,600,000	Ashland Oil Co.; Hunt Petroleum Corp.; Hunt Industries	Oil
8. Glenrock Coal Co. (Wyo.) (Strip) Bridger Coal Co. (Wyo.) (Strip) ^c Decker Coal Co. (Mont.) (Strip) ^d Total	 3,236,616 3,632,635 5,195,210 12,064,461	NERCO, Inc.; Pacific Power & Light	Utility
9. Texas Utilities (Tex.) (Strip) (Est.)	12,000,000	Independent	Utility
10. Bethlehem Mines Corp. (Pa.) (W.Va.) (1,589,755 Strip) (15,176 Auger) Beth-Elkhorn Corp. (Ky.E.) (348,588 Strip) (60,389 Auger) Total	 4,652,342 3,514,954 2,442,674 10,609,970	Bethlehem Steel	Steel

^cNERCO share of ownership 66 2/3%.^dNERCO share of ownership 50%, remainder reported by Peter Kiewit Sons Co.

Table A-5. Ownership of Major Coal Producers, 1977 (Cont'd.)

Coal Company	Tonnage	Controlling Company	
		Name	Type
11. Big Horn Coal Co. (Wyo.) (Strip)	2,394,532	Peter Kiewit Sons Co.	Construction
Rosebud Coal Sales Co. (Wyo.) (Strip)	2,708,888		
Decker Coal Co. (Mont.) (Strip) ^e	5,195,210		
Total	10,298,630		
12. Central Ohio Coal Co. (Ohio)	3,125,220	American Electric Power	Utility
Central Appalachian Coal Co.			
(W.Va.) (142,311 Strip)	484,999		
Windsor Power House Coal Co.			
(W.Va.)	635,206		
Southern Ohio Coal Co.			
Meigs Div. (Ohio)	2,161,425		
Martinka Div. (W.Va.)	778,632		
Braztah Mines (Utah)	909,605		
Southern Appalachian Coal Co.			
(W.Va.) (444,646 Strip)	915,243		
Cedar Coal Co. (615,005 Strip) (W.Va.)	1,212,670		
Total	10,223,000		
13. Western Energy Co. (Mont.) (Strip)	9,773,700	Montana Power Co.	Utility
14. Old Ben Coal Co. (Ill.)	4,781,748	Sohio Petroleum Co.	Oil
Old Ben Coal Co. (Va.)	126,004		
Old Ben Coal Co. (Ind.) (Strip)	4,812,695		
Total	9,720,447		
15. North American Coal Corp.		Independent	Coal
(Western Div., N.D.) (Strip)	787,897		
(Central Div.) (Ohio)	2,962,589		
(Eastern Div.) (Pa.)	502,935		
Florence Mining Co. (Pa.)	1,402,094		
Helen Mining Co. (Pa.)	763,151		

^eOwned 50% by Peter Kiewit and 50% by NERCO, reported separately.

Table A-5. Ownership of Major Coal Producers, 1977 (Cont'd.)

Coal Company	Tonnage	Controlling Company	
		Name	Type
Nacco Mining Co. (Ohio)	1,099,348		
Quarto Mining Co. (Ohio)	1,387,189		
Total	8,905,203		
16. Pittsburg & Midway Coal Mining Co.		Gulf Oil Co.	Oil
(Ky.W.) (2,137,306 Strip)	3,512,260		
(Colo.) (Strip)	1,094,290		
(N.M.) (Strip)	1,369,199		
(Mo.) (Strip)	2,226,892		
Total	8,202,641		
17. Utah International Inc. (N.M.) (Strip)	6,900,000	General Electric Co.	Electrical equipment
18. Freeman-United Coal Mining Co. (Ill.)		General Dynamics Corp.	Electronics, defense
(2,042,000 Strip)	6,700,000		
19. Eastern Associated Coal Co.		Eastern Gas & Fuel Associates	Gas
(Pa.)	215,829		
(W.Va.)	6,187,075		
Affinity Mining Co. (W.Va.)	272,296		
Total	6,675,200		
20. Westmoreland Coal Co.		Westmoreland; Penn-Virginia Corp.	Coal
Hampton Div. (W.Va.) (Part Strip & Auger)	891,857		
Winding Gulf Div. (W.Va.)	969,640		
Imperial Smokeless Div. (W.Va.) (Part Strip & Auger)	592,889		
Stonega Div. (Va.) (Part Strip & Auger)	3,823,441		
Total	6,277,827		

Table A-5. Ownership of Major Coal Producers, 1977 (Cont'd.)

	Coal Company	Tonnage	Controlling Company	
			Name	Type
21.	C & K Coal Co. (Pa.) (Strip)	2,179,000	Gulf Resources and Chemical Co.	Chemical
	Vantage Coal Corp. (Pa.) (Strip)	658,000		
	Shannon Coal Co. (Pa.) (Strip)	1,252,000		
	Stahlman Coal Co. (Pa.) (Strip)	670,000		
	Cambria Coal Co. (Pa.) (Strip)	694,000		
	Total	5,453,000		
22.	Rochester & Pittsburgh Coal Co. (Pa.) (882,150 Strip)	3,783,481	Rochester & Pittsburgh; Independent	Coal
	Helvetia Coal Co. (Pa.)	1,552,742		
	Total	5,336,223		
23.	Falcon Coal Co. Inc. (Ky.E.) (4,913,800 Strip)	5,161,822	Falcon Seaboard, Inc.	Coal, oil, gas
24.	Washington Irrigation & Development Co. (Wash.) (Strip)	4,955,242	Pacific Power & Light; Washington Water Power	Utility
25.	Knife River Coal Mining Co. (N.D.) (Strip)	4,405,593	Montana Dakota Utilities Co.	Utility
	(Mont.) (Strip)	311,385		
	Total	4,716,978		
26.	Zeigler Coal Co. (Ill.)	3,692,609	Houston Natural Gas Corp.	Gas
	(Ky.W.)	573,163		
	Empire Energy Corp. (Colo.)	444,422		
	Total	4,710,194		
27.	Drummond Coal Co. (Ala.) (Strip)	4,550,000	Independent	Coal
28.	Westmoreland Resources (Mont.) (Strip)	4,529,053	Westmoreland Coal Co.; Penn-Virginia Corp; Morrison-Knudsen Co.;	Coal, oil

Table A-5. Ownership of Major Coal Producers, 1977 (Cont'd.)

Coal Company	Tonnage	Controlling Company	
		Name	Type
29. Martiki Coal Corp. (Ky.E.) (Strip)	1,480,976	Mapco, Inc.	Oil
Webster County Coal Corp. (Ky.W.)	2,473,437		
Pontiki Coal Corp. (Ky.E.)	446,794		
Total	4,401,207		
30. Kemmerer Coal Co. (Wyo.) (Strip)	4,385,147	Lincoln Corp.	Coal
31. Energy Fuels Corp. (Colo.) (Strip)	3,850,555	Energy Fuels Corp.	Uranium, coal
32. Monterey Coal Co. (Ill.)	2,624,319	Exxon Corp.	Oil
Carter Mining Co. (Wyo.) (Strip)	1,096,240		
Total	3,720,559		
33. Alabama By-Products Corp. (Ala.) (129,476 Strip)	3,559,394	Independent	Coal, chemicals
34. R & F Coal Co. (Ohio) (Strip)	3,346,000	Shell Oil Co.	Oil
35. Virginia Iron Coal & Coke Co. (Va.) (1,244,000 Strip)	1,748,000	Bates Manufacturing, Inc.	Textiles
Avery Coal Co. (Pa.) (Strip)	1,340,000		
Total	3,088,000		
36. Valley Camp Coal Co. (W.Va.) (107,835 Strip)	2,854,323	Quaker State Oil Refining Corp.	Oil
Valley Camp of Utah Inc. (Utah)	214,220		
Total	3,068,543		

Sources: *Moody's Public Utility Manual*, 1978.
Keystone Coal Mine Directory, 1977.
Keystone Coal Industry Manual, 1978.

APPENDIX B - COAL OUTPUT CONCENTRATION RATIOS, 1973-1977

Table B-1. Coal Output Concentration, 1973

<u>Producing Company</u>	<u>Output (10³ tons)</u>	<u>Percentage of U.S. Total</u>
1. Peabody Coal Co.	69,918,787	
2. Consolidation Coal Co.	60,477,363	
3. Island Creek Coal Co.	22,879,320	
4. Pittston Co.	18,796,305	
Subtotal (4 firms)	172,071,775	29.1%
5. AMAX Coal Co.	16,657,552	
6. U.S. Steel	16,222,038	
7. Bethlehem Steel	14,129,000	
8. Ashland Oil	12,538,631	
Total (8 firms)	231,618,996	39.1%
Total production, 1973	591,738,000	

Source: *Keystone Coal Mine Directory*, 1973.

Table B-2. Coal Output Concentration, 1974

<u>Producing Company</u>	<u>Output (10³ tons)</u>	<u>Percentage of U.S. Total</u>
1. Peabody Coal Co.	68,104,076	
2. Consolidation Coal Co.	51,753,933	
3. Island Creek Coal Co.	20,848,017	
4. AMAX Coal Co.	19,948,871	
Subtotal (4 firms)	160,654,897	26.6%
5. Pittston Co.	17,381,911	
6. U.S. Steel	16,389,000	
7. Ashland Oil Co.	13,878,539	
8. Bethlehem Steel	13,347,625	
Total (8 firms)	221,651,972	36.7%
Total production, 1974	603,406,000	

Source: *Keystone Coal Mine Directory*, 1974.

Table B-3. Coal Output Concentration, 1975

<u>Producing Company</u>	<u>Output (10³ tons)</u>	<u>Percentage of U.S. Total</u>
1. Peabody Coal Co.	73,050,534	
2. Consolidation Coal Co.	54,919,202	
3. AMAX Coal Co.	21,839,895	
4. Island Creek Coal Co.	<u>19,421,121</u>	
Subtotal (4 firms)	169,230,752	26.1%
5. Pittston Co.	18,554,302	
6. U.S. Steel	17,115,873	
7. Ashland Oil	13,467,767	
8. Bethlehem Steel	<u>13,355,111</u>	
Total (8 firms)	231,723,805	35.7%
Total production, 1975	648,438,000	

Source: *Keystone Coal Mine Directory*, 1975.

Table B-4. Coal Output Concentration, 1976

<u>Producing Company</u>	<u>Output (10³ tons)</u>	<u>Percentage of U.S. Total</u>
1. Peabody Coal Co.	70,542,457	
2. Consolidation Coal Co.	55,888,000	
3. AMAX Coal Co.	23,061,000	
4. Island Creek Coal Co.	<u>17,606,404</u>	
Subtotal (4 firms)	167,097,861	24.6%
5. Pittston Co.	17,101,629	
6. U.S. Steel	15,982,000	
7. Bethlehem Steel	14,055,038	
8. Ashland Oil	<u>13,600,000</u>	
Total (8 firms)	<u>227,836,528</u>	33.6%
Total production, 1976	678,685,000	

Source: *Keystone Coal Mine Directory*, 1976.

Table B-5. Coal Output Concentration, 1977

<u>Producing Company</u>	<u>Output (10³ tons)</u>	<u>Percentage of U.S. Total</u>
1. Peabody Coal Co.	65,425,088	
2. Consolidation Coal Co.	47,994,000	
3. AMAX Coal Co.	28,127,161	
4. Island Creek Coal Co.	<u>16,749,859</u>	
Subtotal (4 firms)	158,296,108	22.9%
5. Pittston Co.	14,309,049	
6. U.S. Steel	13,959,000	
7. Ashland Oil	12,600,000	
8. NERCO, Inc.	<u>12,064,461</u>	
Total (8 firms)	<u>211,228,618</u>	30.5%
Total production, 1977	691,344,000	

Source: *Keystone Coal Mine Directory*, 1977.

APPENDIX C - COAL CLEANING

Tables C-1 and C-2 contain information on coal cleaning by deep mines and surface mines in 1978. The EIA-7 data do not distinguish between mines reporting no coal cleaning and mines which did not respond to the question (i.e., mines for which the data are missing). The data in Tables C-1 and C-2 are thus broken into mines that reported coal cleaning and those that did not report coal cleaning (which may include some mines who are cleaning coal but did not report it).

Cleaning coal can influence mine productivity and the prices received for coal. As shown in Table C-1, only for small deep mines in Appalachia is the difference in coal cleaning significant between majors and nonmajors. For the larger deep mines in all regions, virtually the same proportion of output was cleaned by majors and nonmajors.

Table C-2 details cleaning by major and nonmajor surface mines. In all regions but the West, nonmajors clean significantly less of their output than majors. In the West, there is no statistical difference in the extent of coal cleaning between large surface mines controlled by majors and those controlled by nonmajors (both majors and nonmajors clean very little); and major firms control no small surface mines.

Table C-1. Coal Cleaning by Mine Size, Region, and Ownership for Deep Mines, 1978

Mine Size < 100,000 Tons Annually	Number of Mines											
	Appalachia				Interior				West			
	Nonmajor		Major		Nonmajor		Major		Nonmajor		Major	
	N	%	N	%	N	%	N	%	N	%	N	%
Cleaning reported	318	18.3	89	74.8	3	30.0	a		4	23.5	0	0.0
Cleaning not reported	1,424	81.7	30	25.2	7	70.0	a		13	76.5	1	100.0
Total	1,742	100.0	119	100.0	10	100.0	a		17	100.0	1	100.0
χ^2 probability	.0001				b				b			
Mine Size ≥ 100,000 Tons Annually												
Cleaning reported	151	68.6	144	73.5	9	69.2	27	62.8	15	55.6	6	66.7
Cleaning not reported	69	31.4	52	26.5	4	30.8	16	37.2	12	44.4	3	33.3
Total	220	100.0	196	100.0	13	100.0	43	100.0	27	100.0	9	100.0
χ^2 probability	.278				.671				.558			

^aNo mines reported.

^bData insufficient for χ^2 computations.

Source: EIA-7.

Table C-2. Coal Cleaning by Mine Size, Region, and Ownership for Surface Mines, 1978

Mine Size < 100,000 Tons Annually	Number of Mines											
	Appalachia				Interior				West			
	Nonmajor		Major		Nonmajor		Major		Nonmajor		Major	
	N	%	N	%	N	%	N	%	N	%	N	%
Cleaning reported	82	3.6	22	43.1	3	0.3	1	33.3	2	11.8	a	
Cleaning not reported	2,204	96.4	29	56.9	230	98.7	2	66.7	15	88.2	a	
Total	2,286	100.0	51	100.0	233	100.0	3	100.0	17	100.0	a	
χ^2 probability		.0001				.0001					b	
Mine Size ≥ 100,000 Tons Annually												
Cleaning reported	46	12.8	23	44.2	17	21.2	38	70.4	0	0.0	2	5.0
Cleaning not reported	313	87.2	29	55.8	63	78.8	16	29.6	9	100.0	38	95.0
Total	359	100.0	52	100.0	80	100.0	54	100.0	9	100.0	40	100.0
χ^2 probability		.0001				.0001					.493	

^aNo mines reported.

^bData insufficient for χ^2 computation.

Source: EIA-7.

APPENDIX D - EIA-7 SURVEY FORM

EIA 7
10/77
Supersedes
BOM Form No. 6-1401-A

U.S. DEPARTMENT OF ENERGY
Energy Information Administration
Washington, D.C. 20241

Form Approved
O.M.B. No. 038-R0194

BITUMINOUS COAL AND LIGNITE
PRODUCTION AND MINE OPERATION

(Please correct if name or address has changed.)

This report is being collected under mandatory authorities vested in the U.S. Department of Energy under Public Law 93-275 pursuant to Public Law 95-61.

1 - Identification		Identification Number									
Name of reporting producer											
Mailing address of producer: Street		City				State			Zip		
Name of mine											
Location of mine: State		County				Post Office					
2 - Kind of Operation (Check one) ☐ (1) Drift ☐ (2) Shaft ☐ (3) Slope ☐ (4) Strip only ☐ (5) Auger only											
☐ (6) Strip and auger combination ☐ (7) Other (specify) _____											
3 - Status During Year											
If mine produced no coal during year, check reason ☐ (1) Idle ☐ (2) Abandoned ☐ (3) Out of business											
Did mine name and/or mine ownership change during year ☐ (1) Yes ☐ (2) No If Yes, give date of change _____ and, if applicable, new mine name and name and address of new owner _____											
4 - Coal Bed											
a. Name or number of coal bed _____											
b. Average thickness of bed - excluding partings _____ Inches											
c. Estimated remaining recoverable coal in this mine _____ Short tons											
5 - Coal Production and Value by Disposition											
Include all coal shipped to consumer and that used for mine fuel and sold to employees; exclude purchased coal and washery or other refuse.											
Item (1)		Code	Quantity (Short tons) (2)		Total value (f.o.b. mine) (3)						
a. Coal shipped by rail or water (include coal hauled by truck to railroad station or waterway).....		010									
b. Coal shipped by truck from mine to final destination (Exclude coal used by mine employees).....		020									
c. Coal transported to electric utility plants adjacent to or near mine mouth.....		030									
d. All other coal produced.....		040									
e. TOTAL annual production (Clean or as shipped).....		050									
a. Coal sold in open market and coal used as colliery fuel.....		060									
b. Captive coal, coal not sold in open market (Estimate value) (Include only coal used by producing or subsidiary company).....		070									
c. TOTAL production and value by disposition.....		080									

6 - Transportation of total tonnage shipped

Name of railroad or waterway on which product was first loaded (1)	Quantity loaded (Short tons) (2)	Tonnage included in (2) shipped by unit train (3)

7 - Shipments and average sulfur content, by use

Item (1)	Code	United States uses				Exports (Include Canada and Mexico) (6)	Use unknown to producer (7)	Total (8)
		Electric utilities (2)	Coke plants (3)	Other - in- dustrial uses and retail dealers (4)	All other uses 1/ (5)			
Quantity shipped (Short tons).....	010							
Average sulfur content as shipped dry basis (Percent).....	020							
Average value per ton f.o.b. mine (Dollars).....	030							

1/ Include railroad fuel, shipments to Great Lakes and tidewater commercial docks (excluding Canada), mine fuel, sales to mine employees, and not change in mine inventory.

2/ Total short tons shown should be the same as reported in Section 5, Line Code 050.

8 - Underground mine operations

(1)		(2) Code	(3) Number of machines in operation	(4) Quantity (Short tons)
A. Coal mined by different methods:				
1. Continuous mining machines.....		010		
2. Conventional methods:				
a. Cutting machines.....		020		
b. Shot from solid or cut by hand.....		030		
3. Longwall machines (Please check) ☐ (1) Planer ☐ (2) Shearer.....		040		
B. Power drilling by type of drill:			Number of drills	
1. Coal drills:				
a. Hand-held and post-mounted.....		050		
b. Mobile drills.....		060		
2. Roof Bolters:			Number for roof bolting	
a. Rotary drills.....		070		
b. Percussion drills.....		080		
c. Rotary-percussion combination drills.....		090		
C. Coal loaded at face by different methods:			Number of machines in operation	Quantity (Short tons)
Do not include number of shuttle cars, rubber-tired mine cars, or conveyors	By mobile loading machines:			
	Into shuttle cars or rubber-tired mine cars.....	100		
	Onto belt conveyors.....	120		
	By continuous mining machines:			
	Into shuttle cars or rubber-tired mine cars.....	130		
	Onto extensible conveyors.....	150		
	Mobile loader pick up.....	160		
	By shortwall machines.....	165		
	By longwall machines.....	170		
	By scoops.....	180		
Total tonnage mechanically loaded.....		190		
Total tonnage hand-loaded into conveyance equipment.....		200		
Total underground production.....		210		

9 - Underground haulage

Item (1)	Code (2)	Railroad						Rubber-tired vehicles								Avg. Length Ft. (16)
		Locomotives		Mine cars (4)	Personnel and supply cars (5)	Rail track (miles)		Tractors (8)	Mine cars (9)	Shuttle cars			Shuttle buggies hand- loaded (13)	Scoops Clean up (14)	Personnel and supply cars (15)	
		Trolley (3)	Battery			Main line (6)	Spurs and sidings (7)			Cable haul (10)	Diesel (11)	Battery				
Number.....	010															
Capacity (Short tons).....	020															

1/ Include all gathering, main haulage, extensible belt, slope, and face or room conveyors.

10 - Surface mine operations

(1) Total coal mined by stripping _____ (Short tons) (4) Average thickness, overburden _____ (Feet)
 (2) Total coal mined by auger _____ (Short tons) (5) Total area mined _____ (Acres)
 (3) Overburden excavated _____ (Cubic yards) (6) Total area reclaimed _____ (Acres)

11 - Surface equipment

Type of machinery (1)	Code (2)	Total number (3)	Number of machines classified by kind of power used				Number of machines classified by size or bucket capacity in cubic yards			
			Electric (4)	Diesel electric (5)	Diesel (6)	Gasoline (7)	Less than 6 (8)	6-15 Inclusive (9)	16-30 Inclusive (10)	More than 30 (11)
Coal recovery augers.....	010									
Power shovels.....	020									
Dredging excavators.....	030									
Carnall scrapers.....	040									
Buildoers.....	050									
Power drills (Horizontal).....	060									
Power drills (Vertical).....	070									
Front end loaders.....	080									
Wheel excavators.....	090									
Power brooms.....	100									
Motor graders.....	110									
Coal drills.....	120									

12 - Off-the-highway trucks

Capacity (Short tons) (1)	Code (2)	Total number in use			Haulage distance (5)
		End dump (3)	Side dump (4)	Bottom dump (5)	
Under 20.....	010				
20 to 50.....	020				
51 to 100.....	030				
Over 100.....	040				

13 - Mechanical cleaning (Include coal from other mines and purchased coal)

Report tonnage cleaned by type of equipment and method. Estimate if necessary

Type of equipment (1)	Code (2)	Manufacturer (3)	Quantity (Short tons)			Method of conveying refuse (6)
			Raw coal cleaned (4)	Cleaned product (5)	Refuse (6)	
Wet methods						(Please check)
Jigs.....	010					Truck..... ☐
Concentrating tables.....	020					Pipeline..... ☐
Classifiers.....	030					Aerial tram..... ☐
Loaders.....	040					Rail..... ☐
Dense medium processes						Other (Specify)..... ☐
Magnetite.....	050					
Sand.....	060					
Calcium hydroxide.....	070					
Flotation.....	080					
Pneumatic methods.....	090					
TOTAL.....	100					

(170) Name of cleaning plant

Location

14 - Other coal preparation

(1) Tonnage prepared by crushing or screening only..... (Short tons)
 (2) Tonnage loaded for shipment without processing..... (Short tons)

15 - Thermal drying (Exclude electrically heated vibrating screens)

Type of dryer (1)	Code	Manufacturer (2)	Number of units (3)	Size of feed (4)	Quantity dried (Short tons) (5)
Fluidised-bed.....	010				
Multilouver.....	020				
Rotary.....	030				
Screen.....	040				
Suspension or flash.....	050				
Vertical tray and cascade.....	060				
Total.....	070				

MANSHIFTS include all men engaged in production, preparation (at cleaning plant), development work, maintenance and repair work including supervisory and technical personnel at the operation. At underground mines include all men working in surface mine shops and yards, etc. Include proprietors and firm members (owners, operators, or partners) performing manual labor. Calculate by dividing total man-hours by customary length of shift. Exclude office worker.

PRACTICAL POTENTIAL is the highest level of output under realistic conditions. Assume availability of labor and materials sufficient to utilize machinery and equipment in place and ready to use during the year. Take into account the additional down-time for maintenance or repair which would be required. Do not consider added costs (additional personnel, overtime pay, materials, repairs, etc.) to be limiting factors on potential.

16 - Operational Statistics for Calendar Year

Year (1)	Code	Total man hours (2)	Total days worked (3)	Manshifts worked (4)
	010			

17 - Actual and Practical Potential for Employment and Production, Fourth Quarter

Fourth quarter (1)	Code	Total man hours (2)	Average number of shifts per day (3)	Average number of men per shift (4)	Total days worked (5)	Total production (Short tons) (6)
Actual.....	010					
Practical potential.....	020					

18 - Mine Operating Constraints, Fourth Quarter

If mine operated at less than practical potential, rank the following reasons in order of importance. Enter "1" for the most important reason "2" for the second most important reason and so forth. Rank only those reasons that affected your operations.

☐ (a) Manpower shortage ☐ (b) Absenteeism ☐ (c) Railroad car shortages ☐ (d) Shortages of materials and supplies
☐ (e) Environmental regulations ☐ (f) Lack of coal demand ☐ (g) Strike ☐ (h) Other (specify) _____

Remarks:

Name of person to be contacted regarding this report			Tel area code		No.	Ext.
Address		No.	Street	City	State	Zip

Information requested on this form is confidential and if released will cause substantial competitive injury. Yes ☐ No ☐

Written substantial justification is attached. Yes ☐ No ☐

Certification

I certify that the information provided herein and appended hereto is true and accurate to the best of my knowledge.

Name _____ Title _____

Signature _____ Date _____

Title 18, USC 1001. Makes it a crime for any person knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

APPENDIX IV

COAL TAXATION SUMMARY REVIEW

U.S. DEPARTMENT OF ENERGY
memorandum

DATE: NOV 1980

REPLY TO
ATTN OF EI-551 (Regulatory and Competitive Analysis Division)

SUBJECT Coal Taxation Summary Review

TO: The Record

The purpose of this memorandum is to provide a summary review of a Contractor Report, "Energy Taxation: An Analysis of Selected Taxes," prepared by the National Academy of Sciences (Contract DEAC-0179 EI-10553).

This summary was requested by Len Coburn of Policy and Evaluation to assist them in their evaluation of the effects of government policies on the market performance of the coal industry.

Coal is an energy source subject to tax provisions of all three levels of Government--Federal, State, and in a few states, local. The principal taxes on coal are income, property, and production (or severance) taxes. This paper discusses these coal taxes, and indicates their likely effects on coal markets. The paper begins with a discussion of the direct and indirect effects of coal taxes in general it then discusses property and production taxes, federal income taxation, investment tax credits, and concludes with a discussion of the state taxation of coal.

Direct Effects of Coal Taxation

Consider a state severance tax on coal production at a fixed rate of, say, $\$t/\text{ton}$, payable by coal-producing firms. For simplicity, suppose that it is the only tax operative in the coal market, and assume that coal is produced and supplied under competitive conditions. We can assess the effects of the tax on the coal market by comparing the equilibrium price and quantity of coal produced before and after the tax goes into effect. The coal market is depicted diagrammatically in Figure 1.

To see what effect a severance tax would have in this situation, we need only ascertain how the tax would affect the supply and demand curves. When the tax of $\$t/\text{ton}$ is imposed, mining firms recognize that $\$t$ must be paid to the state government for every ton of coal sold. Thus they are now willing to supply a particular quantity only if they receive a price $\$t$ higher than the price previously sufficient to induce that quantity of supply.

This can be represented in Figure 1 by shifting the supply curve backward by $\$t/\text{ton}$ at every quantity supplied. This results in a new supply curve, S_1 , which represents, for every tax-inclusive price, the reduced quantity of coal that sellers will now supply at that price.

Figure 1. Effect of Production Taxes on the Coal Market

The impact of the excise tax is reflected in the new equilibrium determined by the backward-shifted supply curve and the original demand curve. This new equilibrium occurs at the point E_1 and $P_1 > P_0$; corresponds to a higher (tax-inclusive) price for consumers, a lower net price for producers, $P_1 - t < P_0$; and a lower quantity bought and sold in the market, $Q_1 < Q_0$. The market is represented by the shaded area in Figure 1.

All of the major effects of the tax are summarized in Figure 1: revenue is raised, the quantity produced and consumed falls, and economic burdens are imposed on both buyers (who pay a higher price than before) and sellers (who receive a lower net price). In effect, for each ton of coal sold in the market, the government receives $\$t$, of which $(P_1 - P_0)$ is paid by consumers and $\$[P_0 - (P_1 - t)]$ is paid by producers. Of course the entire $\$t/\text{ton}$ is collected from the producer, who is the legal taxpayer. The division of the total tax payment between economic agents is the incidence of the tax. It is important to understand that the incidence of a tax depends on the positions and slopes of the supply and demand curves but is independent of the legal designation of the taxpayer. Collecting the coal excise tax from consumers instead of producers would lead to exactly the same market outcome.

To understand these effects more precisely, we need to consider both the elasticity of supply and elasticity of demand. Essentially, the price elasticity of demand (supply) is a measure of the sensitivity of the quantity of coal desired by consumers (offered by producers) to a change in the price of coal. More technically, the price elasticity of demand is the percentage decrease (increase) in quantity demanded induced by a 1-percent increase (reduction) in price; and the price elasticity of supply is the percentage increase (decrease) in quantity supplied induced by a 1-percent increase (decrease) in price. If the elasticity of demand (or supply) is greater than 1, demand (or supply) is said to be relatively elastic, and the corresponding curve is relatively flat when diagrammed. Conversely, if the elasticity is less than 1, the demand (or supply) is said to be inelastic; and the corresponding curve is relatively steep when diagrammed.

Returning to Figure 1, it can be seen that the more inelastic the demand or the supply curve, the less is the effect of the tax on the quantity of coal bought and sold in the market. That is to say, an excise tax has only a slight effect on resource allocation when either demand or supply is relatively inelastic, i.e., relatively insensitive to price. Under these circumstances, government tax revenues per unit of tax are greater than when supply and demand are relatively elastic. Moreover, if demand is elastic and supply is relatively inelastic, the incidence of the tax falls primarily on

producers. Conversely, if demand is inelastic and supply is relatively elastic, the tax incidence falls primarily on consumers. The general point is that the market participant whose behavior is more price sensitive can shift the burden to others and bear less of the burden directly. These effects can be seen by varying the slopes of the demand and supply curves in Figure 1.

In estimating the effects of a tax, the time frame of an analysis is important. In Figure 1, the posttax supply and demand curves, S_1 and D_0 represent the quantities supplied and demanded over a particular period (say, one year) during which a given price is maintained. But in the long-run, producers and consumers can adjust in more fundamental ways to the tax-induced price increase, and demand and supply curves become more elastic. This means that, relative to its short-run effects, an excise tax of a fixed rate can be expected to generate less revenue and to reduce output by a larger amount after it has been in effect for a longer time, say, a number of years. Similarly, the relative incidence of a tax can be expected to shift over time.

In the case of coal, for example, it is reasonable to assume that demand is more inelastic than supply in the short-run and that both demand and supply are more elastic in the long-run than in the short-run. Unless production is at capacity, supply can be varied in response to short-run price changes by working existing mines more or less intensively. For example, larger or smaller crews can be

employed and overtime adjusted. In the longer-run, new mines can be dug in existing fields and new fields can be developed. On the other hand, the demand for coal in the short-run is closely tied to the capital equipment in place. The type of fuel used in electricity generation, for example, must be compatible with existing boiler facilities. Thus while some short-run response to coal price increases may be expected, a large fraction of the demand is "locked in." In the longer-run, as existing capital equipment wears out and is replaced, substitution away from higher-priced coal may turn out to be an attractive option. In brief, the longer-run demand response is likely to be much greater than the short-run response. While initially the incidence of an excise tax on coal falls primarily on consumers in a competitive market, over time the incidence will shift towards producers.

The distinction between short-run and longer-run time frames has important implications for energy policy. Because of inelastic short-run demand curves, some observers might see (or foresee) little initial impact of taxation on the quantity consumed and conclude erroneously that taxation is an ineffective instrument of energy conservation or that taxation does not seriously affect supply. This conclusion overlooks the important effects of a tax that appear only after it has been in force (and is expected to remain in force) for some time. In general, when there are substantial differences between short-and

long-run elasticities (as is the case in most energy markets), tax policy is not an effective means of altering consumption in the short-run. And to be effective in the long-run, the tax should be perceived as permanent; otherwise, users of an energy resource may not adjust their capital investment policies to reduce consumption of the resource.

Having considered revenue, price and quantity, and distribution effects in the short- and long run, let us now turn to economic efficiency. An excise tax on coal reduces the efficiency with which the market operates because producers and consumers together lose more as a result of the tax than the government gains in revenue. Notice in Figure 1 that many purchases made at the pretax equilibrium price P_0 would also have been made at higher prices. For example; even though some consumers are forced out of the market when the tax boosts the price to P_1 many consumers remain in the market. These consumers enjoyed a surplus of benefits over the price paid for coal at the initial equilibrium. This excess of what they would have been willing to pay for a given amount of coal over what they actually had to pay is called consumers' surplus. Similarly, many sellers supplying coal at the price P_0 would have been willing to sell at least some coal even at lower prices. The excess of what producers actually receive in a market over the minimum payment necessary to induce their supply is called producers' surplus. These surpluses arise because of the downward slope of the demand curve and the upward slope of the supply curve. The total consumer's (or producers')

surplus enjoyed at price P_0 is represented by the area between the demand (or supply) curve and the horizontal line at the price level P_0 . Thus the consumers' surplus at the initial equilibrium is the triangular area BE_0P_0 ; while the producers' surplus is the triangular area AE_0P_0 . Those areas represent the net benefit of participation in the market to consumers and producers, respectively.

When the excise tax of $\$t/\text{ton}$ is imposed, the price paid by consumers rises and the price received by producers net of the tax falls. Thus the net benefit of market participation to both groups is reduced. Moreover, as may be seen from the figure, the size of this reduction exceeds the revenue from the tax by the area E_1E_0C . This area is referred to as the excess burden of taxation and represents a net loss to society from the presence of the tax.

If the demand and supply curves are nearly linear (that is, straight lines) or if the tax rate is small as a percentage of the pretax price, the area E_1E_0C is close to being a triangle and is approximately equal to $\$1/2t(Q_0 - Q_1)$. Since the excess burden of a tax increases with the tax rate and with the amount of the reduction in quantity produced that results from the tax, the excess burden is greater when demand and supply are relatively elastic and, consequently, is greater in the long-run than in the short-run.

The taxation of commodities generally involves some excess burden. However, there are two notable situations when this efficiency loss does not occur, and these are of particular interest for energy. The first situation occurs when the supply of the commodity in question is perfectly inelastic. That is, the quantity made available in the market is independent of the price offered for it. The classic example is land, which has no value in any alternative use other than the use which is taxed. In this situation the total receipts of the suppliers of the commodity are producers' surplus by the definition above. Such earnings constitute one form of what in economics is called rent. Taxation under these circumstances leads to no change in production, and its burden is borne entirely by the sellers. Moreover, the amount by which rents are reduced just equals the tax revenue raised, so there is no excess burden. Thus proceeds from the sale of any commodity available in fixed supply with no alternative economic use can be directly taxed without loss of efficiency.

This aspect of rent taxation is important in energy markets because the supply of land to coal or oil producers (but not coal and oil themselves) is usually quite inelastic. That is, most land used to produce energy resources has a much lower economic value in any alternative use. It does little harm to the use of the surface to drain oil from below, for example, and coal is often produced from lands that, even if temporarily disturbed, have relatively low values in alternative uses. Thus the portion of coal producers' costs that

accrue as royalties to the landowners are largely rents to the landowner. These royalties can be directly taxed without greatly affecting the market equilibrium.

The second situation in which taxation need not lead to excess burden occurs when either production or consumption of the commodity in question involves economic costs that are not fully paid by the buyers or sellers in the market. Such costs are called external diseconomies and may arise for various reasons. If the production of the commodity in question causes noise, air, or water pollution damage, for example, and if the producing firms are not required to pay the full costs of such damage, then taxation may actually improve economic efficiency by causing the firms to bear the monetary cost of production that more closely approximates the true social costs of production. (By social costs we mean the total resource costs of production, including those paid by producers and those unpaid by producers but nonetheless borne by society). Similarly, if individual consumption of a good imposes costs on society as a whole, then a wedge between buying and selling prices (reflecting the taxation of this external cost of consumption) may lead to a more efficient outcome in the market. Dependence arising from the consumption of imported oil is an example of such an external cost. In the presence of external diseconomies, taxation can be an important tool for achieving greater efficiency.

This discussion of an excise tax on coal is intended to illustrate many of the important principles in the analysis of the direct effects, and it is used, implicitly if not explicitly, throughout this report. There are, however, other considerations having to do with the indirect or secondary effects of commodity taxation.

Indirect Effects of Coal Taxation

Among the most important of the indirect effects of a tax are the backward or forward shifting of the tax burden. Most goods produced through the complex technology of our economy go through a production process with stages from the extraction of the raw materials to the delivery of the final product. A tax on any intermediate good reduces the net price received by producers of the intermediate good and increases the price paid to consumers. The tax is said to be shifted forward to the extent that the burden ultimately falls on users at a later stage of the process.

To illustrate, consider what happens after the imposition of an excise tax on coal as an intermediate good. For the sake of simplicity, assume that coal producers use only three factors of production, land, labor, and equipment; that buyers of coal use the coal to produce electricity; and that electricity is sold directly to households at cost (as a result, say, of utility rate regulation). We have already determined that the tax on coal reduces the net price received by producers of coal and raises the price paid by buyers of coal. The

buyers of coal pass along their cost increases to consumers of electricity, if they are able to do so, causing that part of the burden of the coal tax to fall on electricity consumers. Recall that this burden is larger when the demand for coal by producers of electricity is less elastic. Since this elasticity is expected to be very small in the short-run, most of the burden of the tax on coal is shifted forward to the users of electricity. In the longer-run, however, demand for coal is much more elastic because producers of electricity switch habits. This means that less of the burden of the coal tax is shifted forward in the long-run and that the part shifted forward is borne partly by the users of electricity and partly by the manufacturers of coal-fired boilers.

Because the price received by coal producers declines as a result of an excise tax, some backward shifting of the burden to suppliers of land, labor, and equipment also occurs. Imagine a diagram like Figure 1, depicting the market for each of these factors of production. The supply curve would represent the supply responsiveness of landowners workers, or equipment manufacturers to the prices received. The demand curve would reflect the desired purchases of these goods by all firms using them as inputs, including coal producers. When the net price received by coal producers declines due to the excise tax, their desired level of production and their profitability also decline. This reduces their demand for labor and equipment and their willingness to pay for the uses of coal-

bearing land. The ultimate effect is to lower the prices received by the sellers of labor, of mining equipment, and of coal land. This effect is greater when the taxed coal producers represent a large fraction of the purchases of labor, equipment, and land. Backward shifting from coal producers is likely to be greater for landowners and workers since their supply curves are relatively inelastic and nearly all of the demand for their goods and services comes from the taxed coal producers.

Moreover, when the mining industry is widely dispersed among states, there is a tendency for the tax burden of a single state's severance tax to be shifted backward to the factors of coal production in that state in the long-run. Under competitive conditions this occurs because the coal producers would be earning no long-run economic profit either before or after the tax. (The profits reported in their accounting statements would represent only a normal return in equity capital, i.e., part of the cost of production). The excise tax, by lowering revenues to producers in the short-run, would lead to the contraction of coal production in the taxing state via the exit of marginal firms no longer able to earn the economy-wide normal rate of return. The long-run result would be that the demand for (and hence earnings of) productive factors used by the mining industry would be reduced, though the remaining mining firms would continue to earn the normal return on investment.

Coal Production and Property Taxes

The Nature of Energy Production and Property Taxes

Production taxes refer to taxes that are levied on energy sources as they are "produced," which often relates, either directly or indirectly, to that stage of development at which the energy source is "severed" from the earth; hence the term severance tax is often used. Severance taxes are taxes that are levied either on a per-unit or ad valorem basis. They are closely analogous to the common excise taxes that are levied on particular commodities; the major distinction is that severance taxes are at the time of production rather than at the time of sale. However, if there are no inventory buildups, there is no basic difference, and in this report we treat both production and excise taxes levied at the production stage as being equivalent. Severance-type taxes are the most prevalent production tax at the state and local level, with the tax rates and bases varying among energy sources and among states. The other significant type of state production tax is one that is levied on production on the basis of value times some local mill level.

Production taxes are numerous at the state level and are of growing importance. The diversity of the taxes is shown in Table 1, which presents a summary of state production taxes on coal.

Table 1. State Production Taxes on Coal ^a

State	Production Tax Rate
Alabama	33.5¢ per ton
Arkansas	2¢ per ton
Colorado ^{b,c}	60¢ per ton after first 8,000 tons of quarterly production
Florida	5% of gross value
Idaho	2% of net value
Kentucky ^c	4.5% of gross value
Louisiana ^d	10¢ per ton
Montana	The tax varies with the heating quality of the coal and is the greater of: 12-40¢ per ton or 20-30% of FOB mine price on surface mined coal; and 5-12¢ per ton or 3-4% of FOB mine price on underground coal.
New Mexico ^{b,d}	19.2¢ per ton on metallurgical Coal plus surtax 40.5¢ per ton on steam coal plus surtax.
North Dakota ^b	65¢ per ton
Ohio	4¢ per ton
South Dakota	4.5% of taxable value
Tennessee	20¢ per ton
Utah	2% of gross value
Wyoming ^{b,d}	10.5% of gross value

^aGovernmental units impose various nominal taxes to finance conservation and regulatory activities. These types of taxes are omitted from the table.

^bSix states impose excise taxes on the initial sale of coal--Arizona 2.5% of gross receipts, Colorado 3% of gross receipts (coal used for industrial purposes is exempt), New Mexico 4.75%, West Virginia 3.85%, Wyoming 3% (coal used for manufacturing is exempt) and North Dakota 2.5%.

^cThree states impose property taxes on the value of unmined coal, Arizona, Colorado, and Kentucky.

^dProduction taxes also imposed at the local governmental level. In Arizona, production taxes are imposed at the local level but not at the state level.

SOURCE: National Research Council, A Taxonomy of Energy Taxes. Steering Committee on the Impact of Taxation on Energy Markets. Washington, D.C.: National Academy of Sciences, 1979.

In several states property taxes are levied on primary energy sources. These taxes are not important at the state level, but they are significant revenue sources at the local level. As noted below, property taxes have effects on production that are analytically interesting when contrasted to the effects of production taxes.

Features of Production Taxes

Production taxes are levied primarily by subnational units in the form of severance taxes. The federal government imposes only two production taxes, both of which are excise taxes, both enacted in 1977. While not important as a source of federal revenue, they are of interest here. The Black Lung Benefits Revenue Act (P.L. 95-227) taxes surface-mined coal at \$0.25 per ton and underground coal at \$0.50 per ton for the purpose of assisting miners with lung-related diseases. The Surface Mining Control and Reclamation Act (P.L. 95-87) taxes coal (including lignite) at the rate of \$0.15 per ton for underground-mined coal, \$0.35 per ton on surface-mined coal, and \$0.10 for lignite for a fund for the reclamation of abandoned strip-mined lands.

At the state level, severance-type taxes are being increasingly relied on by mineral-rich states as a source of general revenue (see Table 1). Moreover, in the case of Alaska, in addition to the state's realization of revenue from oil production, substantial revenues are generated from the state's royalty share of production from state-owned lands and from the state's share of federal bonus, royalty, and rental payments. The resulting revenue surpluses in Alaska led to

legislation distributing revenues back to residents (in the form of dispersible tax credits) based on their length of residence in Alaska.

Distribution of Production Tax Revenues

A relatively few states dominate the production of U.S. energy minerals and receive the bulk of the revenues generated by production taxes. This geographic concentration in production is in marked contrast to the dispersed use of energy minerals, which offers the opportunity for fiscal conflict between energy-producing and energy-importing states. Coal resources and production are widely dispersed, as can be seen in Table 2. However, because of the importance of transportation and mining costs relative to the value of the mineral resource, coal production rates are not governed as rigidly by resource endowment as is the case with the other fuels. Furthermore, the coal market is customarily separated into eastern and western submarkets.

Many states produce coal from publicly owned lands, either federal or state, and consideration of production taxes must take into account the ability of authorities to tax the production of coal from such deposits owned by other government bodies. Typically, states have collected severance taxes on onshore production of federal leases of all minerals, including coal. The federal coal excise taxes, referred to above, apply to all production regardless of ownership. Production taxes are distinct from rents and royalties going to government from owned deposits, though the revenue in each case comes from the same activity.

Table 2. Coal Production in the United States, 1979^a

Eastern States	Thousand Short Tons	% of U.S. Production
Kentucky	142,000	18.3
West Virginia	114,600	14.8
Pennsylvania	91,250	11.8
Illinois	59,150	7.6
Ohio	45,600	5.9
Virginia	41,570	5.4
All other states	65,875	8.5
Total	560,045	72.2 ^b
Western States	Thousand Short Tons	% of U.S. Production
Wyoming	71,825	9.3
Montana	32,825	4.2
Texas	26,600	3.4
Colorado	17,950	2.3
North Dakota	14,055	1.8
New Mexico	13,730	1.8
Arizona	11,275	1.5
All other states	27,820	3.6
Total	215,705	27.8 ^b
U.S. Total	775,750	100.0

^a preliminary figures.

^b May not add up to total section percentage due to rounding.

SOURCES: (1) Energy Information Administration, Production of Coal, bituminous and lignite, 1980 per week. P.13 in Energy-Data-Reports. Washington, D.C. : U.S. Department of Energy, March 14, 1980.

(2) Energy Information Administration, Pennsylvania anthracite weekly production, 1980. P.2 in Energy-Data-Reports Washington, D.C.: U.S. Department of Energy, January 18, 1980.

The proportion of coal production originating from federal and Indian lands is shown in Table 3. In 1950 the proportion of domestic coal production originating in federal lands was negligible but by 1979, 11 percent of the coal produced domestically came from federal lands. In the western states, where low-sulphur coal predominates, 60 percent of coal resources are federally owned.

Table 3. Production of Coal from Federal and Indian Lands

Year	Coal	
	Thousands of Tons	% of U.S. Production
1950	7,678	1.5
1968	9,149	1.7
1969	10,107	1.8
1970	12,044	2.0
1971	17,263	3.1
1972	18,966	3.2
1973	24,247	4.1
1974	32,139	5.3
1975	43,590	6.7
1976	59,902	8.7
1977	74,848	10.8
1978	79,241	11.2
1979	84,855	10.9

U.S. Geological Survey Federal and Indian Lands Coal, Phosphate, Potash, Sodium, and other Mineral Production, Royalty income, and Related Statistics. Washington, D.C.: U.S. Department of the Interior, June, 1980.

1979 figures are preliminary data from the U.S. Geological Survey 1980 issues of the previous publication.

Energy Information Administration Monthly Energy Resources. Washington, D.C.: U.S. Department of Energy, March 1980.

Production Taxes and Energy Markets

Production taxes can affect the level of output of coal, the amount of labor and capital devoted to coal production, the rates of compensation received by those in the industry, the level of government revenues from other taxes and from ownership of coal resources, and the prices that consumers pay for energy services. Consequently, these taxes can affect the quantity of coal consumed. These and many other less direct effects cause production taxes to be important from the standpoint of national energy policy.

As a tax wedge between the energy producer and the energy consumer, production taxes cause the price of the taxed commodity to change relative to all other commodities and the values of the product of each of the factors of production to change relative to its value in alternative pursuits. Hence, most decisions made on the basis of pretax conditions will no longer be optimal, and economic agents will be motivated to change their behavior. The purpose of this and subsequent sections is to examine how behavior changes when a production tax is imposed or raised and to consider the reasons for those changes.

The first task in this examination was covered earlier when the implications of the fixed and nonrenewable character of coal resources was specified in the discussion of economic rents. As discussed,

taxation of an asset fixed in supply would not seem to lead to a change in behavior by its owner, but this general truth has many exceptions.

The second task in the examination is to clarify the notions of shifting and incidence as they apply to production taxes on coal. In general, taxes do not lie solely on those activities on which they are levied, but instead are at least partly shifted—usually both forward to consumers and backward to suppliers. The fact of shifting is apparent, but by how much, and in which direction, depends on a number of factors.

The third task is to examine the implications of the federal excise taxes on coal, which are the only federal excise levies on a primary energy resource. Following that, production taxation of coal from a state perspective is examined. Our purpose is to determine what taxes have what effects given the demand for coal and the conditions under which it is produced. One of the more important aspects of this examination is the demonstration that the effect of production taxes in one state depends importantly on what taxes exist elsewhere. Another important matter is to examine the manner by which production taxes may be used to achieve social objectives other than energy ones.

Property taxes are fundamentally different from production taxes in their effect on producer decisions. A further task of this report is to explain that difference, even though in practice property taxes do not appear to be of great importance at this time. The final task of

the examination of production taxes in this section is to discuss their implications for investment. Investment in primary energy production is crucial for the achievement of national energy goals.

Historically, some states replaced property taxes with severance taxes because the latter were viewed as a means of improving conservation decisions by producers. Severance taxes, as we have noted, are now motivated largely by the desire of states for revenue to pursue their general government objectives. If production taxes are not imposed other taxes will be. Other taxes (or lower expenditures) also have effects; the comparisons we make are between the effects of production taxes and a corporation income tax. Our analysis, then, is guided in the larger sense by the question of what differential effects production taxes have on energy markets.

The Effects of Federal Production Taxes on Coal

Our comparison of the effects of energy production taxes and property taxes with corporate income taxes begins with national taxes. The only national production-type taxes are levied for the purpose of correcting for the external effects of coal mining. What interests us here is the nature of the impact these taxes have on coal production and development in the United States in both the short-run and long-run.

As noted above, there is general agreement that the coal industry in the United States is a competitive industry.¹ Due to technological factors, there have been some concerns about the long-run competitiveness of western coal, but there is agreement that coal production currently operates under competitive conditions. That is to say, coal prices are determined in markets for particular coal grades through the interaction of supply and demand, and individual producers are price-takers.

The imposition of a per-unit excise tax under these conditions increases the marginal and average cost of producing coal to a mine operator. The increase in marginal cost will, ceteris paribus, cause a mine operator to reduce output in any given period of time. The increase in marginal cost might also affect the grade cutoff decision by the producer so that lower-grade deposits would not be mined. (Since the return per ton declines as the grade level

¹For a discussion of competition in the coal industry, see R. L. Gordon, U.S. Coal and the Electric Power Industry. Baltimore, Md.: Johns Hopkins University Press, 1975, pp. 67-69.

Tennessee Valley Authority, The Structures of the Energy Markets: Reports of TVA's Antitrust Investigation of Coal and Uranium Industries. Washington, D.C.: Tennessee Valley Authority, 1979.

U.S. General Accounting Office, U.S. Coal Development--Promises, Uncertainties. Washington, D.C.: U.S. Government Printing Office, 1977, pp. 4.2-4.4

U.S. General Accounting Office, The State of Competition in the Coal Industry. Washington, D.C.: U.S. Government Printing Office, 1977.

U.S. Department of Justice, Competition in the Coal Industry. Washington, D.C.: U.S. Department of Justice, 1978.

decreases, with the increase in cost due to the tax, the lower grades become unprofitable to mine). This is not as significant a problem in coal mining as in other types of mineral mining. Coal seams tend to be fairly consistent with respect to grade. However, what is of importance is a closely analogous problem. The cost of mining can vary over any particular seam of a given grade. For example, one of the major costs in western strip mining is the cost of removing overburden, and the amount of this overburden may differ considerably at different seam locations. As a result of the tax and the resulting increase in mineral cost, the mine operator may bypass some sections of the seam that are relatively more difficult to get at because they are now unprofitable to mine. Unfortunately, this quite often means that the coal is lost since, even if the tax is later removed, it might not be economical to return and mine small sections previously left unmined. The estimated production of coal in 1985 that is cost justified over various price steps is given in Tables 4 and 5 for two representative coal regions. These tables are presented as suggestive of supply responsiveness in two representative regions.

Table 4. Estimated Price and Supply of Coal^a in Central Appalachia, 1985

Price Step (1975\$/ton)	Incremental Supply (Thousands of Tons per Day)			Cumulative Supply (Thousands of Tons per Day)		
	Surface	Deep	Total	Surface	Deep	Total
Existing mines						
9.32	3.43	1.94	5.37	3.43	1.94	5.37
10.20	23.11	43.69	66.80	26.55	45.63	72.18
10.97	16.11	31.83	47.93	42.65	77.46	120.11
11.60	2.98	18.80	21.78	45.64	96.26	141.89
12.18	1.31	4.55	5.87	46.95	100.81	147.76
12.98	1.44	13.41	14.85	48.39	114.22	162.61
13.67	.42	5.58	6.00	48.81	119.80	168.61
14.56	.42	20.74	21.17	49.24	140.54	189.78
15.39		1.60	1.60	49.24	142.14	191.37
16.13		1.60	1.60	49.24	143.74	192.97
17.80	.13	1.45	1.57	49.36	145.18	194.55
New mines						
14.51	1.30		1.30	1.30		1.30
23.00		2.19	2.19	1.30	7.01	8.31
24.63	1.04	5.48	6.52	1.91	16.87	20.78
26.90		10.30	10.30	3.91	34.85	38.75
28.86	1.30	10.52	11.82	7.03	51.72	58.75
30.26		1.97	1.97	7.03	58.74	65.77
32.72	1.82		1.82	11.46	69.48	80.93
34.76		4.38	4.38	12.76	82.19	94.94
37.87	.26	3.73	3.99	13.54	93.14	106.68
39.89		3.73	3.73	14.84	99.50	114.34

^a Coal type: high Btu (23.8 MMBtu/ton) and medium sulfur (0.67 to 1.68 lbs. /MMBtu).

SOURCE: Brenda J. Allen, The Integrating Model of the Project Independence Evaluation System. Volume VI-Data Documentation, Part I. Energy Information Administration. Washington, D.C. : U.S. Department of Energy, 1979.

Table 5. Estimated Price and Supply of Coal^a from the Western Northern Great Plains, 1985

Price-Step (1975\$/ton)	Incremental Supply (Thousands of tons per day)			Cumulative Supply (Thousands of tons per day)		
	Surface	Deep	Total	Surface	Deep	Total
Existing mines						
3.52	81.48	1.16	82.64	81.48	1.16	82.64
New Mines						
7.14	237.81		237.81	237.81		237.81
7.61	251.23		251.23	489.04		489.04
8.41	463.90		463.90	952.94		952.94
9.09	361.92		361.92	1,314.86		1,314.86
9.92	499.52		499.52	1,814.38		1,814.38
10.67	327.67		327.67	2,142.05		2,142.05
11.38	328.42		328.42	2,470.48		2,470.48
11.68	237.12		237.12	2,707.60		2,707.60
46.24	.26		.26	2,707.86		2,707.86

^a Coal Type: Subbituminous (18.3 MMBtu/ton) and low sulfur (less than 0.67 lbs./MMBtu).

See reference in Table 4.

The short-run effects of federal coal excise taxes will cause the quantities that are produced to fall and the market prices to rise. Since the short-run demand for coal is relatively inelastic (see discussion above), the market price for coal will initially reflect a large proportion of the increase in the tax. However, not all of the tax will be shifted forward; some of it will be shifted backward and will reduce rents that otherwise would go to factor owners. In the short-run the taxes will come out of any quasi rents accruing to labor and capital. Some miners will find their real income reduced, either through reduced real wages or unemployment, and the short-run return to capital may fall below the normal risk-adjusted rate of return on investment.

As indicated in the section on the investment effects below, the long-run effects of the excise taxes will be to reduce investment in mining, both in terms of exploration for new deposits and in opening, maintaining, and enlarging mines. Since the expected return is reduced for coal and since costs must be incurred for discovering new deposits, on the margin there will be a reduction in the effort to locate new deposits. In the case of coal, this is not a serious problem, for known coal reserves are vast and exploration for new deposits is not particularly important. However, the decision to invest in new mines is a different issue. On the margin, capital investment is reduced. The long-run incidence of the tax therefore falls on consumers in the form of higher prices and on resource rents through reduced payments for resource ownership.

An equal-yield increase in the corporation income tax will not affect marginal costs for the competitive firm and therefore, will not have many of the short-run effects of the federal excise taxes. The short-run rate of production or grade cutoff selection should not be directly affected. The long-run effects of exploration are potentially quite different since exploration expenses may be written off as a cost. However, as already indicated, exploration is not a significant factor in the case of coal. The long-run differential impact on mining investment between a corporation income and excise taxes is less clear. Both lower the rate of return on investment, and therefore lower the level of investment. The relative magnitude of the reduction due to one tax instrument relative to the other cannot be readily determined.

Shifting Incidence, and Exportation of State Production Taxes

Potential shifting, incidence, and interstate exportation of state severance taxes depend on a number of factors, including factor mobility, market structure in product markets (industrial structure), dominance of the taxing jurisdiction in the market for the taxed resource, elasticity of demand and supply for the taxed product, and location of ownership of the capital and mineral rights for the taxed resource (i.e., whether or not the owners are residents of the taxing jurisdiction). This section considers the shifting, incidence, and

interstate exportation of state severance taxes on coal. As previously indicated, the coal industry is a competitive industry in the sense that all producers are price-takers and no state dominates production (see Table 2). Almost all regions display some capacity to increase output, even in the short-run. Furthermore, the demand curve facing any particular state is likely to be quite elastic. Table 6 presents estimates of regional demand elasticities for coal for 1985 and 1990. While these regional demands are somewhat inelastic, the demand elasticity for any particular state within a region is apt to be quite elastic in both the short-and-long-run.

The foregoing would suggest little forward shifting of individual state or local severance taxes in the short-run. The incidence of increased production taxes would be expected to be shifted backward in the production extraction industry, coal miners, and owners of mineral rights. Stated differently, some miners will find their real income reduced, either through reduced real wages or unemployment, and the return to capital and mineral rights will fall. To the extent that the owners of capital and mineral rights are out-of-state residents and to the extent that the incidence of the tax falls on capital and mineral royalties, the tax is exported to out-of-state residents.

Table 6. Estimated Own-Price Elasticities for Coal by Region for 1985 and 1990

Region ^a	1	2	3	4	5	6	7	8	9	10
1985	-0.355	-0.110	-0.084	-0.197	-0.142	-0.299	-0.329	-0.252	-0.159	-0.351
1990	-0.405	-0.132	-0.103	-0.238	-0.172	-0.349	-0.377	-0.298	-0.197	-0.399

^aRegion 1: Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont.

- 2: Delaware, New Jersey, New York.
- 3: D.C., Maryland, Pennsylvania, Virginia, West Virginia.
- 4: Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, Tennessee.
- 5: Illinois, Indiana, Michigan, Minnesota, Ohio, Wisconsin.
- 6: Arkansas, Louisiana, New Mexico, Oklahoma, Texas.
- 7: Iowa, Kansas, Missouri, Nebraska.
- 8: Colorado, Montana, North Dakota, South Dakota, Utah, Wyoming.
- 9: Arizona, California, Nevada.
- 10: Alaska, Idaho, Oregon, Washington.

See reference in Table 4.

However, there are several important characteristics of the coal industry that suggest that production taxes are not fully shifted backward in the short-run. First, a significant share of coal production is sold to electric power plants via long-term fixed supply contracts with allowances for "pass-through" of increased production taxes. The initial effect of such contracts is to shift the tax forward to utility companies. To the extent that utilities are allowed to adjust prices upward via the regulatory process, production taxes are shifted to consumers, both in-state and out-of-state.

Further, coal transportation costs are significant. These costs are growing, and because of changes in the market conditions for coal and relaxation of regulation on railroad rates, they will become more significant over time. The location differential reduces the degree of competition among states and makes demand more inelastic. There are two major effects of high transportation costs on tax shifting. First, coal f.o.b. accounts for a relatively low percentage of final demand; this provides greater potential for forward shifting of production taxes because the lower the ratio of resource costs to total costs of the good or service, the more inelastic the demand for the resource. Second, significant transportation costs will have a tendency to segment the national market.

In the long-run, because of the lack of dominance by any single state, large reserves of coal, renegotiation of contracts, availability of alternative energy sources, and the mobility of factors of production, the incidence of production taxes will be shifted primarily backward to resource owners. In the western states, taxes will consequently fall on the federal government (i.e., U.S. taxpayers) in many instances. Therefore, except for the share of federal royalties that go to coal-producing states (which are reduced because of decreased production), some of the state and local production taxes are exported from the taxing jurisdiction in the long-run.

It is important to note that such programs as the synfuels program will increase the demand for coal. Also, a concentration of expanded coal production in several western states could increase the potential for dominance and forward tax shifting. Moreover, to the extent that major producing states harmonize their severance tax policies, the potential for forward shifting increases. In recent years, a number of western states have significantly increased their severance taxes, which has caused some concern at the national level.

Property Taxes and State Income Taxes

If a state wants to generate revenue from mineral production within its borders, it has three general alternative tax instruments: state income taxes, severance or production taxes, and property taxes. Production or severance taxes are the most widely used and important tax from the standpoint of state revenue generation. This section briefly compares income taxes and property taxes to severance or production taxes.

An increase in a state corporation income tax will have few of the short-run effects of state production taxes. The tax will reduce any quasi rents accruing to the firm or, in some cases, reduce the rate of return below the usual returns on capital. In the long-run, investment in energy production will be less since net returns are less, but the relative magnitude of the reduction compared to production taxes cannot be readily determined. Furthermore, just as in the case of production, the treatment of state income taxes by regulatory bodies can influence the incidence of the tax: if the taxes can be shifted forward through higher prices, consumers will pay a portion of the tax.

A property tax has the opposite effect of a severance tax. (Several states levy taxes that they call property taxes but that are in fact production taxes; our analysis refers only to true property taxes.) The property tax is based on the present value of the future receipts from an energy resource, and therefore, a firm can reduce the number of times those receipts will be taxed by "mining out from under the tax"—by increasing the rate of production. The exact effect will depend on the marginal costs of increasing production, but the directional effect will be to increase output at each price. There will be greater pressure for market prices to be reduced in comparison to the state income tax, which probably will have no short-run effect on price. The long-run implications for the property tax are similar to those of an equal-yield increase in a state corporation income tax in that investment and energy production will be reduced.

Effects of Production Taxes on Investment in New Capacity

An important component in the long-run incidence of production taxes relates to investment decisions of coal producing firms.

Also, since investment in energy production is continuing to be discussed as an important national issue, we discuss in some detail in this section the relationship between production taxes, state corporation income taxes, and investment.

Investment in new capacity in coal extraction is divided into three related components: exploration for new deposits, investment in development of new deposits, and investment in the size of extractive plants. Effects of increased taxation on any of these investment components is clearcut: if taxes are increased, present expected values from the activity will fall, and investment will decline. This holds for all forms of taxation, whether income, production, or property taxes. However, the severity of the investment-dampening effects of taxation on new investment in the coal sector are not the same for all taxes that yield the same revenue. Our concern here is not with the long-run effects of taxes in general on new coal supplies but with the differential effects of production taxes on investment in new capacity relative to those of equivalent-yield taxes on net income.

The relative effects of different forms of coal taxation on investment in coal resources are best understood in light of two factors that, if not peculiar to that industry, are at least more characteristic of that industry than of, say, manufacturing or agriculture.

The first characteristic is related to the sequential nature of decision making in the coal industry. The extractive process follows a logical order from exploration to washing in the case of coal. This segmentation allows a firm to focus on one decision at a time: Should more exploration be undertaken? Is more development warranted? Given known reserves, what is the correct size of extractive plant?

The firm therefore has a certain amount of flexibility: exploration, development, and extraction decisions can be revised as conditions change and new information becomes available. Among the important factors that must be taken into account in the sequence of decision making is the matter of taxation. The level and form of tax facing an enterprise will have a bearing on investment decisions at all stages of the production process. However, while the effects of taxes on investment in extraction proper are likely to be minimal if that decision is viewed in isolation, the cumulative effects on investment in extraction may be very substantial once the effects of taxes on earlier stages in the sequence are accounted for. Therefore this section focuses primarily on the earlier stages of the process—the effects of production taxes on new investment in exploration and development.

The second factor of particular relevance insofar as taxes on energy are concerned is the long time interval from initial exploration to extraction and sale. This interval is usually 5-10 years, followed by a mine life that may range from 7 to 25 years. This long horizon expands the role of risk and uncertainty in investment decisions on energy resources. To the extent that different taxes have a differential impact on firms' perceptions of risk and uncertainty, there is ample scope for concern about the impact of taxes on new investment in extractive activities.

Any differential impact of production taxes relative to income taxes on exploration is largely traceable to the treatment of exploration costs in determining the tax base. Even in the absence of special features, such as percentage depletion, income taxes are less depressing on exploration efforts than are production taxes. This is because under the usual form of income tax, exploration expenditures enter into the determination of taxable income either through amortization, or, for certain types of outlays, through expensing. Production taxes in their usual form however, do not allow any recognition of exploration costs. Thus, under income taxes, firms investing heavily in exploration will pay less in taxes than similarly situated firms with comparable production but less in expenditures for exploration. The implications for future energy supplies differ for different resources, being less serious for coal. In the case of coal, known reserves are vast and little additional inducement to explore for new deposits would be expected from any shift away from production to income taxes.

Production taxes also impinge more heavily on investments in the development of already discovered deposits. Again, however, the magnitude of the effect differs according to the quality and accessibility of deposits. Both the income tax and the production tax will curtail investment in development. Investment in high-quality deposits will be reduced, and low-grade deposits may never be developed. However, production taxes involve more significant effects on development decisions than do income taxes as they tend to augment risks perceived by a firm. When there are production taxes, additional output made possible by investment in new development will give rise to tax liability whether the operation is profitable or not. Thus, an operator may pay production taxes on operations that turn out to involve losses. In the case of an income tax, tax liability is incurred only in the presence of profits. Therefore, in relation to an income tax, a production tax will involve greater perceived risks for energy firms and therefore, will depress investment more. These effects will be the greater for energy deposits that are development intensive, a particularly important consideration for coal.

For surface mines, expenditures for development are not significantly different from those made to enable actual extraction; the decision to develop is tantamount to a decision to extract, and the lag between a development outlay and the return on the outlay is

short. For the deep mining of coal the situation is different. Not only are development outlays a larger fraction of total costs in deep mining, but the length of time between initial investment and eventual returns is considerably longer. Therefore, perceived risks are greater, and one may expect that under such circumstances firms will be less inclined to place at risk large sums for development when there are production rather than income taxes. Under both income and production taxes, marginal results from development will be reflected in lower tax obligations. However, for an investment that turns out to be marginal, there will be limited or no income tax liability while production taxes on the same project could still be substantial.

To the extent that further reserves of coal lie in deeper and less accessible formations, these reserves can be tapped only with substantial development outlays. Indeed, such outlays are likely to be more substantial as a proportion of total investment in the industry in the future than in the past. Reliance on production taxes will clearly be less favorable to such development-intensive investment than would be income taxation, and therefore less favorable to expansion of national energy supplies.

Owing to the sequential nature of investment in coal extraction, the effects of production taxes in differentially constricting investment in exploration and development will, of course, ultimately show up in lower investment in extraction itself. With fewer deposits available for development and with less development undertaken on

known deposits, there will be less scope for investment in plant and equipment to extract energy resources. But once the decision process reaches the stage at which investment in extraction must be considered, the differential effects on size of investment in plant and equipment arising from the existence of one or another form of tax are not likely to be as large as in the cases of tax-induced changes in exploration and development. (However, as shown in the previous section, this is not to say that production and income taxes will have similar effects on extractive decisions for investment already in place). But here again, production taxes may still deter investment to a greater extent than income taxes because of the possibility that under the former, but not the latter, taxes will be due whether or not there are profits.

Conclusions

This section has concentrated on the impact that production taxes have on energy markets in the United States. Production (or severance) taxes are primarily imposed at the subnational level by states, the only federal production taxes being those placed on coal to fund environmental and health programs. The incidence of the federal taxes with an equal-yield increase in the corporation income tax have been compared. In addition it was noted that the federal production taxes will be shifted both forward to consumers of coal and backward to the factors of production.

Also, it was noted that a number of states rich in energy minerals have turned to production taxes as a major source of revenue, with part of the motivation for adoption being an attempt to "export" the tax base to residents of other states. The perceived effort to export taxes by a few states has been one factor that has cast the recent debate on energy issues in terms of somewhat narrowly defined regional interests. However, taxes on different energy minerals have different possibilities of being exported. Simply adopting a tax that would appear to be "exportable" does not mean that residents in other states will necessarily pay part of the tax—in either the short or the long run. Due to both market conditions and government regulations, there is some opportunity to export state production taxes in the case of coal.

Finally, the implications of production taxes on investment decisions by energy mineral firms in the United States have been explored. The sequential nature of the investment decision in energy production is especially important to understand, and taxation at either the exploration, development, or extractive stage will, over time, have an impact on investment at the other stages.

Income Taxation of Coal

This section discusses the principal federal income tax provisions applicable to coal production; these include accelerated deduction of certain real capital costs (i.e., mine development expenses) and the exclusion from tax of some income not directly determined by capital outlays (percentage depletion).

Accelerated Write Off Provisions

Immediate write-offs are available for "mine development expenses" that, if treated in a way analogous to other industries, would be capitalized and then recovered by cost depletion. Typically, however, "exploration costs"—those incurred before the existence of coal in commercially marketable quantities is established—are subject to "recapture" if the mine with which they are associated becomes profitable. That is, they are, in effect, converted to a cost-based depletion treatment and the benefit of early deduction is nullified.

The implications of these provisions are to provide maximum benefits to low-risk mine development expenditures and substantially lower benefits for exploratory efforts. Further, high capital/low variable cost investments (such as deep-mined eastern coal) are favored over those with the opposite characteristics (such as strip-mined western coal). Per dollar of subsidy, then, in relative terms, the rapid

write-off provisions reward producing what is known rather than finding new resources. It selectively favors output from some types of deposits over others, and the size of the incentive is not based on the prospective yield in extra energy produced.

Percentage Depletion Provisions

The principal economic effect of percentage depletion in the non-petroleum energy industries arises from the dissimilar tax treatment of processes yielding products that compete in the same end use markets. As a result of such tax treatment, the market values of otherwise similarly valued resources are different, the quantities produced are altered, and the allocation of those resources is distorted. These distortions exist in both markets for energy (electricity from coal is affected differently from electricity from uranium) and in the opportunities for investments in the competing fuels industries.

The sources of this economic effect are several. First, the rates used to calculate percentage allowances vary across energy extractive industries. The rate for uranium is 22 percent; for coal, 10 percent; for oil shale, 15 percent; and for geothermal energy source, 22 percent, to be reduced to 15 percent by 1984. In each of these cases, the percentage depletion allowance for a property in a given tax year is limited to 50 percent of net income from the property in that year.

Second, complications and anomalies arise from different amounts of value added at different steps in the production process. The delivered selling price of material with the same performance characteristics will be the same whatever its source, but the portion of the costs of getting the material to that point that are subject to percentage depletion can vary—substantially and erratically. One source of variation is in the simple matter of how the "cutoff point" is defined. The "cutoff point" is the identified step in the production process at which "mining" activities (eligible for depletion) end, and "manufacturing" activities (not eligible for depletion) begin. For example, coal cleaning (used only for some coals) is included as part of the mining process as is retorting to extract kerogen from oil shale; however, hydrogenation or refining of kerogen is excluded. In general, the percentage depletion deduction covers "ordinary treatment processes" but not processes involving substantial chemical change in the core as a result of heat, chemical treatment, or electrolysis.

A final source of differential effects of the depletion allowance arises from the operations of the 50 percent net-income limitations. Because of its effect, much of the potential benefit from percentage depletion would be denied to relatively unprofitable mines, or to those with high costs whose output had high value because of locational or other characteristics.

Illustrating the Effects: An Example for Coal

Table 7 gives an example of how percentage depletion and related tax provisions yield different tax benefits to eastern deep-mined coal and western open-pit coal delivered at the same price in eastern markets.

In this illustration, deep mining reaps a substantial benefit (\$0.29 per ton) from the deduction of mine development expenses, which are negligible in an open-pit operation. The combination of greater value added (including cleaning) at the mine mouth for eastern coal and the greater transportation cost for the western coal yields a much larger percentage depletion allowance on the former than on the latter. The "50 percent of net" rule sets the depletion allowance for eastern coal, while either the "10 percent of gross" rule or the "50 percent of net" rule is operative for western coal. The total value to the producer of the tax subsidy is an estimated \$1.54 a ton for eastern coal, compared with \$0.50 a ton for western coal. On an equivalent delivered price (\$22.50 a ton in principal eastern markets, shown in Table 7), the effect of the differential subsidy as compared with equal treatment will be "too much eastern" and "too little" western coal production. That is, because of tax treatment (alone), eastern coal can bear higher mining and other costs, while transportation costs help keep distant western coal out of the market. Tax treatment dictates greater use of eastern coal than would occur if pretax resources costs alone were the basis for producer and consumer decisions.

Table 7. Difference in Tax Benefits Between Eastern Underground and Western Surface Mined Coal

Delivered Costs by Source Per Tbn^a

<u>Eastern-Underground-Mining</u>		<u>Western-Surface-Mining</u>	
Delivered Price	\$22.50	Delivered Price	\$22.50
Less: Transportation	<u>5.00</u>	Less: Transportation	<u>17.50</u>
Shipping Price	\$17.50 ^c	Shipping Price	\$5.00 ^b
of which:		of which:	
Cleaning	2.00	cleaning:	1.00
mine mouth cost	15.50	mine mouth cost	4.00

Tax Benefits

<u>Underground-Mining</u>		<u>Surface-Mining</u>	
(1) 50% of profit on mining and cleaning	\$1.25	(1) 50% of profit on mining and cleaning	\$.50
(2) 10% of gross, mining and cleaning	1.75 ^c	(2) 10% of gross, mining and cleaning	.50 ^c
(3) Percentage depletion: Lesser of (1) or (2)	1.25	(3) Percentage depletion: lesser of (1) or (2)	.50
(4) Value of deduction of mine development expenses	.29	(4) Value of deduction of mine development expenses	0
(5) Total tax benefit	<u>1.54</u>	(5) Total tax benefit	<u>\$.50</u>

^a The tax treatment of mine development expenses is converted to an operating cost equivalent by assuming that normal depreciation deduction over twenty year life with a double declining balance depreciation are worth \$.20 on \$1.00 of cost, but the current deduction are worth \$43. Half of the capital cost is mine development expense, so tax benefits cover 11.5 percent of the capital cost. The annual equivalent of the capital cost is \$2.50 for deep mining, and 11.5 percent of this is \$.29. The mine development cost is negligible for open pit mining.

^b Shipping price includes a return on investment (profit).

^c Cost depletion is assumed to be less than percentage depletion.

SOURCE: The relative costs are taken from Sidney Katell, Economic Analysis of Coal-Mining Costs for Underground and Strip-Mining Operations. HCP/I 7608-01. Washington, D.C. : U.S. Department of Energy 1978; ICF, Inc. Coal and Electric Utilities Model Documentation, Third edition, 1979.

The Investment Tax Credit

Two types of investment tax credit are relevant to the energy industry. The first is the investment tax credit of 10 percent, subject to an upper limit, available to any business investing in certain depreciable property. There is an additional 10-percent credit applicable to selected energy investments.

The investment tax credits has a second differential effect within the energy industry. The preference increases with the capital intensity of sources of energy. For example, electricity can be generated by gas turbines, which are high in fuel cost but low in capital cost, or by steam power plants, which have exactly the opposite characteristics. Relatively, then, the investment tax credit makes the high capital cost option cheaper to investors than justified by the resources actually expended. It thus tends to induce choices that absorb more capital in generating the same amount of electricity than would be the case without the tax credit. Even within one fuel source distortions can occur. The investment tax credit alters the relative cost of deep-mined as compared with strip-mined coal, for example, because the proportions of the total pretax cost of coal subject to the investment tax credit is larger for deep mines.

Generalizations about the capital intensity of the energy industries relative to the rest of the economy are difficult, but it is at least plausible that an investment tax credit available to all investment will lead to a relative advantage in the energy sector. If it does so, then coal production (and consumption) is encouraged.

State Taxation of Coal

The only major tax levied on energy producers by the national government and also by most states is the corporation income tax: 44 states levy a corporation income tax (only Michigan, Nevada, South Dakota, Texas, Washington, and Wyoming do not). In recent years, state corporation income tax collections have totalled about one-sixth of the federal collection: \$9.2 billion in 1977, \$10.7 billion in 1978, and \$12.1 billion in 1979 collected by the states (Bureau of the Census 1977, 1978, 1979), and \$54.8 billion, \$59.9 billion, and \$65.7 billion in the same years by the federal government (Executive Office of the President 1978, 1979, 1980). There do not appear to be any data on the proportion of state corporation income taxes that result from energy corporations. But it is possible that the one-sixth ratio of state-to-federal corporation income tax collections would be somewhat high for tax revenues from energy producers because two major energy-producing states, Texas, and Wyoming, do not have state corporation income taxes.

If the one-sixth ratio of state-to-federal corporate income tax collections does not prove too high for tax revenues from coal producers, then one could argue that coal production is subsidized by the extent of the forgone state collections from coal producers. Such tax expenditures (as they are called) would probably result in additional mining and coal production as they tend to increase the effective investment results to the coal producers.

The tax burden of corporations, of course, does not rise by the full amount of the state corporation income tax added to the federal levy. From the beginning, Congress has permitted corporations to subtract all state and local taxes as a cost of doing business. Hence for most income subject to the tax, state taxes are reduced by the deduction from the federal corporation income tax, with the bulk of the deductions being applicable at the 46-percent marginal tax rate. Moreover, although, many state income tax returns begin with the same data that the corporation reports to the Internal Revenue Service, the statutory appointment or allocation formula that the corporation must then apply allows for numerous interpretations. Few states undertake significant field auditing, and each corporation's own tax accountants make those interpretations of state law most beneficial to their company.

Since in our federal structure identical state taxes and identical compliance are most unlikely and since there is an unequal distribution of coal resources and consumption, unequal coal tax burdens exist among citizens in different states. Further, federal tax and regulatory actions may add to or reduce the disparate energy tax burdens. In the case of corporation income taxes, different state rates and different compliance presumably can have only slightly different effects on coal corporations than on corporations generally. On the other hand, states singling out coal production for high taxes may (depending on the type of tax and its incidence) export a significant part of those taxes to residents in other states.

The nonproducing states suffer a further loss from the increase in tax revenues in coal-producing states. The long-run share of federal taxes of the nonproducing states will increase due to the deductibility of larger state taxes from the calculation of federal corporation income taxes. Since this additional burden takes a substantial time to work itself through the system it is often overlooked. Nevertheless, on the assumption that national expenditures will not go down in response to the reduced tax collections following increased state taxes from coal production, the nonproducing states may eventually pick up a disproportionate share of the loss. This effect is offset by the fact that coal-producing corporations will pay higher federal corporation income taxes as a result of increased income due to higher prices for coal. This could result in reduced tax burdens for individuals and corporations in non-energy-producing states.

Conclusions

Differentials traceable to the federal system or to state constitutional principles involving tax immunity patterned after the federal system are compounded by the variety and complexity of mineral tax policies among the states. Coal production is taxed through income taxes, property taxes, and production taxes. It is virtually impossible to derive data on the effect of these taxes on coal production because they cannot be analyzed in isolation.

For example, state-to-state comparisons of the income tax on the production of minerals are hampered because some states do not have income taxes, and the taxes^o of other states are substantially different in effective rates due to the deductability or non-deductability of federal income taxes. Similarly, the various state policies regarding the use of income tax deductions to encourage coal production make it difficult to analyze state policies with any degree of accuracy. The same generalization can be made concerning property taxes, for which, in addition to differentials among states in their methods for valuation, there may be considerable variance within a state owing to the autonomy of assessors at the county or city level.

Thus, the effects of federal and state (and local) taxation on competition in the coal industry would be very difficult to estimate. But, since the coal industry is, as stated earlier, generally considered to be a competitive one, it is likely that coal taxation policies have not had significantly negative competitive effects on the industry, and may even have positively affected competition in the industry.

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