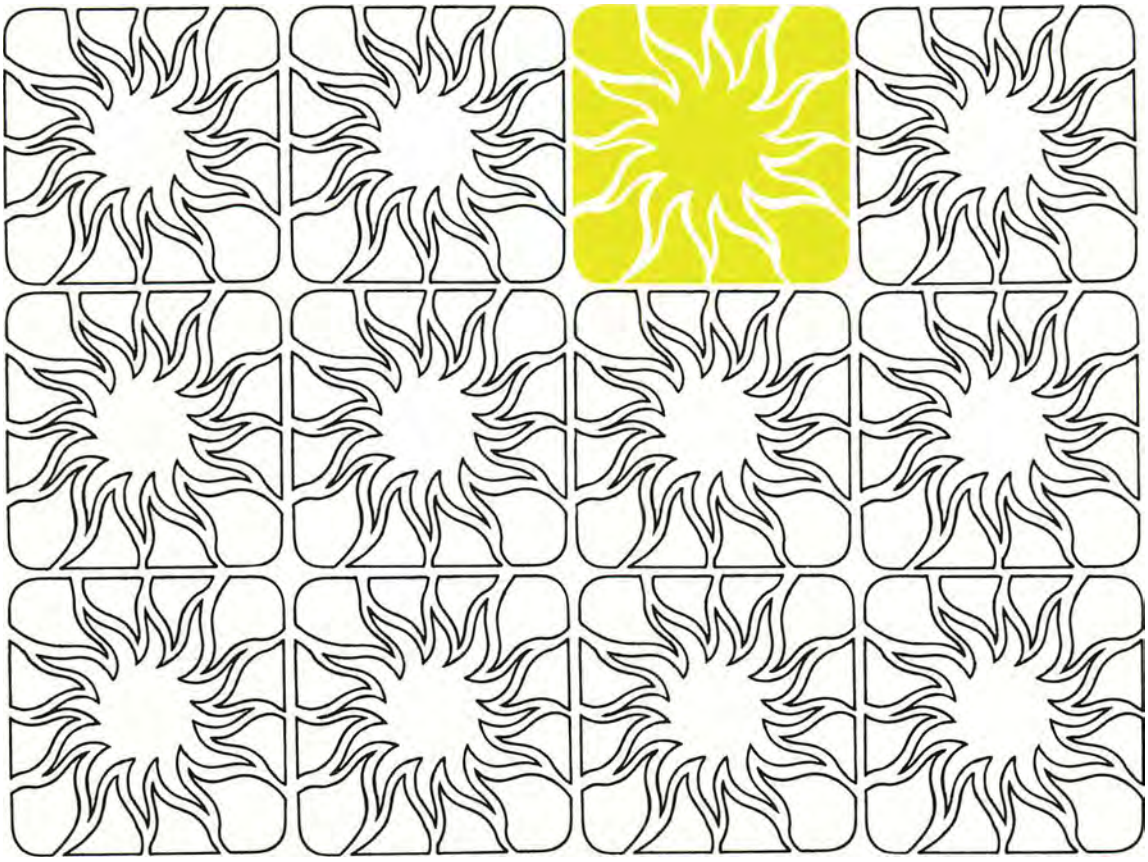

U.S. Energy Outlook

Coal Availability

National Petroleum Council

U.S. Energy Outlook

Coal Availability

A Report by the
Coal Task Group of the
Other Energy Resources Subcommittee
of the National Petroleum Council's Committee
on U.S. Energy Outlook

Chairman - E. H. Reichl
Consolidation Coal Company

National Petroleum Council

NATIONAL PETROLEUM COUNCIL

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PREFACE

On January 20, 1970, the National Petroleum Council, an officially established industry advisory board to the Secretary of the Interior, was asked to undertake a comprehensive study of the Nation's energy outlook. This request came from the Assistant Secretary-Mineral Resources, Department of the Interior, who asked the Council to project the energy outlook in the Western Hemisphere into the future as near to the end of the century as feasible, with particular reference to the evaluation of future trends and their implications for the United States.

In response to this request, the National Petroleum Council's Committee on U.S. Energy Outlook was established, with a coordinating subcommittee, four supporting subcommittees for oil, gas, other energy forms and government policy, and 14 task groups. An organization chart appears as Appendix B. In July 1971, the Council issued an interim report entitled *U.S. Energy Outlook: An Initial Appraisal* 1971-1985 which, along with associated task group reports, provided the groundwork for subsequent investigation of the U.S. energy situation.

Continuing investigation by the Committee and component subcommittees and task groups resulted in the publication in December 1972 of the NPC's summary report, *U.S. Energy Outlook*, as well as an expanded full report of the Committee. Individual task group reports have been prepared to include methodology, data, illustrations and computer program descriptions for the particular area studied by the task group. This report is one of ten such detailed studies. Unlike the other task group reports, however, this report has incorporated some of the task group's detailed findings resulting from the Initial Appraisal which were not ready for publication following the release of the NPC's interim report. Other fuel task group reports are available as listed on the order form included at the back of this volume.

The findings and recommendations of this report represent the best judgment of the experts from the energy industries. However, it should be noted that the political, economic, social and technological factors bearing upon the long-term U.S. energy outlook are subject to substantial change with the passage of time. Thus future developments will undoubtedly provide additional insights and amend the conclusions to some degree.

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INTRODUCTION

Of all the Nation's energy fuel sources, coal is apparently the most abundant. Thus, in the face of a widening U.S. energy gap, our domestic coal resources represent an asset of significant potential value. Throughout the U.S. Energy Outlook study, a major question has been the extent to which the United States can capitalize on this asset, both by expanding coal production and by developing additional uses for coal which are evironmentally acceptable and economically sound.

With the further development and application of technologies (1) for solving the environmental problems inherent in the mining and combustion of coal and (2) for transforming solid coal into synthetic gaseous and liquid fuels, U.S. coal resources can make a major contribution to the Nation's energy needs in the 1970-1985 period. The ultimate size of this contribution will depend primarily on the outcome of government policy issues. However, even under the most favorable circumstances, it is unlikely that coal alone could completely eliminate the Nation's dependence on imported fuels prior to 1985.

Chapter One

SUMMARY AND CONCLUSIONS

COAL DEMAND

Domestic demand for coal is expected to grow at a rate of 3.5 percent during the 1970-1985 period--from 519 million tons in 1970 to 734 million tons in 1980 and potentially to 863 million tons per year in 1985.* Demand for coal exports will grow at a more rapid rate--4.5-percent per year during the same period. Total exports which include principally coking coal used in steelmaking and some smaller amounts of electric utility coal amounted to 71 million tons in 1970. By 1985 it is anticipated that total exports will amount to some 138 million tons.

Currently, some 83 percent of total demand for U.S. coal (domestic demand plus demand for exports) originates from only two consuming sectors--coke production and electric power generation. By 1985, these sectors will represent nearly 92 percent of total demand.

Due to technological advances, the growth in the domestic demand for coking coal will lag behind the growth in steelmaking. Accordingly, domestic demand for coking coal will grow at a rate of only 2 percent per year. However, a vigorous growth rate (7 percent per annum) is anticipated for U.S. coking coal exports, which implies a potential export demand of over 150 million tons per year in 1985. Although this 1985 figure has been arbitrarily reduced to 120 million tons to reflect growing foreign competition, it still implies a 5.2 percent growth rate.

By far, the largest consumer of U.S. coal is the electric utility sector, which in 1970 alone accounted for nearly 60 percent of total demand. By 1985, this sector is projected to consume some 672 million tons of U.S. coal per year. Of these 672 million tons, 654 million tons (97 percent) will be allocated to domestic use, and the remaining 18 million tons will be exported for use by foreign utilities.

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* This does not include added demand for coal shown in the NPC's *U.S. Energy Outlook: An Initial Appraisal* 1971-1985 Volume One (July 1971), to reconcile total U.S. energy demand projections with available supply. The addition of this demand (30 million tons in 1975, 65 million tons in 1980 and 70 million tons in 1985) would increase the total domestic demand for coal to 933 million tons in 1985, for a growth rate of 4 percent per year from 1970 to 1985.

COAL RESOURCES

Approximately 150 billion tons of recoverable coal--105 billion located underground and 45 billion located near the surface--have been firmly defined in formations of comparable thickness and depth to those being mined under current technological conditions. Even at the maximum production growth rate considered feasible (5 percent per year for the conventional domestic market and 6.7 percent when production for export and for synthetic fuels is included), production to 1985 will use only about 10 percent of the 150 billion tons of the type of resources currently being mined.

These 150 billion tons represent less than 5 percent of the 3.21 trillion tons of total coal resources which are estimated by the U.S. Geological Survey (USGS) to exist in the United States. Further mapping and exploration of the Nation's coal resources should result in substantial additions to those reserves which can be mined with present-day technology. This is expecially so in the western states where large areas of coal bearing formations have been only partially explored. In addition to identifying new reserves by better resource definition, improved mining technology might yield a large increase of coal reserves by increasing effective recovery rates from present reserves and by making deeper and thinner seams economically recoverable. Unfortunately, current efforts toward development of new technology are minimal.

In this report, future supply of coal is examined in two distinct areas of use: (1) coal used in present conventional markets and (2) coal used in gasificaiton and liquefaction. Major markets in the conventional category are electric power generation and steelmaking. Future supply prospects for these current uses are evaluated under the assumption that technological changes in the utility and steel industries will not greatly alter the coal use patterns of these industries. For all of the coal growth rates examined in this report, it is assumed that these conventional markets are supplied by the same type of recoverable reserves from which they have been supplied in the past.

In the case of coal-based synthetic gas and liquid production, the simplifying assumption is made that all coal supply for synthetics would come from western surface-mined reserves during the period to 1985. Exceptions to this assumption might occur, but they would not materially affect the conclusions drawn in this report.

COAL MINING

Although historically underground mlnlng has accounted for the largest share of U.S. coal production, the contribution from surface mining also has been substantial and has been increasing in recent years. In 1970, about 44 percent of total bituminous coal and lignite production came from surface mines compared to some 31 percent as late as 1960.* Surface mInIng is attractive because it requires less investment and operating cost (less manpower) and because it is not subject to the health and safety problems associated with deep mining. However, it is subject to increasingly stringent environmental requirements. In spite of the importance of surface mining, the future ability of the coal industry to supply its overall share of U.S. energy demand will depend on its continued ability to produce coal from deep mines in an efficient and economic manner.

Currently, three systems of underground mining are in use: conventional mining, continuous mining and longwall mining. Conventional and continuous mining are similar in that they both involve a room and pillar approach. However, they differ in terms of machinery used and in operating sequence. Generally, continuous mining machines permit more effective use of manpower. Longwall mining, long prevalent in Europe, has recently entered the United States where it is expected to become increasingly important because it concentrates production in a smaller area of the mine, offering better productivity and simplified ventilation.

Conventional mining, as a percentage of U.S. underground production, has declined in recent years--from 55 percent in 1965 to 40 percent in 1970. On the other hand, continuous mining has been subject to considerable growth, and since 1966 its output has exceeded conventionally mined tonnages. Today, continuous mining accounts for nearly 60 percent of total underground production, and this contribution is expected to increase. Although current production from longwall mining is very small (some 2 percent), it too is expected to make a larger contribution in the future.

Productivity of underground mining grew steadily until the end of the 1960's (a 2.7-percent rate during the 1965-1969 period). However, the enactment of the Coal Mine Health and Safety Act of 1969 has had a profound impact on productivity. Although conclusive statistics are not yet available, some individual mines have reported 15- to 30-percent reductions.

Surface mining can be divided into two broad classes: area mining and contour mining. Area mining permits operation with a nearly indefinite number of successive pits as typically found in coal fields of the Midwest and West. Contour mining is employed where comparatively steep surfaces are found, as in the Appalachian coal fields.

Feasibility of surface mining (stripping) is highly dependent on the stripping ratio, usually expressed in cubic yards of overburden to be removed to recover 1 ton of coal. The limiting ratio

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* When this study was initiated, only 1969 information was available. Information for 1970 became available during the course of the study and is shown here. More recent information, now available, indicates that in 1972 surface-mined coal accounted for more than 50 percent of total production.

depends on the value of the coal as well as other items. Hence, actual ratios up to 30 to 1 have been mined. Higher stripping ratios are typically found in the eastern and midwestern coal regions, whereas the lower ratios are found in the West. The current average stipping ratio in the western states is 6:1, although considerable reserves exist in that region at ratios under 1.5:1.0.

Surface mining has the advantage of high productivity of manpower which represents one of the main incentives for utilization of this type of mining. For example, in 1969 productivity of stripping operations was nearly 36 tons per man day. This figure compared to a 1969 overall industry average (including underground and surface mines) of some 20 tons per man day. On the negative side, however, one must again consider the increasing opposition to stripping operations, particularly to contour mining.

FUTURE COAL SUPPLY OUTLOOK

The future supply of coal for the traditional markets was analyzed for three assumed cases in six underground and three surface mining regions, using a hypothetical underground and surface mine. For each region and for the U.S. average, the investment and operating costs of coal mining were defined, and average required "prices" were calculated using Discounted Cash Flow (DCF) rates of return of 10, 15 and 20 percent. The potential impact of future changes in individual cost components were considered, including, among others,productivity of manpower, investment for new mines and reclamation. The results have been presented in constant 1970 dollars in a series of graphs which lead to the following conclusions concerning future conventional uses of coal:*

- The cost of coal will continue to vary by regions over an exceedingly wide range (as it has in the past) as a result of the great variances in regional mining conditions.

- The cost of underground coal will increase more slowly after the large increases in recent years, based on the assumption that productivity will return to its historical upward trend.

- The cost of eastern U.S. surface-mined coal will rise by about 30 percent by 1985 due primarily to increased reclamation costs and higher overburden ratios.

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* Wherever used in this report, the term "constant 1970 dollars" refers to the purchasing power of the U.S. dollar in the year 1970. This term is used to provide a measure of comparability (or common denominator) to projections of Gross National Product, costs, revenues, capital requirements and other financial data which might otherwise be distorted by varying estimates of the unpredictable factor of inflation or deflation in future years.

A maximum possible sustained growth for coal production through 1985 was defined because of the important role intended for coal in future domestic energy development. The uncertainties associated with coal's future make such a growth rate difficult to project with confidence. A 5-percent sustained rate of growth using presently worked reserves as the base is considered feasible, based on past industry experience. This growth rate was chosen to represent the maximum growth condition, Case 1.*

Case I provides for production of 1,093 million tons of coal per year to supply the conventional domestic markets by 1985. This compares to the demand figure from the Initial Appraisal of 863 million tons (3.5-percent per annum growth rate), which is used here to represent Cases II and III. For Case IV, a minimum growth to 819 million tons by 1985 was used, reflecting a 3-percent per annum growth rate.

In addition to supplying coal for the conventional domestic market, the domestic industry produces coal for export and may in future years produce coal for conversion to synthetic liquids and gas. Projected coal exports are unchanged from the demand analysis conducted in the Initial Appraisal--in 1985, exports amount to 138 million tons. The projections of 1985 coal requirements for synthetics vary widely for the several cases--between 339 million tons for Case I and 47 million tons for Case IV. While coal for synthetics is assumed to come from western surface mines, it is recognized that small volumes of synthetics may be produced in other areas.

Combining the coal requirements for these several categories yields the overall required tonnages shown in Table 1 for the period to 1985.

A number of determining factors will affect the future supply and consumption of coal, and these must receive proper attention if the projections are to materialize.

- Developments in improved mining technology must be substantially accelerated to offset the severe impact of the Coal Mine Health and Safety Act of 1969 on production capacity.

- A program for rapid development of manpower, both mine workers and mining engineers, must be vigorously pursued.

- To guarantee the transport of increasing tonnages, the pool of railroad hopper cars as well as the efficiency of car utilization must be increased, and certain locks must

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* It is noteworthy that the NPC U.S. Energy Outlook includes several energy balances and that, in all but one case, there remains an *excess* of coal and nuclear energy supply available above demand. The 5-percent maximum growth rate thus appears ample.

TABLE 1

TOTAL FUTURE COAL SUPPLY-CONVENTIONAL MARKET, EXPORTS AND SYNTHETIC FUELS

	Millions of Tons 1970*	1975	1980	1985	Annual Growth Rate (Percent)
			Case I		
Conventional Markets	519	662	852	1,093	5.0
Export	71	92	111	138	4.5
Synthetic Fuels					
Gas	0	0	48	232	
Liquids	0	0	12	107	
Total	590	754	1,023	1,570	6.7
			Cases II/III		
Conventional Markets	519	621	734	863	3.5
Export	71	92	111	138	4.5
Synthetic Fuels					
Gas	0	0	31	121	
Liquids	0	0		12	
Total	590	713	876	1,134	4.5
			Case IV		
Conventional Markets	519	603	704	819	3.0
Export	71	92	111	138	4.5
Synthetic Fuels					
Gas	0	0	15	47	
Liquids	0	0	0	0	
Total	590	695	830	1,004	3.6

* The 1970 data were based on preliminary Bureau of Mines estimates. Actual consumption in 1970 was about 1 percent higher:

	Million Tons
Present Markets	525
Export	72
Changes in Stocks and Losses	16
Total Production	613

be improved in the river system to prevent major bottlenecks. To keep U.S. export coals competitive, better ways must be found to accommodate the new larger sized coal carrying ships at our ports, notably Hampton Roads, Virginia.

Technology must be developed to permit use of high-sulfur coal in power generation without polluting the air. Alternate processes should be pursued to fit the widely varying needs of existing plants, new and old, large and small. Desulfurizing by liquefaction and by gasification, as well as by stack gas cleanup, may all be required during the next 15 years. The present substantial research programs in these areas should be further expanded.

POTENTIAL FUTURE COAL UTILIZATION

Utilization of coal as a boiler fuel in conventional markets will depend on future air quality standards. At present, low-sulfur oil, most of it imported, is being used to displace coal in a wide and increasing segment of this market because viable pollution control technology is not yet available for coal-fired boilers. Forty-three percent of estimated coal resources east of the Mississippi River have a high sulfur content (over 3 percent), and 80 percent of these reserves exceed I-percent sulfur content. In Case I, where domestic energy sources are to be maximized, it is assumed that technology will be available to permit the use of all sulfur levels of coal. Cases II through IV are premised on somewhat less success in solving the problems which are retarding coal's usage. Future use of the higher sulfur-content coal is likely to require (1) stack gas cleanup, (2) conversion to clean gas (high- or low-BTU), and/or (3) conversion to low-sulfur liquids. Research and development efforts in the first two of these three areas now appear adequate to solve the respective problems, but work on liquefaction is not being vigorously pursued.

Commercially proved technology to produce synthetic pipeline gas from coal is nearly available and at costs ($0.85 to $1.15 per million BTU's) comparable to other supplements to domestic natural gas. Improved technology, now under rapid development, may lower costs 10 to 15 percent, and such improved systems may be available by the end of the projection period.

Utilization of coal for synthetic pipeline gas is projected in 1985 to supply 2.48 trillion cubic feet (TCF) per year under Case I, 1.31 TCF per year under Cases II and III, and 0.54 TCF per year under Case IV. The coal utilized to meet gasification demand for Case I would reach a maximum of 232 million tons per year by 1985.

Conversely, technology for economically producing coal-based liquids is not available today. The Case I output of coal-based liquids is projected to be 680,000 barrels per day (680 MB/D)--107 million tons of coal per year--in 1985. To approach such a level of production, an immediate decision would be required to proceed with the design and construction of a first commercial demonstration liquefaction plant. Case I assumes a 30 MB/D capacity plant which could start operation by 1977. This plant would be a high-risk venture because technology is now only partially developed. Under current economic conditions, the incentives to develop and build such a plant do not exist. Cases II and III therefore project only a modest supply of coal-based liquids in 1985, while Case IV does not envision any liquefaction before 1985.

Initially, the cost of synthetic liquids (distillates) would fall probably between $6 and $7 per barrel, based on western strip-mined coal. Following development, costs of $4.50 to $5.50 per barrel appear within reach for conversion of high-sulfur coal to low-sulfur heavy fuel oil (0.3- to 0.5-percent sulfur).

The reserve base available for synthetics production appears to be ample. Specific western surface minable coal reserves are known to be available to supply the coal needs envisioned for Case I gasification and liquefaction plants as well as to supply coal for the growing demand for power generation.

An important conclusion regarding synthetic gases and liquids from coal for the period to 1985 is that they cannot be developed fast enough to replace the Nation's expanding imports of petroleum. However, the annual growth of capacity for production of coal synthetics in the period to 19'85 could have a significant bearing on the U.S. energy balance in the post-1985 period.

SUMMATION

The Nation's domestic coal resources are abundant. Further mapping and exploration and advances in mining technology might yield great increases in the amount of this resource which would be economically recoverable.

Use of coal for conventional markets is expected to increase, provided that pollution control regulations do not seriously restrict future use of coal in electric power generation. There is reason to believe that imminent technological advances will make possible the achievement of future pollution control objectives. Delays in the enforcement of severe air pollution regulations pending commercial availability of the respective technologies may well be in the public interest.

Growth in coal use for synthetics holds great promise in easing our dependence on foreign'sources of energy in the longer term. The projected building rates for synthetics are dependent on water availability as well as on coal availability. Achievement of these rates will require (1) massive government expenditures to provide the necessary water for mine-mouth synthetic plants in the relatively water-deficient western states and (2) coordination of action by government bodies to ensure the legal availability of this water. Much needs to be done to facilitate the development of coal-based gas and more particularly liquids production into viable commercial industries.

Chapter Two

DEMAND FOR COAL

The demand for coal in recent years in relation to the U.S. energy demand as a whole is shown in Table 2. These coal demand figures show only domestic consumption and do not include the more rapidly growing demand for exported coal, which reached 71 million tons in 1970. Export coal is needed to support steel operations throughout the Western World and to supply power, mostly in Canada. It is, therefore, included in the subsequent demand projections.

TABLE 2

COAL DEMAND RELATIVE TO OVERALL ENERGY DEMAND-1965 AND 1970

	Total U.S. Energy Needs (Trillion BTU's)	Domestic Coal Use		Coal as Percent of Total U.S. Energy Needs
		Million Tons	Trillion BTU's	
1965	53,785	454	12,030	22.4
1970	67,827	519	13,062	19.3
Growth Rate	4.7%		1.7%	

The use of coal in steelmaking and other industrial applications will continue largely along current lines. There will be continued reduction in the amount of coke needed for each ton of steel due to technological advances. Air pollution problems are the major uncertainties surrounding the use of coal in its present markets.

Of total coal demand, 83 percent involves only the two markets of coke production and electric power generation. These two uses are expected to represent 92 percent of all demand by 1985, assuming no conversion of coal to either gas or liquid fuel during this period.* Future demand can, therefore, be fairly well defined by detailed consideration of the steel and power markets which are discussed further below.

The Coal Task Group projects the total domestic demand less synthetics to grow at a 3.5-percent rate. Projections of total domestic demand by market sectors and by Petroleum Administration for Defense (PAD) districts, in trillions of BTU's, are listed in Tables 3 and 4. The figures listed in Table 3 are repeated in Table 5 in millions of tons per year, together with export demands. Appendix E contains a detailed description of the assumptions and methodology used in arriving at the data displayed in Tables 3 through 5.

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* The potential growth rate of synthetic fuels industries (synthetic pipeline gas from coal and synthetic hydrocarbon liquids from coal) is covered in a later chapter of this report.

TABLE 3

U.S. COAL DEMAND BY MARKET SECTOR
(Trillion BTU's)

	1970	1975	1980	1985
Coking coal (14,000 BTU/lb.)	2,688	3,136	3,360	3,528
Industrial (13,000 BTU/lb.)	2,366	2,262	2,184	2,080
Residential/Commercial (14,000 BTU/lb.)	280	196	140	84
Electric Utility (12,000 BTU/lb.)	7,728	9,960	12,600	15,696
Total"	13,062	15,554	18,284	21,388
(Average BTU's per Ton- Thousands)	(25,167)	(25,046)	(24,910)	(24,783)

* These quantities are less than the total demand figures shown in the NPC's *U.S. Energy Outlook: An Initial Appraisal* 1971- 1985, Volume One (July 1971), because they do not include "Assumed Replacement for Shortfall in Other Fuel Supplies." The added quantities for coal, in terms of tons of coal, would be 30 million tons in 1975, 65 million tons in 1980 and 70 million tons in 1985.

TABLE 4

U.S. COAL DEMAND BY PAD DISTRICTS
(Trillion BTU's)

	1970	1975	1980	1985
PAD District I	4,745	5,394	6,071	6,871
PAD District II	6,998	8,416	9,859	11,533
PAD District III	920	1,178	1,503	1,857
PAD District IV	279	416	642	854
PAD District V	120	150	209	273
Total"	13,062	15,554	18,284	21,388

* These quantities are less than the total demand figures shown in the NPC's *U.S. Energy Outlook: An Initial Appraisal* 1971- 1985, Volume One (July 1971), because they do not include "Assumed Replacement for Shortfall in Other Fuel Supplies." The added quantities for coal, in terms of tons of coal, would be 30 million tons in 1975, 65 million tons in 1980 an 70 million tons in 1985.

It should be noted that the domestic demand figures shown in Tables 3 ana 5 were the results of the task group's initial appraisal. These figures were projected for conventional uses only; requirements for synthetics production were not inCluded. Furthermore, the domestic demand figures were derived on the basis of a single growth rate--3.5 percent. However, the domestic supply projections resulting from the task group's second appraisal and previously shown in Table 1, were based on two additional growth rates--5 and 3 percent which correspond to Supply Cases I and IV respectively. Domestic supply projections for Supply Cases II and III were premised on the 3.5-percent growth rate that was used previously in the demand analysis. Hence, the projections for these cases (Cases II and III), with the exception of coal supplies for synthetics production, are identical to the demand figures illustrated in Table 5.

TABLE 5

COAL DEMAND BY MARKET SECTOR
(Millions of Tons per Year)

	1970	1975	1980	1985
Blast Furnaces	86	102	110	116
Foundries and Miscellaneous	10	10	10	10
Total Coking Coal	96	112	120	126
Residential/Commercial	10	7	5	3
Industrial	91	87	84	80
Electric Utilities	322	415	525	654
Total Domestic U.S.	519	621	734	863
Coking Coal Export	56	76	94	120
Electric Utility Export	15	16	17	18
Total Export	71	92	111	138
Total*	590	713	845	1,001

* These quantities are less than the total demand figures shown in the NPC's *U.S. Energy Outlook: An Initial Appraisal 1971 - 1985*, Volume One (July 1971), because they do not include "Assumed Replacement for Shortfall in Other Fuel Supplies." The added quantities for coal, in terms of tons of coal, would be 30 million tons in 1975, 65 million tons in 1980 and 70 million tons in 1985.

DEMAND FOR COKING COAL

The production of steel and the impact of future technology on the demand for coking coal were estimated in detail by the U.S. Steel Corporation, with assistance from the American Iron and Steel Institute (see Appendix F). The impact of new technology, such as lower coke rates and direct reduction, are expected to be felt in 1975 at the earliest. Thereafter the growth in coking coal demand will lag behind the growth in steelmaking. Accordingly, U.S. demand for coking coal will grow at a rate of 2 percent per year, but the much faster growth in world steel production is reflected in a vigorous growth rate for U.S. coking coal export of 7 percent per annum. This rate leads to a potential export demand of over 150 million tons per year in 1985, but this figure has been arbitrarily reduced *tb* 120 million tons (or a 5.2-percent implied growth rate) in 1985 to reflect growing foreign competition.

The rapid increase in the cost of the highest quality, low volatile, U.S. metallurgical (coking) coal has led to increased efforts by coke oven operators to minimize its use by various changes in technology. The lower projected figure (120 million tons) also reflects this trend. Even so, metallurgical coal exports are one of the largest items in the U.S. foreign trade balance, approaching $1 billion in 1970, and future projections imply more than twice this figure in 1985 (in constant 1970 dollars).

The growth of U.S. metallurgical coal demand is offset by an expected reduction of industrial coal use. This market is projected to decline at a rate of some 1.0 percent per year. Since residential/commercial and transportation uses of coal are almost negligible in overall U.S. demand, the balance then depends on the projected use of coal in power generation.

DEMAND BY ELECTRIC UTILITIES

The Energy Demand Task Group of the NPC's U.S. Energy Outlook study commented on the extremely low elasticity of demand to price change for total energy. This lack of elasticity is especially pronounced in power generation due to the very long lead time (presently 5 to 7 years) between the decision to build a power plant and the date it becomes operational. As a result, all the power stations that will operate in 1975 and some 85 percent of those that will operate in 1980 are either existent or already committed as far as design and choice of fuels are concerned. Fuels are not interchangeable between nuclear and fossil-fuel plants, a fact which further limits the flexibility of the demand.

The most important matter bearing on future use of coal in power generation is the impact of the Clean Air Amendments of 1970 (Public Law 91-604). In compliance with this legislation, the use of low-sulfur coal might constitute a nationwide answer except for the fact that such coal is severely limited in certain geographic regions. The eastern United States is particularly deficient. Low-sulfur coal is relatively more abundant in western regions, but unfortunately this coal is distant from the major demand centers in the East. Further, emission restrictions are continually tightening and suggest that even fuel with 0.5-percent sulfur will not be usable in wide areas without removal of S02 from stack gases. Alternate solutions to the problem are conversion of coal to low-sulfur producer gas (low-BTU gas) or to low-sulfur fuel oil ahead of the boiler.

The methodology used by the Coal Task Group to project coal demand by electrical utilities is presented below:

- The total energy demand by electric utilities (in BTU's) was obtained from the NPC Energy Demand Task Group. (This figure is supported by the Federal Power Commission [FPC] and Edison Electric Institute studies.)

- The power generating capacity assigned to each fuel, whether currently in existence or announced for startup in the future, is then added for 5-year intervals. For the first half of the period to 1985, this estimate involves little guesswork because most new stations scheduled for startup in this period have been announced. The projection for the second half of the period requires an assumption regarding the use of coal *vis-a-vis* gas, oil, hydro or nuclear fuel. As a result, the projections by various groups diverge increasingly as they reach further into the future.

- After the generating capacity to be in operation with each fuel is determined for each period, it is necessary to determine the operating factors of the various segments of the total system. The figures used by the Coal Task Group are based on a 70-percent operating factor for all nuclear plants in 1975 and a 74-percent factor in 1980 and 1985. This compares with a 52- to 54-percent average for all fossil-fueled plants and a declining hydropower operating factor (52 to 45 percerit).

- The fossil fuel demand (essentially the remainder after nuclear, hydro and gas turbines have made their contribution) is then estimated for oil, gas and coal, reflecting the capability of existing plants to burn these fuels and giving some consideration to the availability of each for use in power plants. The resulting coal figures are tabulated in Table 5.

NUCLEAR IMPACT ON UTILITIES DEMAND FOR COAL

The coal demand projections are based on nuclear capacity in existence and operating at the stated load factors in 1975, 1980 and 1985 of 50,000, 127,900 and 251,260 megawatts (MW), respectively. The assumption that the nuclear plant operating factor will be 74 percent, however, must be viewed in light of an actual average operating factor of only 48 percent achieved so far by the 14 nuclear plants already operating in 1970. Thus, the ability of the nuclear sector to contribute its share at a 74-percent average output is still in doubt, and any shortfall would impact increasingly on the demand for fossil fuels as the nuclear capacity increases. In 1970, when nuclear capacity was only a small part of the U.S. total power plant, its low operating factor was already reflected in a greater demand for fossil fuels.

The following figures give an indication of the sensitivity of estimates of fossil fuel demand to the "nuclear impact." If the average output obtained by the nuclear sector in 1975 were to be only 60 percent rather than 70 percent, the estimate of fossil fuel demands would have to be increased 2.7 percent. But in 1985, when nuclear capacity represents a far greater fraction of the total and a 74-percent operating factor is assumed, a drop of the nuclear operating factor to 60 percent would require a 13-percent increase in fossil fuels (including almost 90 million tons of coal). This rise would be required in that 1 year alone, unless anticipated years earlier.

The coal industry is increasingly moving toward firm, long-term, contract-based operations both in the metallurgical and power-generation markets. This trend reduces the amount of excess mining capacity which can be counted on to permit coal-burning plants to pick up the slack in case nuclear plants fall behind schedule in becoming operational or in case they prove less reliable than expected. The rate of future commitment to nuclear power, fossil-fueled power and mine development will presumably reflect this consideration.

For further details concerning the demand for coal refer to Appendices E and F.

Chapter Three

COAL RESOURCES

SOURCES OF SUPPLY FOR CONVENTIONAL USES AND SYNTHETICS

Prior to examining future coal supply (supply is examined in Chapter Five), it is desirable to distinguish between (1) the growth of coal supply from the present sources for the major conventional coal markets (electric power and steel) and (2) the potential growth of supply associated with use of coal for synthetic gas and liquids.

Through 1985, the increased supply of coal for the conventional markets can be assumed to come essentially from deposits similar (in terms of seam thickness and depth) to those presently mined. The impact of production growth on future costs can therefore be approximated fairly closely without having to consider the costs of mining deeper or thinner seams.

In contrast, the supply of coal for conversion to gas or liquids through 1985 can be expected to be based largely on use of surface coal deposits in the Rocky Mountain area in view of the much lower mining costs associated with that area. Therefore, the adequacy of this specific resource will be considered in connection with the future production of synthetic fuels. This does not mean that only western coals will be used for synthetic feedstocks. Coal from other areas may also be used, but the quantity would probably be negligible by comparison.

REGIONS OF U.S. COAL RESOURCES

An examination of future coal supply requires some manner of geographically categorizing the available resources. The categorization is most useful if the resources are grouped so that each region is somewhat uniform in terms of coal deposits and mining method. Figures 1 and 2 show the coal fields of the United States, with the six underground mining regions shown in Figure 1 and the six surface mining regions shown in Figure 2. These regions are also outlined in Table 6. The total resources are first divided between underground- and surface-mined coal. These two groups are then subdivided into major coal basins where mining conditions vary only within a narrow range. Future cost projections are made for each of these basins.

MAGNITUDE OF THE COAL RESOURCE BASE

Coal represents the largest, most accessible reserve of energy available within the continental United States. The Coal Task Group has made a potential resource estimate which is based on a

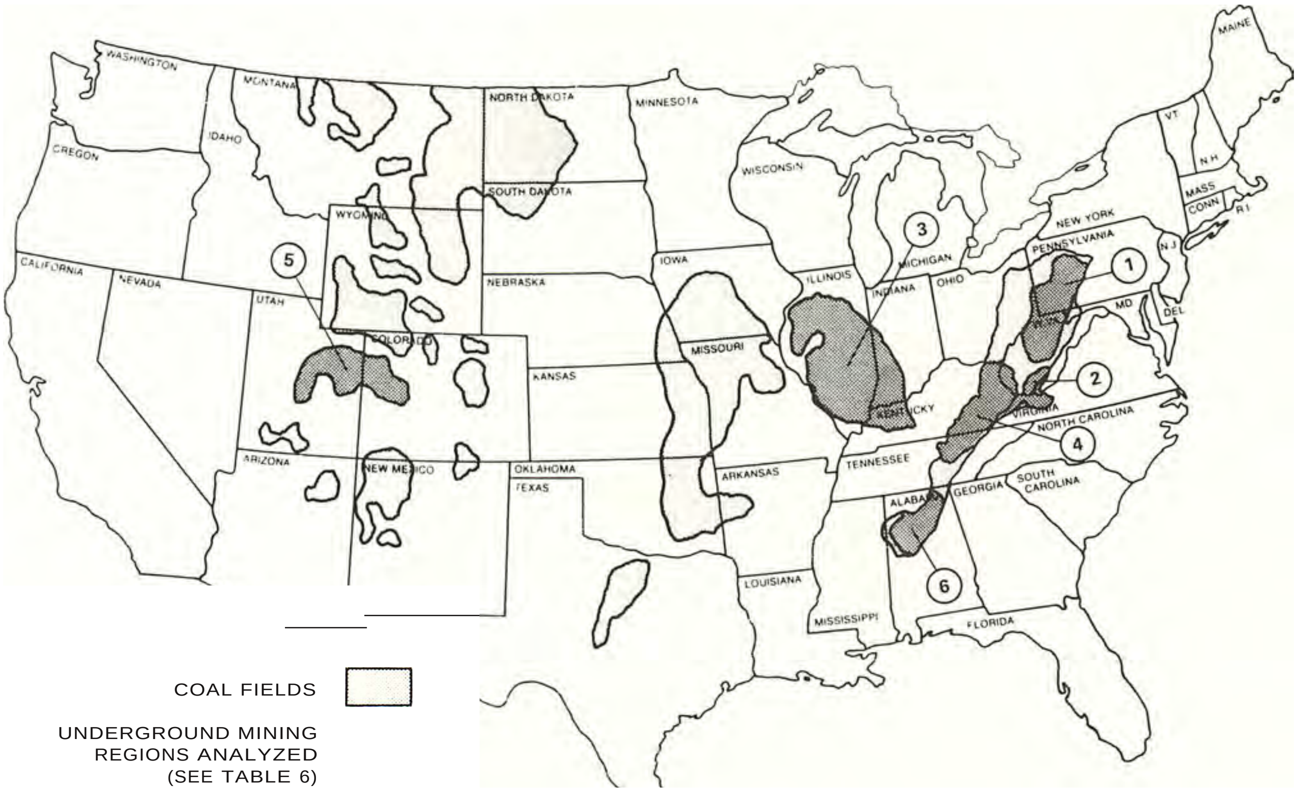


Figure 1. Coal Fields of the United States--Major Underground Mining Regions.

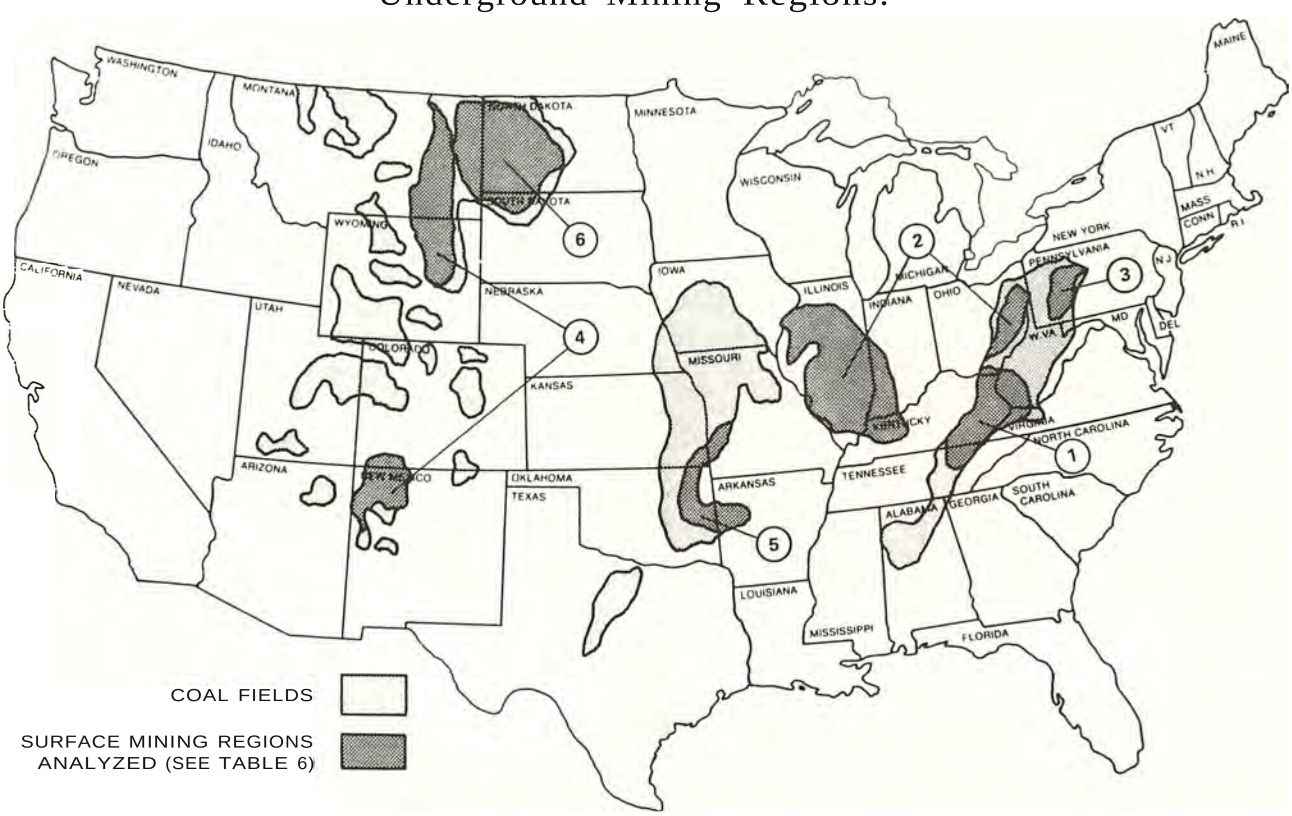


Figure 2• Coal Fields of the United States--Major Surface Mining Regions.

TABLE 6
COAL FIELDS OF THE UNITED STATES

Underground		Surface	
	Region 1		
1.	West Virginia	1.	Kentucky
2.	Pennsylvania	2.	West Virginia
		3.	Virginia
		4.	Tennessee
	Region 2		
1.	Mercer County, W. Va.	1.	Illinois
2.	McDowell County, W. Va.	2.	Indiana
3.	Wyoming County, W. Va.	3.	Iowa
		4.	Ohio
	Region 3		
1.	Illinois	1.	Pennsylvania
2.	Indiana		
3.	Ohio		
	Region 4		
1.	Kentucky	1.	Colorado
2.	Tennessee	2.	Montana
3.	Virginia	3.	New Mexico
		4.	Wyoming
	Region 5		
1.	Utah	1.	Oklahoma
2.	Colorado	2.	Kansas
		3.	Missouri
	Region 6		
1.	Alabama	1.	North Dakota

* Does not include Mercer, McDowell and Wyoming Counties in West Virginia; these three counties produce mainly low-volatile coking coal and are considered separately in Region 2.

report on U.S. coal resources prepared by the USGS. The total coal in place is given as 3.21 trillion tons and is broken down as shown in the following tabulation:*

* Paul Averitt, *Coal Resources of the United States*, USGS Bulletin 1275 (January 1, 1967).

	Trillion Tons
Mapped and Explored: 0-3,000' Overburden	1.56
Probable Additional Resource in Unmapped and Unexplored Areas: 0-3,000' Depth	1.31
3,000-6,000' Depth	0.34
Total	3.21

Figure 3, taken directly from the original USGS report, shows the percentage distribution of the 1.56 trillion tons at less than a 3,000-foot depth in the mapped and explored areas. The total is subdivided by depth, by seam thickness and by three categories of certainty.

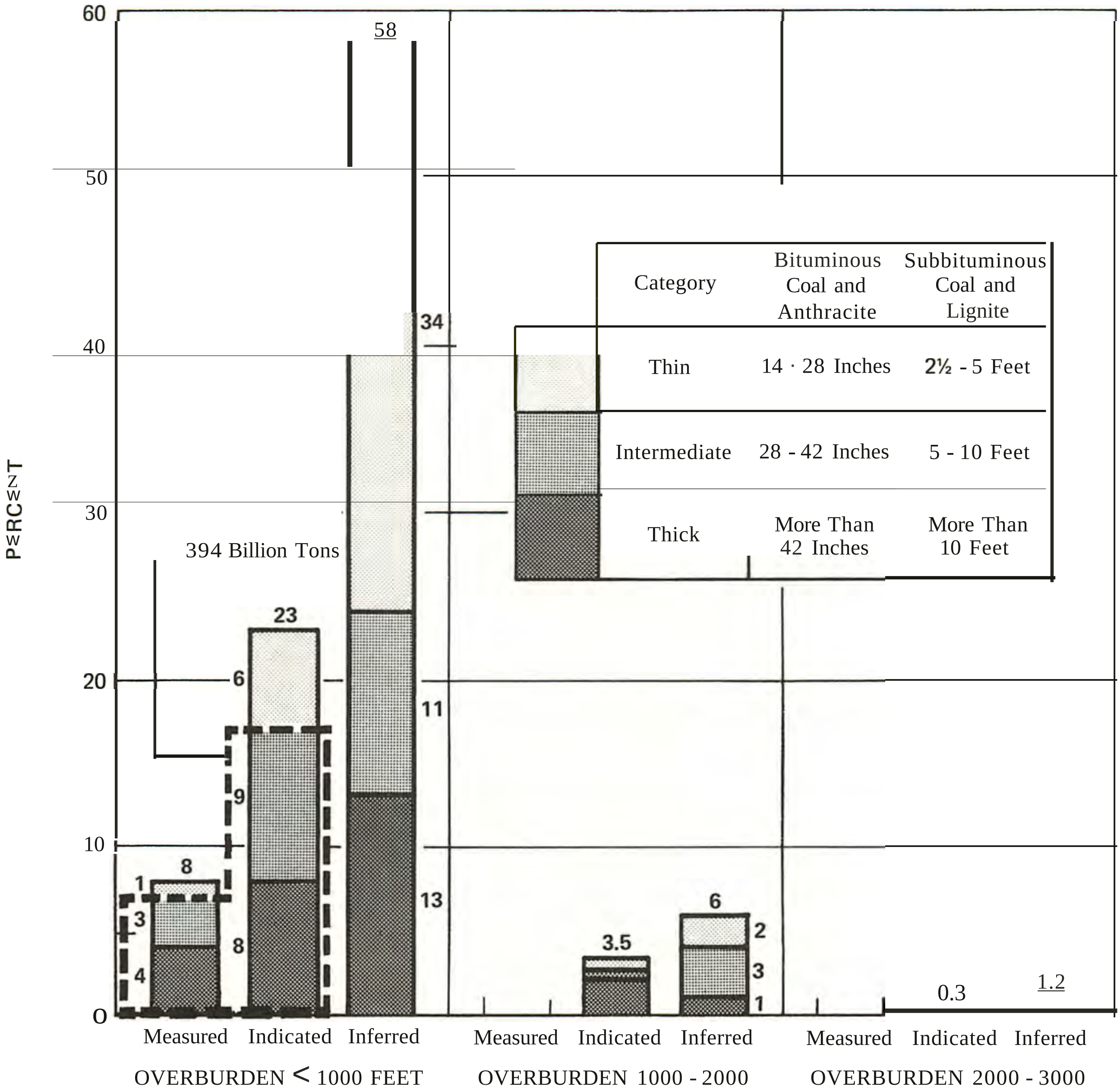
Coal resources in place (i.e., not necessarily recoverable) are commonly divided into three categories according to the relative abundance and reliability of data used in preparing the estimates. These categories are termed "measured," "indicated" and "inferred." Measured resources are resources for which tonnage is computed from dimensions revealed in outcrops, trenches, mine workings and drill holes. Indicated resources are resources for which tonnage is computed partly from specific measurements and partly from a projection of visible data for a reasonable distance on the basis of geologic evidence. Inferred resources are resources for which quantitative estimates are based largely on broad knowledge of the geologic character of the bed or region and for which few measurements are available.

Information on measured and indicated resources as tabulated by the Bureau of Mines (see Appendix G) shows that the U.S. coal resources, in beds over 28 inches thick and under less than 1,000 feet overburden, are as follows:

	Millions of Short Tons
Bituminous Coal	261,510
Subbituminous Coal and Lignite	119,861
Anthracite	12,735
Total	394,106

The block shown in Figure 3 within the dotted line represents these 394 billion tons. This figure is termed "remaining measured and indicated reserves" and is composed of 349 billion tons of underground resources and 45 billion tons of surface resources.

These 394 billion tons, however, do not include measured and indicated coal seams which are less than 28 inches thick and below 1,000 feet overburden and which are thus beyond current economic mining practices. These 394 billion tons, in fact, represent only



SOURCE: Paul Averitt, Coal Resources of the United States, *USGS Bulletin* 1275 *(Januarv 1,* 1967).

Figure 3. Estimated Mapped and Explored Coal Resources--U.S.A. (Total Shown--l.56 Trillion Tons).

about 25 percent of all measured and indicated resources of more than 14 inches in thickness and under less than 3,000 feet cover. The latter will have no significance during the next 15 years, but future needs and new approaches to mining technology can someday place most of these 1.56 trillion tons within reach.

In Tables 7 and 8, the "remaining" resources have been assigned to the regions defined in Table 6. In the case of underground coal, shown in Table 7, the remaining resources (349 billion tons) are further narrowed down to "economically available reserves" by ex-

TABLE 7

UNDERGROUND COAL RESERVES AND PRODUCTION
(Minable by Underground Mining Methods)

Region	Billions of Tons: Remaining Measured and Indicated Reserves*	Billions of Tons: Economically Available Reservest	Billions of Tons: Recoverable Reserves‡	1970 Production (Millions of Tons)	Life of Recoverable Reserves at % Growth Rate (Years): 0%	3%	5%
1	92.7	67.1	33.5	145.8	230	69	50
2	9.1	9.1	4.6	N.A.			
3	83.1	59.5	29.7	52.3	568	96	68
4	34.5	24.4	12.2	95.0	129	52	40
5	21.9	13.3	6.7	8.6	774	106	74
6	1.6	.6	.3	9.1	35	23	20
Other	106.3	35.2	17.6	N.A.			
Total §	349.1	209.2	104.6	338.8	309	80	58

• Bituminous, subbituminous and lignite in seams of "intermediate" or greater thickness and less than 1,000 feet overburden (see Figure 501.

t Excludes lignite and "intermediate" thickness seams of bituminous and subbituminous coal.

‡ Based on 50-percent recovery of economically available reserves.

§ May not add correctly due to rOllnding.

TABLE 8

SURFACE COAL RESERVES AND PRODUCTION
(Minable by Surface Mining Methods)

Region	Recoverable Reserves (Billions of Tons)	1970 Production (Millions of Tons)	Life of Reserves at % Growth Rate (Years): 0%	3%	5%
1	4.2	101.2	42	27	23
2	5.6	91.0	62	36	29
3	0.8	25.1	.32	23	19
4	23.8	19.1	1,246	122	85
5	1.6	8.3	193	65	48
6	2.1	5.6	375	85	62
Other	6.9	13.8	500	95	67
Total	45.0	264.1	170	61	46

eluding underground lignite and intermediate thickness bituminous and subbituminous seams. A recovery factor of 50 percent has been used to arrive at the total recoverable underground reserves. This reduces the total underground reserve to 104.6 billion tons. In order to emphasize the magnitude of this resource, it has been related to the 1970 rate of production, and the life of these reserves in years is shown for compounded annual growth rates of 0, 3 and 5 percent.

It is apparent that these resources are of sufficient magnitude to obviate production from any thinner or deeper seams for some time to come, even at the 5-percent growth rate.

The amounts shown in Table 7 are particularly sensitive to the impact of mining technology. This tabulation assumes the application of current techniques and economics and assumes, as previously mentioned, a 50-percent recovery factor. A wide-scale switch to longwall mining or any other system which yields higher recovery could add substantially to the recoverable reserves.

Similarly, the recoverable surface-mined coal reserves are grouped in Table 8 according to the regions outlined in Table 6. In Table 8, a recovery factor is not applied since, in most cases of surface mining, it will exceed 90 percent. The life of these surface reserves is related to the 1970 production rate at annual growth rates of 0, 3 and 5 percent. This life excludes those reserves of the western United States for synthetic fuels production.

On the basis of 11,000 BTU's per pound (an assumed average value), the 394 billion tons of coal, currently regarded as the Nation's resource base, should supply 8,670 quadrillion BTU's. Although less than one-half of these reserves are currently considered recoverable, this latter figure alone represents a very sizable reserve measured in many years of supply in relation to our projected demand for coal. Until a successful breeder reactor is developed, no other U.S. energy resource is or will be comparable to this reserve. From the point of view of untapped resources, at least, the coal reserves of the United States are sufficient to supply the Nation's basic energy needs until the breeder or the fusion reactor, or perhaps solar energy, can remove the ever growing concern about our ultimate energy sources.

It is quite significant that the reserves shown above in Tables 7 and 8 exclude inferred resources plus potential coal yet to be found in unmapped and unexplored areas. Since the two tables together represent only about 150 billion tons of recoverable coal reserves, or less than 5 percent of the total potential resource in place (3.21 trillion tons), the size of the additional coal reserves which may be potentially accessible should also be emphasized. As Figure 3 shows, even within existing mapped and explored areas there are thick resources under less than 1,000 feet which are potentially available. These resources could represent about 215 billion tons if they were better defined. This would be in addition to the 394 billion tons now regarded as the Nation's resource base.

Unmapped and unexplored coal resources could also yield significantly greater coal reserves. As previously noted, resources in this category are presently estimated at 1.31 trillion tons. Table 9, an excerpt of USGS data for a sample of states, gives an indication of the additional potential in unmapped and unexplored areas.

The last column in Table 9 gives an indication of the remalnlng potential for each state. With the East having been well explored, the greatest potential remains to be found in the Rocky Mountain region, followed by the Midwest. While additional coal resources in the West are likely to be somewhat less accessible than the Nation's eastern sources, they should still include substantial

TABLE 9

SELECTED COMPARISON OF "MAPPED AND EXPLORED" AND "UNMAPPED AND UNEXPLORED" RESOURCE
(Billions of Tons)

	Total Resource	Mapped	Unmapped	Unmapped/ Total (Percent)
New Mexico	88	61	27	31
Utah	80	32	48	60
Colorado	227	81	146	64
Wyoming	445	120	325	73
Montana	379	222	157	41
North Dakota	530	350	180	34
Illinois	240	140	100	42
Indiana	57	35	22	39
Pennsylvania	80	70	10	13
West Virginia	102	102		
Ohio	44	42	2	5

amounts of coal within current economic reach.

Metallurgical Coal Reserves

Steelmaking requires a special type of coal, known generally as metallurgical coal. So-called metallurgical coals are needed to produce coke for blast furnace operation. These coals must have a property known as caking (or coking) and must be low in sulfur (under 1.5 percent and preferably well under 1.0 percent). In addition, a high content of fixed carbon is desirable (volatile matter content between 17.5 and 25.0 percent), and ash levels should be low (5.0- to 7.0-percent ash is acceptable).

Coals of this type are in short supply throughout the world. The Bureau of Mines tabulation in Appendix G indicates reserves of 20.3 billion tons of low and medium volatile coals in seams of 28 inches or thicker and under less than 1,000 feet cover. This relates to a demand of 96 to 126 million tons per year for the United States. To this must be added the already large and rapidly growing export volume (56 million tons in 1970, potentially 120 million tons in 1985). The U.S. reserve position for metallurgical coals, while safe for many decades, is clearly not comparable to that of the coal reserves as a whole.

Adequacy of Reserves

In summary, the supply of coal reserves in place is adequate to meet the U.S. (and export) demand during the next 15 years and through the rest of the century with a wide margin of safety, including coal for conversion to gaseous and liquid fuels.

Chapter Four

COAL MINING

COAL PRODUCTION

Coal is produced in the United States from both underground and surface mines. Most surface-mined coal involves removal of the overburden (stripping), with auger mining contributing the balance.

The history of coal production for the 1935-1970 period is shown on Figure 4, which indicates total U.S. coal production and a breakdown into underground and surface bituminous coal (including lignite) and anthracite.

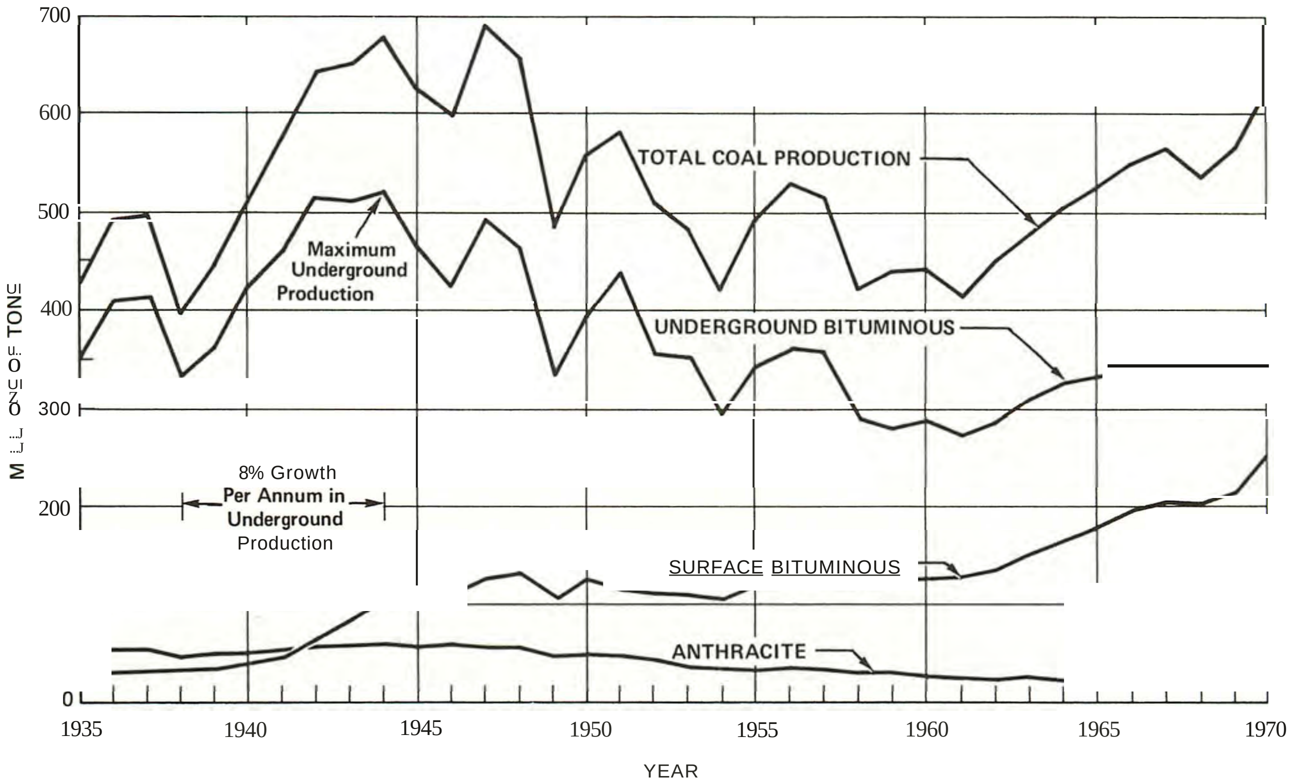


Figure 4. Production of Bituminous Coal (Including Lignite) and Anthracite--1935-1970.

It is evident that the contribution of surface mining is large and increasing. This trend is reflected in Table 10.

Surface mining is attractive due to lower investment and operating costs (less manpower) and because it is not subject to the health and safety problems associated with deep mining, although it is subject to increasingly stringent environmental requirements.

TABLE 10

TREND OF TYPE OF COAL MINES
(Percent of Total Bituminous Coal and Lignite Production*)

	1960	1965	1970
Deep Mining of Coal	68.6	65.0	56.2
Surface Mining of Coal	31.4	35.0	43.8
Total	**100.0**	**100.0**	**100.0**

* Actual production figures for the 1960 - 1969 period are included in Appendix H.

COAL MINING METHODS

Underground Mining

During the 1950-1970 period, underground production was based on four distinct mining systems:

- Handloading
- Conventional
- Continuous
- Longwall.

Handloading, which once produced significant coal tonnages, has declined to such an extent since 1950 that it is now insignificant.

Conventional and continuous mining provide the bulk of United States underground coal tonnages today. Both systems involve a room and pillar approach, but they differ in terms of machinery used and in operating sequence. A continuous mining machine, for example, combines into one machine the work done in conventional mining by the cutter, the face drill, the loading machine and the blasting operation. One such machine breaks or digs the coal out of the solid seam and loads it into a conveyance vehicle. Haulage and roof support, however, are accomplished in much the same manner for either conventional or continuous mining.

Although the conventional mining share of underground production has declined steadily since 1950, it is still expected to produte an important portion of total tonnage in the future. Production from continuous mining, on the other hand, has steadily increased since 1950 and equaled conventional tonnage in 1966. Since 1966, continuously mined tonnage has accounted for virtually all of the increase in underground tonnage.

Longwall mining, long prevalent in Europe, has recently entered the United States. In longwall mining, a large block of coal to be mined is isolated by driving entries, or tunnels, around four sides of the block. Mining is then done across the width of the block (300 to 800 feet), a slice at a time. The mining machine is either a drum-type shearing machine or a plow which is moved along the coal face. As the coal is dug from the face, it falls to the floor where it is continuously removed by a conveyor assembly.

Although the percentage of total underground production by the longwall method in 1970 was very small, this method is expected to become increasingly important because it concentrates production in a smaller area in the mine, offering better productivity and simplified ventilation.

Figure 5 shows the percentage of underground bituminous production developed by conventional, continuous and longwall mining systems during the 1950-1972 period.

As Figure 5 indicates, conventional mining accounted for the largest share of underground production through the mid 60's. In the late 1960's, however, production from continuous mining exceeded coal tonnages produced by conventional mining methods. During that same year, longwall mining accounted for a small but growing 2 percent of underground production. Thus, in light of current trends, it is anticipated that by 1975 continuously mined tonnages will amount to 63 percent of underground production, longwall mining tonnages will expand to 5 percent, and tonnages produced by conventional mining methods will decline further to 32 percent.

Productivity of Underground Mining

As a result of continued growth of continuous mInIng and near elimination of handloading, the average productivity of manpower steadily increased through the late 1960's (a 2.7-percent rate during the 1965-1969 period). Historical data given in Table 11 show this trend in tons per man per day.

However, with the enactment of the Coal Mine Health and Safety Act of 1969, a profound negative impact on productivity has resulted as suggested by the 1969-1970 downturn which is also shown in Table 11. Conclusive statistics are not yet available to show the full impact of the law on productivity, but reductions at individual mines from 15 to 30 percent have been reported.*

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* Data for 1971 confirms a further decline in productivity of underground mining--12.03 tons per man-day.

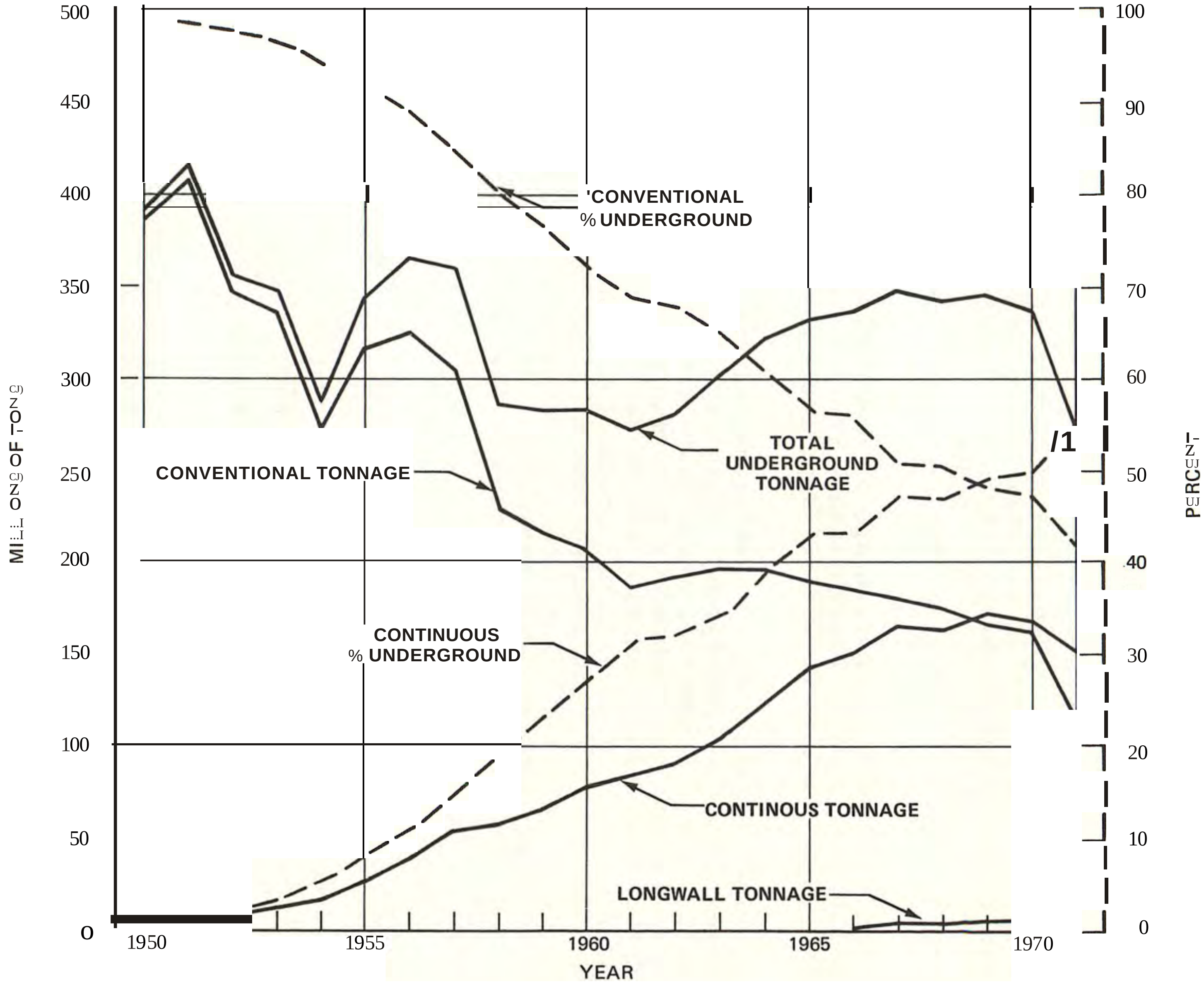

Figure 5. U.S. Underground Bituminous Coal Production Systems--1950-l972 (in Percentages and Millions of Tons).

TABLE 11

RELATIVE PRODUCTIVITY OF UNDERGROUND MINING
(Tons per Man per Day)

	Underground	Total Industry*
1960	10.64	12.83
1965	14.00	17.52
1969	15.61	19.90
1970	13.76	18.84

* Includes both underground and surface mining.

The dust control provision of the 1969 statute calls for a target maximum of 2 milligrams respirable dust per cubic meter of air, which will affect mine productivity. This provision will be strictly enforced by January 1, 1976. Other provisions regarding roof control, ventilation requirements and other limitations of the mining cycle will also have a similar impact on productivity. Interpretation of the act in the field has not yet reached the point where its provisions have been put to use as a steady practice, and it has been in effect for too short a time to permit a full analysis of its impact on underground mining. It is hoped, however, that the setback in productivity resulting from this act can be regained during the near future. In any event, it is now difficult to project manpower requirements with confidence.

Surface Mining

Surface Mining Methods

In general terms, surface mining (sometimes referred to as strip mining) involves removal of the overburden to expose the coal seam for subsequent loading. Surface mining can be divided into two broad classes: contour mining and area mining. Contour mining (in some regions called collar mining) is employed in hilly areas where topography governs pit design. Where the terrain is steep, the recoverable reserves tend to lie in a narrow band adjacent to the coal outcrops. The coal pits are usually developed in the form of long, narrow strips, each of which follows a certain contour interval around the mountain or hill. Since the coal beds are nearly flat and the terrain is quite rough, in most cases only a few cuts can be made around the hills before the maximum economic stripping ratio is reached.

Area mining is used in flat or slightly rolling areas where the coal seams are relatively flat. The pit design is governed mainly by the equipment and the desired level of production. The pits are developed in a series of long, narrow strips. As the mining progresses, the overburden from each strip is cast back into the open pit of the previous strip. Thus, a series of parallel furrows are formed in much the same manner as a farmer plows his field. For this reason, area mining is sometimes referred to as furrow mining.

In the Appalachian region, both surface mining techniques are employed. Area mining is used in Alabama, Ohio, Pennsylvania and parts of West Virginia. Contour mining is practiced in parts of Alabama, Pennsylvania, Ohio, West Virginia, Maryland, Virginia, East Kentucky and Tennessee. In the western states, surface mining will be largely area mining.

Auger mining of coal is frequently done in association with surface mining. In some mountain areas where surfaces lie on steep slopes, auger drills are used to remove the coal from the bank after the coal seam has been uncovered with one or two strip pits.

<u>Coal Production by Strip Mining</u>

In 1970, about 44 percent of the bituminous coal and lignite produced in the United States came from strip mines.* The production capacity of strip mines generally ranges from 0.5 to 6.0 million tons per year with an average output of about 2 million tons per year. However, one western mine is scheduled to exceed 8 million tons per year production.

<u>Coal Stripping Ratios</u>

The key figure on which feasibility of surface mining depends is the stripping ratio, usually expressed in cubic yards of overburden to be removed to recover 1 ton of coal. The limiting ratio depends on the value of the coal among other items; hence, ratios of up to 30 to 1 have been profitably mined. Area averages are as follows:

Midwest:	Kentucky	11:1
	Illinois-Indiana	18:1
	Ohio	15:1
Western States:	Overall Average	6:1

The Bureau of Mines Coal Reserve Tables show some 25 billion tons of low-rank coals strippable at ratios from 1.5:1.0 to 18.0:1.0 in the western states (see Appendix G).

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* When this study was initiated, only 1969 information was available. Information for 1970 became available during the course of the study and is shown here. More recent information now available indicates that in 1972 surface-mined coal accounted for more than 50 percent of total production.

Productivity of Surface Mining

The high manpower productivity of surface mining is apparent from a comparison of the figures shown in Table 12 with those previously listed for underground mining in Table 11. This high productivity represents one of the main incentives for surface mining.

TABLE 12

RELATIVE PRODUCTIVITY OF SURFACE MINING
(Tons per Man per Day)

	Stripping	Auger Mining	Total Industry*
1960	22.93	31.36	12.83
1965	31.98	45.85	17.52
1970	35.96	34.26	18.84

* Includes both underground and surface mining.

On the negative side, there is increasing opposition to stripping operations, particularly contour mining. Land reclamation of strip-mined land is currently subject to varying state laws. In general, these laws require grading the mined area and seeding or planting to reestablish vegetation. The cost of reclamation depends on the average amount of coal recovered per acre of stripped land, hence the seam thickness. While the actual amount varies widely, it is not prohibitive per se; however, proposed stricter reclamation requirements will have a marked impact on stripping cost and will preclude stripping of some reserves.

Possible effects of environmental restrictions on surface mining will be presented in a later chapter.

STRUCTURE OF THE COAL INDUSTRY

The structure of the coal industry is similar to the agricultural industry: the capacity and scope of individual operating units vary over a very wide range. Production of bituminous coal in 1970 was distributed as shown in Table 13. As this table indicates, in 1970 less than 6 percent of the mines produced over 59 percent of the coal while over 71 percent of the mines produced less than 10 percent of total coal production. Obviously, the operating conditions at a mine producing, for example, 25,000 tons per year (about 100 tons per work day) differ tremendously from those of a facility producing 2 million tons per year (about 8,750 tons per work day).

The industry trend in recent years is toward increasing the number of days worked per year as well as the size of individual

TABLE 13

DISTRIBUTION OF COAL PRODUCTION-1970*

Mine Capacity (Tons per Year)	Number of Mines	Percent of Total Production
Over 500,000	307	59.6
200,000 - 500,000	266	14.0
100,000 - 200,000	405	9.3
50,000 - 100,000	617	7.2
Under 50,000	4,006	9.9
Total	5,601	100.0

* Detailed statistics for the 1960 - 1969 period are given in Appendix H.

mines. Table 14 indicates the number of days worked per year between 1960 and 1970.

TABLE 14

TRENDS IN WORKING OF MINES
(Number of Days Worked per Year)

	Type of Mine			
	Underground	Surface	Auger	Total
1960	188	213	119	191
1965	216	238	136	219
1970	229	236	148	228

In 1950, mines producing over 500,000 tons per year produced 36 percent of total production. By 1960, this group's contribution was 49 percent. In 1970, its share reached 59.6 percent (see Table 13). This trend is expected to continue as more and more companies take advantage of the economies of scale that may be obtained at large mines with larger, more efficient equipment.

Chapter Five

FUTURE COAL SUPPLY OUTLOOK

GROWTH CAPACITY FOR THE DOMESTIC INDUSTRY

In the Initial Appraisal, a sustained growth rate for coal of 3.5 percent per year was projected through 1985 from reserves presently mined. However, a subsequent review of future coal supply indicated that a maximum rate of growth of 5 percent per year could be sustained by the coal industry. In addition to evaluating the effect of growth rate on costs and "prices," a more moderate rate of growth of 3 percent per year was also analyzed. The results of these growth rates are shown in Table 15.

U.S. coal mines produce coal for export, and in the future will produce coal for conversion to synthetic gas and liquids. Table 1 in the Summary at the beginning of this report adds the coal required for these purposes to the conventional domestic figures and gives Case I through IV projections for total coal supply and use. The expected growth of exports is the same as that projected while analyzing demand in the Initial Appraisal. Derivations of the synthetic gas and liquids projections are given in a later section of this report.

Rationale for Use of Maximum Growth Rate

As previously illustrated in Figure 4 (Chapter Four), the greatest output from underground bituminous mines was reached during 1944 (518.7 million tons), and this peak output was preceded by a sustained growth in underground coal production over a 6-year period of almost 8 percent compounded annually. In the light of this performance, the 5-percent maximum growth rate indicated in Table 15 seems reasonable for future underground production.

As far as surface-mined coal (for conventional markets) is concerned, there is adequate historical justification for the 5-percent maximum growth rate. Annual growth in surface production since 1944 has been at a rate of 3.8 percent. Since 1954, production has grown at a rate of 6.1 percent. Again, this 5-percent projection relates primarily to surface mining in the eastern United States where most of the surface coal has actually been produced in the past.

ECONOMICS OF FUTURE COAL SUPPLY

Approach to Economic Analysis

In conducting its economic analysis of future coal supply, the task group employed a somewhat rigorous quantitative approach. In particular, an economic model was designed, developed and pro-

TABLE 15

FUTURE COAL SUPPLY FROM PRESENTLY USED RESERVES
FOR CONVENTIONAL DOMESTIC MARKETS ONLY

	Growth Rate (Percent)	1970*	1975	1980	1985
		Trillion BTU's per Year			
Case I	5.0	13,062	16,650	21,200	27,100
Cases II/III	3.5	13,062	15,554	18,284	21,388
Case IV	3.0	13,062	15,100	17,550	20,300
		Million Tons per Year			
Case I	5.0	519	665	851	1,093
Cases II/III	3.5	519	621	734	863
Case IV	3.0	519	603	705	819
Average: Thousand BTU/Ton		25,167	25,046	24,910	24,783

* Based on preliminary Bureau of Mines estimates. See footnote, Table 1.

grammed for a computer to assist in making an evaluation of future coal costs and to project a range of future coal "prices."*

The model itself was developed in three major sections, each of which performed a particular function. The first section was primarily concerned with estimating the average cost of producing coal at various production levels in the United States during the period covered by the study. The second section (a cash flow program) calculated, for a range of coal production growth rates (3 to 5 percent), the future average value or "price" of coal per ton (f.o.b. mine) required to yield three DCF rates of return on investment (10, 15 and 20 percent). The third section consisted of a regression program that was used to calculate the future coal values or "prices" on a regional basis. The regions for which these "prices" were calculated were the six underground and three surface mining regions (Regions 1, 2 and 3) that were illustrated in Table 6 (Chapter Three).

The model assisted in examining certain aspects of the conventional coal industry in the East and Midwest. The coal industry in these areas might be described best as a mature industry in an economic sense, and historical data which could be used for the purposes of this study were available. For several reasons, the model could not be used to analyze the relatively new coal industry in the West where opening or closing one or two mines might completely change the basic economic structure of the industry in that area.

* "Price" as used here is *not* a future market price but refers to an economic unit value which would, on the basis of the supply cases analyzed, support projected levels of coal production. Calculated "prices" in this study necessarily cover mining costs and yield a specified DCF rate of return on investment.

A vast amount of statistical data pertaining to the various operating aspects of the coal industry have been published by the U.S. Bureau of Mines as well as by a number of state agencies in the principal coal producing regions. However, little data have been published regarding the *average* capital and operating costs of producing coal. Those variables which related directly to capital and operating costs were determined and were subsequently categorized into four general classes, i.e., economic, physical and technological variables as well as certain governmental policies. The historical values for each of the variables were then collected and analyzed. The information obtained was used to design a model reflecting the average operating conditions which existed in the coal industry during the base year--1969.* These costs and operating conditions were then projected forward into the 1970-1985 period.

Because the cost of producing coal at underground mines is significantly different from the cost of producing coal at surface mines, it was necessary to consider both mining methods separately in developing the model. Consequently, two hypothetical coal mines --one surface and one underground--were created to serve as the

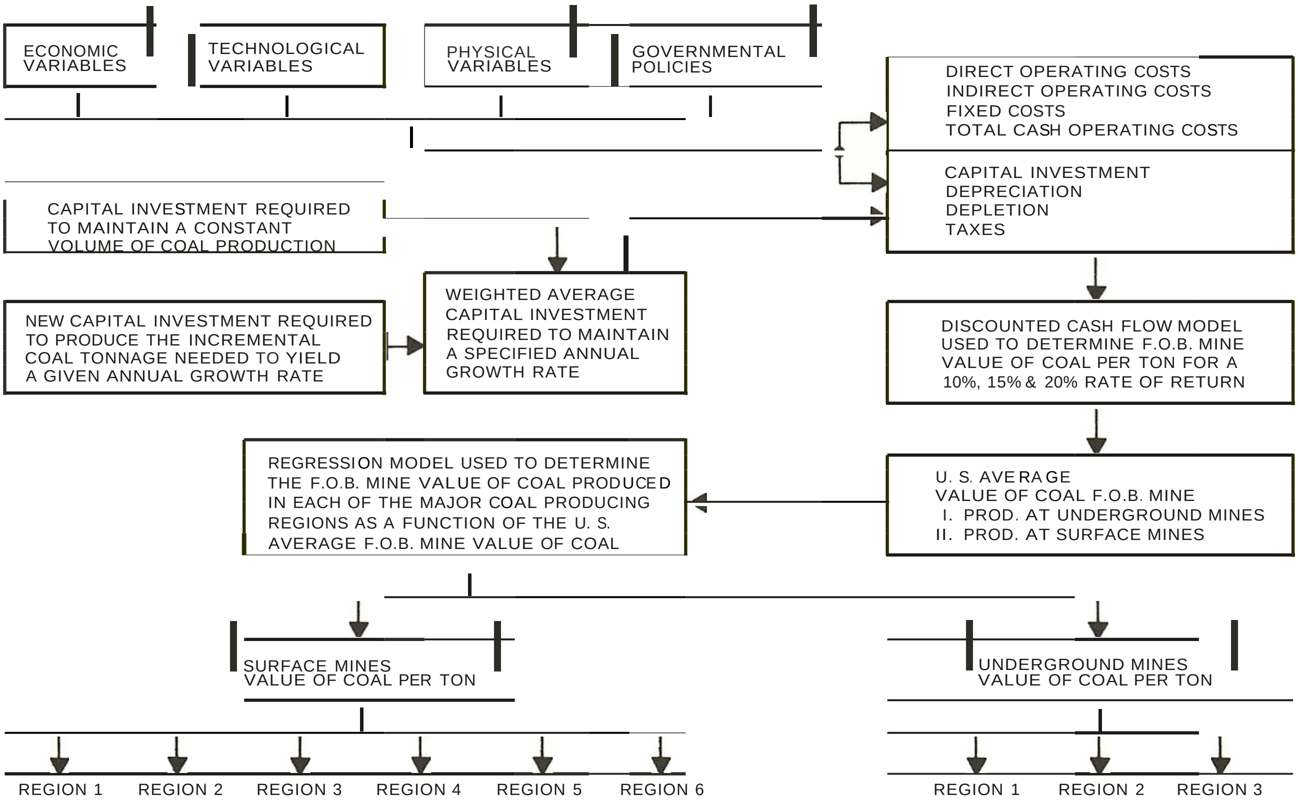

Figure 6. Method of Analysis--Coal Economic Model.

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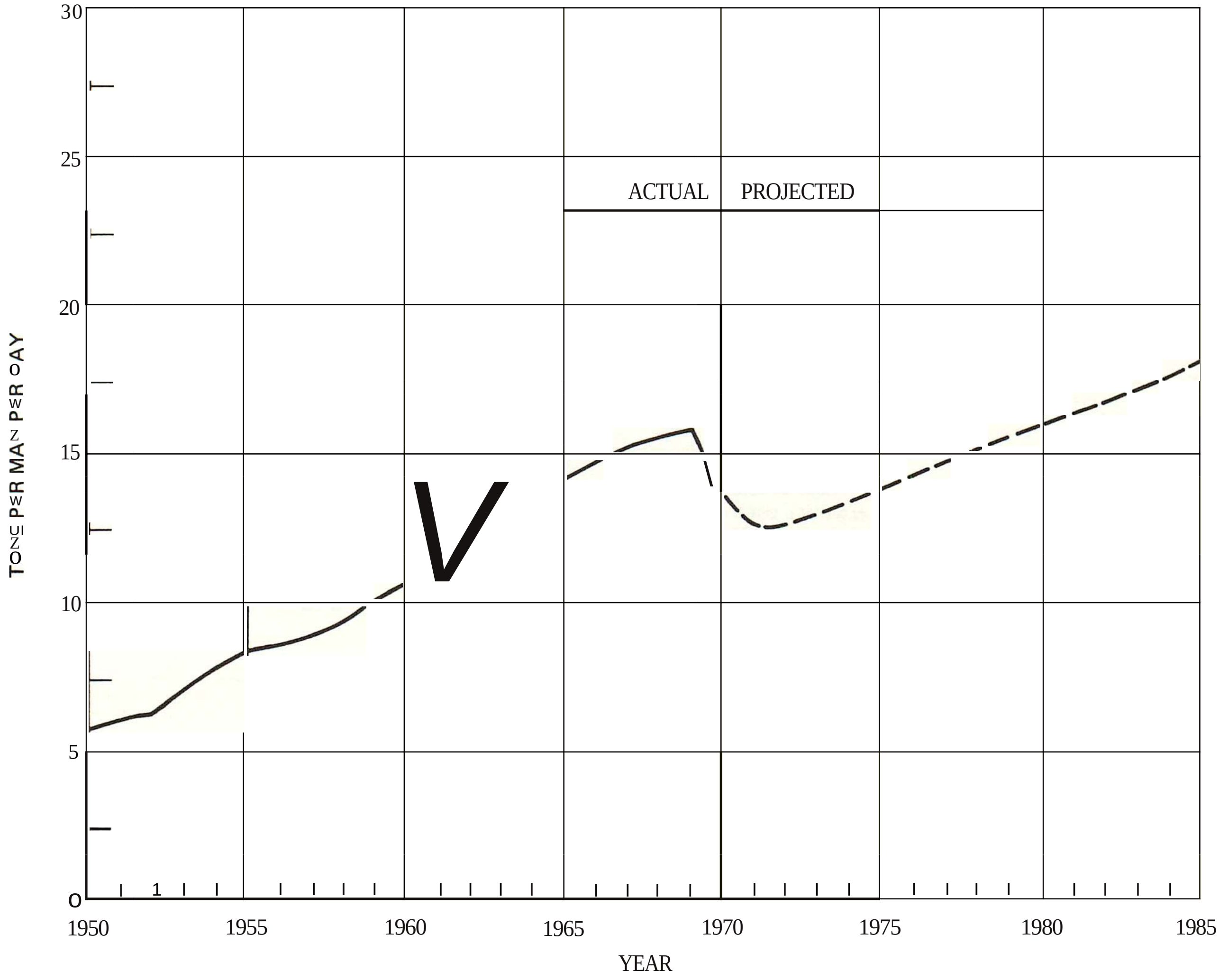
* 1969 was used as the base year for the model as it was the last year for which most of the statistical data used in the study was available. However, the 1970 Bureau of Mines data became available during the course of the study and have been incorporated into the model.

basis for the model to evaluate the future costs of supplying coal at various levels of production. The basic structure of the economic model is described conceptually in Figure 6.

It should be noted that the values of the variables used in the model to describe the future coal industry were estimated each year over the life of the study to account for variances in the average mine size, status of technology, the impact of governmental policies, etc. One such variable to which the coal model is properly sensitive is mining productivity, particularly that of underground mining. The U.S. average productivity for underground and surface mines is shown in Figures 7 and 8, respectively. It can be noted for underground mines (Figure 7) that productivity between 1969 and 1970 suffered a sharp dec1ine--from 15.61 tons per man-day in 1969 to 13.76 tons per man-day in 1970. This decrease in productivity reflects the rather severe impact of the Coal Mine Health and Safety Act of 1969. However, as Figure 7 illustrates, the model assumes that the decline has now reached its nadir and that



Source of historical data -- U.S. Bureau of Mines.

Figure 7. Output per Man per Day at Underground Bituminous Coal Mines.

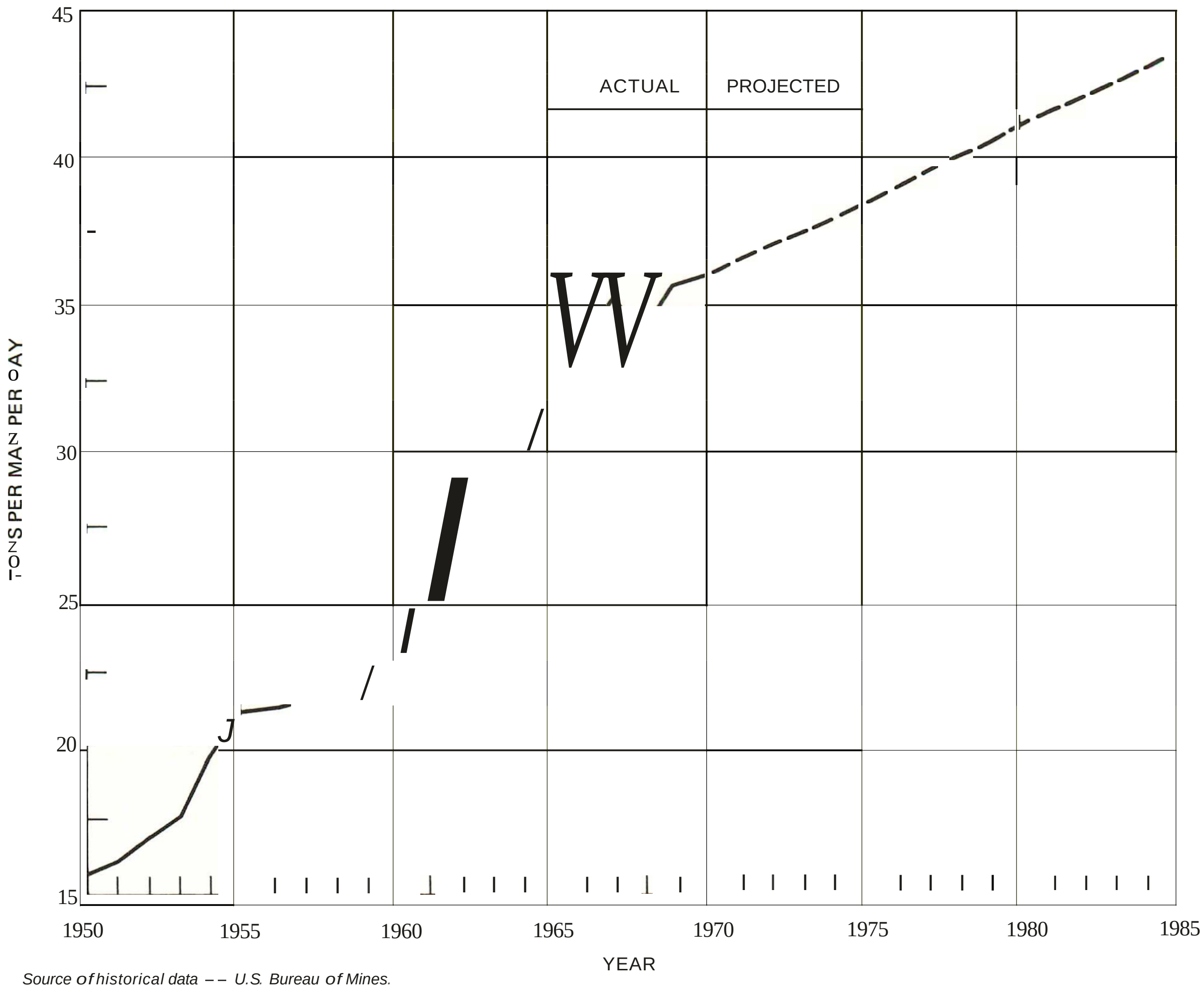


Figure 8. Output per Man per Day at Surface Bituminous Coal Mines.

productivity will again increase and ultimately reach 17.80 tons per man-day in 1985. Alternatively, Figure 8 illustrates future changes in productivity at surface mines for Regions 1, 2 and 3. Estimates were made for future changes in other major variables where there was a rationale for making such an estimate.

Limitations of the Economic Analysis

There are certain limitations inherent in the use of an economic model to predict coal mining costs. An economic model can never reflect an actual cost situation at any specific mine with perfect accuracy. Mining costs differ very widely, depending on the specific conditions reflected in investment and operating costs prevailing in different regions. Seam thickness and depth, topography, roof conditions, underground water flow and many other items that affect cost vary from mine to mine. Some of these factors are not readily predictable.

The bulk of surface-mined coal now originates in the eastern United States, where future mining costs are uncertain. The model makes allowance for the still undefined rapid rise in reclamation costs which may arise from more stringent reclaiming regulations, but it may understate these costs by a considerable amount. This item alone can exceed $1.00 per ton under certain conditions. The reclamation cost actually used by the model for the U.S. average is projected to grow from $0.02 per ton in 1970 to $0.34 per ton in 1985 (in constant 1970 dollars).

Results of the Economic Analysis

Cost of Producing Coal

Production costs were estimated separately for underground and surface mines and were broken down into cash operating costs and capital costs. Projections of the average cash operating cost for underground and surface mines are given in detail in Appendix I. Capital cost projections are briefly discussed here.

Shown in Table 16 are the estimated average unit capital investments required for both surface and underground mines through 1985. These figures include both the initial and the total capital investment per annual ton of production required over the life of the mine. Specifically included is the cost of land acquisition, exploration, initial mine investment, working capital and deferred capital costs.

TABLE 16

ESTIMATED AVERAGE CAPITAL INVESTMENT PER ANNUAL TON OF PRODUCTION AT U.S. COAL MINES-1970 -1985

(30-Year Life-Constant 1970 Dollars)

	Operating Year							
	Underground Mines				Surface Mines			
	1970	1975	1980	1985	1970	1975	1980	1985
Original Capital Investment	7.15	8.46	9.20	9.84	6.39	7.33	8.07	8.78
Total Capital Investment over Life of Mine	19.66	23.17	25.03	26.64	10.59	12.15	13.79	14.44

▪ Less salvage value.

The investment required to open a new mine is greater than the average capital investment for all mines currently producing coal. For example, information for the year 1970 indicates that original capital investment for a new mine ranged between $8.00 and $20.00 per annual ton of production. However, Table 16 shows that the *average* original capital investment per annual ton of production at underground mines in 1970 was estimated by the economic model to be only $7.15.

TABLE 17

CAPITAL REQUIREMENTS FOR UNDERGROUND AND SURFACE MINES- 1970-1985
(Millions of Constant 1970 Dollars)

	McGraw-Hili Capital Spending Survey*	Case I (5% Growth)	Case II (3.5% Growth)	Case III (3.5% Growth)	Case IV (3.0"10 Growth)
		Supply Cases with Corresponding Growth Rates			
1963	124				
1964	387				
1965	153				
1966	387				
1967	325				
1968	368				
1969	382				
1970	435	543.2	449.5	449.5	427.2
1971	457	595.5	485.2	485.2	459.0
1972	626	645.1	514.1	514.1	487.9
1973	588	687.6	545.1	545.1	510.5
1974	559	731.7	570.9	570.9	532.1
1975	525	776.4	596.7	596.7	554.1
1976		822.8	624.2	624.2	566.8
1977		872.8	651.9	651.9	600.3
1978		925.5	680.7	680.7	623.3
1979		979.8	711 .0	711.0	647.1
1980		1,036.8	741.1	741.1	670.0
1981		1,096.6	773.9	773.9	696.2
1982		1,158.5	806.3	806.3	723.5
1983		1,223.2	840.1	840.1	757.9
1984		1,295.7	875.8	875.8	776.6
1985		1,370.9	912.8	912.8	807.3
	Total	14,762.1	10,779.3	10,779.3	9,831.9

• McGraw-Hili Economics Department, "Capital Spending Survey," Spring and Fall Surveys (1964 through 1972); figures in current dollars; figures for 1963 through 1971 are actual, and figures for 1972 through 1975 are estimated.

The economic model was also used to calculate the total capital expenditures required each year to satisfy the several different supply schedules (Cases I through IV). First, the average annual capital investment required to maintain a constant volume of coal production was estimated (O-percent annual growth). To sustain a constant volume of coal production, an annual replacement rate of 3 percent of the total productive capacity is needed to compensate for those mines depleted each year. This replacement rate reflects the fact that the average coal mine has an estimated life of 33.3 years. A following calculation was made to derive the new annual capital investment required to produce the incremental coal tonnage needed to yield several different growth rates. The incremental capital investment was determined for three specific coal production growth rates--namely, 5.0, 3.5 and 3.0 percent corresponding to Supply Cases I, II and III, and IV, respectively. Finally, the total weighted average annual capital investment required to sustain each of the specified growth cases was determined. The results are shown in Table 17.

As indicated in Table 17, the annual capital expenditures required to achieve the projected production levels are estimated to grow from an actual 1970 figure of $435 million to between $807.3 million (Case IV) and $1,370.9 million (Case I) per year in 1985. This increase means that the coal industry must invest between $9.8 billion and $14.8 billion during the 1970-1985 period in order to supply the quantity of coal that will be needed.

Projected Coal "Prices"

Considering the wide range of coal mining conditions in the United States, it is not surprising to find a wide range of "prices" projected for the different regions. Figures 9 and 10 show the "price" projections determined by the economic model for all underground mining operations. Only the highest and lowest "price" regions are shown together with the U.S. average. These "price" figures are based on only two of the three growth rates assumed in this study (3 percent and 5 percent) with assumed DCF rates of return of 10, 15 and 20 percent.

Figures 11 and, 12 illustrate the "price" projections for the surface mining areas which have been active in the past (Surface Regions 1, 2 and 3). The same growth rates (3 percent and 5 percent) and rates of return (10, 15 and 20 percent) were used. Not included here are the coal "price" projections for the major new surface mines associated with the possible application to synthetic fuels; these are treated separately in a later section.

Figures 13 and 14 show the average U.S. value or "price" underground- and surface-mined coal, in both constant and current dollars.

Table 18 shows the projected "prices" over rates of retUr-n of 10, 15, and 20 percent for new underground-mined and surface-mined coal and compares these with the corresponding U.S. average values which were based on both new and old mines. The resulting differences are generally less than 10 percent. The results of the model may understate the real problem, however, because it may be desirable to sell coal from an existing mine at "prices" associated with a low rate of return, but it would not be attractive at the same time to invest in a new mine unless a greater return were expected.

To illustrate, the 1970 average "price" of underground coal, at a 10-percent DCF rate of return, is shown in Table 18 as $7.36 per ton. To achieve a 20-percent DCF rate of return, which might better represent the return needed to motivate investment in new production, a "price" of $9.43 per ton results. The new coal "price" is thus 28 percent above the average.

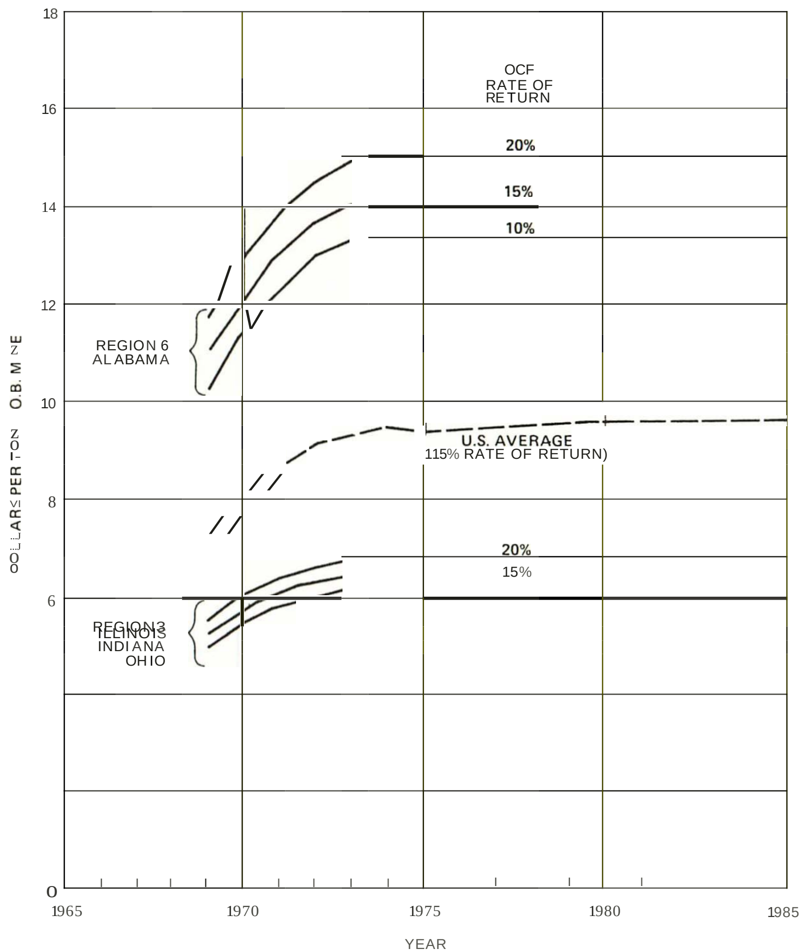


Figure 9. Range of Projected Underground Coal "Prices"; Regional Extremes and U.S. Average (Years 1969 Through 1985--3 Percent Growth Rate Case--Constant 1970 Dollars)

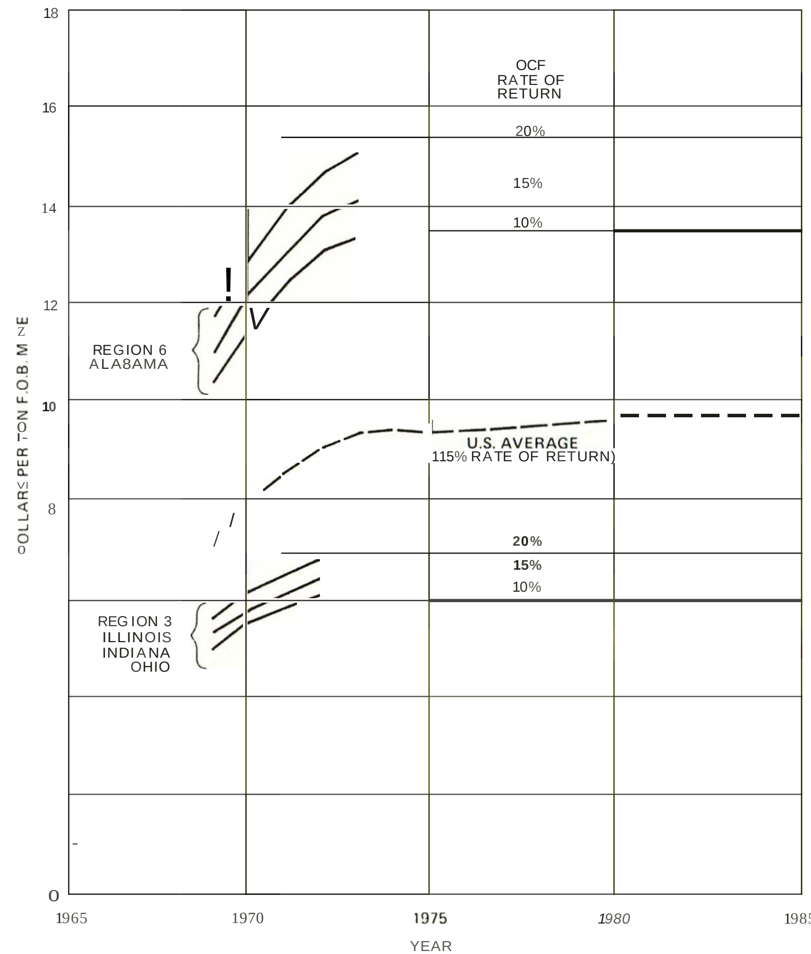


Figure 10. Range of Projected Underground Coal "Prices"; Regional Extremes and U.S. Average (Years 1969 Through 1985--5 Percent Growth Rate Case--Constant 1970 Dollars)

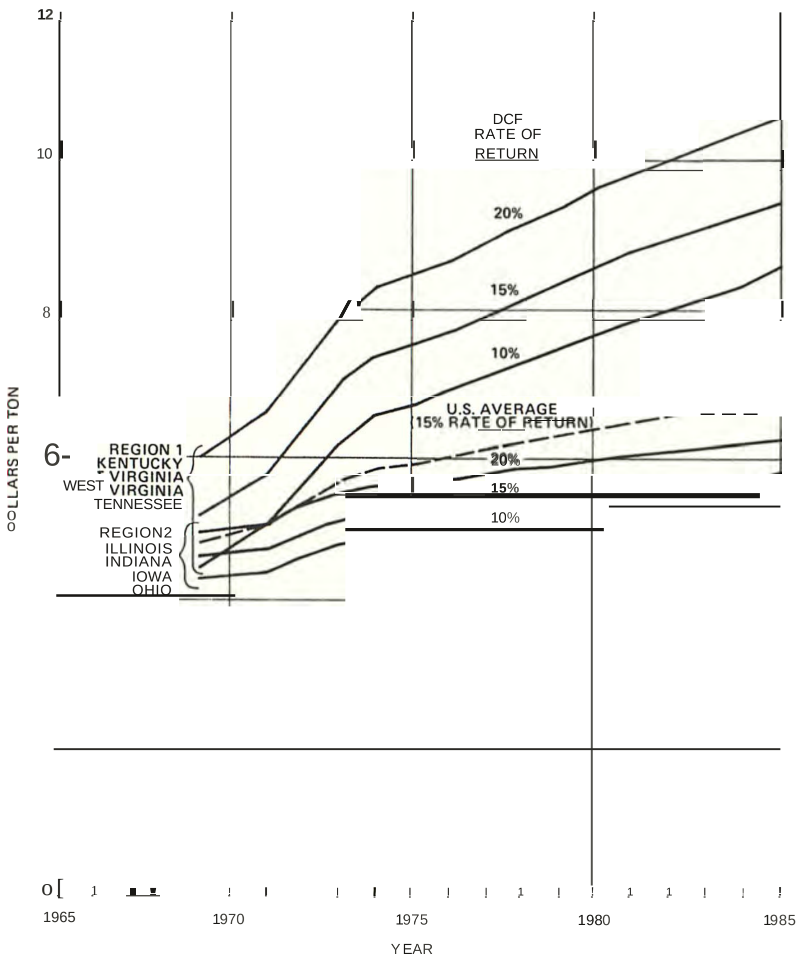


Figure 11. Range of Projected Surface Coal "Prices": Regional Extremes and U.S. Average (Years 1969 Through 1985--3-Percent Growth Rate Case --Constant 1970 Dollars).

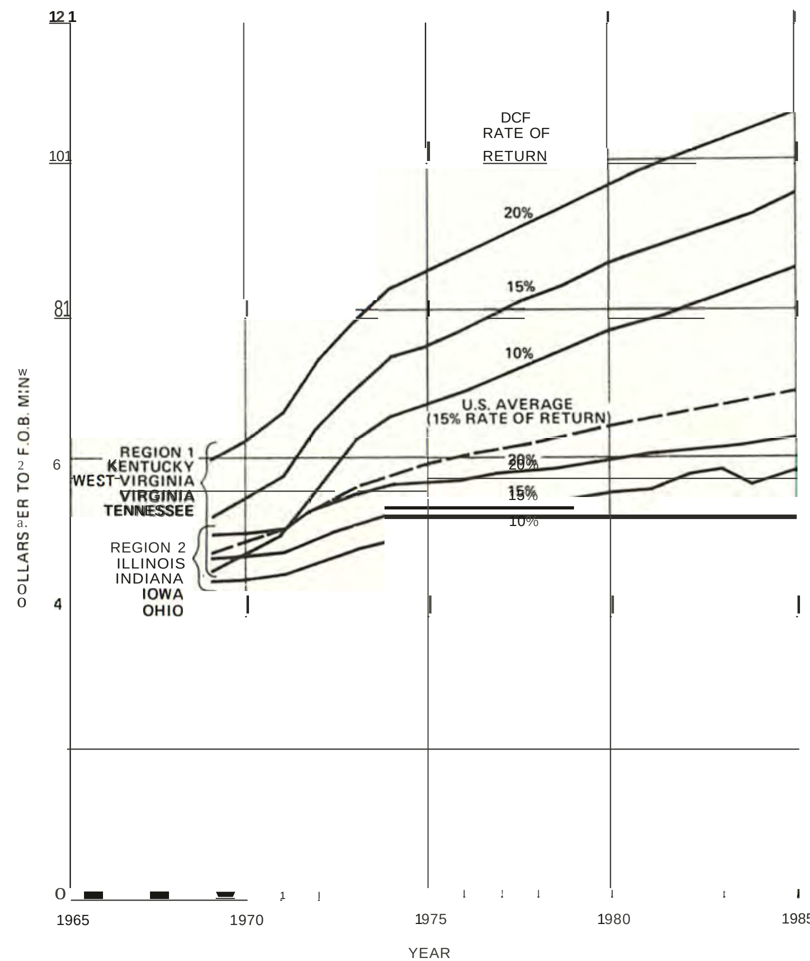


Figure 12. Range of Projected Surface Coal "Prices": Regional Extremes and U.S. Average (Years 1969 Through 1985--S-Percent Growth Rate Case --Constant 1970 Dollars).

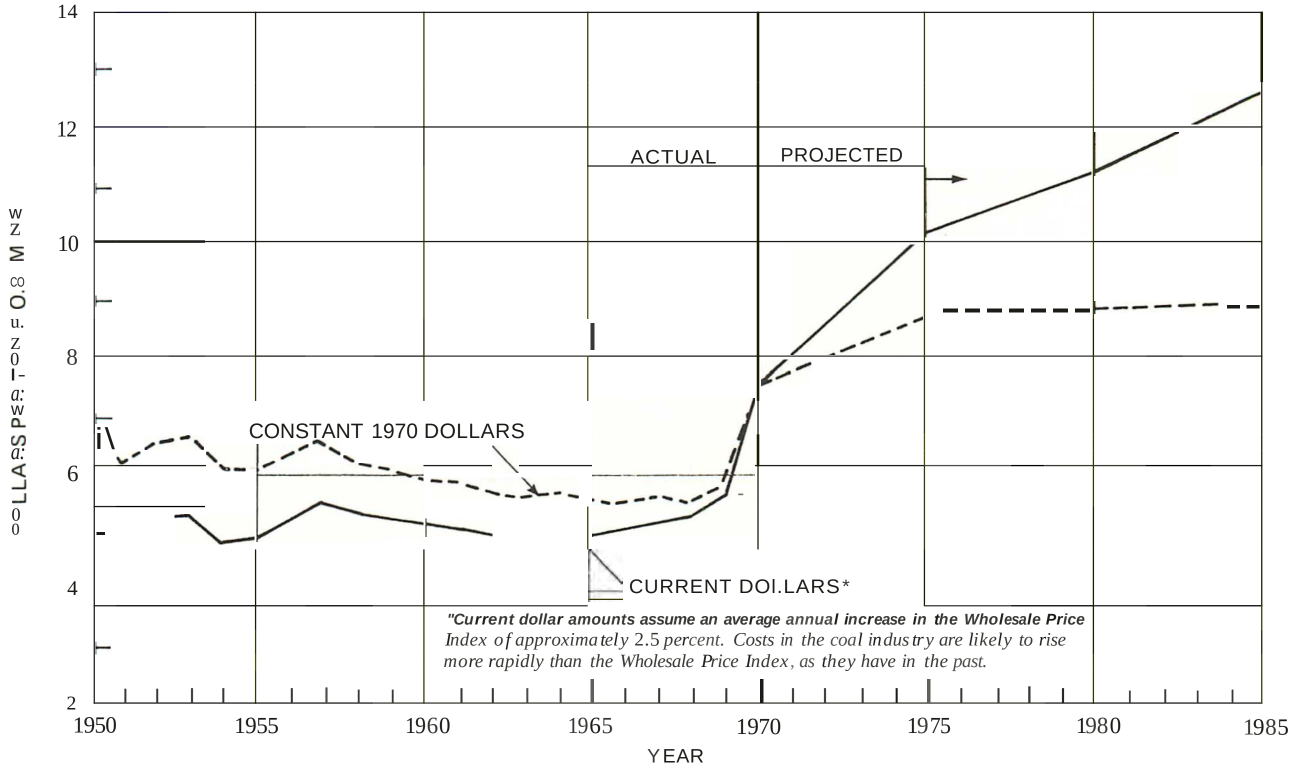


Figure 13. Average Value of Bituminous Coal from Underground Mines-Comparison of Historical and Future Values in Current and Constant 1970 Dollars (la-Percent Rate of Return--3-Percent Growth Rate) .

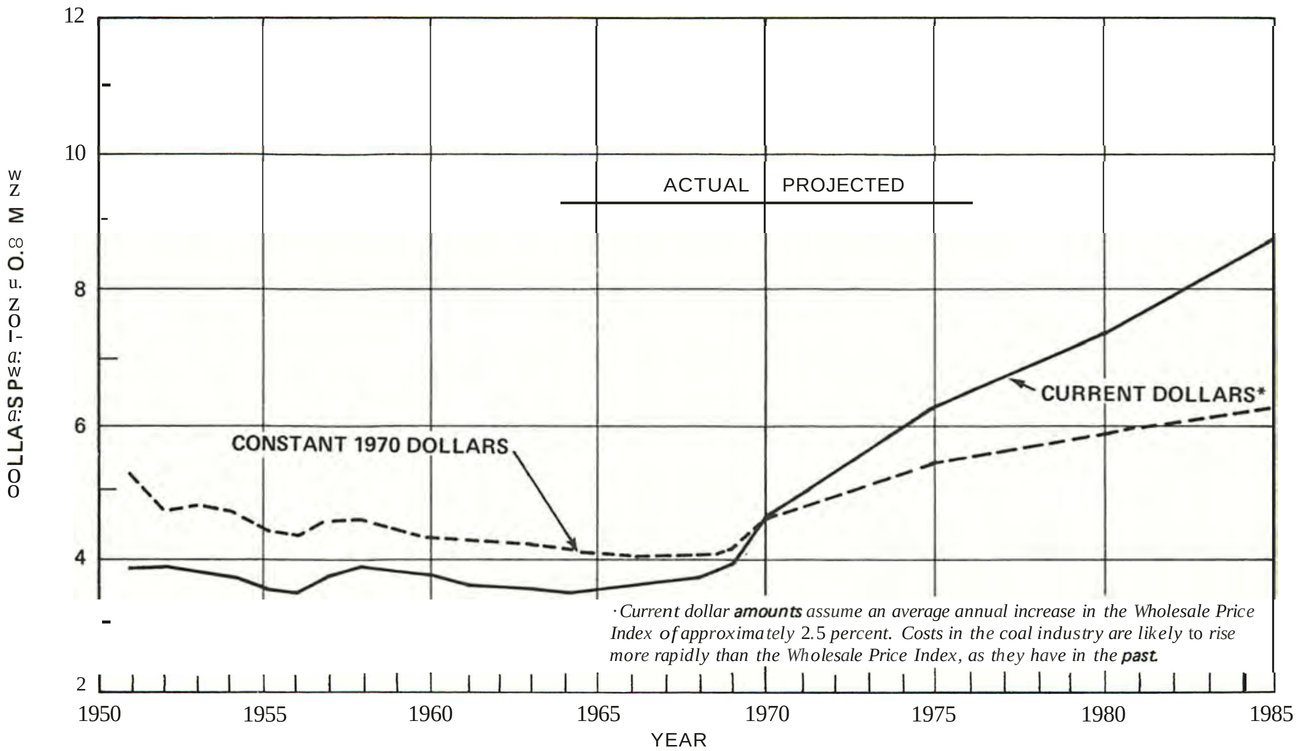


Figure 14. Average Value of Bituminous Coal from Surface Mines--Comparison of Historical and Future Values in Current and Constant 1970 Dollars (la-Percent Rate of Return--3-Percent Growth Rate).

TABLE 18

COMPARATIVE "PRICE" OF COAL-NEW MINES VERSUS AVERAGE FOR ALL MINES*
(Constant 1970 Dollars per Ton f.o.b. Mine)

DCF Rate of Return	Underground Mines 1970	1975	1980	1985	Surface Mines 1970	1975	1980	1985
	U.S. Average Value ("Price") for All Mines in Production (New and Old)							
10%	7.36	8.76	8.85	8.97	4.44	5.38	5.82	6.21
15%	7.84	9.32	9.45	9.60	4.87	5.87	6.36	6.79
20%	8.42	9.99	10.16	10.35	5.36	6.43	6.96	7.45
	"Price" of Coal from New Mines Only							
10%	8.02	9.40	9.43	9.49	4.63	5.56	5.99	6.37
15%	8.66	10.11	10.16	10.24	5.12	6.11	6.58	7.00
20%	9.43	10.97	11.05	11.25	5.67	6.74	7.25	7.72

* 3-percent growth rate case.

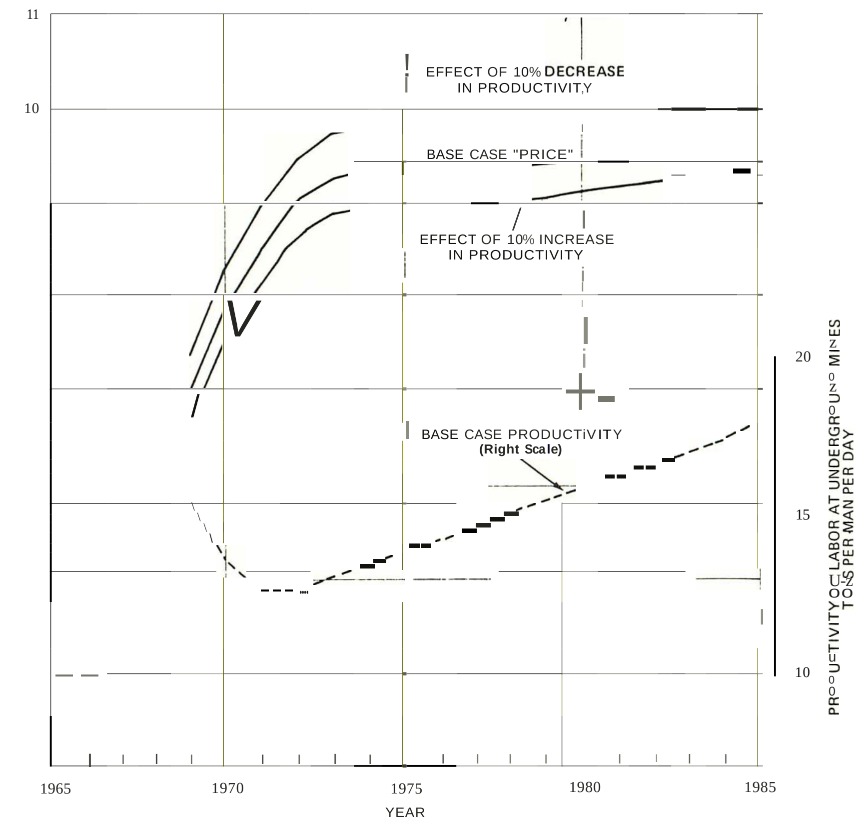
Sensitivity Studies

A number of sensitivity calculations were performed to evaluate the effect that different assumptions on some of the important input factors might have on the calculated "price" of coal. These factors include productivity, income tax rates, capital costs and depletion.

Productivity: Productivity is of obvious importance in coal mining. A sensitivity analysis was undertaken to determine the impact of a la-percent change in labor productivity on the calculated "price" of coal. Figures IS and 16 illustrate the results for the hypothetical underground and surface mines. For easy reference, the productivity used in the base case calculation of average value ("price") is shown on the bottom of each figure.

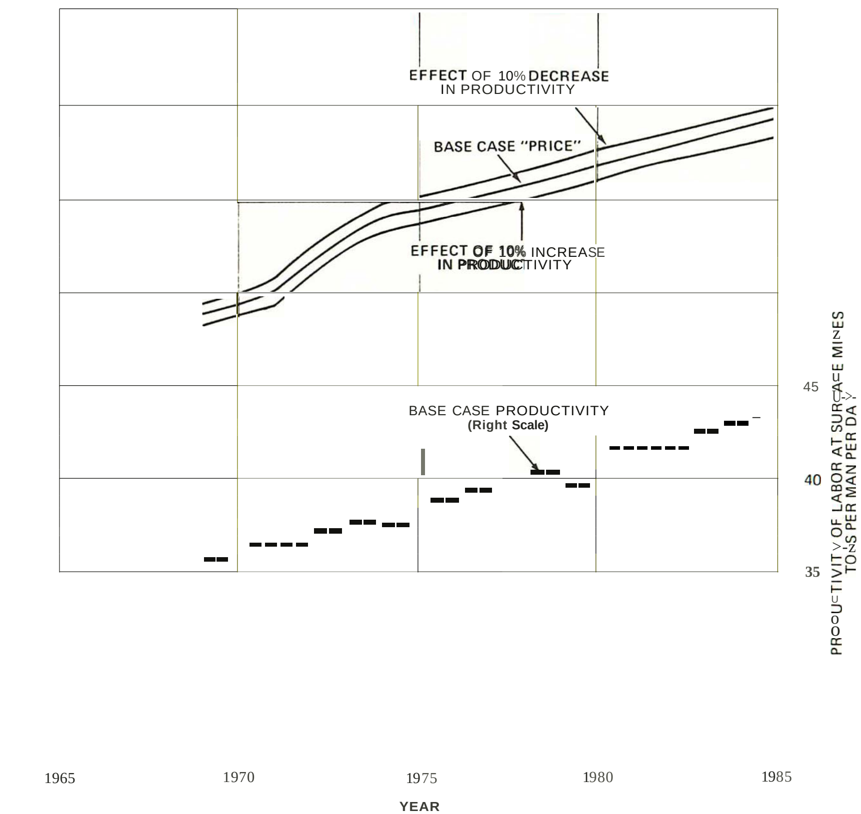
Figures IS and 16 show that underground mining is more labor-intensive than surface mining. The rapid increase in the average value of coal at underground mines during the 1969-1973 period is primarily due to the decrease in the productivity of labor, resulting largely from the Coal Mine Health and Safety Act of 1969. It was assumed, however, that this Act will not have a great impact on the productivity of labor at surface coal mines. To the contrary, environmental regulations governing such activities as surface reclamation could decrease surface productivity by more than 10 percent.

Income Tax Rate: A change in the income tax rate was also analyzed to determine its effect upon the calculated "price" of coal. As Table 19 indicates, the average value of a ton of coal is not highly sensitive to a la-percent change in the effective tax rate. For example, in the case of an average underground mine in 1970, a la-percent increase in the effective tax rate results in only a 1.2-percent increase in the "price" of coal because net



NOTE: Base case "price" ranges are shown in Figures 9 and 10.

Figure 15. Effect of Productivity on the Average Value of Coal from Underground Mines (Constant 1970 Dollars--15 Percent Rate of Return--3-Percent Growth Rate).



NOTE: Base case "price" ranges are shown in Figures 11 and 12.

Figure 16. Effect of Productivity on the Average Value of Coal from Surface Mines (Constant 1970 Dollars--15-Percent Rate of Return--3-Percent Growth Rate).

TABLE 19

EFFECT OF INCOME TAX ON THE AVERAGE VALUE OF COAL IN THE UNITED STATES*
(Constant 1970 Dollars per Ton f.o.b. Mine)

	Effective Tax Rate		
	Underground Mines		
1970	7.77	7.84	7.93
1975	9.23	9.32	9.42
1980	9.36	9.45	9.55
1985	9.51	9.60	9.71
	Surface Mines		
1970	4.80	4.87	4.96
1975	5.79	5.87	5.97
1980	6.27	6.36	6.46
1985	6.70	6.79	6.90

* 15-percent DCF rate of return; 3-percent growth rate.

profits after taxes, in this example, are only about 11.4 percent of the f.o.b. mine value of the coal.

Capital Costs: These costs vary considerably between areas, mining conditions, mining methods and even different mining companies. For these reasons, a sensitivity analysis was undertaken to illustrate the effect that a la-percent or 20-percent increase in capital costs would have on the average value per ton of coal. The results are shown in Table 20.

Depletion: Under the percentage method permitted by the Internal Revenue Code for depletion computation, a la-percent statutory rate on gross income is allowed for the coal industry, unless the resulting deduction exceeds a limitation of SO percent of net income.

Table 21 shows that eliminating the depletion allowance would raise the "price" of coal by as much as $1.aa per ton. The tab Ie also shows that, at low rates of return, the SO-percent net income limitation applies. For example, for both la-percent and IS-percent rates of return at underground mines, the SO-percent net income allowable depletion is lower than the corresponding la-percent gross income allowable depletion. (For surface mines, the SO-percent net income limit comes into play only for a rate of return of 10 percent. The difference is due to the fact that surface mines are relatively more capital-intensive than underground

TABLE 20

EFFECT OF THE CAPITAL INVESTMENT ON THE AVERAGE VALUE OF COAL IN THE UNITED STATES*
(Constant 1970 Dollars per Ton f.o.b. Mine)

DCF Rate of Return	Underground Mines 1970	1975	1980	1985	Surface Mines 1970	1975	1980	1985
	Rate of Return with Projected Capital Investment							
10%	7.36	8.76	8.85	8.97	4.44	5.38	5.82	6.21
15%	7.84	9.32	9.45	9.60	4.87	5.87	636	6.79
20%	8.42	9.99	10.16	10.35	5.36	6.43	6.97	7.45
	With 10% Higher Capital Investment							
10%	7.54	8.96	9.07	9.21	4.57	5.53	5.98	6.39
15%	8.06	9.58	9.73	9.90	5.04	6.07	6.57	7.03
20%	8.67	10.31	10.51	10.73	5.58	6.68	7.24	7.75
	With 20% Higher Capital Investment							
10%	7.71	9.17	9.29	9.45	4.69	5.67	6.14	6.56
15%	8.29	9.84	10.01	10.20	5.21	6.27	6.79	7.26
20%	8.97	10.64	10.87	11.11	5.80	6.93	7.52	8.05

* 3-percent growth rate.

mines.) Thus, "prices" at low rates of return are likely to be those falling under the "50 percent" heading in the table; those at high rates of return are likely to be those under the "10 percent" heading.

TABLE 21

EFFECT OF DEPLETION ON THE AVERAGE VALUE OF COAL IN THE UNITED STATES*
(Constant 1970 Dollars per Ton f.o.b. Mine)

Rate of Return		10% Gross Income Depletion 1970	1975	1980	1985	50% Gross Income Depletion 1970	1975	1980	1985	No Depletion 1970	1975	1980	1985
		Underground Mines											
10%	Average Coal Value	7.04	8.37	8.48	8.61	7.36	8.76	8.85	8.97	7.75	9.21	9.33	9.47
	Allowable Depletion	0.70	0.84	0.85	0.86	0.38	0.40	0.47	0.50				
15%	Average Coal Value	7.66	9.09	9.25	9.42	7.82	9.32	9.45	9.60	8.43	10.00	10.17	10.36
	Allowable Depletion	0.77	0.91	0.93	0.94	0.59	0.61	0.72	0.76				
20%	Average Coal Value	8.42	9.97	10.19	10.41	8.42	9.99	10.16	10.35	9.26	10.97	11.20	11.45
	Allowable Depletion	0.84	1.00	1.02	1.04	0.85	0.88	1.04	1.10				
		Surface Mines											
10%	Average Coal Value	4.37	5.27	5.70	6.10	4.44	5.38	5.82	6.21	4.81	5.80	6.27	6.70
	Allowable Depletion	0.44	0.53	0.57	0.61	0.37	0.40	0.46	0.50				
15%	Average Coal Value	4.95	5.93	6.42	6.87	4.87	5.87	6.36	6.79	5.44	6.52	7.06	7.55
	Allowable Depletion	0.50	0.59	0.64	0.69	0.57	0.58	0.70	0.76				
20%	Average Coal Value	5.60	6.67	7.23	7.75	5.36	6.43	6.96	7.45	6.16	7.34	7.95	8.52
	Allowable Depletion	0.56	0.67	0.72	0.78	0.75	0.82	0.99	1.07				

* 3-percent growth rate.

FACTORS POTENTIALLY LIMITING SUPPLY

Manpower

In spite of the importance of surface mining, the future ability of the coal industry to supply its overall share of U.S. energy demand will depend on its ability to produce coal from deep mines. In this operation, the manpower problem will be a key factor. Developments of improved mining technology must be substantially accelerated to offset the impact of the Coal Mine Health and Safety Act of 1969 on existing production capacity. These developments will have an even greater impact on the energy supply during the 1985-2000 period when it may be necessary to reach further into available coal reserves and to mine thinner seams under deeper cover.

Underground mines in the United States employed 106,000 men to produce 360 million tons in 1970. Production should reach 430 million tons per year by 1980. Assuming no further loss in average productivity during this period, there would be a need for a net addition of 20,000 men. Moreover, the labor turnover in the industry is high, so the total need for recruiting and training will be substantially greater than this figure.

The need for trained new miners is a continuing problem. Figure 17 shows the historical relationship of total mining employment to the total U.S. labor force. The percentage of U.S. employment devoted to mining is now at a very low level--less than 0.2 percent. It may be inferred that theoretically manpower should not be a limiting parameter for the range of industry growth rates used in this report. However, attraction of adequate numbers of young workers into mining remains a problem, especially in view of the increasingly sophisticated equipment employed, which raises the level of worker competence and training required.

Even more crucial is the shortage of professionally trained people. In 1969, the total number of mining engineers in the industry was 3,300. Replacements and modest additions totaling 5 percent of the work force annually would require 165 new engineers each year. However, only 20 colleges and universities in the United States offer undergraduate degrees in mining engineering or related fields. In 1970, 132 mining engineers graduated from these schools; 184 were scheduled to graduate in 1971. According to the Engineering Manpower Commission Association, a maximum of 722 mining engineers are expected to graduate (with B.S. degrees) between 1971 and 1975 (145 per year).*

The percentage of technically trained manpower required varies between regions and size of operations. A 2.0-percent to 2.5-percent range is representative now, but the percentage may have to be increased as mining technology becomes increasingly

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* Engineering Manpower Commission Association, *Engineer Manpower Bulletin* (April 1967).

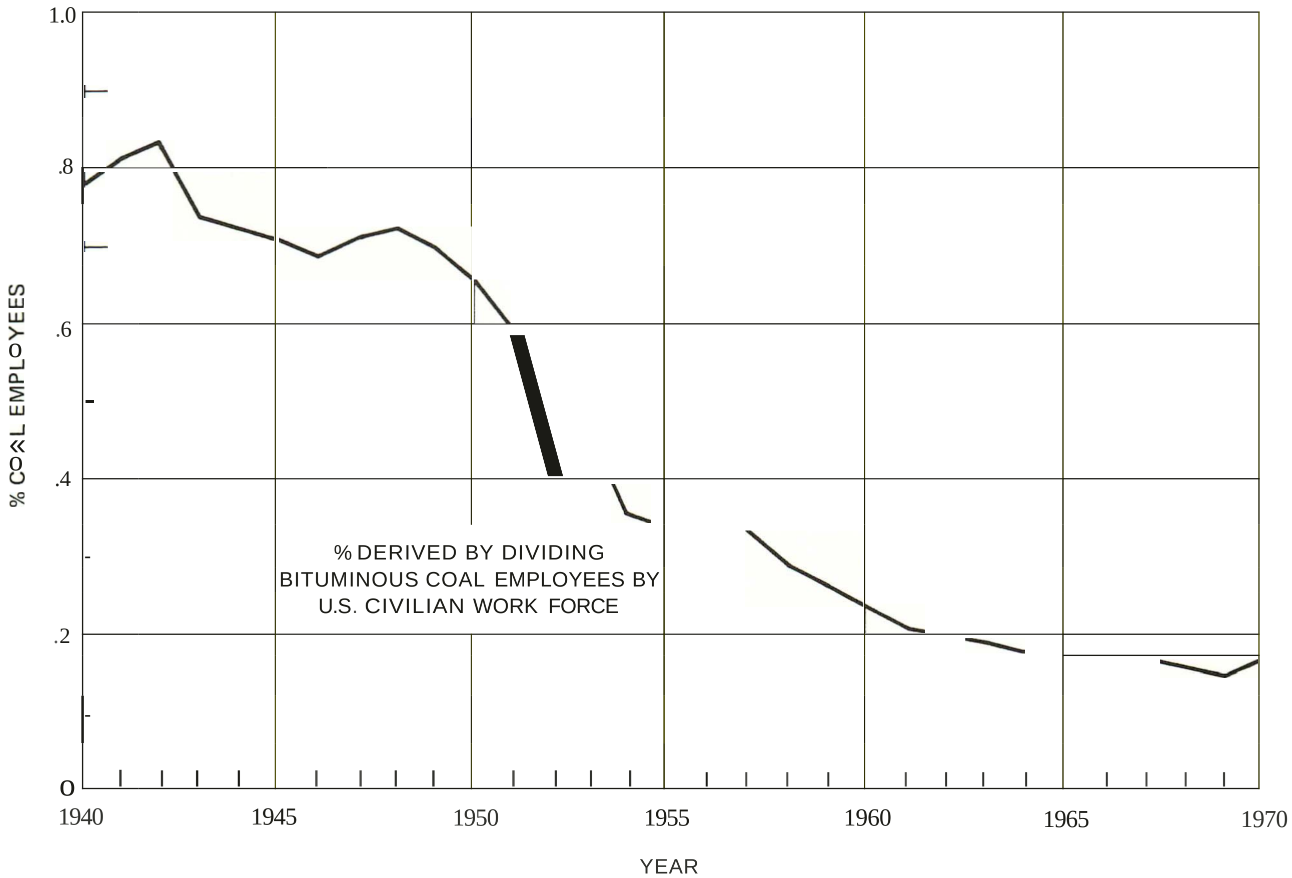

Figure 17. Coal Employees as Percent of Total U.S. Work Force.

complex. On the basis of the 2.5-percent figure and a 5-percent annual turnover caused by engineers leaving the coal industry, the annual demand for engineers equals approximately 310 and will grow in direct proportion to coal production. Thus, the potential imbalance between supply and demand of these specialists is a significant problem. However, this imbalance, in itself, need not limit the growth of the coal industry within the ranges projected by this study. Additional engineers may be recruited from other engineering disciplines (civil, electrical, etc.).

Restrictions on Surface Mining

The subject of future growth must be considered in light of possible environmental restrictions on surface mining. This topic was explored by the U.S. Bureau of Mines, and their findings are included here in part.

Surface minable recoverable reserves were shown earlier to approximate 45 billion tons. Practically, none of this coal can be recovered by underground methods. A federal law prohibiting all surface mining would thus result in elimination of all these recoverable reserves from our U.S. energy supply. In 1970, surface mining accounted for 264 million tons or 43.8 percent of the total coal produced.

Given that there are regional differences in surface mln1ng methods, the reserves in various coal fields can be grouped to evaluate the effect of proposed surface mining restrictions. If all contour mining were prohibited, for example, an estimated 4.4 billion tons of recoverable reserves would become unavailable for production. If surface mining were prohibited in countries having no previous record of surface mining, 10.4 billion tons would become unavailable. This figure can be broken down as shown in the following tabulation.

Rank	Billions of Tons
Bituminous Coal	2.2
Subbituminous Coal	4.3
Lignite	3.9
Total	10.4

The impact on actual coal output under either of these two assumptions would be major in the period prior to 1985, particularly as it affects supply for conventional markets. The combined effect (total ban on surface mining) would reduce projected coal output over 40 percent in each year studied and under each supply case studied. Table 22 shows an estimate of contour and area mining as a percentage of total surface mining by state in

TABLE 22

CONTOUR AND AREA MINING
AS A PERCENTAGE OF SURFACE MINING
(Surface Regions 1 Through 3)

	Contour (Percent)	Area (Percent)
Region 1		
Kentucky	20	80
West Virginia	90	10
Virginia	90	10
Tennessee	100	O
Region 2		
Illinois	O	100
Ohio	25	75
Indiana	O	100
Iowa	O	100
Region 3		
Pennsylvania	25	75

TABLE 23

EFFECT OF CONTOUR AND TOTAL SURFACE MINING CURTAILMENT*
(Surface Regions 1 Through 3)

	Millions of Tons		
	1975	1980	1985
		Case I	
Underground and Surface Production (for Conventional Domestic Use)	662	852	1,093
With Contour Mining Ban	592	748	961
With All Surface Mining Ban	395	497	641
		Case 11/111	
Underground and Surface Production (for Conventional Domestic Use)	621	734	863
With Contour Mining Ban	547	645	757
With All Surface Mining Ban	363	427	499
		Case IV	
Underground and Surface Production (for Conventional Domestic Use)	603	704	819
With Contour Mining Ban	524	613	710
With All Surface Mining Ban	351	413	480

* Production is for domestic conventional markets (see Table 1). A total ban of surface mining in 1970 would have reduced total production by 264 million tons.

surface Regions I through 3. Table 23 indicates the aggregate effect of a contour mining ban in these surface regions for the entire Case I through IV range of projected production levels. Also shown is the effect of a total strip mining ban in these regions.

Restrictions on Sulfur Content

No data are available on the sulfur characteristics of the specific 150 billion tons of presently recoverable reserves listed in Tables 7 and 8 (Chapter Three). However, limited information is available on the u.S. coal resource base as a whole. According to the Bureau of Mines, 46 percent (720,060 million tons) of the Nation's total known coal reserves under less than 3,000 feet of cover contain 0.7-percent or less sulfur. Of this low sulfur-content coal, 93 percent is located in the states west of the Mississippi River. Thus, most of the Nation's low-sulfur coal is distant from the major demand centers in the East. In the eastern states, 43 percent of the total reserves have sulfur contents of over 3.0 percent, while only 11 percent contain 0.7-percent or less sulfur. Much of this 11 percent is low- or medium-volatile coal and is used primarily as metallurgical coal--its characteristics are such that it is not well suited for most existing power generation plants. A large part of these low-volatile coal reserves are committed to steelmaking.

Tables 24 and 25 indicate the sulfur content of certain coal reserves within less than 3,000 feet depth which have been mapped and explored. States with the largest coal concentrations of 0.7-percent or less sulfur content are listed in Table 26.

Existing and projected SO_2 emission regulations would preclude use of even the lowest sulfur coals from substantial areas in the United States. Clearly, the continued use of coal requires technical solution of the SO_2 problem.

Availability of Adequate Transportation Systems

As indicated in Table 27, almost two-thirds of all U.S. coal depends on rail movement, and one-fourth moves on waterways. However, the figures illustrated in Table 27 are not additive because

TABLE 24

ESTIMATED REMAINING COAL RESERVES OF ALL RANKS BY SULFUR CONTENT IN THE UNITED STATES*

	Million Tons	Percent
0.7% or Less Sulfur	720,060.0	46
0.7% - 1.0% Sulfur	303,573.4	19
1.0% - 3.0% Sulfur	238,374.0	15
Over 3.0% Sulfur	314,159.0	20
Total	1,576,166.4	100

* As of January 1, 1965.

TABLE 25

ESTIMATED REMAINING COAL RESERVES OF ALL RANKS BY SULFUR CONTENT IN STATES EAST OF THE MISSISSIPPI RIVER*

	Million Tons	Percent
0.7% or Less Sulfur	50,062	11
0.7% - 1.0% Sulfur	45,219	9
1.0% - 3.0% Sulfur	177,281	37
Over 3.0% Sulfur	206,495	43
Total	479,057	100

* As of January 1, 1965.

TABLE 26

STATES WITH LARGEST COAL CONCENTRATIONS OF 0.7-PERCENT OR LESS SULFUR

State	Million Tons
Alaska	71,115.6
Montana	154,298.9
New Mexico	38,735.0
Wyoming	35,579.7
North Dakota	284,129.1

TABLE 27

MOVEMENT OF U.S. COAL PRODUCTION (Million Tons)

	Total U.S. Production	Railroads (Class I)	Waterborne (All Types)
1965	520	353	142
1969	561	376	142

a substantial amount of coal moves sequentially by rail and barge or lake boat.

Railroad Transportation

Railroad transportation affects the supply of coal to the consumer. The coal and railroad industries are greatly interdependent as indicated in the following tabulation:

	1965	1969
Total Coal Freight Revenue ($ Billion)	1,102	1,171
Coal as Percent of Total Freight (Revenue)	11.9	10.8
Coal as Percent of Total Freight (Tons)	25.4	25.6

No other commodity approaches coal as a source of rail freight and revenue. During the last decade, the ratio of rail revenue to mine value has declined from 0.72 to 0.62 due to introduction of the "unit train" concept, which has helped to increase efficiency of car utilization. Because definitions of the term unit train differ, it is impossible to state precisely what percentage of all coal currently moves by this mode. The available figures vary from one-third to one-half; hence, further increases in efficiency can be expected.

In coal transportation by rail, the term "efficiency" relates largely to utilization of hopper cars. While hopper cars spend 7.7 percent of their total time in line-haul service, this figure is 13.4 percent for all other rail cars, and it is substantially higher for unit trains which are specifically assigned to given point-to-point movements. The need for further improvement in utilization of hopper cars is emphasized by the ever present car shortage. Because a majority of mines are not equipped to store coal, lack of hoppers forces mines to close. Car population and total car capacity in the 1965-1969 period are shown in the following tabulation:

	1965	1969
Average Size of Cars (Tons)	65.6	71.9
Total Number of Cars	425,236	388,609
Aggregate Capacity (Million Tons)	27.89	27.95

Between 1965 and 1969, rail movement grew 7 percent, primarily as a result of better utilization (longer line-haul service) of cars.

To keep up with the growing demand for coal transport, the fleet must be increased. Over $36 billion of new expenditures for railroad plant and equipment is necessary over the next decade. Of this total, between $5 and $6 billion will be required for coal cars and associated motive power. However, coal transportation rates must be adequate to generate the necessary return on investment for adding hopper car capacity.

Water Transportation

Water transportation is the second major mode of coal movement. It includes movement in barges through rivers and canals, lake shipment and coastal shipment. The total amount of coal moved in 1968 was 156 million tons, including 14 million tons of local shipment (shipments within the confines of a port) as well as long-haul tonnage. The total may grow to 205 to 225 million tons by 1980. Most of this increase will be on the rivers and canals. Some 21 percent of the total waterborne coal in 1968 involved joint rail/barge movements, and this increases to 31 percent if the tidewater and lake ports are included. An efficient system of handling coal between rail and water is important.

Water transport is relatively low in cost. Large-volume barge movements cost approximately 2.5 mills per ton mile, while the u.S. average barge cost is nearly 3.0 mills per ton mile. These figures compare to 5 mills per ton mile for certain unit train hauls and about 10 mills per ton mile for the average rail coal haul.

Trends toward long-distance water transport are evident. Between 1965 and 1968, water transport grew 9.6 percent. Of this growth, 38.5 percent involved tonnage which moved over 1,000 miles. Thus, the waterways open markets for coal which otherwise would remain beyond economic reach.

Technological improvement has increased the tonnage of individual tows and brought the power of tow boats into the range of oceangoing ships. Tows of 40,000 tons are becoming common on the lower Mississippi, and tows of 36,000 tons have moved on the Ohio. Positive action is required, however, to modernize and enlarge the navigation system to cope with traffic which has reached the economic capacity of certain gateways.

The most crucially overloaded locks are Numbers 50 through 53 on the lower Ohio River and Numbers 26 and 27 south of Alton, Illinois, on the Mississippi. The following tabulation shows the growth of aggregate transitting tonnage (in millions of tons per year) at the Ohio locks Numbers 50 and 51.

	1965	1970
Coal Tonnage	7.5	16.0
All Commodities	26.0	43.0

The estimated economic capacity of these locks is 40 million tons per year. Construction of adequate new facilities has now been initiated but will take 5 years to complete. Thus, the growth of coal movement through this area will be constricted for some years. Other segments of the river system are similarly affected.

A specific problem exists at the Hampton Roads, Virginia, port where most of the exported U.S. metallurgical coal is loaded. Total U.S. coal exports are projected to grow from 56 million tons in 1970 to 120 million in 1985. Such expansion may require a completely new approach to the port problem or diversion to other ports. Present draft limitations in U.S. East Coast harbors are inadequate for vessels over about 75,000 deadweight tons (DWT), and some way must be found to accommodate larger vessels if U.S. coal is to remain competitive in world markets.

For a more detailed discussion of coal transportation including slurry pipelining in the Western United States, see Appendices J-L.

COAL SUPPLY FOR SYNTHETIC FUELS PRODUCTION

Resources Available and Probable Costs

The simplifying assumption has been made in this study that all production of synthetic pipeline gas or synthetic liquid fuels in the period to 1985 would come from the Nation's large surface minable reserves in the West. Possible exceptions are not precluded, but it appears that the generally much lower cost of these reserves would more than offset the greater cost of transporting synthetic fuels to the centers of demand. The cost of pipelining liquids of high-BTU gas is comparatively low.

The total amount of these reserves appears adequate to support even the highest rate of production of synthetics foreseeable for the period in question.

The cost of these particular surface-mined coals should be significantly below other U.S. coals because a large part of this resource is known to exist in thick seams and under low overburden. Recoverable reserves in the key western states amount to approximately 28 billion tons (see Table 8, Chapter Three, Regions 4, 5 and 6). Information on the overburden characteristics of western coal is limited, but the information which is available shows a total range of overburden/coal ratio for the three western regions of up to 18:1 (see Appendix G). In all likelihood, the coals needed to supply the projected synthetic fuel plants will not require mining at ratios above 7:1.

In order to determine the range of costs which might be incurred, a model of a surface (area) mine has been composed and the cost of coal calculated as a function of the overburden/coal ratio. Figure 18 shows the results of this evaluation for 10-percent, IS-percent and 20-percent DCF rates of return.

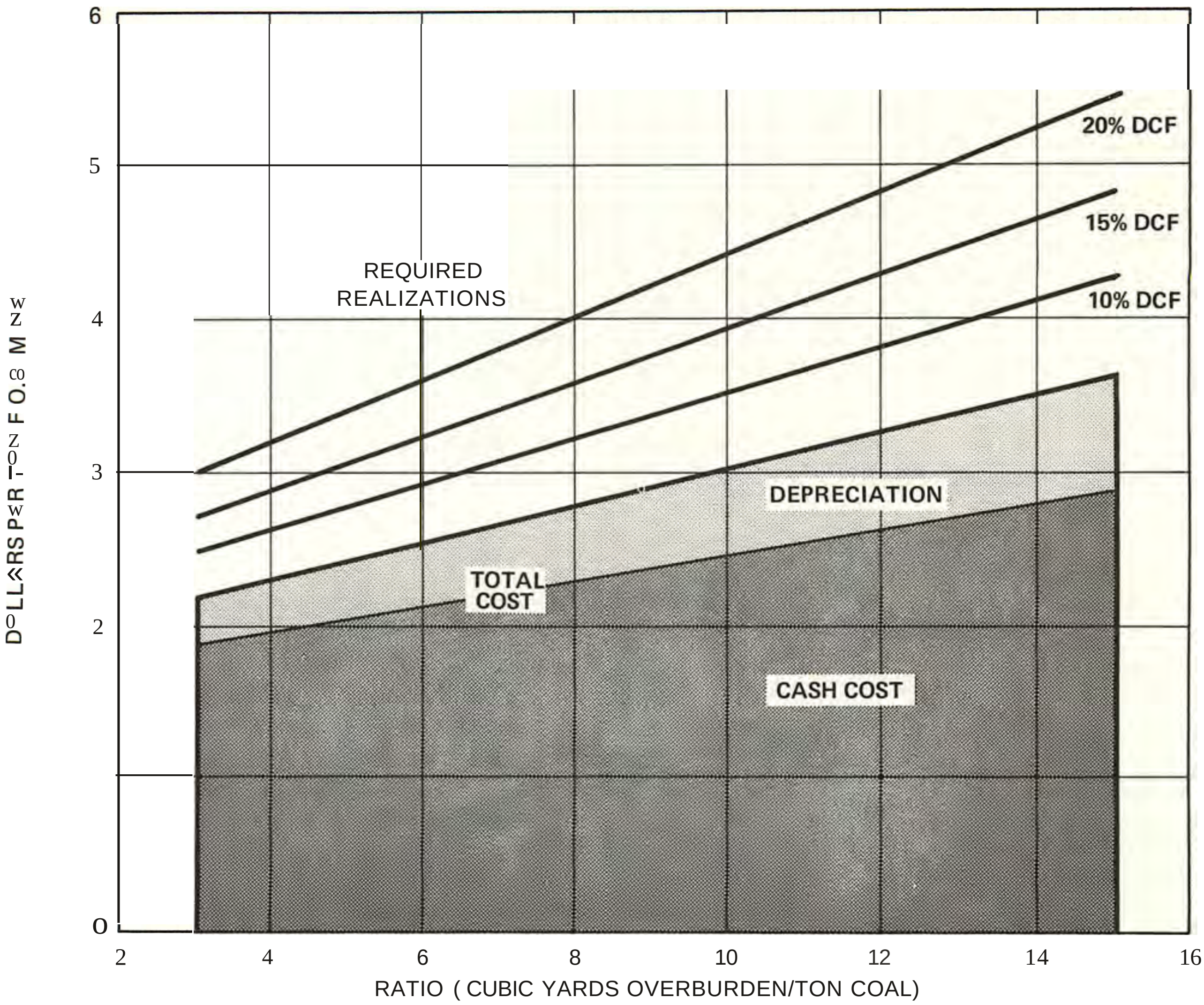

Figure 18. Western Surface Coal Value Analysis (Constant 1970 Dollars).

Figure 19 shows that the impact of any variance in three additional factors--hauling distance, seam thickness and invest-ment--is not significant.

The unit value of coal supplied to the initial group of synthetic fuel plants is likely to range between $2.75 and $4.00 per ton. The likely range of "prices" can vary depending on seam thickness and cost of reclamation. Legislation concerning the latter is still in a state of flux. Table 28 illustrates the potential impact of reclamation costs on the particular reserves under consideration. Reclamation costs for eastern reserves are much higher.

While cost per acre may be high, the reclamation cost will not greatly affect the overall economics of synthetic fuel production.

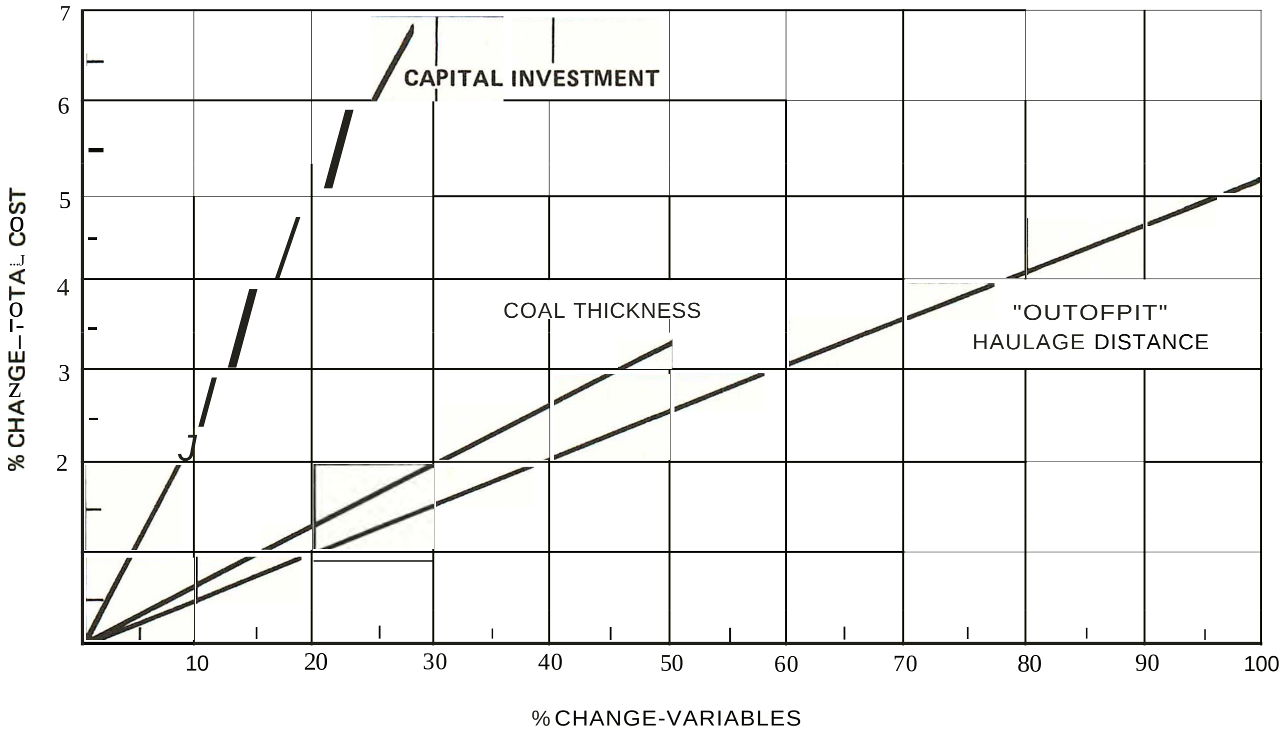

Figure 19. Western Surface Coal Analysis Sensitivity of Total Cost at Constant Overburden Ratio.

TABLE 28

IMPACT OF COST OF RECLAMATION IN WESTERN UNITED STATES (Cents per Ton of Coal Mined)

Seam Thickness (Feet)	Approx. Recovery (Ton/Acre)	Reclamation Cost (Dollars/Acre) $500	$1,000	$1,500
5	9,000	5.6	11.2	16.8
10	18,000	2.8	5.6	8.4
20	36,000	1.4	2.8	4.2

Allocation of Western Surface-Mined Coal

To obtain an approximate distribution of western surface coal by use, it has been assumed that western coal reserves would be used in "standard-size" plants based on the following simplifying assumptions:

- Power generation: 1,000 MWe, 70-percent average load factor; heat rate--9,500 BTU's per KWH
- Synthetic gas plant: 250 billion BTU's per day, 90-percent operating factor; thermal efficiency--67 percent
- Synthetic liquid fuel plant: 50 MB/D, 90-percent operating factor; thermal efficiency--72 percent.

To define the reserves which must be committed to these types of units, it has further been assumed that each plant will have a 30-year life at full capacity and that the average BTU content of the three types of coal reserves would be as follows:

- Bituminous coal: 11,500 BTU's per pound
- Subbituminous coal: 8,500 BTU's per pound
- Lignite: 6,750 BTU's per pound.

These assumptions result in the following tonnages of committed reserves required for each plant (in millions of tons):

Plant	Bituminous	Subbituminous	Lignite
1,000 MW Power Plant	76	103	129
250 x 10^9 BTU/D Synthetic Gas Plant	160	216	272
50 MB/D Synthetic Liquid Plant	179	242	304

The western surface minable coal recoverable reserves are arbitrarily assigned to such plants in Table 29. Western reserves would be adequate over a 30-year period to supply coal to generate 46.5 million KW (at an average load factor of 70) *plus* the equivalent of 4.73 TCF per year of pipeline gas (at 915 BTU's per cubic foot) *plus* 2.64 MMB/D liquids.* As will be shown, these levels of production for synthetics will not be attained by 1985. In fact, a large portion of these reserves will remain uncommitted at that time. It is likely that only the more desirable part of the reserves (thick seams and lower overburden/coal ratio) will be used during the pre-1985 period.

The 28 billion tons considered in Table 29 were only the measured and indicated part of the resource in the mapped and ex-

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* Using 915 BTU's per cubic foot gas may be conservative. Technological advance could be expected to increase this figure by a small percent. Note that an increased BTU content of the gas would result in a corresponding decrease in gas volume. Coal requirements would remain the same.

TABLE 29

ASSIGNMENT OF WESTERN SURFACE MINABLE COAL TO SUPPLY ELECTRIC POWER, SYNTHETIC GAS AND SYNTHETIC LIQUIDS PLANTS

State	Recoverable Coal Reserve (Million Tons)	Arbitrary Assignment* Electric Power	Synthetic Gas	Synthetic Liquid
	Bituminous Coal (11,500 BTU/lb)			
Arizona	387	387		
New Mexico	2,471	750	1,000	724
Utah	150	150		
Colorado	500		250	250
Total	3,511	1,287	1,250	974
Number of Standard-Size Plants		16.9	7.8	5.4
	Subbituminous Coal (8,500 BTU/lb)			
Wyoming	13,971	1,000	3,000	9,971
Montana	3,400	500	2,000	900
Washington	135	135		
Total	17,506	1,635	5,000	10,871
Number of Standard-Size Plants		15.9	23.1	44.9
	Lignite (6,750 BTU/lb)			
Montana	3,497	525	2,500	472
North Dakota	2,075	750	1,000	325
South Dakota	160	160	0	
Texas and Arkansas	1,334	334	1,000	
Total	7,066	1,769	4,500	797
Number of Standard-Size Plants		13.7	16.5	2.6
Total Number of Standard-Size Plants		46.5t	47.4	52.9

• The distribution used in this table does not imply any existing or intended commitment of reserves but recognizes certain announcements of plans for synthetic gas and power plants and the suitability of various coals for these uses.

t The 46.5 million KW assumed to be supplied from this resource is shown on this table only to indicate that the conventional market for coal, i.e., power generation, in this area will have the needed reserves *in addition* to reserves for synthetics.

plored areas. The USGS suggests that a substantial amount of similar coal could be found by further drilling, mapping and exploration. This would uncover new resources and would move "inferred" deposits into the measured and indicated category. The USGS figures presented in Table 30 give the percentages of measured and indicated reserves based on the total known coal reserves in the western states. These figures suggest a good chance for success from an expanded exploration program.

TABLE 30

MEASURED AND INDICATED RESERVES OF KNOWN
COAL RESERVES IN WESTERN STATES

	Measured and Indicated Reserves as Percent of Total Known Western Reserves
Bituminous Coal	
Arizona	N.A.
New Mexico	3.4
Utah	29.0
Colorado	16.5
Subbituminous Coal	
Wyoming	24.8
Montana	17.6
Washington	24.3
Lignite	
Montana	17.6
North Dakota	10.3
South Dakota	N.A.
Texas & Arkansas	53.2

Chapter Six

POTENTIAL FUTURE COAL UTILIZATION

USE OF COAL FOR POWER GENERATION

The use of coal In future power generation will depend on satisfactory resolution of air pollution problems. For the near term, this implies cleanup of the existing coal-fired plants which constitute a large share of current installed capacity. For existing stations, this cleanup requires add-on stack gas cleanup systems except for those stations which can obtain low-sulfur fuels (including low-sulfur fuels made from coal itself). For newly built plants, stack gas cleanup must compete with alternate ways of converting coal to electricity in a pollution-free manner. Appendix M includes an in-depth discussion of the use of coal for power generation and is summarized below.

Stack Gas Cleanup

The latest authoritative review of this subject was prepared in 1970 by an ad hoc panel of the National Academy of Science and the National Academy of Engineering (NAS/NAE). The panel stated, *inter alia*, that "commercially proven technology for control of sulfur oxides from combustion processes does not exist" and that "unless the necessary technology becomes available, the country may have to choose between clean air and electricity."*

There is, however, a concerted effort under way at this time to solve the problem. The U.S. Government, through the Air Pollution Control Office of the Environmental Protection Agency (EPA), is planning to support scrubbing development with a total of $57.5 million between 1971 and 1975. To this can be added an unknown amount spent by private industry. However, at least 2 to 3 years will be required before operational results as well as the relevant economics become clear. At that time, a better judgment of the viability of this technology can be made.

Although maximum immediate attention is being given to scrubbing of stack gases with various forms of lime, limestone and dolomite, other more economic systems will probably follow. Several alternatives are already under development, and the driving force for research and development in this area is generally recognized.

The key problem for the next 5 to 10 years, in the words of the NAS/NAE panel, is that "...care must be exercised...to insure that realistic criteria and plans are adopted which can be implemented in concert with the development of technology....There is

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* NAS/NAE, *Abatement of Sulfur Oxide Emissions from Stationary Combustion Sources*, Prepared by Ad Hoc Panel on Control of Sulfur Dioxide from Stationary Combustion Sources (1970).

a real danger that the public may be led to expect environmental improvements at a rate that cannot be realized." Even if a commercially proved process were available right now, it would take many years to equip only the most important plants with cleanup devices. The total installed fossil-fuel generating capacity is around 250,000 MW. At a low average cost of $25 per kilowatt (KW) for cleanup equipment, it would cost $3 billion to fit just half of the U.S. stations with SO_2 removal systems. Obviously this requires time.

The present status of stack gas cleanup is best described by reference to Table 31. It lists the scrubbing systems of commercial size which have been built or which are contracted for installation in U.S. power stations at this time. As Table 31 indicates, many of the planned systems will not be on stream until late 1972 or 1973. Thus, while there is considerable promise in many of these programs, their specific potential cannot yet be evaluated. In addition, an average cost associated with scrubbing is difficult to estimate. For example, scrubbing systems will differ over a very wide range because the problem of retrofitting an existing plant varies significantly depending on site, type of plant and load factor (which on individual generator sets may vary all the way from 30 percent to 90 percent).

For stations which are initially designed for stack gas cleanup, and where efficient removal of particulate matter is combined with SO_2 cleanup, the costs of SO_2 removal are lower than for retrofitting of existing stations. The SO_2 removal problem is much more difficult to solve on existing stations because they are often cramped for space, disposal of waste sludge from the scrubbers is very difficult, and operating factors are low. The latter is a particular burden because the high cost of add-on scrubbing equipment cannot be amortized over as many tons of coal as compared to a new station.

Since over 5,000 MW have already been committed to stack gas cleanup, this technique seems likely to emerge as one possible answer to pollution control. However, plant design, location and configuration may preclude retrofitting in some instances.

In the event that all stack gas scrubbing developments should fail to satisfy air quality standards, either the direct use pf coal in existing power stations will have to be reduced drastically or else sulfur regulations will have to be relaxed.

Combined-Cycle Power Plant

Combined-cycle power plants are recelvlng increased attention. Several U.S. utilities have announced their intent to install such plants based on the desire to use clean fuel. The fuel, either gas or low-sulfur oil, must be satisfactory for combustion in a gas turbine. These plants are low in initial cost in comparison to standard coal-burning steam-electric plants. They are thus espe-

TABLE 31

SULFUR DIOXIDE REMOVAL SYSTEMS AT U.S. STEAM-ELECTRIC PLANTS*

Power Station	Unit Size (MW)	Designer SO_2 System	New or Retro-fit	Scheduled Start-Up	Anticipated Efficiency SO_2 Removal
Limestone Scrubbing:					
1. Union Electric Co., Meramec No. 2†	140	Combustion Engineer	R	September 1968	Operated at 73% Efficiency During EPA Test
2. Kansas Power & Light, Lawrence Station No. 4	125	Combustion Engineer	R	December 1968	Operated at 73% Efficiency During EPA Test
3. Kansas Power & Light, Lawrence Station No. 5	430	Combustion Engineer	N	December 1971	Will Start 65% & Be Upgraded to 83%
4. Kansas City Power & Light, Hawthorne Station NO. 3	100	Combustion Engineer	R	Late 1972	Guaranteed 70%
5. Kansas City Power & Light, Hawthorne Station NO. 4	100	Combustion Engineer	R	Late 1972	Guaranteed 70%
6. Kansas City Power & Light, Lacygue Station	800	Babcock & Wilcox	N	Late 1972	80% as Target
7. Detroit Edison Co., St. Clair Station No.3	180	Peabody	R	Late 1972	90% as Target
8. Detroit Edison Co., River Rouge Station No. 1	265	Peabody	R	Late 1972	90% as Target
9. Commonwealth Edison Co., Will County Station No.1	175	Babcock & Wilcox	R	February 1972	Guaranteed 80%
10. Northern States Power Co., Sherburne County Station Minu. No. 1	700	Combustion Engineer	N	1976	
11. Arizona Public Service, Chella Station Co.	115	Research Cottrell	R	December 1973	
12. Tennessee Valley Authority, Widow's Creek Station No. 8	550	Undecided	R	1974-1975	
13. Duquesne Light Co., Phillips Station	100	Chemico	R	March 1973	Guaranteed 80%
14. Louisville Gas & Electric Co., Paddy's Run Station	70	Combustion Engineer	R	Mid-Late 1972	Guaranteed 80%
15. City of Key West, Stock Island ‡	37	Zurn	N	Early 1972	Guaranteed 85% Removal
16. Union Electric Co., Meramec No. 1	125	Combustion Engineer	R	Spring 1973	80% as Target
Sodium Hydroxide Scrubbing Installation:					
1. Nevada Power Co., Reed Gardner Station	250	Combustion Equipment Associates	R	1973	Guaranteed 90% SO_2 While Burning 1% S Coal
Magnesium Oxide Scrubbing Installations:					
1. Boston Edison Co., Mystic Station No. 6	150	Chemico	R	February 1972	90% Target
2. Potomac Electric Power, Dickerson No. 3	195	Chemico	R	Early 1974	90%
Catalytic Oxidation:					
1. Illinois Power, Wood River§	100	Monsanto	R	June 1972	Guaranteed 85% SO_2 Removal

* *Federal Register,* Vol. 37, No. 55 (March 21,1972), p. 5768, updated.

† Now abandoned.

‡ Oil-fired plants (remainder are coal-fired).

§ Partial EPA funding.

cially desirable for so-called intermediate load, or cycling power generation.

This type of load represents a large share (35 to 40 percent) of total load. With increasing use of nuclear plants for base-load generation, the combined-cycle can be expected to supply an increasing part of the fossil-fueled power load if suitable clean fuels can be made available at a competitive price. This means that increased efforts will be warranted to learn how to use coal synthetics in these plants.

Combined-cycle plants can be coal fired either by converting coal to low-BTU gas (175 BTU per cubic foot) in the power plant proper, or by conversion at mine mouth to higher-BTU gas or low-sulfur liquid for distribution to the plants by pipeline. The transportation of low-BTU gas by pipeline is uneconomical, except for very short distance movements. Moreover, all of these possibilities will require additional research and development.

At the present time, a 172 MW coal-fired combined-cycle plant is under construction in Germany, and it will be watched with a great deal of interest by the U.s. power industry. This plant will convert coal to low-BTU gas at the plant site itself. Although the plant will not have sulfur removal, the designer feels that conventional washing processes can be used to remove the H_2S from the gas.

Essentially all segments of the technology to be employed at this plant are commercially proved, and the plant is expected to be at least competitive with a plant of ordinary design. However, with the addition of established sulfur removal, it would be pollution-free. The real promise inherent in the combined cycle lies in the potential future increases in gas turbine inlet temperature, which should lead to higher plant efficiency. With vigorous development which the system merits, it could begin to make an appearance in the United States toward the end of the IS-year projection period.

Implications Concerning Alternative Uses of Coal in Power Generation

Without speculating on the relative commercial buildup rates of the alternate methods by which coal may be used in pollution free power generation, the particular requirements of individual power plants will dictate which route appears most suitable. Regardless of the route chosen--whether it involves stack gas cleanup, gasification (high- or low-BTU gas) or liquefaction, or whether it is based on conventional stearn-electric or combined-cycle power plants it will affect the overall U.S. energy balance as a result of the somewhat different overall efficiency of conversion from coal to electricity. Demand for complete freedom from pollution will cause this overall power plant efficiency to decline sharply. The extent of this decline and the resulting additional demand for coal is not known at this time.

USE OF COAL FOR SYNTHETIC PIPELINE GAS

Interest in the use of coal for synthetic pipeline gas has grown in recent years, and hence the task group has examined the present state of the art. Coal can, of course, be "converted" to gas most efficiently by direct replacement of natural gas in all those applications where coal can be used, notably in boilers and power stations. However, proved technology is currently available to convert coal to pipeline gas, although at a somewhat reduced heat content. Coal-based gas will contain from 900 to 925 BTU's per cubic foot compared to 1,025 to 1,050 BTU's per cubic foot for natural gas.

A satisfactory process of manufacturing synthetic gas from coal is presently available for commercial use. Developed over 30 years ago by Lurgi G.m.b.H. of Germany, this process has been in commercial use ever since. Although the demonstration of the important methanation step needed to raise the BTU content of the gas is not yet complete, a project working toward this goal is currently in progress. Thus, no delay is required due to a lack of technology. In any event, the Lurgi process is particularly suited for non-caking or mildly caking coals and requires a feed size generally above 1/4 inch. Therefore, most western and mid-western coals which are in relative abundance can be used, and strip mining generally minimizes the production of minus 1/4 inch size to the point where the amount of fines is just adequate for the auxiliary boiler needed to make process steam.

The Coal Task Group, in analyzing the future potential of coal-based synthetic pipeline gas, concluded that neither technological considerations nor the adequacy of supply of feedstocks would be major factors affecting the growth of synthetic gas production. The buildup rate would, in fact, be primarily influenced by economic or other considerations.

The task group's analysis of the potential growth of synthetic pipeline gas from coal involved two separate appraisals, conducted approximately 1 year apart. The task group's Initial Appraisal resulted in an estimate of a possible "maximum" growth potential and the associated capital required to support that possible accelerated growth.

The projections from the Initial Appraisal, reflecting this maximum buildup rate, are presented in Table 32. It should be noted that these figures represent the maximum amount of capacity that could be added without regard to economic considerations with the further assumption that a full program is begun immediately, utilizing the existing technology.

As Table 32 indicates, cumulative capacity of coal-based synthetic pipeline gas, under the assumptions given, was projected to be some 3.0 TCF per year by 1985. This would be approximately the equivalent of some 36 plants, each producing 250 million cubic feet per day (MMCF/D). The total cumulative capital investment

TABLE 32

POTENTIAL GROWTH OF SYNTHETIC PIPELINE GAS FROM COAL*
(Initial Appraisal)

	Capacity Added (TCF/Yr.)	Cumulative Carcity (TCF/Yr.	Millions of Dollars Invested: Plant	Strip Minest	Total in Year	Total Cumulative
1975	0.08	0.08	210	40	250	250
1976	0.16	0.24	420	80	500	750
1977	0.16	0.40	420	80	500	1,250
1978	0.25	0.65	600	120	720	1,970
1979 - 1985	0.33‡	3.0	800‡	160‡	960‡	8,690

• Assumes existing technology and immediate accelerated rate of buildup.

t Total mining capacity (strip) in 1985: 225 to 250 million tons per year (8 to 9 billion tons reserves!.

‡ Each year.

deemed necessary to arrive at that capacity level was expected to be some $8.7 billion.

However, it should be re-emphasized that these maximum growth projections in the Initial Appraisal were made without regard to economic considerations. The task group thus concluded that without substantial changes in the current economic climate, the accelerated bUildup rate suggested in Table 32 would be very difficult, if not impossible, to achieve. In light of this, a more moderate buildup rate was projected. As a result, cumulative capacity of coal-based synthetic gas was projected to be 0.18 TCF per year by 1980 and 0.54 TCF per year by 1985.

In its second and final appraisal, the task group developed a range of prospective bUildup rates of synthetic gas production. Three cases in all were developed, and they are presented as follows:

- Case I: A maximum rate of buildup under special conditions and appropriate special policies
- Cases II and III: A rapid but practical buildup rate
- Case IV: A minimum rate of buildup which can be foreseen on the basis of current economics.

Table 33 illustrates the growth of capacity for these three cases.

Although the Case I projections are similar to the "maximum" projections indicated in the Initial Appraisal, they are, however, correspondingly less. This principally is a reflection of decreased optimism on the part of the Coal Task Group over the intervening time period concerning the ability of the coal gasification

TABLE 33

INSTALLED CAPACITY OF SYNTHETIC GAS FROM COAL
(TCF per Year-90-Percent Operating Factor)

Case	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
I	0.08	0.16	0.28	0.40	0.56	0.80	1.12	1.52	2.00	2.48
II/III	0.08	0.12	0.16	0.24	0.36	0.52	0.68	0.84	1.08	1.31
IV*					0.18					0.54

* This case is the same shown in the Initial Appraisal. See: NPC, *U.S. Energy Outlook: An Initial Appraisal* 1971-1985. Vol. II (November 1971), Table LV, p. 81. In that table, total SNG amounted to 0.91 TCF per year in 1985- 0.37 TCF per year produced from naphtha and 0.54 TCF per year from coal.

industry to increase its capacity at the accelerated rate suggested earlier. The task group considers this somewhat less accelerated buildup likely even if the industry were operating under special conditions and with appropriate special policies.

Under the assumption that a plant of 250 MMCF/D capacity produces 0.082 TCF per year at a 90-percent operating factor, the maximum case (Case I) would require a total of 30 plants of the above capacity in operation by 1985.* The rate of addition at the end of the period would reach six plants in 1 year, requiring about $1.5 billion (constant 1970 dollars) per year in new investment.

The ability to construct plants at this rate can probably be measured best by considering the implied total annual investment and by relating it to other construction or to the capacity of the U.S. construction industry as a whole. One 250 MMCF/D plant has been estimated to cost in excess of $250 million. This figure is comparable to an 800 MW power plant. There will probably be some 50,000 MW (equivalent to 63 plants of 800 MW capacity) added annually to U.S. power generation facilities during the pre-1985 period. By comparison, the suggested construction of six synthetic gas plants per year by 1985 appears very reasonable. It has been recognized, however, that different types of construction may be involved in this comparison.

At the end of the period, the cumulative investment for the total period for Case I (in constant 1970 dollars) would be approximately $7.5 billion. The slower buildup indicated by Cases II and III, by comparison, suggests a total of 16 plants of the 250 MMCF/D size by 1985 with cumulative investment reaching $4.0 billion. At the end of the period, increased capacity would be added at the rate of three plants per year. Case IV is identical to the Initial Appraisal projection.

* For simplicity it was arbitrarily assumed that a 250 billion BTU/day plant is comparable to a 250 MMCF/D plant.

Coal Requirements for Synthetic Gas

The annual tonnage required for one coal gasification plant for the three types of coal involved, based on 2S0 MMCF/D of pipeline gas, is as follows:

- Bituminous coal (ll,SOO BTU/lb)--S.3 million tons
- Subbituminous coal (8,SOO BTU/lb)--7.2 million tons
- Lignite (6,7S0 BTU/lb)--9.l million tons.

In Table 34, the potential number of plants has been assigned for the principal supply cases to the three types of coal in the various states. The number of plants is lower in all instances than that showing in Table 29 (Chapter Five), illustrating again that coal reserves are adequate.

TABLE 34

DISTRIBUTION OF COAL GASIFICATION PLANTS IN 1985

	Case I		Cases II/111		Case IV	
	No. of Plants	TCF	No. of Plants	TCF	No. of Plants	TCF
			Bituminous Coal			
New Mexico	4.0	0.33	4.0	0.33	2.0	0.16
			Subbituminous Coal			
Wyoming	7.0	(').58	3.4	0.28	2.1	0.18
Montana	6.4	0.53	3.0	0.25	1.0	0.08
			Lignite			
Montana	8.0	0.66	3.6	0.29	0.0	0.00
North Dakota	4.6	0.38	2.0	0.16	1.5	0.12
Total	30.0	2.48	16.0	1.31	6.6	0.54

Table 3S indicates the annual coal requirement for synthetic gas plants for the various cases.

TABLE 35

ANNUAL COAL REQUIREMENT FOR SYNTHETIC GAS PLANTS IN 1985

	Case I		Cases II/III		Case IV	
	No. of Plants	Million Tons/Yr.	No. of Plants	Million Tons/Yr.	No. of Plants	Million Tons/Yr.
Bituminous Coal	4.0	21.2	4.0	21.2	2.0	10.6
Subbituminous Coal	13.4	96.5	6.4	46.1	3.1	22.3
Lignite	12.6	114.7	5.6	51.0	1.5	13.7
Total	30.0	232.4	16.0	118.3	6.6	46.6

Economics of Coal Gasification

In its Initial Appraisal, the Coal Task Group conducted an economic analysis of the Lurgi coal gasification process and subsequently developed an order-of-magnitude cost of gas. A utility-type calculation was performed based on a coal gasification plant operating at a capacity of 270 MMCF/D and producing 900 BTU's per cubic foot gas. The results of this calculation are presented in Table 36.

TABLE 36

COST OF COAL BASED SYNTHETIC PIPELINE GAS
(Initial Appraisal)

Annual Operating and Capital Costs of Synthetic Gas Plant*		Cost per Million BTU's of Gas
Cost of Coal t	$ 17,900,000	**22.2¢**
Operating Cost	16,100,000	20.0
Capital Charge*	37,700,000	46.7
Total	$ 71,700,000	**88.9¢**

* Assumes 1970 investment and operating costs.

t Assumes western strip-mined coal at $0.15 per million BTU's converted to gas at 68-percent thermal efficiency.

‡ Computed at 18 percent of the rate base.

The feedstocks expected to be used in this plant are western surface coals, which are estimated to range from $2.75 to $4.00 per ton (in constant 1970 dollars) through 1985. The range of BTU levels involved (13.5 million BTU's per ton to 23.0 million BTU's per ton) indicates a possible range of $0.12 to $0.30 per million BTU's for coal feedstocks. The actual range, however, is likely to be narrower because the low-BTU lignites are likely to fall into a lower "price" range.

The particular results shown in Table 36 were obtained by using a lower cost coal ($O.lS per million BTU's). Calculations indicate that the variations in the cost of coal will cause the cost of synthetic pipeline gas to vary from approximately the $0.90 (shown in Table 36) to $1.10 (constant 1970 dollars) per million BTU's at a western plant site (see Appendix N).* Should this gas be pipelined to the Midwest, the pipelining charges could add an additional $0.20 to $0.30 per million BTU's for a delivered city gate gas cost of about $1.10 to $1.40.

It is important to emphasize that the Initial Appraisal calculations were performed in 1970 and thus assumed investment and operating costs applicable at that time. However, during the period following the Initial Appraisal, the rapid inflation and increased demands for environmental protection have resulted in a major increase in the investment and operating costs of synthetic gas plants.

Following construction and beginning commercial operation of a coal gasification plant, there should be no significant variation in the cost of gas other than that resulting from variations in the cost of coal. There is essentially no supply elasticity involved in building a series of identical gasification plants. However, in the post-198S period, following development and commercial operation over a number of years, the cost of gas (in constant 1970 dollars) will probably decrease by roughly 2 to S percent per year as design and operating improvements are developed from the commercial operations and from continuing research, i.e., from the "learning curve."

At present, several new gasification processes have already reached the pilot plant stage of development. These new processes offer potential savings in plant investment from IS to 20 percent. While the savings appear greater when one considers solely the process plant proper, there are major segments of overall plant cost which remain unaffected by selection of process. As a result, new processes which may become commercially available at the middle of the IS-year projection period offer savings between $0.08 and $0.12 per million BTU's in the price of synthetic gas.

Some $80 million will be spent on these pilot plants, and it will then be necessary to demonstrate the new technology in a plant representing a single full-size reactor train. Such a unit will cost $100 million. The incentive for such a development is ample--if synthetic gas were to supply 3 TCF per year at the end of the period (10 percent of expected demand) and the new development were to save $0.10 per million BTU's, the annual saving is $300 million.

---

* The costs indicated here and in Appendix N were calculated on a utility financing basis. On the basis of a IS-percent DCF rate of return on investment, the cost of coal-based synthetic pipeline gas was calculated to be $1.20 per million BTU's.

USE OF COAL FOR SYNTHETIC LIQUID FUELS

The problem of liquefaction differs from that of gasification because an acceptable technology for liquefaction has yet to be proved. Coal liquefaction was practiced in Germany prior to World War II, but the technology is not considered economically viable in the United States today. The rate of buildup of a synthetic liquid enterprise in the United States is therefore dependent on the rate at which technology is developed.

Production of synthetic liquid fuels from coal will depend primarily upon development of new technology in hydrogenation of coal or coal-derived intermediates and in production of hydrogen, also from coal or coal derived material. The hydrogen is produced substantially by the same process as that used for production of pipeline gas, and the demonstrated technology presently available is sufficiently close to new alternates to serve for an appraisal of the subject.

The hydrogenation step proper has been under development intermittently ever since World War II when some 100 MB/D of liquid fuels were produced from coal in Germany. Several significant improvements have since been tested which would be required to bring coal liquefaction within reach of practical economics under U.S. conditions. The key step involves the use of efficient catalysts under the high pressures needed for the process. The so-called ebullating bed reactor appears to offer the best hope, and this has been evaluated by Hydrocarbon Research, Inc. (For detailed information, see Appendix O.)

As with coal gasification, the Coal Task Group conducted two separate appraisals of the future potential of coal liquefaction in the United States. Table 37 shows the results of the task group's Initial Appraisal. Specifically, this table illustrates two possible coal liquefaction buildup rates (conservative and accelerated) and their associated capital requirements to the year 1985.

In its second and final appraisal, the task group developed a series of possible growth cases (three in all) which represented a reasonable range of buildup rates and subsequently described the assumptions used for each case.

The buildup under Cases II and III, shown in Table 38, is based upon the assumption that, after 2 years of research and development effort, a prototype, semi-commercial plant will be built. This plant will take 5 years to build and successfully operate. The initial plant will be followed by a small commercial plant of 30 MB/D capacity 4 years later. Thus, the first plant would become operational 11 years from the start of the research and development program. Subsequent buildup could then follow as shown in Table 38. This buildup reflects a moderate growth, assuming a reasonable incentive for buildup of domestic liquid fuel sources. It is, of course, possible to visualize faster buildup under greater economic incentives of new government policies, but only *after* technology has been established.

TABLE 37

SYNTHETIC LIQUIDS FROM COAL*
(Initial Appraisal)

	Capacity Added (MB/D)	Cumulative Capacity (MB/D)	Millions of Dollars Invested: Plant	Strip Minest	Total in Year	Total *Cumulative*
	Assumes New Technology Available in 1978 and Conservative Rate of Buildup					
1981	30	30	200	20	220	220
1985	50	80	320	35	355	575
	Assumes New Technology Available in 1977 and Accelerated Rate of Buildup					
1980	50	50	320	50	370	370
1981	100	150	600	100	700	1,070
1982	100	250	600	100	700	1,770
1983	200	450	1,100	200	1,300	2,070
1984	200	650	1,100	200	1,300	3,370
1985	200	850	1,100	200	1,300	4,670

* Compare these capital requ irements with those needed for expansion of power generation capacity: The total capacity is expected to grow from 340,000 MW in 1970 to 977,000 MW in 1985. At $200 per KW installed cost, the capital requirements will grow from about $6 billion in the beginning of the period to $12 billion in 1985.

t Total mining capacity (strip-accelerated buildup) in 1985: 140 million to 150 million tons per year (5 to 6 bill ion tons reserves!.

TABLE 38

COMMERCIAL COAL LIQUEFACTION
PLANT BUILDUP - CASES 11/111

Years Elapsed from Start of R&D	Plant Addition (MB/D)	Total Capacity in Operation (MB/D)
15	50	80
16	100	180
17	100	280
18	200	480
19	200	680

Table 39 portrays the various cases (Case I--maximum incentive; Cases II and III--a moderate buildup; and Case IV--no incentive, i.e., no commercial liquefaction of coal during the period to 1985). The maximum case differs from Cases II and III by assuming that a

TABLE 39

BUILDUP OF SYNTHETIC LIQUIDS FROM COAL
(MB/D)

	1977	1978	1979	1980	1981	1982	1983	1984	1985
Case I	30	30	30	80	130	180	280	480	680
Cases II/III					30	30	30	30	80
Case IV									0

"high risk" 30 MB/D plant will be placed on-stream in 5 years, to be followed by three 50 MB/D plants 3, 4 and 5 years later, with a buildup reaching 200 MB/D per year at the end of the period.

The Case I buildup shown in Table 39 is at least 1 year behind the schedule suggested as a possible accelerated buildup in the Initial Appraisal. The slippage reflects the lack of activity in major liquefaction development during the intervening time period. The Case I growth rate requires a virtual immediate decision to proceed with a 30 MB/D commercial demonstration plant in spite of the high technical risks involved. Such a decision would require policies other than those prevailing today.

Economics of Coal Liquefaction

The principal examination of liquefaction economics was conducted by the Coal Task Group in its Initial Appraisal. Specifically, the task group selected a liquefaction process under development by Hydrocarbon Research, Inc., to evaluate the costs of producing synthetic crude from coal. This process was judged to be competitive with other processes under development, and published information was available on experimental results and on engineering design of a commercial plant.

The results of the task group's economic evaluation indicated that such a process which includes the manufacture of hydrogen from coal would require a total investment ranging from $6,000 to $8,000 per daily barrel of synthetic crude. Initially, at the 30 MB/D to 50 MB/D scale, investment would be some $7,400 per daily barrel, and later, at the 200 MB/D level, this figure would decrease to $6,500 per daily barrel. The resulting cumulative investment for Case I would amount to some $4.58 billion by 1985, and the total for Cases II and III would be approximately $592 million.

Assuming a feedstock of bituminous coal at $6.50 per ton ($0.27 per million BTU's) and considering a 10-percent DCF rate of return on investment, a cost from the first plant of $7.50 per barrel of synthetic liquid (syncrude of approximately 32° API gravity) is indicated. However, using western surface-mined coal, which is expected to range from $2.75 to $4.00 per ton (in constant 1970 dollars) through 1985, results in a reduced cost for synthetic crude varying between $6.25 and $6.75 per barrel at the western plant gate. At a 15-percent DCF rate of return (again assuming western surface-mined feedstocks), the resulting cost of synthetic crude should vary between $7.75 and $8.25 per barrel. It should be noted, however, that the lower cost associated with western surface-mined coal is offset by generally lower coal quality. Plant size, too, has some effect on the ultimate cost of synthetic crude. For example, the above calculations were based on a 30 MB/D commercial demonstration plant. For operations exceeding 100 MB/D, a reduction of $0.50 per barrel can be expected. It was the conclusion of the task group, however, that once the liquefaction process is developed and applied in large plants on western strip coal, costs in the range of $6.00 to $6.25 per barrel can probably be reached.

A more limited objective considered by the task group was the possible conversion of high-sulfur coal to low-sulfur heavy fuel oil for power plant use. Hydrogenation of coal removes a substantial amount of sulfur while the coal substance is liquefied. A process can probably be developed, and preliminary estimates suggest a cost of $4.50 to $5.50 per barrel for a fuel oil of approximately OOAPI gravity containing 0.3- to 0.5-percent sulfur. This could be of considerable import within the next IS-year period.

Coal Requirements for Synthetic Liquids

If the western surface coal reserves suggested in Table 29 (Chapter Five) were totally committed, they could provide sufficient feedstocks for 52.9 synthetic liquid plants, each producing 50 MB/D. Given that Case I indicates the equivalent of 13.6 plants and Cases II and III indicate only 1.6 plants by 1985, the available supply of coal thus appears to be quite adequate for the suggested buildup. The annual coal tonnage required for each 50 MB/D plant is as follows:

- Bituminous Coal (11,500 BTU/lb)--6.0 million tons
- Subbituminous Coal (8,500 BTU/lb)--8.l million tons
- Lignite (6,750 BTU/lb)--lO.l million tons.

TABLE 40

ASSUMED DISTRIBUTION OF COAL LIQUEFACTION PLANTS IN 1985

	Case I		Case IIIIII		Case IV	
	No. of Plants	MB/D	No. of Plants	MB/D	No. of Plants	MB/D
Bituminous Coal						
New Mexico	1.6	80	0.6	30		
Subbituminous Coal						
Wyoming	10.0	500	1.0	50		
Montana	2.0	100				
Total	13.6	680	1.6	80	None	None

In Table 40, the potential number of plants is assigned for the principal supply cases to the three types of coal in the various states.

TABLE 41

ANNUAL COAL REQUIREMENT FOR SYNTHETIC LIQUID PLANTS IN 1985

	Case I		Case II/III		Case IV	
	No. of Plants	Million Tons/Yr	No. of Plants	Million Tons/Yr	No. of Plants	Million Tons/Yr
Bituminous Coal	1.6	9.6	0.6	3.6		
Subbituminous Coal	12.0	97.2	1.0	8.1		
Total	13.6	106.8	1.6	11.7	None	None

Table 41 shows the annual coal requirements for the assumed set of synthetic liquid fuel plants for Cases I through IV.

TABLE 42

CUMULATIVE CAPITAL REQUIREMENTS FOR
COAL-BASED SYNTHETIC GAS
AND LIQUID PLANTS
(Millions of Dollars)

	1970	1975	1980	1985
Case I				
Synthetic Gas Plants'			1,700	7,500
Synthetic Liquid Plantst			590	4,500
Associated Mine Investment*			387	2,030
Total			2,677	14,030
Cases 11/111				
Synthetic Gas Plants			1,100	4,000
Synthetic Liquid Plants				590
Associated Mine Investment			187	780
Total			1,287	5,370
Case IV				
Synthetic Gas Plants			550	1,650
Synthetic Liquid Plants				
Associated Mine Investment			108	280
Total			658	1,930

• Basis: $250 million per standard-size plant.

t Basis: $7,400 per *BID* first 80,000 *BID;* $6,500 per *BID* above initial 80,000 *BID*.

‡ Basis: $6.00 per annual ton of surface mine capacity.

U.S. CAPABILITY TO BUILDUP FUELS INDUSTRY

The total investment, on a cumulative basis, for plants and associated mines for Cases I through IV is shown in Table 42.

The annual investment rate in 1985 for Case I would be about $3 billion or approximately one-third of the total 1970 investment rate of the chemical and petroleum industries combined. While no detailed study has been made, such a rate of investment in 1985 appears to be feasible.

Appendices

APPENDIX A

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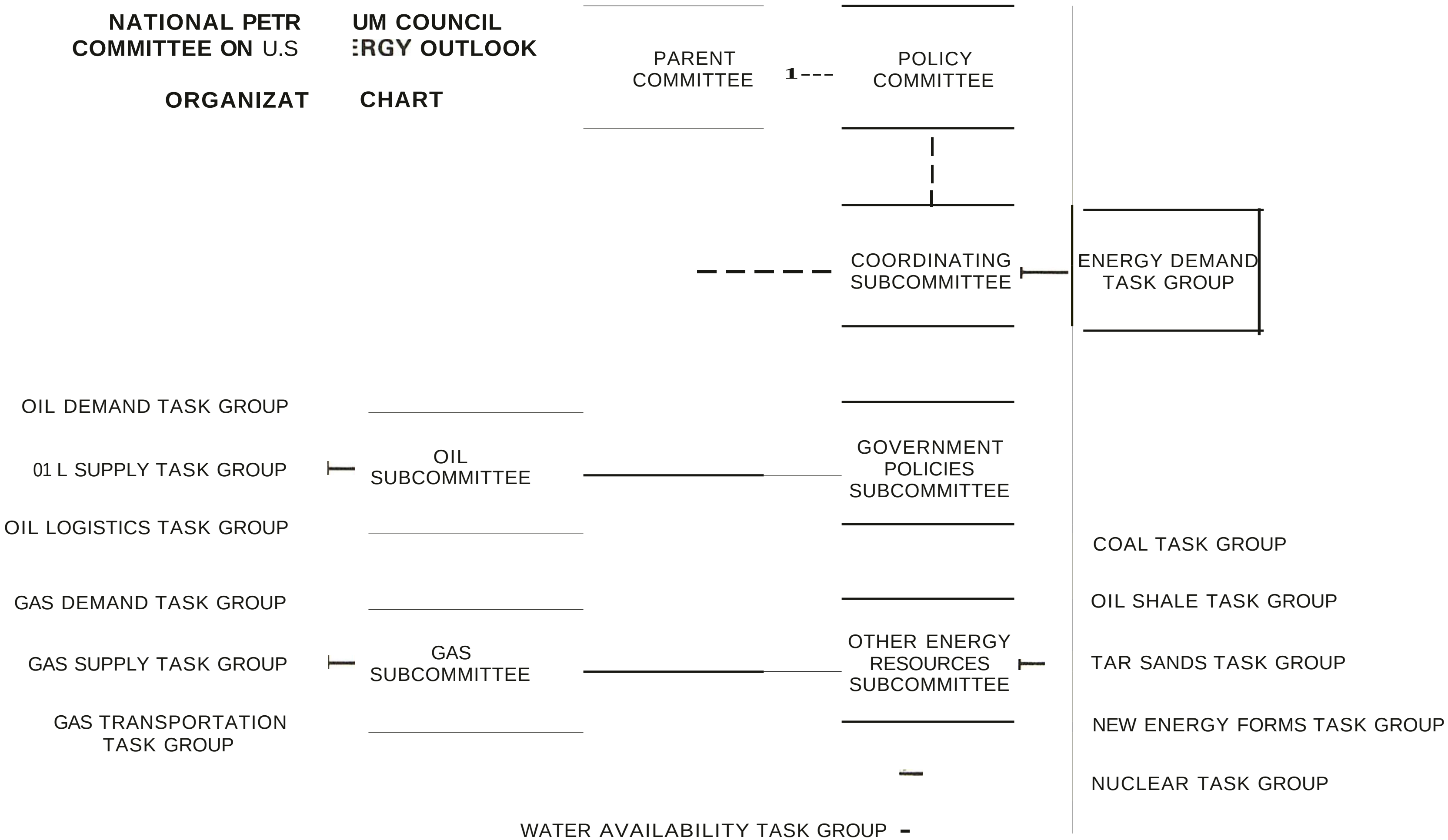

APPENDIX B

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The following appendices consist of 11 individually prepared papers which were submitted by task group members and other experts to complement the task group's in-depth assessment of coal as a major energy form. Because of the valuable findings in these papers, the task group decided to include them to enhance the reader's understanding of this important energy resource. By consulting these papers, it is also hoped that the reader will be given an additional insight into the rationale on which many of the statements made in the Coal Task Group report were based.

It should be recognized that the majority of these papers have been edited and in some cases reorganized for clarity of presentation. However, every effort has been made to keep their principal themes intact. These papers do not necessarily reflect the views of the National Petroleum Council.

The task group would like to express their gratitude to those non-members who have contributed their time and effort in preparing these papers.

Appendix E: U.S. Coal Consumption and Exports--V. M. Johnston, Manager, Economic Services, Island Creek Coal Sales Company

Appendix F: Coking Coal Requirements--D. T. King, Director, Coal Preparation and Dlstribution, U.S. Steel Corporation

Appendix G: Coal Reserves of the United States--J. A. deCarlo, U.S. Bureau of Mines; W. A. Crentz, Assistant Director, U.S. Bureau of Mines

Appendix H: Selected U.S. Coal Industry Statistics--1960-l969--W. L. Kurtz, Director, Economics and Statistics, National Coal Association

Appendix I: An Economic Model of the U.S. Coal Industry--J. A. Sittner, Staff Mining Engineer, Gulf Mineral Resources Company

Appendix J: Rail Transport of Coal--J. N. Martin, R. L. Banks & Associates, Inc., Transportation Consultants

Appendix K: Water Transport of Coal--M. J. Barloon, Professor of Economics, Case-Western Reserve University

Appendix L: Coal Slurry Pipelining in the Western United States--E. J. Wasp, Manager, Solids Pipeline Department, Bechtel Corporation

Appendix M: Electric Power Generation from Coal--J. N. Landis, Consultant, Bechtel Corporation

Appendix N: Manufacture of Pipeline Gas from Coal--G. T. Skaperdas, Manager, Process Development, The M. W. Kellogg Company

Appendix 0: Manufacture of Hydrocarbon Liquids from Coal--B. L. Schulman, Synthetic Fuels Development; H. M. Siegel, Manager, Synthetic Fuels Development, Esso Research and Engineering

APPENDIX E

U.S. COAL CONSUMPTION AND EXPORTS

OVERVIEW

Demand for coal as projected in this Appendix includes the conventional consuming sectors and exports but does not include demand for conversion to synthetics. Requirements for manufacturing gas and liquids are treated in later appendices. Domestic plus export demand for U.S. bituminous coal is shown in Table E-l.

TABLE E-l

U.S. BITUMINOUS COAL CONSUMPTION (AND EXPORTS)
(Millions of Net Tons)

	1970	1975	1980	1985
For Blast Furnaces	86	102	110	116
For Foundries and Misc.	10	10	10	10
Total for Coking	96	112	120	126
Residential/Commercial	10	7	5	3
Industrial	91	87	84	80
Electric Utility	322	415	525	654
Total Domestic	519*	621	734	863
Export Metallurgical	56	76	94	120
Export Steam	15	16	17	18
Total Export	71	92	111	138
Total Domestic Plus Export	590	713	845	1,001

* The 1970 domestic consumption figure was obtained from the U.S. Bureau of Mines, "Production of Coal--Bituminous and Lignite--197l," *Mineral Industry Surveys*, Weekly Coal Report #2789 (February 26, 1971).

- The projection for blast furnace use through 1985 was provided by the U.S. Steel Corporation (see Appendix F).

- The projection of 10 million tons a year for foundry coke and miscellaneous was based on data in the Bureau of Mines report, *Coke and Coke ChemicaZs* (December 1970). The opinion was that this will hold about even with losses in some markets to be offset by gains in foundry coke and other special uses.

- The residential/commercial market shows a diminishing demand for coal as indicated by the 70-percent decline in demand from 1970 to 1985. Bureau of Mines data over several years support this trend.

- Industrial use reflects a declining trend of some 12 percent over the next 15 years. This market (as reflected by Bureau of Mines Weekly Reports and Quarterly Distribution Reports) has been declining modestly since 1966. A reversal in this trend was recorded in the final quarter of 1970, and, while the industry is hopeful of a continuation of this upward trend, a decline was nevertheless projected in the interest of conservatism.

- The most important factor in determining coal demand for electric utilities through 1985 is the proportion of capacity and generation assigned to nuclear fuels. There is little doubt that combined nuclear generation and coal usage will increase in a quantity to support these projections, dependent upon the proportion assigned to each. Chairman John N. Nassikas of the Federal Power Commission estimates that coal and nuclear use, in tons of coal equivalent, will grow by some 900 million tons between 1970 and 1985.* A growth of 332 million tons has subsequently been assigned to bituminous coal between 1970 and 1985.

- Exports are also included to indicate the total demand on the industry and to provide a basis to measure capacity to perform in meeting U.S. demands.

As indicated in Table E-l, a production level of 863 million tons is required in 1985 to satisfy domestic demand. This represents an increase of 66 percent over the 15-year period--approximately a 3.5-percent growth rate compounded annually. Demand for export coal shows an even more rapid growth rate--4.5 percent per year through 1985.

Table E-l further illustrates that, in 1970, 83 percent of total demand (domestic demand plus exports) involved only two markets--coke production and electric power generation. These two uses are expected to represent 92 percent of total demand by 1985, assuming no conversion of coal to either gas or liquid fuel during

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* "An Analysis of the Current Energy Problem," Presented by John N. Nassikas at Electric World Conference for Utility Executives, Shoreham Hotel, Washington, D.C., January 14, 1971.

the intervening time period. Future consumption can, therefore, be fairly well defined by considering these two consuming sectors and their corresponding requirements which are developed in detail later. Demand by electric utilities is considered in this Appendix. Coking coal requirements are considered in Appendix F.

Table E-2 shows domestic coal demand expressed in BTU's. The average number of BTU's per ton in 1970 was 25,167,000 which equates to 12,583 BTU's per pound. By 1985 (when a larger percentage of low-BTU coal is projected), the average BTU figure will drop to 24,783,000 per ton or 12,392 per pound.

TABLE E-2

CONVERSION OF BITUMINOUS COAL TONNAGE TO BTU'S--U.S. CONSUMPTION
(Trillions of BTU's)

	1970	1975	1980	1985
Coking Coal (14,000 BTU/lb)	2,688	3,136	3,360	3,528
Residential/Commercial (14,000 BTU/lb)	280	196	140	84
Industrial (13,000 BTU/lb)	2,366	2,262	2,184	2,080
Electric Utility (12,000 BTU/lb)	7,728	9,960	12,600	15,696
Total	13,062	15,554	18,284	21,388
(Average BTU per Ton--Thousands)	(25,167)	(25,046)	(24,910)	(24,783)

In Table E-3, the demand projections illustrated in Table E-2 are converted into market categories as defined by the National Petroleum Council. Included in industrial use is coking coal used mainly for blast furnaces. However, a portion of the coking coal totals (Table E-2) has also been allocated to the raw materials category.

COAL DEMAND BY ELECTRIC UTILITIES

The following procedure, utilizing a sequence of tables together with rationale, was established as a means of developing projections of bituminous coal demand by electric utilities through 1985.*

Initially, historical as well as projected total energy demand figures for electric utilities (in BTU's) was obtained from the NPC's Energy Demand Task Group. These data, which provided a basis

* Anthracite is assumed to be included in the forward projections, 1975-1985.

TABLE E-3

DOMESTIC CONSUMPTION OF BITUMINOUS COAL
BY NATIONAL PETROLEUM COUNCIL CATEGORIES
(Trillions of BTU's)

	1970	1975	1980	1985
Residential/Commercial	280	196	140	84
Transportation	neg.	neg.	neg.	neg.
Industrial	4,463	4,708	4,805	4,832
Electric Utility	7,728	9,960	12,600	15,696
Raw Materials	591	690	739	776
Total Bituminous Coal	13,062	15,554	18,284	21,388
Total U.S. Energy Demand*	67,827	83,481	102,581	124,942
Bituminous (Percent)	19.3	18.6	17.8	17.1

* As projected by the NPC Energy Demand Task Group.

TABLE E-4

ELECTRIC UTILITY BTU CONSUMPTION
(Energy Demand Task Group Projections--January 19, 1971)*

	Consumption	Growth Rate per Annum (%)
1965-1969	11,110	
		8.4
1970-1974	16,614	
		7.1
1975-1979	23,361	
		7.0
1980-1984	32,809	
		6.1
1985	44,161	

* It should be noted that these are preliminary profections. Subsequent projections have been published by the Energy Demand Task Group which vary only slightly from the preliminary figures. The impact from using the latter projections as a basis for calculating coal demand for electric utilities would be relatively insignificant.

TABLE E-5

ELECTRIC ENERGY DEMAND BY PAD DISTRICTS*

PAD District	Demand	1970	1975	1980	1985
I	Percent	33.5	33.7	34.2	34.5
	BTU's (10^{12})	5,566	7,873	11,221	15,235
II	Percent	33.6	32.2	31.1	30.5
	BTU's (10^{12})	5,582	7,522	10,203	13,469
III	Percent	13.9	15.0	15.3	15.3
	BTU's (10^{12})	2,309	3,504	5,020	6,757
IV	Percent	2.8	2.9	2.8	2.8
	BTU's (10^{12})	465	678	919	1,237
V	Percent	16.2	16.2	16.6	16.9
	BTU's (10^{12})	2,692	3,784	5,446	7,463
Total	Percent	100.0	100.0	100.0	100.0
	BTU's (10^{12})	16,614	23,361	32,809	44,161

* Adjustments to 100 percent made in the largest districts (-0.1 points in 1970, 1975, and 1985).

for subsequent calculations of coal demand (by electric utilities), are illustrated in Tables E-4 and E-5.

Power generating capacity was then compiled by prime mover (see Table E-6). Table E-6 shows both historical and projected capacity by prime mover for electric utilities through 1985. The projected figures tie in closely in total with Mr. Nassikas' paper and with many other estimates of industry capacity. Mr. Nassikas' data interpreted for 1985 is about 962,500 MW. Additional capacity has been added to pumped storage and gas turbine categories to arrive at 977,528 MW. Calculations on a BTU basis support these figures, under assumptions of normal average industry load factors.

The proportion of the capacity allotted to hydropower, pumped storage, internal combustion and gas turbine was determined by information received from the National Coal Association (NCA) and the FPC. Hydropower is assumed to grow at a 2.5-percent annual rate--less than the rate for recent years--although the recent rate includes umped storage which is now shown separately. Hydropower and pumped storage combined, of course, represent a very sizable growth rate. Gas turbine projections are felt to be minimal and could prove to be higher.

TABLE E-6

ELECTRIC UTILITY CAPACITY BY PRIME MOVER
(MW)

	Hydro	Pumped Storage	Conventional Steam	Nuclear	Internal Combustion	Gas Turbine	Total
1965	43 782	*	186,666	926	3,365	1,388	236,127
1966	44:977	*	195,431	1,942	3,509	1,984	247,843
1967	48,112	*	211,080	2,887	3,818	3,355	269,252
1968	51,168	*	226,927	2,817	3,978	6,168	219,058
1969t	52,753	*	242,317	3,980	4,205	10,094	313,349
1970t	51,459	3,600+	259,000	6,493	4,321	15,480	340,353
1975	58,221§	15,300‡	353,000"	50,144**	4,500tt	20,000tt	501,165
1980	65,872§	27,000‡	412,100"	127,900**	4,750tt	35,000tt	672,622
1985	74,528§	50,000‡	546,740"	251,260**	5,000tt	50,000tt	977,528

* Pumped storage capacity included in hydropower through 1969.

t Revised 1969 and preliminary 1970 data from FPC. FPC reported 1970 hydro at 55,059 MW. To arrive at 1970 figure above 3,600 MW pumped storage subtracted from hydro total.

‡ Pumped storage estimates are actual and/or figures interpolated by John N. Nassikas.

§ Hydro estimated growth rate--2.5 percent annually.

" Conventional steam capacity estimated by subtracting estimated nuclear capacity from combined total capacity figures for fossil steam and nuclear.

** Nuclear capacity estimates allowing for unscheduled delays. The 1970 figure based on NCA, *Steam Electric Plant Factors--1970* (November 1970).

tt Internal combustion and gas turbine capacity estimates based on conversations with knowledgeable persons in electric utility matters.

The critical determination of capacity lies in the assigned division between nuclear and conventional steam. Combined, they are 265,493 MW in 1970 and rise to 798,000 MW in 1985--a growth of 532,507 MW in 15 years. This is nearly 84 percent of total projected industry capacity growth during the period.

Nuclear capacity of 50,144 MWe by 1975 is rather well documented. An exhibit from the Atomic Energy Commission (AEC), Division of Industrial Participation, dated January 1, 1971, shows 55,896 MWe scheduled by electric utilities to be installed by the end of 1974. This data, however, reflects the original scheduled dates for completion, and any attempt to make realistic projections must recognize the difficulties and delays that have occurred, are occurring, and that will probably occur in the future. It is almost axiomatic that the current squeeze on power supply stems mainly from the unexpected delay in nuclear plants coming on-stream as projected and in operating at effective rates when they do. Therefore, the nuclear estimates for 1975 and 1980 are calculated to make allowance for the inability of the industry to meet scheduled on-line dates.

Effective nuclear capacity for 1980 is estimated at 127,900 MWe, compared to the standard projection of 147,000 MWe released by the AEC. However, referring to this AEC release, present scheduled capacity is only 86,893 MWe, with time beginning to run out for additional units under the presently recognized lead time of 7 years. Allowing another 41,000 MWe over the 86,893 MWe now scheduled appears reasonably optimistic.

The nuclear projection of 251,260 MWe for 1985 is a judgment figure, resulting from extensive study of available industry information. Mr. Nassikas and other analysts have assumed 500,000 MWe by 1990, a 13-percent annual increase from the 147,000 MWe of 1980. If a 13-percent growth rate is applied to nuclear capacity of 127,900 MWe as of 1980, the result is 236,000 MWe for 1985, compared to the 25! ,200 MWe as was estimated. The latter figure represents a 14.5-percent annual growth rate. Achieving such a growth rate in a major, new industry is not impossible, and with all the problems involved and the alternatives offered by fossil fuels, it is believed that the 251,260 MWe is a reasonably optimistic figure.

The balance not allotted to nuclear and the other prime movers is assigned to conventional steam. The latter projects a capacity growth of 5.1 percent per year from 1970 to 1985 in conventional steam capacity, less, of course, than in the past, but quite reasonable by almost any standard.

Having projected capacity by prime mover, it was then necessary to determine the contribution (in terms of KWH's and BTU's) assigned to each prime mover through 1985. Tables E-7, E-8 and E-9, corresponding to the years 1975, 1980 and 1985, illustrate the methodology employed to arrive at the projected KWH and BTU figures. It should be noted that the contribution assigned to conventional steam is essentially a residual figure.

Reviewing these tables, it can be seen that the heat rate used for nuclear is optimistic, but by choice. Experts in the field place it 'generally 200 to 300 BTU's per KWH above this data.

The load factor used for nuclear is 70 percent in 1975, rising to 74 percent in 1980 and 1985. This is contrasted to a 48-percent load factor for fully operating plants in 1970. There is no doubt that the 1970 load factor will improve. However, there are serious doubts that any realistic study of future energy should assume an average nuclear load factor above 74 percent. One reason is the physical problem of keeping a large number of plants operating at that rate in view of present and probable technology, and another is the fact that, as nuclear becomes a larger percentage of industry capacity, it will be more and more subject to all the influences operating in the industry, resulting historically in a load factor of 50 to 55 percent. For instance, shutdowns for changing nuclear fuel core will result in an average loss of time of about 1 month per year, and other maintenance and breakdowns will require more time.

The official AEC release projects 55,986 MWe nuclear installed capacity at the end of 1974 and 63,740 MWe for 1975--an average of 59,863 MWe during 1975. While this is considerably above the end-of-the-year figure of 50,144 MWe projected here, using a 58.6-percent load factor in 1975--compared to 47.5 percent as occurred in 1970--and applied to 59,863 MWe will give the same nuclear generation as shown in Table E-7. It is believed to be highly unrealistic to assume both (1) installation of 63,740 MWe by the end of 1975 and (2) a load factor of 70 percent. Thus, even should the capacity projection prove low, considerable cushion exists in the projected load factor for 1975 to 70 percent.

Table E-IO summarizes the load factors and heat rates utilized in the computations illustrated in Table E-7 through E-9. It should be noted that the heat rates in Table E-IO are quite close to those projected for use by the NPC Energy Demand Task Group.

Table E-ll restates the data for conventional steam plants and converts coal equivalent tonnages using a conversion factor of 12,000 BTU's per pound of coal. It is believed that the 1970 heat rate given in Table E-ll is an aberration and that it will revert to a more normal pattern in later years. The load factor of 57.5 percent in 1980 is based on Mr. Nassikas' data for the entire industry and may be low. The data in this Appendix indicates a growth in capacity between 1975 and 1980 of 34.2 percent and a growth in generation of 42.4 percent. The latter is more likely reflective of actual conditions to be encountered.

It was then necessary to allocate the total conventional steam requirements illustrated in Table E-ll between coal, oil and gas. This was accomplished in Table E-12. Coal equivalent tonnages for 1970 were based on actual data. Tonnages for 1975, 1980 and 1985 were computed with preliminary percentage allocation estimates from the Bureau of Mines. Table E-12 also shows this allocation in BTU's.

TABLE E-7

KWH AND BTU CONTRIBUTION BY PRIME MOVER--1975
ASSUMING FIXED CAPACITY GROWTH IN HYDRO AND NUCLEAR

Nuclear Capacity--50,144 MW		
365 x 24 = 8,760 x 50,144		439,261 Million KWH
x 70% Load Factor	=	307,483 Million KWH
x Heat Rate 10,400		3,198 Trillion BTU's
Hydro Capacity--58,221 MW		
365 x 24 = 8,760 x 58,221		510,016 Million KWH
x 52.5% Load Factor		267,758 Million KWH
x Heat Rate 10,300		2,758 Trillion BTU's
Pumped Storage Capacity--15,300 MW		
365 x 24 = 8,760 x 15,300		134,028 Million KWH
x 7.5% Load Factor		10,052 Million KWH
x 1.65% (Steam Generated KWH)		16,586 Million KWH
x Heat Rate 10,300		171 Trillion BTU's
Gas Turbine Capacity--20,000 MW		
365 x 24 = 8,760 x 20,000		175,200 Million KWH
x 7.5% Load Factor		13,140 Million KWH
x Heat Rate 16,000	=	210 Trillion BTU's
Internal Combustion Capacity--4,500 MW		
365 x 24 = 8,760 x 4,500		39,420 Million KWH
x 7.5% Load Factor		2,957 Million KWH
x Heat Rate 12,000		35 Trillion BTU's

Balance Due to Conventional Steam--Electric Fuels:

Total Given	23,361 Trillion BTU's
Less Nuclear	3,198 Trillion BTU's
Less Hydro	2,758 Trillion BTU's
Less GT	210 Trillion BTU's
Less IC	35 Trillion BTU's
Remainder	17,160 Trillion BTU's*

If Heat Rate Is 10,300 = 1,666,019 Million KWH.

	1,666,019 Million KWH
	307,483 Million KWH
	267,758 Million KWH
	10,052 Million KWH
	13,140 Million KWH
	2,957 Million KWH
	16,586 Million KWH†
Total	2,250,823 Million KWH

* Includes BTU's used by steam-electric plants to pump water up to pumped storage.

† Minus steam-electric generated KWH used to pump water up to pumped storage.

TABLE E-8

KWH AND BTU CONTRIBUTION BY PRIME MOVER--1980
ASSUMING FIXED CAPACITY GROWTH IN HYDRO AND NUCLEAR

Nuclear Capacity--127,900 MW		
365 x 24 = 8,760 x 127,900		1,120,440 Million KWH
x 74% Load Factor		829,130 Million KWH
x Heat Rate 10,300	=	8,540 Trillion BTU's
Hydro Capacity--65,872 MW		
365 x 24 = 8,760 x 65,872		577,039 Million KWH
x 50.0% Load Factor		288,520 Million KWH
x Heat Rate 10,100	=	2,914 Trillion BTU's
Pumped Storage Capacity--27,000 MW		
365 x 24 = 8,760 x 27,000		236,520 Million KWH
x 7.5% Load Factor	=	17,739 Million KWH
x 1.65 (Steam Generated KWH)		29,269 Million KWH
x Heat Rate 10,100		296 Trillion BTU's
Gas Turbine Capacity--35,000 MW		
365 x 24 = 8,760 x 35,000		306,600 Million KWH
x 7.5% Load Factor		22,995 Million KWH
x Heat Rate 12,000		368 Trillion BTU's
Internal Combustion Capacity--4,750 MW		
365 x 24 = 8,760 x 4,750	=	41,610 Million KWH
x 7.5% Load Factor		3,121 Million KWH
x Heat Rate 12,000	=	37 Trillion BTU's

Balance Due to Conventional Steam-Electric Fuels:

Total Given	32,809 Trillion BTU's
Less Nuclear	8,540 Trillion BTU's
Less Hydro	2,914 Trillion BTU's
Less GT	368 Trillion BTU's
Less IC	37 Trillion BTU's
Remainder	20,950 Trillion BTU's*

If Heat Rate Is 10,100 = 2,074,250 Million KWH.

	2,074,250 Million KWH
	829,130 Million KWH
	288,520 Million KWH
	17,739 Million KWH
	22,995 Million KWH
	3,121 Million KWH
	29,269 Million KWH†
Total	3,206,486 Million KWH

* Includes BTU's used by steam-electric plants to pump water up to pumped storage.

† Minus steam-electric generated KWH used to pump water up to pumped storage.

TABLE E-9

KWH AND BTU CONTRIBUTION BY PRIME MOVER--1985
ASSUMING FIXED CAPACITY GROWTH IN HYDRO AND NUCLEAR

Nuclear Capacity--251,260 MW	
365 x 24 = 8,760 x 251,260	2,201,100 Million KWH
x 74% Load Factor	1,628,820 Million KWH
x Heat Rate 10,200	16,614 Trillion BTU's
Hydro Capacity--74,528 MW	
365 x 24 = 8,760 x 74,528	652,865 Million KWH
x 45% Load Factor	293,789 Million KWH
x Heat Rate 10,000	2,939 Trillion BTU's
Pumped Storage Capacity--50,000 MW	
365 x 24 = 8,760 x 50,000	438,000 Million KWH
x 7.5% Load Factor	32,850 Million KWH
x 1.65 (Steam Generated KWH)	54,203 Million KWH
x Heat Factor 10,000	542 Trillion BTU's
Gas Turbine Capacity--50,000 MW	
365 x 24 = 8,760 x 50,000	438,000 Million KWH
x 7.5% Load Factor	32,850 Million KWH
x Heat Factor 16,000	526 Trillion BTU's
Internal Combustion Capacity--5,000 MW	
365 x 24 = 8,760 x 5,000	43,800 Million KWH
x 7.5% Load Factor	3,285 Million KWH
x Heat Rate 12,000	39 Trillion BTU's

Balance Due to Conventional Steam-Electric Fuels:

Total Given	44,161 Trillion BTU's
Less Nuclear	16,614 Trillion BTU's
Less Hydro	2,938 Trillion BTU's
Less GT	526 Trillion BTU's
Less IC	39 Trillion BTU's
Remainder	24,044 Trillion BTU's*

If Heat Rate is 10,000 = 2,404,400 Million KWH.

	2,404,400 Million KWH
	1,628,820 Million KWH
	293,789 Million KWH
	32,850 Million KWH
	32,850 Million KWH
	6,570 Million KWH
	54,203 Million KWHt
Total	4,345,076 Million KWH

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* Includes BTU's used by steam-electric plants to pump water up to pumped storage.

t Minus steam-electric generated KWH used to pump water up to pumped storage.

TABLE E-10

LOAD FACTORS AND HEAT RATES USED IN COMPUTATIONS

	1975		1980		1985	
	Load Factor (Percent)	Heat Rate (BTU/KWH)	Load Factor (Percent)	Heat Rate (BTU/KWH)	Load Factor (Percent)	Heat Rate (BTU/KWH)
Nuclear	70.0	10,400	74.0	10,300	74.0	10,200
Hydro	52.5	10,300	50.0	10,100	45.0	10,000
Pumped Storage	7.5	10,300	7.5	10,100	7.5	10,000
Gas Turbine	7.5	16,000	7.5	16,000	7.5	16,000
Internal Combustion	7.5	12,000	7.5	12,000	7.5	12,000
Steam-Electric	53.9	10,300	57.5	10,100	50.2	10,000

TABLE E-11

CONVENTIONAL STEAM DATA

	1970	1975	1980	1985
Capacity MW	259,000	353,000	412,100	546,740
KWH (Million)	1,244,246	1,666,019	2,074,250	2,404,400
BTU (Trillion)	13,895	17,160	20,950	224,044
Heat Rate (BTU/KWH)	11,167	10,300	10,100	10,000
Coal Equivalent (Million Tons) (12,000 BTU/1b Coal)	579	715	873	1,002
Load Factor	54.8	53.9	57.5	50.2

The major changes projected in shares of this market are (1) the increase in oil from 14 percent in 1970 to 18 percent in 1985, and (2) the decline in gas from 30 percent to 17 percent.

Oil's growth rate from 1970 to 1985 was calculated to be 5.5 percent compounded annually. Gas participation in the convention-al steam-electric utility market is projected to reach a peak in 1975 and decline in the succeeding 5-year intervals, with oil passing it in total in 1985. These are conventional steam uses only and do not include gas turbine and internal combustion uses (for both gas and oil).

Coal's share of this market is shown to rise from 56 percent to 65 percent, reflecting (1) declining gas availabilities for this low priority market and (2) oil's limitation to areas reachable by imported residual.

Table E-13, which is self-explanatory, shows both a historical as well as projected allocation of conventional steam-electric capacity between coal, oil and gas.

TABLE E-12

COAL, OIL AND GAS*

	Share of Conventional Stearn-Electric Market (Millions of Tons Coal Equivalent--24 Million BTU's per Ton)			
	1970	1975	1980	1985
Total	579	715	873	1,002
Coal	322	415	525	654
% of total	56	58	60	65
Oil	81	114	167	181
% of total	14	16	19	18
Gas	176	186	181	167
% of total	30	26	21	17
	Conventional Stearn by BTU (10^{12}) Share			
Total	13,895	17,160	20,950	24,044
Coal	7,728	9,960	12,600	15,696
Oil	1,943	2,736	4,006	4,344
Gas	4,224	4,464	4,344	4,004

* Gas and oil used in gas turbines and internal combustion generators not included.

TABLE E-13

CONVENTIONAL STEAM-ELECTRIC CAPACITY--
COAL, OIL AND GAS*
(MW)

	Coal	Oil	Gas	Total
1965	124,000	16,000	48,000	188,000
1970	145,000	36,000	78,000	259,000
1975	205,000	56,000	92,000	353,000
1980	247,100	78,000	87,000	412,100
1985	354,000	98,000	94,740	546,740

* Estimates for each fuel projected on the basis of market shares.

Table E-14 is the first in a series of summary tables illustrating coal demand by electric utilities. This table specifically shows bituminous coal distribution in conventional units by Census Divisions.

Table E-IS shows bituminous coal usage by Census Divisions in BTU's, and Table E-16 illustrates electric utility coal consumption in BTU's by PAD districts. Table E-17 projects coal demand in BTU's by PAD districts for the balance of the domestic markets utilizing coal.

TABLE E-14

BITUMINOUS COAL DISTRIBUTION BY CENSUS DIVISIONS--ELECTRIC UTILITIES
(Thousand Tons)

	1970	1975	1980	1985
New England	3,000	2,000	1,000	
Mid-Atlantic	43,000	48,000	52,000	55,000
East North Central	121,100	151,300	181,200	216,000
West North Central	28,300	37,000	50,600	69,000
South Atlantic	63,700	84,300	107,500	137,000
East South Central	48,200	64,000	82,100	106,000
West South Central				
Mountain	14,520	28,000	50,000	70,000
Pacific and Alabama	200	400	600	1,000
Total	322,000	415,000	525,000	654,000

TABLE E-15

BITUMINOUS COAL USAGE BY CENSUS DIVISIONS--ELECTRIC UTILITIES
(Trillions of BTU's)

	1970	1975	1980	1985
New England	75	50	25	
Mid-Atlantic	1,075	1,200	1,300	1,375
East North Central	2,926	3,685	4,456	5,335
West North Central	684	901	1,244	1,704
South Atlantic	1,538	2,054	2,644	3,384
East South Central	1,165	1,558	2,019	2,618
West South Central				
Mountain	261	504	90b	1,260
Pacific and Alaska	4	8	12	20
Total	7,728	9,960	12,600	15,696

TABLE E-16

BITUMINOUS COAL CONSUMPTION BY PAD DISTRICTS--ELECTRIC UTILITIES
(Trillions of BTU's)

	1970	1975	1980	1985
PAD District I	2,688	3,304	3,969	4,759
PAD District II	4,402	5,641	7,072	8,819
PAD District III	473	700	1,000	1,330
PAD District IV	138	267	477	668
PAD District V	27	48	82	120
Total	7,728	9,960	12,600	15,696

TABLE E-17

DEMAND BY PAD DISTRICTS
(Trillions of BTU's)

	1970	1975	1980	1985
Residential/Commercial				
PAD District I	52	36	25	15
PAD District II	203	142	102	60
PAD District III	5	4	3	2
PAD District IV	12	8	6	4
PAD District V	8	6	4	3
Total	280	196	140	84
Industrial				
PAD District I	1,740	1,750	1,760	1,775
PAD District II	2,160	2,358	2,385	2,332
PAD District III	379	400	420	440
PAD District IV	112	120	135	155
PAD District V	72	80	105	130
Total	4,463	4,708	4,805	4,832
Raw Materials				
PAD District I	265	304	317	322
PAD District II	233	275	300	322
PAD District III	63	74	80	85
PAD District IV	17	21	24	27
PAD District V	13	16	18	20
Total	591	690	739	776

APPENDIX F

COKING COAL REQUIREMENTS

A summary of domestic, world and U.S. export coking coal requirements is illustrated in Table F-l.

TABLE F-1

DOMESTIC, WORLD AND U.S. EXPORT COKING COAL REQUIREMENTS--1970-2000 (Millions of Tons)

	Domestic Requirement	World Requirement	U.S. Export Requirement*
1970	86	440	56
1975	102	560	80
1980	110	650	130
1985	116	750	150
1990	124	850	170
1995	132	940	188
2000	140	1,040	208

*This projection was later reduced by the Coal Task Group. See section entitled, "U.S. Export Requirements."

DOMESTIC REQUIREMENTS

Domestic coking coal requirements were initially developed through the years 1985 and 2000 by projecting steel requirements for those years and then determining the coke required under present steelmaking practices.

Domestic steel shipments in 1985 and 2000 were estimated to reach 127 and 175 million tons, respectively. This projection was based on a 2.5-percent growth rate from 1970 to 1980 and a 2.0-percent growth rate from 1980 to 2000. Based on a current raw steel to shipment yield of 68.5 percent, the raw steel requirements for 1985 would be 185 million tons and 255 million tons for the year 2000. With blast furnace production in the last 10 years averaging 68 percent of raw steel production, the hot metal requirement for 1985 was computed at 125 million tons and 173 million tons for 2000. Presently, 0.7 tons of coke are consumed for every ton of hot metal produced, resulting in 86 and 121 million tons of coke required in 1985 and 2000, respectively. Currently, the coal to coke ratio is 1.44. The coking coal requirements, then, under today's steelmaking practices, amount to 134 million tons in 1985 and 184 million tons in 2000. The above analysis is summarized in the following tabulation:

	1985	2000
Total Shipments (Million Tons)	127	175
Shipment/Raw Steel Yield	0.685	0.685
Raw Steel (Million Tons)	185	255
Hot Metal/Raw Steel	0.677	0.677
Hot Metal	125	173
Coke/Hot Metal	0.7	0.7
Coke	86	121
Coal/Coke	1.44	1.44
Coal	134	184

Using the development shown in the above tabulation as a method for arriving at coking coal requirements from projected shipments, the implication of future trends, which may affect the conversion factors used, were also considered. Each conversion factor used was investigated in regard to its possible changes in future years.

Raw Steel to Shipment Yield

As continuous casters become widely accepted, the amount of raw steel required for a given amount of finished steel will decrease. The yield from raw steel to finished steel (shipments) is increased using continuously cast semi-finished instead of ingot semi-finished. The present 68.5-percent yield is increased to 80.6 percent with continuous casting. Overall industry yield could increase to 75 percent by 1985 and 80 percent by 2000, which would decrease the amount of hot metal and consequently the coke required. The raw steel required with these projected higher yields would be lowered to 170 million tons in 1985 and 219 million tons in 2000.

Proportion of Hot Metal to Raw Steel

To project the ratio of blast furnace to raw steel production in 1985 and 2000, the methods which will be in use for steel production must be considered. While the proportion of Basic Oxygen Process (BOP) and electric production has increased and the open hearth proportion has decreased, the ratio of blast furnace production to raw steel production has remained relatively constant in the last 10 years. This can be explained as follows: Even though the hot metal requirements are greater and increasing for BOP, the combination of decreasing open hearth requirements and increasing electric furnace production which uses no hot metal have had an offsetting effect and kept the ratio constant. However, as the open hearth is phased out, the ratio should change. A projection based upon the open hearth decline since 1964 indicates that they should be completely phased out or, at best, be of relatively little importance by 1985. This implies that blast furnace production would be consumed primarily by BOP shops.

To project the proportions of BOP and electric steel in 1985 and 2000, numerous factors must be considered. Recent developments in furnace technology could theoretically put it on the threshold of a great expansion. Such a projection, however, would have to determine if the supplies of scrap, metallized pellets and electricity are adequate to support the growth. To determine the potential growth of metallized pellets, consideration must be given to the limitations of the natural gas supply which is presently used in the reducing process. Direct reduction could also become reality. Without considering all variables involved, since each one such as those listed above involve a study in themselves, an assumption was made to obtain the split between BOP and electric furnace shops. A straight line projection of their growth since 1964 was used to determine the proportion in 1985 and 2000.

From Figure F-l, the electric furnace proportion is estimated at 20 percent in 1985 and 25 percent in 2000. The balance of the steel is assumed to be BOP. The upper limit on the percentage of hot metal to BOP steel is 80 percent. Although scrap charges vary depending on the shop, temperature restrictions presently require a 20-percent minimum scrap charge. Assuming the electric/BOP split, BOP production in 1985 and 2000 was estimated at 136 and 164 million tons, respectively. At a maximum 80-percent hot metal charge, blast furnace production should reach 109 and 131 million tons.

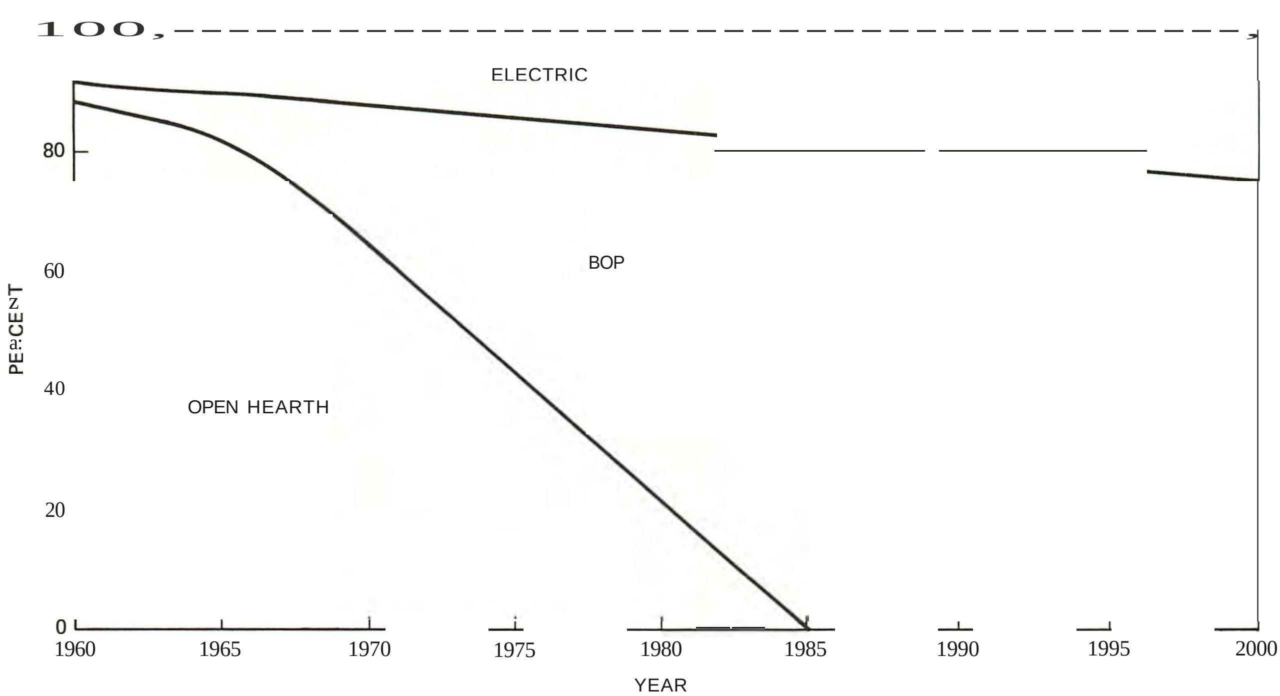

Figure F-l. Steel Production by Type of Furnace.

Coke to Hot Metal

The demand for coke must take into account any foreseeable technical developments in melting practice and the possibilities of exploiting other forms of energy for melting which could affect the demand for coke. Hot blast and oxygen enrichment as well as fuel oil and natural gas injection into the furnace are being tried but have not entirely been justified in terms of coke rate reduction. Up until now, no proved furnace has been developed which can take advantage of the lower cost heat unit of fuels such as coal tar, pulverized coal or natural gas in comparison with coke. There is no technical development in blast furnace melting practice for the foreseeable future which is likely to sharply affect the present coke to hot metal ratio. Therefore, projecting the trend of the last 5 years, the coke consumption per ton of hot metal should be 0.58 in 1985 and 0.54 in 2000. Total coke requirements, then, for the respective years are 63 and 71 million tons.

Coal/Coke Ratio

This ratio is not expected to vary from the present level of 1.44 due to the natural chemistry of coal. This subsequent analysis with the revised conversion factors is summarized in the following tabulation:

	1985	2000
Shipments (Million Tons)	127	175
Shipment/Raw Steel Yield	0.75	0.80
Raw Steel (Million Tons)	170	219
BOP/Raw Steel	0.80	0.75
BOP	136	164
Hot Metal/BOP (Maximum)	0.80	0.80
Hot Metal	109	131
Coke/Hot Metal	0.58	0.54
Coke	63	71
Coal/Coke	1.44	1.44
Coal	91	102

In summary, the domestic coking coal requirements for 1985 and 2000 are 134 and 184 million tons, respectively, based on the present state of the art of steelmaking. However, when the trends of this industry over the last 10 years (see Table F-2) are projected to 1985 and 2000 at the same increasing or decreasing increment each year, the coking coal requirements decrease to 91 and 102 million tons, respectively.

Combining the above requirements which assumed both present practices and future technological developments in steelmaking, a final set of requirements categorized as probable actual was calculated to represent future domestic demand for coking coal. A

TABLE F-2

TRENDS OF THE U.S. STEEL INDUSTRY--1960-1969*

	Blast Furnace Production	Open Hearth	BOP	Electric	Total Raw Steel Production	Ratio: Blast Furnace/ Raw Steel	Ratio: Coal/Coke
1960	67,320	86,368	3,346	8,379	99,282	0.678	
1961	65,295	84,502	3,967	8,664	98,014	0.666	
1962	66,291	82,957	5,553	9,013	98,328	0.674	
1963	72,375	88,834	8,544	10,920	109,261	0.662	1.41
1964	86,212	98,098	15,442	12,678	127,076	0.678	1.43
1965	88,859	94,193	22,879	13,804	131,462	0.676	1.43
1966	92,150	85,025	33,928	14,870	134,101	0.687	1.43
1967	87,647	70,069	41,434	15,089	127,213	0.689	1.43
1968	89,333	65,836	48,812	16,814	131,462	0.679	1.42
1969	95,480	60,894	60,236	20,132	141,262	0.676	1.44

* Annual Statistical Report of AISI, 1969.

tabulation of these calculated requirements is shown by 5-year increments in Table F-3.

Table F-3 indicates that probable actual coking coal requirements will closely parallel present practice requirements through 1975 and then fall between the limits established by projections of present practice and reduced consumption made possible through future technological developments. These projected requirements are further illustrated in Figure F-2.

WORLD REQUIREMENTS

Future world coking coal requirements were derived using the same basic assumptions utilized to develop domestic requirements.

TABLE F-3

DOMESTIC COKING COAL REQUIREMENTS--1970-2000
(Millions of Tons)

	With Present Practices	With Future Technological Devel.	Probable Actual
1970	86	86	86
1975	102	88	102
1980	118	89	110
1985	134	91	116
1990	151	94	124
1995	167	97	132
2000	184	102	140

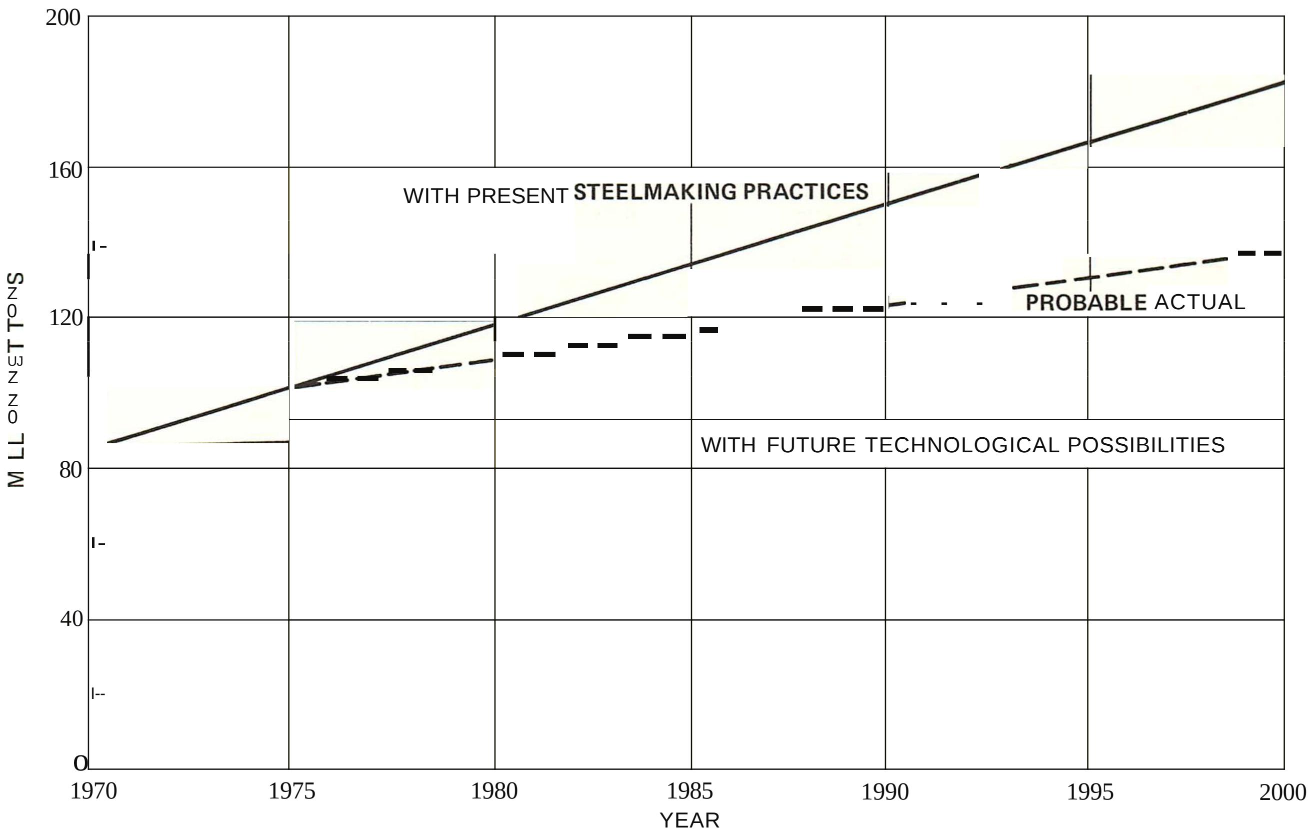

Figure F-2. Domestic Coking Coal Requirements--1970-2000.

Starting with estimated world raw steel production of 650 million tons in 1970 and 1 billion tons in 1980, a 3.0-percent growth rate was used from 1980 to 2000. Present and future world steelmaking practices were assumed to be consistent with those in the domestic industry, and the possibility of technological advances were also recognized. World coking coal requirements considering present melting practices and future technological possibilities were computed to be 790 million tons and 620 million tons in 1985 and 1,230 million tons and 840 million tons in 2000, respectively. These calculations are summarized below.

	World Coking Coal Requirements Assuming Present Steelmaking Practices	
	1985	2000
Raw Steel (Million Tons)	1,160	1,800
Hot Metal/Raw Steel	0.677	0.677
Hot Metal	785	1,219
Coke/Hot Metal	0.7	0.7
Coke	550	853
Coal/coke	1.44	1.44
Coal (Million Tons)	790	1,230

	World Coking Coal Requirements Assuming Possible Future Technological Developments	
	1985	2000
Raw Steel (Million Tons)	1,160	1,800
BOP/Raw Steel	0.8	0.75
BOP	928	1,350
Hot Metal/BOP	0.80	0.80
Hot Metal	742	1,080
Coke/Hot Metal	0.58	0.54
Coke	431	583
Coal/Coke	1.44	1.44
Coal (Million Tons)	620	840

Probable actual world requirements were also developed utilizing the same procedure conducted in the domestic analysis. A summary of the world coking coal requirements is shown in Table F-4 and graphically illustrated in Figure F-3.

It should be noted that the probable actual world requirements follow a pattern identical to the corresponding domestic figures--closely paralleling present practice requirements through 1975, then falling between the present practice and technological developments.

U.S. EXPORT REQUIREMENTS

In 1970, U.S. coking coal exports supplied approximately 12.7 percent of world requirements. However, it is anticipated that the U.S. contribution to the world market will increase in future years. Therefore, U.S. coking coal exports were projected to

TABLE F-4

WORLD COKING COAL REQUIREMENTS--1970-2000
(Millions of Tons)

	With Present Practices	With Future Technological Devel.	Probable Actual
1970	440	440	440
1975	560	500	560
1980	680	560	650
1985	790	620	750
1990	940	690	850
1995	1,120	760	940
2000	1,230	840	1,040

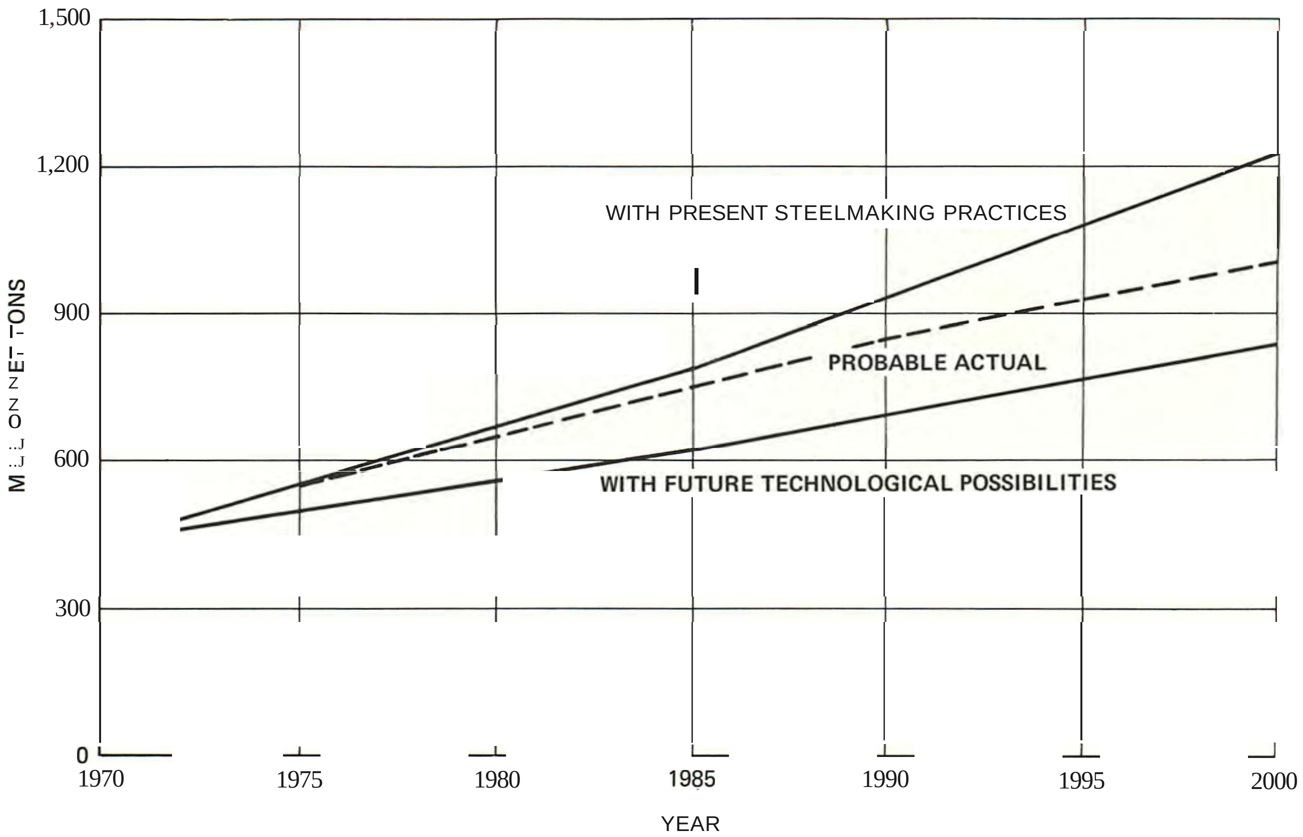

Figure F-3. World Coking Coal Requirements--1970-2000.

increase to 20 percent of world requirements by 1980 and to retain that share of the market through the year 2000.* Projected U.S. exports in relation to future world requirements are shown in Table F-5.

* This projection implies a rather vigorous growth rate in U.S. coking coal exports--nearly 7 percent per annum between 1970 and 1985. Due to growing foreign competition, the Coal Task Group was somewhat skeptical as to the industry's ability to sustain this suggested growth. Therefore, the export figures shown in Tables F-1 and F-5 were reduced to reflect a growth which would reach 120 million tons in 1985. No attempt was made by the task group to revise the post-1985 projections.

TABLE F-5

U.S. CONTRIBUTION TO WORLD COKING COAL MARKET

	World Requirements (Millions of Tons)	U.S. Export Requirements (Millions of Tons)	U.S. Share of World Market (in Percent)
1970	440	56	12.7
1975	560	80	14.3
1980	650	130	20.0
1985	750	150	20.0
1990	850	170	20.0
1995	940	188	20.0
2000	1,040	208	20.0

APPENDIX G

COAL RESERVES OF THE UNITED STATES

The estimated measured and indicated coal reserves of the United States in beds more than 28 inches thick and under less than 1,000 feet of overburden as of January 1, 1970, totaled approximately 394,106 million short tons. This total consisted of 261,510 million tons of bituminous coal (67 percent), 119,861 million tons of subbituminous and lignite (30 percent), and 12,735 million tons of semi-anthracite and anthracite (3 percent).

Coal reserves generally reported by USGS are divided into three categories according to the relative abundance and reliability of data used in preparing the estimates. These classes are termed "measured," "indicated" and "inferred." In this compilation, *inferred reserves are not included*, and the following data relate only to measured and indicated reserves. Measured reserves are those for which tonnage is computed and dimensions revealed in outcrops, trenches, mine workings and drill holes. The points of observation and measurement are so closely spaced and the thickness and extent of coal are so well defined that the tonnage is judged to be accurate within 20 percent of true tonnage. Although the spacing of the points of observation necessary to demonstrate continuity of the coal differs from region to region according to the character of the coal beds, the points of observation are, in general, about 0.5 mile apart.

Indicated resources are those for which tonnage is computed partly from specific measurements and partly from projection of visible data for a reasonable distance on the basis of geologic evidence. In general, the points of observation are about 1.0 mile apart, but they may be as much as 1.5 miles apart for beds of known continuity.

The sizing categories selected to classify the bed thickness of the reserves in this estimate are limited to those that conform closely to present mining practices. Specifically, for higher rank coals (bituminous, semi-anthracite and anthracite), reserves are classified into two bed thicknesses, namely 28 to 42 inches and more than 42 inches. For lower rank coals (subbituminous and lignite), bed thicknesses are limited to 5 to 10 feet thick and more than 10 feet thick.

Table G-l shows a tabulation by states of the measured and indicated coal reserve in beds 28 inches and more in thickness under a maximum overburden thickness of 1,000 feet. Comparison is made of these specific conditions with coal resources in the ground having a bed thickness of 14 inches or more and under a maximum overburden thickness of 3,000 feet.

Tables G-2, G-3 and G-4 show by individual states the estimated remaining measured and indicated reserves as of January 1,

TABLE G-1

TOTAL ESTIMATED REMAINING MEASURED AND INDICATED COAL RESERVES OF THE UNITED STATES AS OF JANUARY I, 1970*
(In Beds 28 Inches and More Thick, for Bituminous, Anthracite and Semi-Anthracite, and 5 Feet
or More Thick for Subbituminous and Lignite Beds--Mi11ion Tons)

State	Remaining" Measured and Indicated Reserves					Tota1--A11 Ranks	
	Bituminous	Subbituminous	Lignite	Anthracite Semi-Anthracite	Total	More than 14" and 3,000' Overburden	Measured & Indicated as Percent of Total
Alabama	1,731	a	t	a	1,731	13,444	12.9
Alaska	667	5,345	‡	§	6,012	130,087	4.6
Arkansas	313	a	t	67	380	2,420	15.7
Colorado	8,811	4,453	a	16	13,280	80,679	16.5
Georgia	18	a	a	0	18	18	100.0
Illinois	60,007	a	a	a	60,007	139,372	43.1
Indiana	11,177	a	0	a	11,177	34,661	32.2
Iowa	2,159	a	a	a	2,159	6,513	33.1
Kansas	328	0	a	a	328	18,678	1.8
Kentucky West	20,876	a	0	a	20,876	36,482	57.2
Kentucky East	11,049	a	a	a	11,049	28,850	38.3
Maryland	557	a	a	a	557	1,168	47.7
Michigan	125	a	a	a	125	220	56.8
Missouri	12,623	a	a	a	12,623	23,339	54.1
Montana	862	31,228	6,878	a	38,968	221,698	17.6
New Mexico	1,339	779	a	2	2,120	61,455	3·4
North Carolina	"	a	a	a	t	110	0.0
North Dakota	a	a	36,230	a	36,230	350,649	10.3
Ohio	17,242	a	a	0	17,242	41,568	41.5
Oklahoma	1,583	0	a	0	1,583	3,195	49.5
Oregon	**	**	0	0	**	332	0.0
Pennsylvania	24,078	a	a	12,525	36,603	69,686	52.5
South Dakota	a	a	757	a	757	2,031	37.3
Tennessee	939	a	0	a	939	2,606	36.0
Texas	**	a	6,870	a	6,870	12,918	53.2
Utah	9,155	150	0	0	9,305	32,070	29.0
Virginia	3,561	0	0	125	3,686	9,817	37.3
Washington	312	1,188	0	0	1,500	6,183	24.3
West Virginia	68,023	0	0	a	68,023	101,186	67.3
Wyoming	3,975	25,937	‡	0	29,912	120,684	24.8
Other States	**	**	46	0	46	4,721	1.0
Total	261,510	69,080	50,781	12,735	394,106	1,556,840	25.3

*** Figures are reserves in ground, about half of which may be considered recoverable. Includes all beds under less than 1,000 feet of overburden and over 28 inches in bed thickness for bituminous and anthracite and 5 feet or more for subbituminous and lignite.**

t Small reserves of lignite in beds less than 5 feet thick.

‡ Small reserves of lignite included with subbituminous reserved.

§ Small reserves of anthracite in the Bering River Field believed to be too badly crushed and folded to be **economically recoverable.**

" Negligible reserves with overburden less than 1,000 feet.

**** Data not available to make estimate.**

TABLE G-2

SUMMARY OF ESTIMATED ORIGINAL OR REMAINING RESERVES OF BITUMINOUS COAL OF THE UNITED STATES ACCORDING TO THICKNESS OF BEDS AND UNDER LESS THAN 1,000 FEET OF OVERBURDEN*
(Million tons)

State	Type of Estimate†	Estimated Original or Remaining Resources	Resources Depleted to 1-1-70: Production‡	Resources Depleted to 1-1-70: Production Plus Loss in Mining§	Remaining Resources 1-1-70	Remaining Reserves in Measured and Indicated Categories Under Maximum Overburden Thickness of 1,000 Feet According to Bed Thickness: 28"-42"	Over 42"	Total Over 28"
Alabama	R-1958	13,754	165	330	13,424	1,035	696	1,731
Alaska	Orig.	19,429	7	14	19,415	238	429	667
Arkansas	Orig.	1,816	81	162	1,654	153	160	313
Colorado	Orig.	63,203	417	834	62,369	1,435	7,376	8,811
Georgia	R-1945	24	3	6	18	18		18
Illinois	R-1965	140,000	314	628	139,372	8,667	51,340	60,007
Indiana	Orig.	37,293	1,316	2,632	34,661	2,576	8,601	11,177
Iowa	Orig.	7,237	362	724	6,513	1,037	1,122	2,159
Kansas	R-1957	18,706	14	28	18,678	Neg.	328	328
Kentucky West	Orig.	38,878	1,198	2,396	36,482	445	20,431	20,876
Kentucky East	Orig.	33,440	2,295	4,590	28,850	7,395	3,654	11,049
Maryland	R-1950	1,200	16	32	1,168	369	188	557
Michigan	Orig.	297	46	92	205	110	15	125
Missouri	Orig.	23,977	319	638	23,339	9,448	3,175	12,623
Montana	Orig.	2,363	88	176	2,187	192	670	862
New Mexico	Orig.	10,948	94	188	10,760	486	853	1,339
North Carolina	Orig.	112	1	2	110	‖		‖
Ohio	Orig.	46,488	2,460	4,920	41,568	14,202	3,040	17,242
Oklahoma	Orig.	3,673	188	376	3,297	800	783	1,583
Oregon	Orig.	50	1	2	48	**	**	**
Pennsylvania	Orig.	75,093	8,966	17,932	57,161	9,382	14,696	24,073
Tennessee	R-1959	2,748	71	142	2,606	713	226	939
Texas	Orig.	6,100	26	52	6,048	††	††	††
Utah	Orig.	32,522	301	602	31,920	4,878	4,277	9,155
Virginia	Orig.	11,696	1,111	2,222	9,474	2,489	1,072	3,561
Washington	R-1960	1,869	1	2	1,867	62	250	312
West Virginia	Orig.	116,618	7,716	15,432	101,186	20,036	47,987	68,023
Wyoming	Orig.	13,235	275	550	12,685	831	3,144	3,975
Other States‡‡		620	1	2	618	**	**	**
Total		723,389	27,853	55,706	667,683	86,997	174,513	261,510

* USGS Bulletins 1136 and 1275, with adjustments for production and losses in mining through 1969.

† R--remaining resources in ground as of January 1 of the year indicated; original resources in the ground before the advent of mining.

‡ Production from year of earliest record or from year that remaining resources were estimated through 1969.

§ Past losses assumed to equal production.

‖ Negligible reserves with overburden less than 1,000 feet.

** Data not available to make estimates.

†† Negligible reserves in measured and indicated categories.

‡‡ Arizona, California, Idaho, Nebraska and Nevada.

TABLE G-3

SUMMARY OF ESTIMATED ORIGINAL OR REMAINING RESERVES OF SUBBITUMINOUS COAL AND LIGNITE OF THE UNITED STATES ACCORDING TO THICKNESS OF BEDS AND WITH LESS THAN 1,000 FEET OF OVERBURDEN*
(Million Tons)

	Type of Estimatet	Estimated Original or Remaining Resources	Resources Depleted to 1-1-70: Productiont	Resources Depleted to 1-1-70: Production Plus Loss in Mining§	Remaining Resources 1-1-70	Remaining Reserves in Measured and Indicated Categories Under Maximum Overburden Thickness of 1,000 Feet According to Bed Thickness: 5'-10'	Over 10'	Total Over 5'
Subbituminous								
Alaska	Orig.	110,696	12	24	110,672	757	4,588	5,345
Colorado	Orig.	18,492	130	260	18,232	2,346	2,107	4,433
Montana	Orig.	132,151	82	164	131,987	11,615	19,613	31,228
New Mexico	Orig.	50,801	55	110	50,691	576	203	779
Oregon	Orig.	290	3	6	284	"	"	
Utah	Orig.	156	3	6	150	0	150	150
Washington	R-1960	4,194	Neg.	Neg.	4,194	822	366	1,188
Wyoming	Orig.	108,319	160	320	107,999	9,222	16,715	25,937
Other States	Orig.	4,065	4	8	4,057		"	"
Total		429,164	449	898	428,266	25,338	43,742	69,080
Lignite								
Alabama	Orig.	20	0	0	20	0	0	0
Alaska	Orig.	**	0	0	**	0	0	**
Arkansas	Orig.	350	0	0	350	0	0	0
Kansas	Orig.	tt	0	0	tt	0	0	tt
Montana	Orig.	87,533	3	6	87,527	4,960	1,918	6,878
North Dakota	Orig.	350,910	130	260	350,650	22,591	13,639	36,230
Oklahoma	Orig.	tt	0	0	tt	0	0	tt
South Dakota	Orig.	2,033	1	2	2,031	705	52	757
Texas	Orig.	7,070	100	200	6,870	6,870	0	6,870
Washington	R-1960	117	0	0	117	0	0	0
Wyoming	Orig.	**	0	0	**	0	0	**
Other States	Orig.	50	2	4	46	46	0	46
Total		448,083	236	472	447,611	35,172	15,609	50,781
Grand Total		877,247	685	1,370	875,877	60,510	59,351	119,861

* USGS Bulletins 1136 and 1275, with adjustments for production and losses in mining through 1969.

t R--remaining resources in the ground as of January 1 of the year indicated; original resources in the ground before the advent of mining.

‡ Production from years earliest record or from year that remaining reserves were estimated through 1969.

Past losses assumed to equal production.

" Classification of reserve data not available.

** Small resources and production of lignite included under subbituminous coal.

tt Small resources of lignite in beds generally less than 30 inches thick.

TABLE G-4

SUMMARY OF ESTIMATED ORIGINAL OR REMAINING RESERVES OF ANTHRACITE AND SEMI-ANTHRACITE COAL RESERVES OF THE UNITED STATES ACCORDING TO THICKNESS OF BEDS AND WITH LESS THAN 1,000 FEET OF OVERBURDEN*
(Million Tons)

State	Type of Estimatet	Estimated Original or Remaining Resources	Productionf	Production Plus Loss in Mining§	Remaining Resources 1-1-70	Remaining Reserves in Measured and Indicated Categories Under Maximum Overburden Thickness of 1,000 Feet According to Bed Thickness: 28"-42"	Over 42"	Total
Alaska	-	‖	0	0	0	0	0	0
Arkansas	Orig.	456	20	40	416	54	13	67
Colorado	Orig.	90	6	12	78	6	10	16
New Mexico	Orig.	6	1	2	4	1	1	2
Pennsylvania	Orig.	22,805	5,140**	10,280	12,525	tt	tt	12,525
Virginia	Orig.	355	6	12	343	11	114	125
Washington	R-1960	5	Neg.	Neg.	5	‡‡	‡‡	‡‡
Total		23,717	5,173	10,346	13,371	72	138	12,735

* USGS Bulletins 1136 and 1275, with adjustments for production and losses in mining through 1969.

t R--remaining reserves in the ground as of January 1 of the year indicated; original resources in the ground before the advent of mining.

‡ Production from year of earliest record or from year that remaining reserves were estimated through 1969.

Past losses assumed to equal production.

‖ Small resources of anthracite in the Bearing River Field believed to be too badly crushed and faulted to be economically recoverable.

** Excludes anthracite recovered from culm banks and dredging.

tt Classification of reserves according to bed thickness is not available.

‡‡ Small reserves are in the inferred category.

1970, in various bed thicknesses with maximum overburden of less than 1,000 feet. These data were derived by using the various reports listed in USGS Bulletins 1136 and 1275 and various Bureau of Mines reports. All production data were derived from the Bureau of Mines reports. Losses in mining were assumed to have been equal to production, and production plus losses in mining have in all cases been subtracted from measured reserves.

Table G-5, which is a compilation of the remaining reserves of medium and low volatile bituminous coals, has been prepared to give some indication of the reserves of these coals which are used largely for special purposes (coking) in the United States and abroad and may not be available for heat and power generation use. As shown in Table G-5, these special purpose coals represent less than one-fifth of the measured and indicated reserves of bituminous coal in those states where they are found.

Tables G-6 and G-7 contain statistics on strippable coal reserves in the United States obtained from a study conducted by the Bureau of Mines in 1970. These tables show the minimum coal bed

TABLE G-5

SUMMARY OF MEASURED AND INDICATED RESERVES OF MEDIUM AND LOW VOLATILE BITUMINOUS COAL IN THE UNITED STATES ACCORDING TO BED THICKNESS AND UNDER LESS THAN 1,000 FEET OVERBURDEN*
(Million Tons)

State	Remaining Reserves According to Thickness of Beds--1-1-70			Total Remaining Reserves--All Grades over 28"	Medium & Low Volatile as % of Total
	28"-42"	Over 42"	Total		
Alabama	420	380	800	1,731	46
Arkansas	153	160	313	313	100
Colorado	0	386	386	8,811	4
Marylandt	200	100	300	557	54
Oklahoma	273	274	547	1,583	35
Pennsylvaniat	2,200	5,200	7,400	24,078	31
Tennesseet	60	160	220	939	24
Virginia	770	330	1,100	3,561	31
Washington	40	80	120	312	38
West Virginiat	2,730	6,370	9,100	68,023	13
Total	6,846	13,440	20,286	109,908	19

* Based on data published in USGS Bulletins 1136 and 1275 and various U.S. Bureau of Mines publications containing data on analysis of bituminous coal in individual states.

t Based in part on data published in U.S. Bureau of Mines Coking Coal Survey Reports (1948-1955--Dowd reports).

TABLE G-6

SUMMARY OF ESTIMATED RESERVES OF STRIPPABLE BITUMINOUS COAL IN THE UNITED STATES*
(Million Short Tons)

Region and State	Remaining Strippable Reserves	Available Strippable Reserves	Minimum Coal Bed Thickness (Inches)	Maximum Overburden Thickness (Feet)	Economic Stripping Ratio (Feet:Feet)
Appalachia					
Alabama	607	134	14	120	24:1
Kentucky--East	4,609	781	28	120	14:1
Maryland	150	21	28	120	15:1
Ohio	5,566	1,033	28	120	15:1
Pennsylvania	2,272	752	28	120	15:1
Tennessee	483	74	28	120	19:1
Virginia	2,741	258	28	120	15:1
West Virginia	11,230	2,118	28	120	15:1
Subtotal	27,658	5,171			
Midwest					
Arkansas	200	149	14	60	30:1
Illinois	18,845	3,247	18	150	18:1
Indiana	2,741	1,096	14	90	20:1
Iowa	1,000	180	28	120	18:1
Kansas	1,388	375	12	120	15:1
Kentucky--West	4,746	977	24	150	18:1
Michigan	6	1	28	100	20:1
Missouri	3,425	1,160	12	120	15:1
Oklahoma	434	111	12	120	15:1
Subtotal	32,785	7,296			
Rocky Mountain & Pacific Coast					
Alaska†	1,201	480	14	120	10:1
Colorado	870	500	60	50 to 120	4:1-10:1
Utah	252	150	60	39 to 150	3:1-8:1
Subtotal	2,323	1,130			
Total‡	62,766	13,597			

* Based on recent Bureau of Mines study of strippable coal reserves of the United States.

† Includes 478 million tons of reserves in Northern Alaska Fields (North Slope) that may not be economically strippable at this time.

‡ Strippable bituminous coal reserves for Idaho, Montana, New Mexico, Texas and Washington were not estimated.

TABLE G-7

SUMMARY OF ESTIMATED RESERVES OF STRIPPABLE SUBBITUMINOUS AND LIGNITE COAL IN THE UNITED STATES*
(Million Short Tons)

Region and State	Remaining Strippable Reserves	Available Strippable Reserves	Minimum Coal Bed Thickness (Inches)	Maximum Overburden Thickness (Feet)	Economic Stripping Ratio (Feet: Feet)
	Subbituminoust				
Rocky Mountain & Pacific Coast					
Alaska	6,190	3,926‡	60	120	12:1
Arizona	400	387	60	130	8:1
California	100	25	60	100	1:1
Montana	7,813	3,400	60	60 to 125	2:1-18:1
New Mexico	3,307	2,474	60	60 to 90	8:1-12:1
Washington	500	135	60	100	10:1
Wyoming	22,028	13,971	60	60 to 200	1.5:1-10:1
Total	40,338	24,318			
	Lignite!				
Southwest					
Arkansas	32	25	60	100	15:1
Texas	3,272	1,309	60	90	15:1
Subtotal	3,304	1,334			
Rocky Mountain & Pacific Coast					
Alaska	8	5	0	0	0
Montana	7,058	3,497	60	60 to 125	2:1-18:1
North Dakota	5,239	2,075	60	50 to 125	3:1-12:1
South Dakota	399	160	60	100	12:1
Subtotal	12,704	5,737			
Total	16,008	7,071			
Total all Ranks	119,112	44,986			

* Based on recent unpublished Bureau of Mines study of strippab1e coal reserves of the United States.

t Subbituminous coal reserves not estimated for Colorado and Oregon; lignite reserves not estimated for Alabama, Kansas, Louisiana and Mississippi.

‡ Includes 179 million tons of undifferentiated subbitumous-1ignite and 3,387 million tons of subbituminous coal reserves in the Northern Alaska Fields (North Slope) that may not be economically strippab1e at this time.

thickness, maximum overburden thickness and economic stripping ratio. The original in-place resource was obtained mainly in two ways:

- In published reports where outcrop maps were available, the length of each minable coal bed outcrop was measured by map meter or the area was measured by planimeter, and an average coal bed thickness was determined for each bed. An average bench width from outcrop to maximum overburden thickness was estimated. These data gave acres of strippable coal which, when multiplied by a tonnage factor, gave total original in-place resource.

- From latest estimates of the U.S. Geological Survey, State Geological Surveys, coal mining companies and railroad companies.

Remaining strippable reserves are total original coal resources reduced by depletion computed from past strip and auger production to date of estimate. Available strippable reserves are the recoverable reserves adjusted to conform to the economic stripping ratios assigned to the various states. Coal that cannot be mined owing to proximity of natural or man-made features is excluded from this estimate.

APPENDIX H

SELECTED COAL INDUSTRY STATISTICS--1960-1969

This Appendix contains a compilation of coal industry statistics covering the years 1960 through 1969 as follows:

- Table H-1 and Figure H-1 show production of bituminous coal by size of mine output and by number of mine in each size range.
- Table H-2 and Figure H-2 show total bituminous coal production and a breakdown for coal produced at deep and surface mines.
- Table H-3 and Figure H-3 show output per man per day by type of mining.
- Table H-4 and Figure H-4 show output per man per year by type of mining.
- Table H-5 and Figure H-5 show average number of days worked per year by type of mining.

TABLE H-l

PRODUCTION OF BITUMINOUS COAL BY SIZE OF MINE OUTPUT*

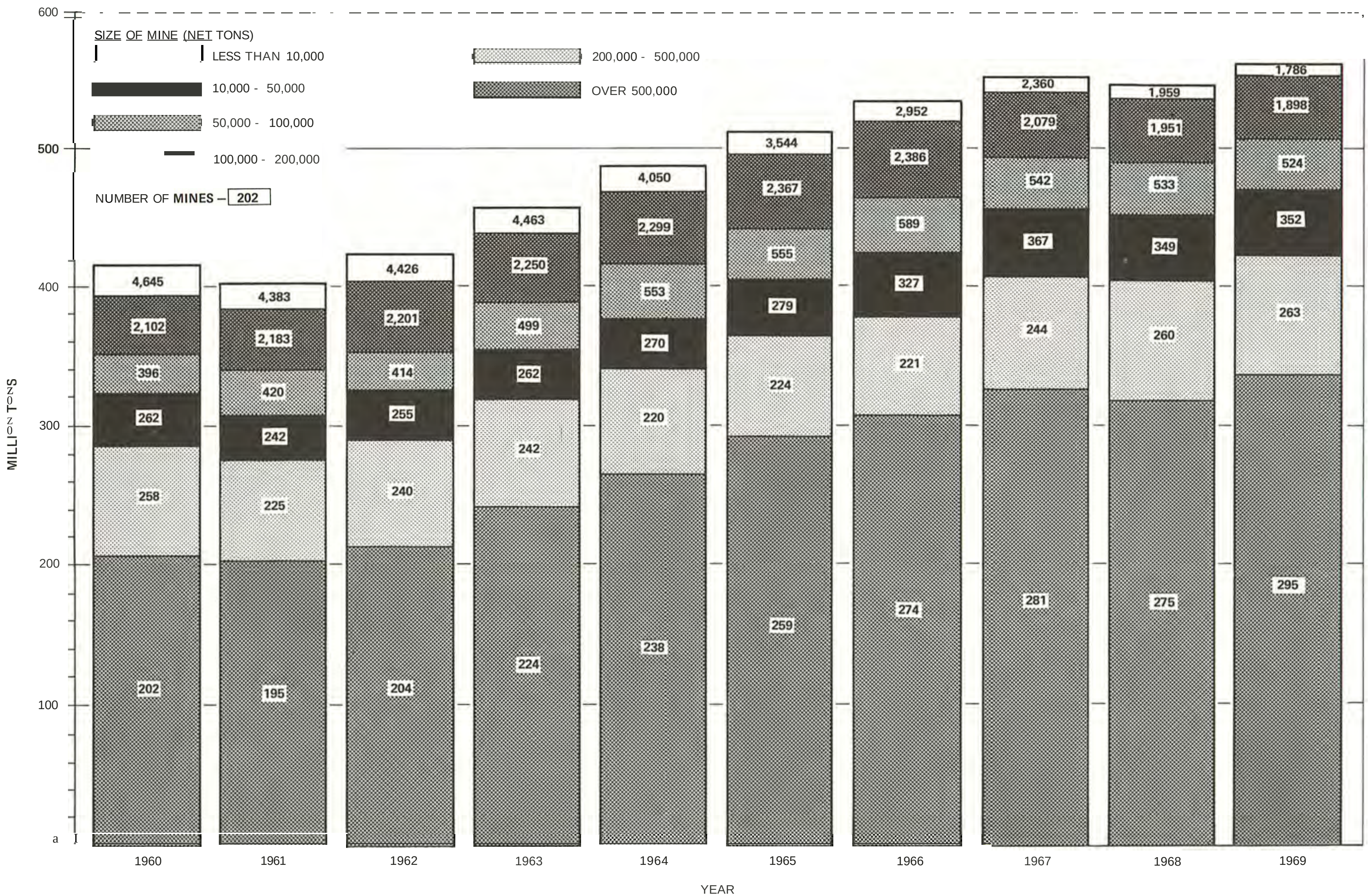

Figure H-l. Production of Bituminous Coal by Size of Mine Output and Number of Mines in Each Class.

TABLE H-2

PRODUCTION OF BITUMINOUS COAL AND LIGNITE--1960-1969*
(Thousand Tons)

	Surfacet	Deep	Total
1960	130,624	284,888	415,512
1961	130,211	272,766	402,977
1962	140,883	281,266	422,149
1963	156,672	302,256	458,928
1964	165,190	321,808	486,998
1965	179,427	332,661	512,088
1966	195,357	338,524	533,881
1967	203,494	349,133	552,626
1968	201,103	344,142	545,245
1969	213,373	347,132	560,505

* U.S. Bureau of Mines, *Minerals Yearbook* (1960-1969).

t Strip mining and auger mining as reported by U.S. Bureau of Mines.

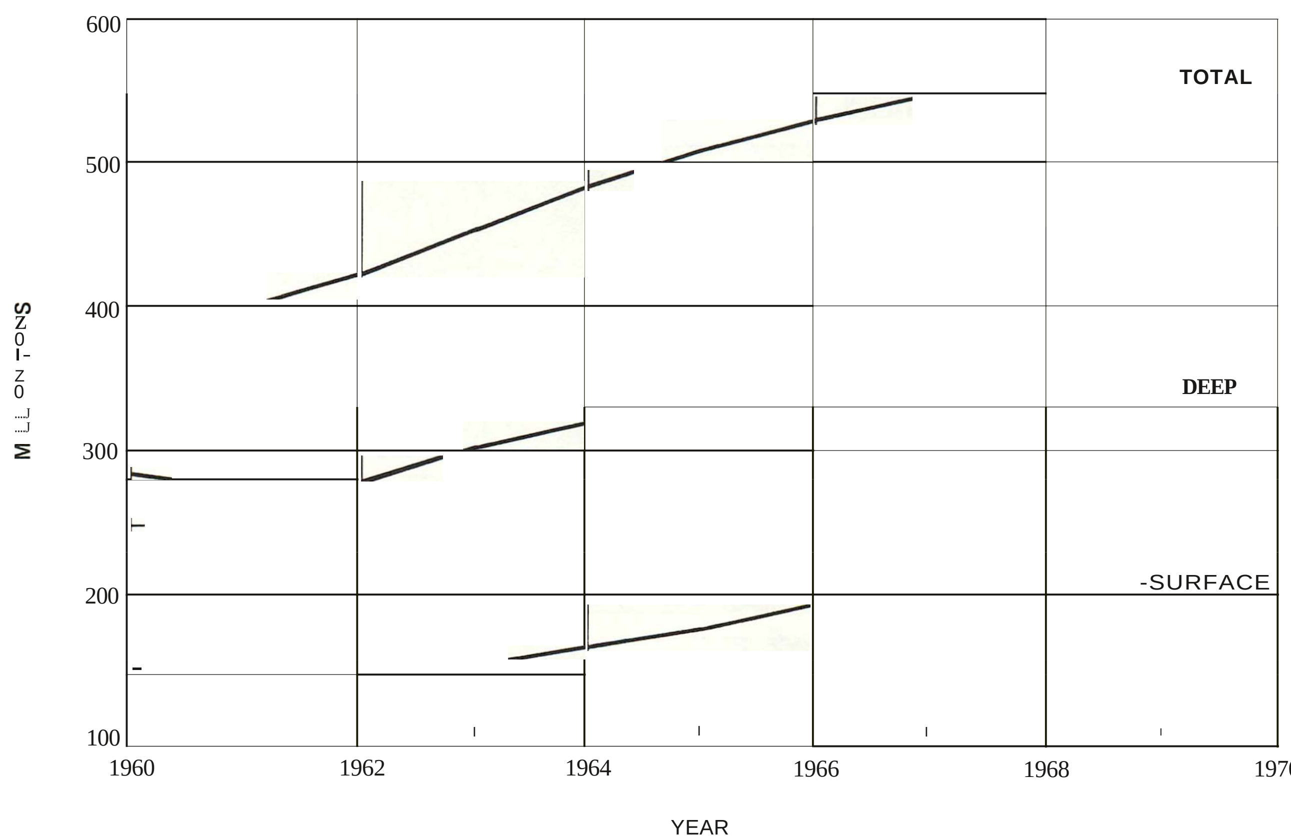

Figure H-2. Production of Bituminous Coal and Lignite.

TABLE H-3

OUTPUT PER MAN PER DAY BY TYPE OF MINING--1960-1969*

	Underground	Strip	Auger	Total
1960	10.64	22.93	31.36	12.83
1961	11.41	25.00	30.61	13.87
1962	11.97	26.76	36.51	14.72
1963	12.78	28.69	38.87	15.83
1964	13.74	29.29	42.63	16.84
1965	14.00	31.98	45.85	17.52
1966	14.64	33.57	44.43	18.52
1967	15.07	35.17	46.48	19.17
1968	15.40	34.24	40.46	19.37
1969	15.61	35.71	39.88	19.90

* U.S. Bureau of Mines, *Minerals Yearbook* (1960-1969), and *Mineral Industry Surveys*, Weekly Coal Report No. 2794 (April 2, 1971).

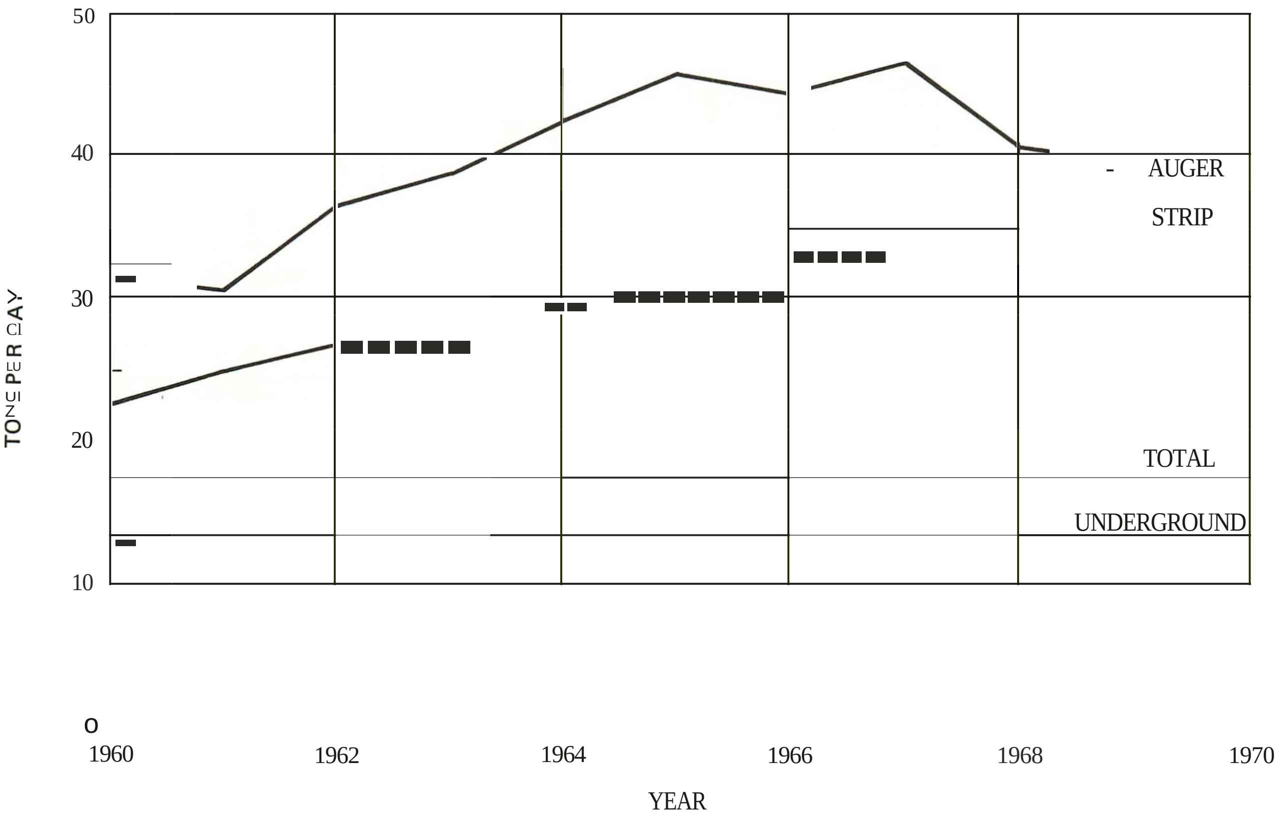

Figure H-3. Output per Man per Day by Type of Mining.

TABLE H-4

OUTPUT PER MAN PER YEAR BY TYPE OF MINING--1960-1969*

	Underground	Strip	Auger	Total
1960	2,005	4,874	3,725	2,453
1961	2,180	5,301	3,551	2,678
1962	2,342	6,152	4,139	2,935
1963	2,592	6,381	5,077	3,240
1964	3,066	7,141	5,410	3,784
1965	3,031	7,605	6,255	3,829
1966	3,146	8,278	6,412	4,052
1967	3,250	8,729	6,169	4,198
1968	3,343	8,312	5,881	4,263
1969	3,497	8,826	5,561	4,501

* U.S. Bureau of Mines, *Minerals Yearbook* (1960-1969), and *Mineral Industry Surveys*, Weekly Coal Report No. 2794 (April 2, 1971).

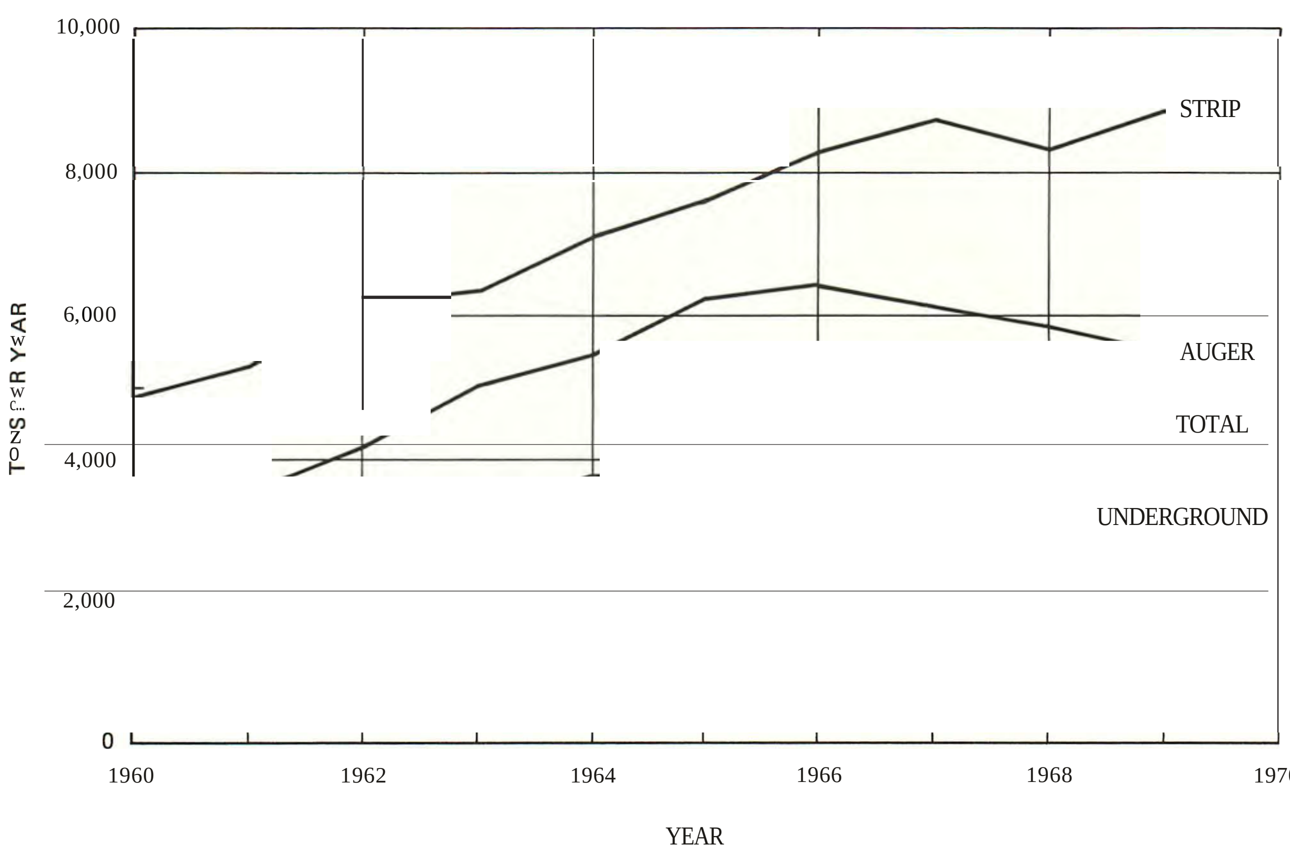

Figure H-4. Output per Man per Year by Type of Mining.

TABLE **H-5**

AVERAGE NUMBER OF DAYS WORKED PER YEAR BY TYPE OF MINING--1960-1969*

	Underground	Strip	Auger	Total
1960	188	213	119	191
1961	191	212	116	193
1962	196	230	120	199
1963	203	222	131	205
1964	223	244	127	225
1965	216	238	136	219
1966	215	247	144	219
1967	216	248	133	219
1968	217	243	145	220
1969	215	243	145	226

* U.S. Bureau of Mines, *Minerals Yearbook* (1960-1969), and *Minerals Industry Surveys,* Weekly Coal Report No. 2794 (April 2, 1971).

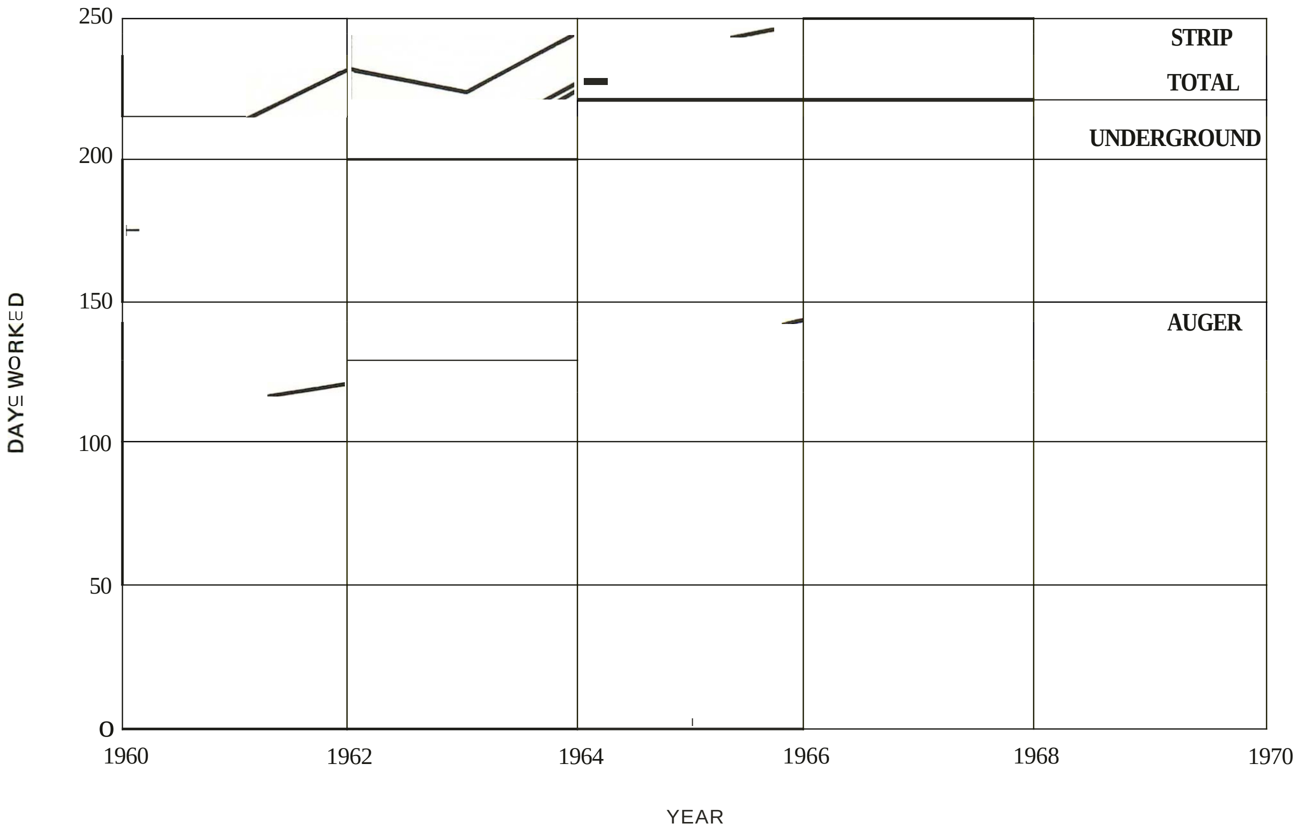

Figure H-S. Average Number of Days Worked per Year by Type of Mining.

AN ECONOMIC MODEL OF THE U.S. COAL INDUSTRY

INTRODUCTION

The costs of supplying the different forms of energy have changed relative to each other with time. These changes have affected the supply and demand for coal. As a result, the production of coal has fluctuated considerably during the past 30 years and will inevitably continue to fluctuate somewhat in the future. As the level of production could vary over a considerable range in response to the overall supply and demand for energy, it is desirable to estimate future changes in those items that affect production costs in order to estimate the long-term cost of supplying coal at various production levels.

Since 1940, total coal production peaked at 687.8 million tons in 1947 and then dipped to a low of 420.4 million tons in 1961.* Following 1961, the long-term trend in coal production reversed itself and increased to a level of 612.7 mil110n tons in 1970.

The drop in annual coal production from 1947 to 1961 was due directly to the decrease in coal demand by the residential/commercial and transportation sectors of the economy. Indirectly, it was due to the increased supply of oil and gas which were becoming a less expensive and more convenient form of fuel.

Conversely, the 1961-1970 increase in coal production was due to both an overall increase in energy demand and an increase in supply of lower cost coal. The increase in demand resulted primarily from the natural growth of the electric utility industry, the steel industry and the export market. The increase in the supply' of lower cost coal resulted from switching from high cost underground mining methods to lower cost surface mining. Finally, gains in the productivity of labor brought about by technological progress helped to maintain the supply of low cost coal during the 1960's.

It is impossible to predict exactly the quantities of coal that will be required in the future to meet the ever increasing demand for energy. The approach used here employed four principal cases to cover a range of reasonable supply projections. As a result, it became necessary to estimate future changes in those items affecting the long-term cost of supplying coal at different levels of production.

The factors affecting the cost of coal mining vary over a wide range from one mining district to the next, between mines in the

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* "Total coal production" refers to anthracite as well as bituminous coal and lignite production.

same district, and even within a given mine. Mining technology, operating conditions, productivity of labor and capital, supply of skilled labor, governmental regulations and the many other pertinent factors tend to change with time. These variables interact with each other in numerous ways. As a result, it is difficult to project the future unit revenues required to support the various levels of exploration, development and production necessary to supply the amounts of coal that are estimated to be required between 1970 and 1985. Consequently, a model was developed that enables us to focus our attention on only the most important aspects of the coal industry.

Only those items which were estimated to have a significant impact on mining costs were used in the model in order to retain a manageable size. Economic laws are not exact, and the interaction between the variables in very complex models tends to give less accurate results even though they may appear more realistic. Moreover, the structure of the model is limited by available data. For example, little data has been published in regard to the capital and cash operating costs of mining coal.

Those variables of which capital and operating costs are a function were determined and were subsequently broken down into four general classes--economic, physical and technological variables as well as certain governmental policies. The historical values for each of the variables used were then collected and analyzed. The information obtained was used to design the model so that it reflected the average operating conditions which existed in the coal industry during the base year--1969.*

Two of the major factors which affect the cost of mining a given coal deposit are the seam thickness and its depth from the surface. These factors therefore determine to a great extent the system used to mine the deposit. A number of methods are used to mine coal under a wide variety of operating conditions--surface, underground and auger mining. Auger mining was not considered in the model because it accounts for less than 4 percent of the total coal pruduction and therefore its effect on supply is only limited. Underground mines produced about 56 percent of the coal in 1970 while surface mines produced over 40 percent. As the cost of producing coal at underground mines is significantly different from the cost of producing coal at surface mines, the two mining methods were considered separately in the coal model. Consequently, two hypothetical coal mines--one surface and one underground mine--were designed as a basis for the economic model.

The economic model was described conceptually in the task group report but is repeated here in Figure I-I for easy reference. The major categories of cost for these hypothetical mines were

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* 1969 was used as the base year for the model as it was the last year for which most of the statistical data used in the study was available. However, the 1970 Bureau of Mines data became available during the course of the study and have been incorporated into the model.

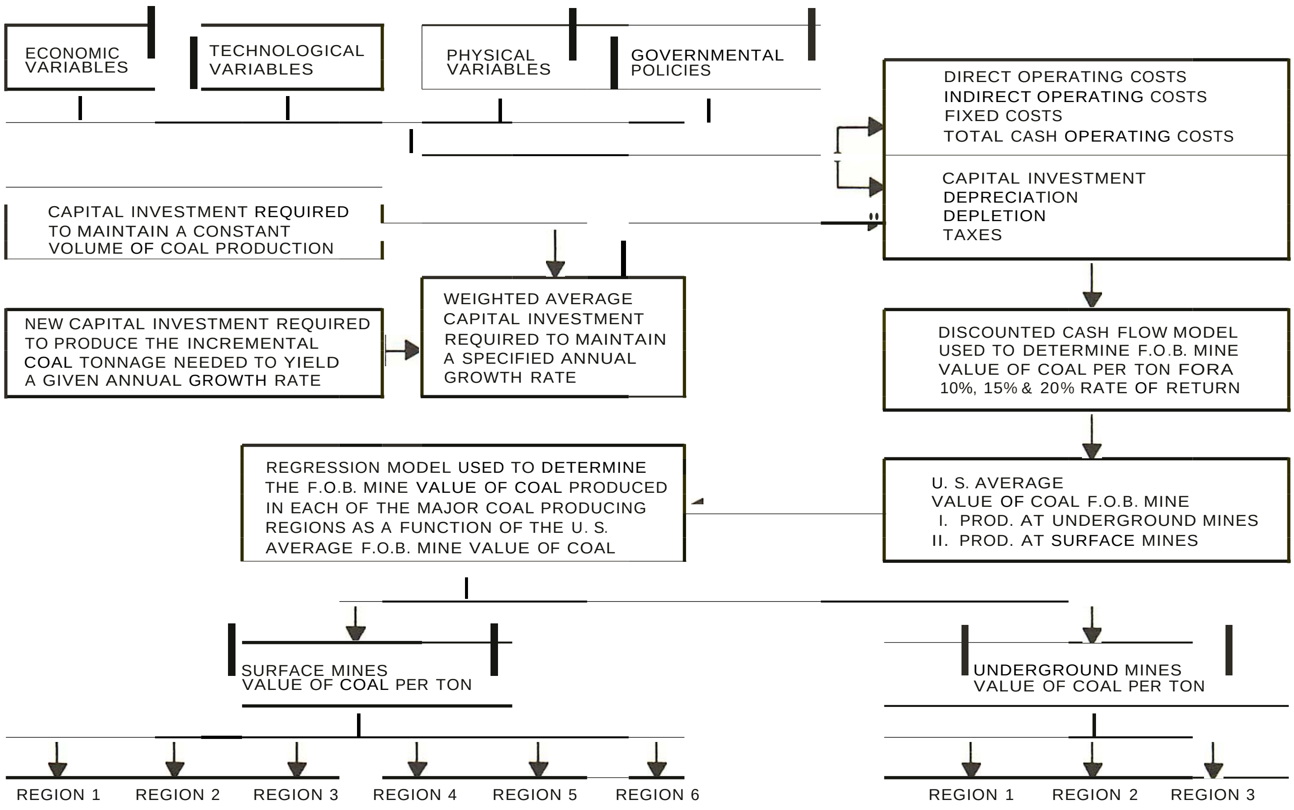

Figure I-I. Method of Analysis--Coal Economic Model.

based on an analysis of historical data which was then projected forward into the 1970-1985 period. This analysis was done on a regional basis for six underground and three surface mining regions for which historical data are available, as well as for the United States as a whole.

Future mining costs were estimated for coal produced both from underground mines and from surface mines. The resulting unit "prices" needed to cover capital and operating costs and to provide specified DCF rates of returns have been calculated.

The unit revenues required to support the production of coal depend upon many factors, e.g., the cost of labor, capital and intermediate inputs (maintenance and operating supplies, power and services acquired from without the industry). They also are a function of the rate at which the coal industry is required to grow in order to meet the increasing need for energy. Unit values also reflect depreciation, depletion and tax policies; the risk involved in finding, developing and marketing the coal; the interchangeability of fuel; and changes in the short-term, intermediate- and long-term supply and demand for coal.

The market value is determined between the producer and the purchaser in the free and competitive market place. There is no way that this model can predict the actual value of coal in the market place. It was not designed to do so, nor was that the purpose of the coal study. Consequently, the average unit values given in this paper cannot meaningfully be used for that purpose. The terms "price" or "value" as used here refer generally to economic levels which would, on the basis of the cases analyzed, support given levels of coal production over the long term.

Over the long term, the average "value" of a commodity in an ongoing, competitive industry will tend to reflect a certain minimum attractive rate of return. This "price" must reflect finding, developing and operating costs, plus the minimum rate of return on investment required to attract the needed capital to the industry. In order to estimate the economic levels which would support the projected levels of production, a range of specified DCF rates of return have been calculated.

The DCF mathematical procedure of calculating rates of return on capital investments is a method of economic analysis particularly useful for analyzing investment projects that are capital-intensive and have long development periods (capital expenditures) prior to receiving any return of cash. This method considers the time value of money and the earning power of each individual investment over its entire life. However, it does not lend itself to analyzing short-term and intermediate changes in supply and demand. The coal model should, therefore, be considered a long-term supply model.

THEORY

Cost Factors

Economic factors that affect the cost of supplying coal include the unit costs of labor, capital and intermediate inputs (operating and maintenance supplies, power and services required from outside the industry). Other economic variables used in the model are the Wholesale and the Consumer Price Index, the effective tax rate, depreciation, depletion, reclamation requirements and proposed environmental regulations.

There are a wide range of physical factors that affect the cost of producing coal. The average seam thickness and depth of overburden are two of the main factors. The ratio between the two is called the strip ratio and is measured in cubic yards of overburden per ton of coal. In areas where coal seams outcrop or are near the surface, coal can be mined from the surface until the maximum limit to the economic strip ratio is reached. This ratio was estimated to be 12.6 in 1970 for the Nation as a whole. This ratio, of course, varies over an extremely wide range. After the surface reserves have been depleted within a given area, one of the underground mining systems must be used if mining is to continue. The fact that mining costs are different for these two systems is evidenced by the fact that in 1970 the actual average price of coal produced at underground mines was $7.40 per ton as compared to $4.69 per ton at surface mines.

Other physical conditions which affect the cost of mining coal are as follows:

- Type of overburden affects the cost of drilling, shooting and removing the overburden at surface mines.
- Amount of methane gas emissions affect underground ventilation costs.
- Average roof conditions affect the cost of roof bolting and other supports.
- The average topography affects the selection of capital equipment at surface mines.

A number of proposed or enacted governmental laws and regulations could or already have affected the cost of mining coal. Some of these are the Coal Mine Health and Safety Act of 1969, the proposed ban on strip mining in certain areas, new reclamation requirements and other proposed environmental standards. Already, scores of underground mines have been closed (671 between 1970 and 1971) because of increased production costs of operating under regulations imposed by the Coal Mine Health and Safety Act of 1969.*

The Coal Mine Health and Safety Act of 1969 sets allowable dust levels, ventilation requirements, noise standards and other requirements deemed necessary to ensure the health and safety of the coal miners. The result has been higher operating costs, lower productivity of labor, higher capital costs and a decrease in underground production. On the other hand, the coal industry is learning to operate within the limits set by the federal standards. Further, the standards should actually reduce some of the mining costs, such as workmen's compensation and public liability insurance. Also, the improved working conditions should produce a more stable work force and, hence, an increase in productivity. Each of these factors had to be considered when estimating the overall affect that the Coal Mine Health and Safety Act of 1969 might have on future production costs.

Gains in productivity brought about by advancements in technology have historically kept the real costs of supplying coal relatively constant. Advancements in technology and their result are illustrated by the increase in the percentage of coal produced by longwall and continuous miner systems of production at underground mines. The result that this change is having on productivity has already been briefly mentioned in the task group report. An even better example is the growth in surface mining. The coal industry is switching to surface mining where possible in order to stay competitive with the other primary forms of energy.

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* U.S. Bureau of Mines, "Coal-Bituminous and Lignite in 1971," *Mineral Industry Surveys* (September 27, 1972), p. S.

Historically, the bulk of the annual coal production has come from underground mines. However, surface mining is becoming the preferred method of production. This is evident from the rapid decline in the number of underground mines--from over 7,000 in 1950 to less than 3,000 in 1970. Underground production decreased from 392.8 million tons to 338.8 million tons during this same period. Surface mining increased to offset the loss in underground production and to provide for the growth in demand.

There are two major factors contributing to the trends towards increased surface production. The first, the Coal Mine Health and Safety Act of 1969 has already been discussed. The second factor which is benefiting surface mining is its increasingly lower cost relative to underground mining. The increasing spread in the average cost of producing coal at underground mines as opposed to surface mines is the major reason for the decrease in productive capacity at underground mines. The relative difference is reflected in the average value per ton, f.o.b. mine, produced during the 1940-1970 period (see Table I-I). Notice, in 1940 there was only a $0.38 spread between a ton of coal produced at underground mines and a ton of coal produced at surface mines. During that same year, surface mining accounted for only some 9 percent of total production. However, by 1970, when the difference in the average value per ton of coal had increased to $2.71, surface mining accounted for over 40 percent of total production. The reason for this dramatic change in the mode of production is quite clear. The coal industry is switching to the less expensive mining method where possible in order to stay competitive with the other primary forms of energy.

Coal Supply

The time element of the problem must be considered when estimating the cost of supplying a commodity at different levels of production. In the case of coal, the elasticity of supply is quite sensitive to the time span within which the incremental tonnage is to be produced. The short-term coal supply is estimated to be quite inelastic. The first part of the medium-term supply curve should tend to be elastic but then becomes inelastic. The long-term coal supply was estimated to be quite elastic.

Short-Term Supply

For the purpose of considering the supply of coal, the term will signify a time span of not more than one year.

A number of factors limit the incremental amount of coal which can be produced and made available for consumption within this short time frame. New mines capable of producing significant tonnages could not be developed and brought into production within a year. The only new capacity which would come on-stream during the year would be from mines which had been previously planned in order to replace the tonnage lost from mines depleted during the year and to provide for the expected growth in demand. Beyond this, any

TABLE I-I

AVERAGE VALUE OF BITUMINOUS COAL--1940-1970
UNDERGROUND AND SURFACE MINES
(Actual Dollars per Ton Mine)

	Surface Mines	Underground Mines	Surface Mines as a Percent of Total Production
1940	$ 1.56	$ 1.94	9.4
1945	2.65	3.16	19.0
1950	3.87	5.15	23.9
1955	3.48	4.86	24.8
1956	3.74	5.20	25.4
1957	3.89	5.52	25.2
1958	3.80	5.33	28.3
1959	3.76	5.23	29.4
1960	3.74	5.14	29.5
1961	3.67	5.02	30.3
1962	3.64	4.91	30.9
1963	3.57	4.82	31.4
1964	3.55	4.92	31.2
1965	3.57	4.93	32.3
1966	3.64	5.05	33.7
1967	3.68	5.18	33.9
1968	3.75	5.22	34.1
1969	3.98	5.62	35.2
1970	4.69	7.40	40.5

incremental supply would have to come from the existing mines by increasing their production to full capacity.

Coal production at existing mines could be increased in a number of ways: (1) increasing the number of work days per year, (2) increasing the average number of shifts worked per day, (3) depleting the more accessible coal reserves first, and (4) employing more labor and capital.

The U.S. Bureau of Mines estimates that the mining capacity that is theoretically available is 280 working days per year. For a number of reasons, a more attainable figure would be 250 working days. The 1970 coal mine capacity would be in the area of 660 million tons at that rate.* Beyond this point, production costs

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* This calculation is for bituminous coal and lignite production: $\frac{\text{602.9 million tons}}{\text{year}} \times \frac{\text{250 maximum work days}}{\text{228 average work days}} = \frac{\text{660 million tons}}{\text{year}}$

would become higher due to increasing labor and supply costs and decreasing mine efficiency.

It is apparent that the short-term coal supply is quite inelastic. Only limited additional coal can be supplied within this period regardless of the increased effort put into production or the demand for coal in the marketplace. The coal model is not designed to handle such a situation. The model is not sensitive to short-term changes in supply and demand, and thus it cannot be used to predict the value of coal in the marketplace.

Medium Term Supply

The term "medium term supply" will cover a period from 3 to 5 years. This is the approximate time required to bring a new coal mine, with an annual capacity of 1 to 3 million tons per year, into production. During this period, established mining companies could bring new mines which were planned during the first year into production by the third or fifth year. However, it is not likely that new firms could enter the industry and develop a significant productive capacity within this time frame. Any additional tonnage would have to come from bringing the existing mines up to full capacity and increasing their capacity when possible. Growth in supply would still have to come from the existing industry during this period of time.

Some of the factors which limited the expansion of production over the short term would not limit expansion during this time frame. For example, most coal mines have little flexibility in the amount of coal that can be stored at the surface. Their surface storage and loading facilities are designed to operate within a rigid schedule with one of three cyclic modes of transportation--rail, water or truck. The expansion of this system would be difficult to accomplish within 1 year. However, this system could be expanded 5 years.

The Coal Task Group has estimated that the maximum annual growth rate that could be sustained by the coal industry is 5 percent. The maximum amount by which the coal supply could be increased within the medium term is 10.25 percent assuming that the coal industry had been experiencing no net annual growth at the start of the 5-year period. If the industry had already been growing at 5 percent, then the maximum incremental growth during this same time span would be 27.63 percent. However, achievement of these growth rates requires that adequate cash be generated to provide for the net increase in capital investment.

The amount of capital needed to sustain this 5-percent growth rate would be approximately $0.50 per ton of coal produced, given an average capital investment of $10.00 per ton of annual production. The amount given in this example can be determlned ln the following manner. The total U.S. production of bituminous coal and lignite was 602.9 million tons during 1970. The coal lndustry would have to invest $301.5 million in net new capacity to obtain a 5-percent growth rate if the average capital investment per ton of annual production required to open a new coal mine was $10.00.* The $301.5 million required spread over 602.9 million tons of production amounts to $0.50 per ton.

As stated, it is not likely that new firms could enter the industry and develop a significant productive capacity within three to five years. Thus, the economic environment during the medium-term must be such that $0.50 of the revenue from each ton of coal produced (in the example given) can be devoted to new capital investment or the desired 5 percent growth cannot be achieved utilizing solely industry generated capital.

The coal model does not consider whether the range of the rates of return on investment calculated are sufficient to generate the capital needed to sustain a given growth rate. This is a basic limitation of the model.

Long-Term Supply

The long-term supply period covers a time span during which existing firms can develop new coal mines or deplete old ones and during which new firms can enter the industry and old ones can leave. The minimum length of this period would be greater than 5 years but certainly less than 30 years. (The average mine has an expected life of approximately 30 years.)

The model was used to calculate coal costs for six underground and three surface mining regions and for the United States as a whole for coal production growth rates of 3 to 5 percent. Thus, the cost of supplying coal estimates range from 590 million tons (Case IV in 1970) to 1,231 million tons (Case I for conventional and export markets in 1985).

There are a number of factors that could affect the long-term supply of coal in the United States. These factors could either limit the industry's capacity for growth, or they could affect the cost of producing coal at the various growth rates or with time. The main factors that have been considered include the following: (1) labor supply, (2) availability of an adequate transportation system, (3) trends in the cost of capital equipment and operating supplies, (4) trends in technology, (5) governmental policies, (6) adequate coal reserves, and (7) the industry's ability to generate the capital required for growth. The general effect that these items are expected to have on the long-term supply of coal has been discussed in the Coal Task Group Report.

It is expected, however, that the industry's capacity for growth over the long term will not be limited by these factors at

* The initial capital investment required to open a new mine varies over an extremely wide range, from a low of less than $6.00 per ton of annual production for a large surface mine in the West to over $25.00 per ton of annual production for a deep metallurgical coal mine in the East.

least within the limits established for this study--3- to 5-percent annual growth rates. The long-term costs of producing coal are estimated not to vary significantly from the 3-percent growth case to the 5-percent growth case. In 1985, this represents a possible range in production of 566 million tons of coal per year. Thus, the average long-term cost of producing coal is expected to remain approximately level (at a given point in time) over a wide range of supply possibilities.

The coal supply curve can be interpreted in terms of costs. In the case of pure competition, it tends to approximate the curve of average costs for the industry over the long-term. As a result, the long-term supply of coal was estimated to be extremely elastic. The basis for this conclusion is that the United States has approximately 150 billion tons of recoverable coal reserves comparable to those being mined today. Even at the maximum production growth rate considered feasible, cumulative production to 1985 will use only about 10 percent of the recoverable reserves. On the other hand, the real costs of producing coal are expected to increase significantly with time. The projected percentage increase between 1970 and 1985 (in terms of constant 1970 dollars) is about 30 percent (at the mine).

Rate of Return

The average "price" levels of a commodity in an ongoing, competitive industry will approach some minimum attractive rate of return. The cost of mining coal was estimated as a function of the cost of labor, capital and intermediate inputs (maintenance and operating supplies, power and services acquired from outside the industry). Two hypothetical coal mines--one surface and one underground mine--were designed to serve as the basis of estimating the average costs for the industry. The coal industry must be able to generate the capital required to sustain growth or to attract this capital from outside the industry. The coal model is based on the premise that the required capital will come from the industry's cash flow in the long term. Therefore, the general economic levels which would be needed to support the projected levels of production must be determined. Thus, the average "price" of coal over the long term must reflect finding, developing and operating costs plus the minimum return on investment required to generate the required capital.

The coal model uses the discounted cash flow (DCF) method to calculate the "price" levels needed to cover mining costs and provide specified minimum rates of return. The "prices" needed are calculated for each of the supply cases at three rates of return (10, 15 and 20 percent). "Prices" for the six underground and three surface mining regions at a 3-percent growth rate are given in Table 1-2. The estimated average coal values for the United States as a whole (again assuming a 3-percent growth rate) are shown for both surface and underground mines in Tables 1-3 and 1-4, respectively. The results of the coal model cannot be used to predict selling "price" of coal. The term "price" or "value" as used in this study, therefore, should not be interpreted to represent a future market value. The calculation of the cost of supplying coal over a broad range of reasonable rates of return is a more valid approach than to arbitrarily select a specific rate of return for a competitive industry composed of numerous individuals and firms.

The DCF mathematical procedure of calculating rates of return on capital investment is a method of economic analysis particularly useful in analyzing investment projects that are capital-intensive and that have long development periods (capital expenditures) prior to receiving any return of cash. This method considers the time

TABLE 1-2

ESTIMATED VALUE OF COAL PER TON F.O.B. MINE AT A 3-PERCENT GROWTH RATE--1969-1985
(Constant 1970 Dollars)

DCF Rate of Return	1969	1970	1971	1972	1973	1974	1975	1976	1977
Region 1 Underground (West Virginia and Pennsylvania)*									
10%	6.77	7.63	8.31	8.82	9.08	9.14	9.10	9.10	9.12
15%	7.23	8.13	8.84	9.37	9.64	9.71	9.69	9.69	9.72
20%	7.78	8.73	9.47	10.03	0.32	10.40	10.39	10.40	10.43
Region 2 Underground (Mercer, McDowell and Wyoming Counties West Virginia)									
10%	8.47	9.92	11.05	11.94	12.40	12.55	12.54	12.58	12.65
15%	9.21	10.72	11.89	12.81	13.30	13.46	13.47	13.52	13.60
20%	10.08	11.66	12.89	13.86	14.37	14.55	14.57	14.64	14.73
Region 3 Underground (Illinois, Indiana and Ohio)									
10%	4.97	5.41	5.74	5.99	6.10	6.10	6.05	6.03	6.02
15%	5.23	5.68	6.04	6.29	6.41	6.42	6.38	6.36	6.35
20%	5.53	6.01	6.38	6.66	6.78	6.80	6.76	6.75	6.74
Region 4 Underground (Kentucky, Tennessee and Virginia)									
10%	5.94	6.86	7.59	8.15	8.44	8.53	8.51	8.53	8.56
15%	6.42	7.38	8.14	8.72	9.02	9.12	9.12	9.14	9.18
20%	6.99	8.00	8.79	9.40	9.72	9.83	9.83	9.87	9.92
Region 5 Underground (Utah and Colorado)									
10%	6.83	7.00	7.27	7.38	7.39	7.32	7.23	7.15	7.09
15%	7.04	7.30	7.50	7.62	7.64	7.58	7.49	7.41	7.36
20%	7.28	7.57	7.78	7.92	7.94	7.88	7.80	7.73	7.68
Region 6 Underground (Alabama)									
10%	10.29	11.42	12.29	12.94	13.26	13.31	13.24	13.21	13.21
15%	10.92	12.09	13.00	13.69	14.02	14.08	14.02	14.01	14.02
20%	11.67	12.90	13.85	14.57	14.93	15.00	14.96	14.96	14.98
Region 1 Surface (Kentucky, West Virginia, Virginia and Tennessee)									
10%	4.42	4.70	4.95	5.58	6.12	6.50	6.65	6.84	7.03
15%	5.13	5.43	5.70	6.35	6.91	7.32	7.48	7.69	7.89
20%	5.93	6.24	6.54	7.22	7.81	8.23	8.42	8.64	8.86
Region 2 Surface (Illinois, Indiana, Iowa and Ohio)									
10%	4.28	4.31	4.35	4.55	4.72	4.83	4.85	4.88	4.93
15%	4.58	4.63	4.68	4.89	5.07	5.19	5.21	5.25	5.30
20%	4.93	4.98	5.04	5.26	5.46	5.59	5.61	5.66	5.72
Region 3 Surface (Pennsylvania)									
10%	4.71	4.95	5.17	5.75	6.25	6.61	6.74	6.90	7.08
15%	5.38	5.64	5.88	6.49	7.00	7.38	7.52	7.70	7.89
20%	6.14	6.42	6.68	7.31	7.85	8.25	8.41	8.61	8.81

DCF Rate of Return	1978	1979	1980	1981	1982	1983	1984	1985
Region 1 Underground (West Virginia and Pennsylvania)*								
10%	9.13	9.16	9.20	9.23	9.25	9.28	9.30	9.33
15%	9.74	9.78	9.83	9.86	9.89	9.92	9.95	9.99
20%	10.47	10.51	10.57	10.62	10.65	10.69	10.73	10.78
Region 2 Underground (Mercer, McDowell and Wyoming Counties West Virginia)								
10%	12.71	12.79	12.89	12.96	13.02	13.09	13.15	13.23
15%	13.68	13.76	17.87	13.96	14.03	14.11	14.18	14.28
20%	14.83	14.93	15.05	15.15	15.24	15.33	15.41	15.52
Region 3 Underground (Illinois, Indiana and Ohio)								
10%	6.01	6.00	6.01	6.01	6.00	6.00	6.00	6.00
15%	6.34	6.34	6.35	6.36	6.36	6.36	6.36	6.37
20%	6.75	6.75	6.77	6.77	6.78	6.78	6.79	6.80
Region 4 Underground (Kentucky, Tennessee and Virginia)								
10%	8.60	8.64	8.70	8.74	8.78	8.82	8.85	8.90
15%	9.23	9.28	9.34	9.39	9.43	9.48	9.52	9.58
20%	9.98	10.03	10.11	10.17	10.22	10.27	10.32	10.39
Region 5 Underground (Utah and Colorado)								
10%	7.04	6.99	6.96	6.92	6.88	6.84	6.80	6.77
15%	7.31	7.27	7.24	7.20	7.16	7.13	7.09	7.07
20%	7.63	7.59	7.57	7.54	7.50	7.47	7.44	7.42
Region 6 Underground (Alabama)								
10%	13.22	13.23	13.27	13.29	13.31	13.32	13.34	13.37
15%	14.04	14.06	14.11	14.14	14.17	14.19	14.21	14.26
20%	15.01	15.05	15.12	15.16	15.19	15.23	15.26	15.32
Region 1 Surface (Kentucky, West Virginia, Virginia and Tennessee)								
10%	7.22	7.41	7.62	7.79	8.30	8.47	8.28	8.46
15%	8.10	8.30	8.52	8.71	9.24	9.42	9.24	9.44
20%	9.08	9.31	9.54	9.75	10.30	10.50	10.33	10.54
Region 2 Surface (Illinois, Indiana, Iowa and Ohio)								
10%	4.97	5.02	5.08	5.12	5.31	5.35	5.24	5.29
15%	5.35	5.41	5.47	5.52	5.72	5.77	5.66	5.72
20%	5.78	5.84	5.91	5.97	6.18	6.23	6.13	6.19
Region 3 Surface (Pennsylvania)								
10%	7.25	7.42	7.61	7.77	8.24	8.40	8.21	8.37
15%	8.08	8.27	8.47	8.64	9.13	9.30	9.13	9.30
20%	9.01	9.22	9.43	39.62	10.13	10.32	10.15	10.35

* Does not include Mercer, McDowell and Wyoming Counties in West Virginia. These three counties produce mainly low volatile coking coal and are considered separately in Region 2.

TABLE 1-3

AVERAGE VALUE FOR THE UNITED STATES
ESTIMATED VALUE OF COAL PRODUCED FROM SURFACE MINES AT A 3-PERCENT GROWTH RATE--1969-1985
(Constant 1970 Dollars per Ton)

Unit Value or Costs	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1985
Productivity per Day (Tons/Man)	35.71	35.96	36.50	37.00	37.50	38.00	38.50	39.00	39.50	40.00	40.50	41.00	43.50
Estimated Production Cost													
Direct Operating Cost													
Total Cost of Labor	1.64	1.67	1.69	1.90	2.04	2.11	2.09	2.11	2.12	2.14	2.16	2.19	2.22
Total Cost of Hourly Labor	1.45	1.48	1.49	1.70	1.84	1.91	1.89	1.91	1.92	1.94	1.96	1.99	2.01
Supervision	0.19	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.21	0.21	0.21	0.21	0.21
Maintenance and Operating Supplies	0.91	0.94	0.97	0.97	0.99	1.00	1.02	1.04	1.05	1.07	1.10	1.12	1.23
Power	0.28	0.29	0.29	0.29	0.28	0.28	0.28	0.29	0.29	0.29	0.29	0.29	0.30
Reclamation Cost	0.02	0.02	0.02	0.08	0.17	0.23	0.24	0.25	0.26	0.27	0.28	0.29	0.34
Ind. Costs--Gen. and Admin. Expense	0.26	0.28	0.28	0.29	0.29	0.30	0.30	0.31	0.31	0.32	0.32	0.33	0.36
Fixed Costs	0.09	0.09	0.10	0.10	0.10	0.11	0.12	0.12	0.13	0.13	0.14	0.15	0.18
Total Cash Operating Costs	3.18	3.27	3.32	3.61	3.85	4.01	4.03	4.08	4.14	4.20	4.27	4.34	4.61
Depreciation Expense	0.31	0.32	0.33	0.34	0.35	0.36	0.36	0.37	0.38	0.39	0.39	0.40	0.43
Capital Investment per Ton of Annual Production*													
Avg. of all Mines Currently in Production	6.25	6.39	6.64	6.83	7.01	7.17	7.33	7.49	7.64	7.79	7.93	8.07	8.78
Capital Required to Open a New Mine	7.32	7.44	7.70	7.88	8.05	8.20	8.35	8.50	8.63	8.77	8.90	9.02	9.65
Average Value of Coal per Ton f.o.b. Mine	4.12	4.69	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Estimated Value of Coal per Ton f.o.b. Mine													
Value at 10% Rate of Return	4.34	4.44	4.54	4.86	5.14	5.33	5.38	5.46	5.54	5.63	5.72	5.82	6.21
Value at 15% Rate of Return	4.76	4.87	4.99	5.32	5.61	5.81	5.87	5.96	6.06	6.15	6.25	6.36	6.79
Value at 20% Rate of Return	5.24	5.36	5.49	5.84	6.14	6.36	6.43	6.53	6.63	6.74	6.85	6.96	7.45

* Total initial investment required to bring mine up to full production. The amount shown does not include land acquisition, exploration, working capital, or deferred capital expenditures; however, these items are included in the analysis.

TABLE 1-4

AVERAGE VALUE FOR THE UNITED STATES
ESTIMATED VALUE OF COAL PRODUCED FROM UNDERGROUND MINES AT A 3-PERCENT GROWTH RATE--1969-1985
(Constant 1970 Dollars per Ton)

Unit Value or Costs	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1985
Productivity per Day (Tons/Man)	15.61	13.70	12.60	12.60	13.00	13.40	13.80	14.20	14.60	15.00	15.40	15.80	17.80
Estimated Production Cost													
Direct Operating Cost													
Total Cost of Labor	3.23	3.74	4.18	4.51	4.70	4.70	4.61	4.56	4.52	4.49	4.46	4.45	4.31
Total Cost of HQur1y Labor	2.85	3.28	3.67	3.99	4.18	4.20	4.11	4.07	4.04	4.01	3.99	3.98	3.85
Supervision	0.39	0.46	0.52	0.53	0.52	0.51	0.50	0.50	0.49	0.48	0.48	0.48	0.46
Maintenance and Operating Supplies	1.30	1.45	1.54	1.60	1.61	1.62	1.63	1.64	1.65	1.66	1.68	1.69	1.76
Power	0.16	0.18	0.18	0.19	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.17
Ind. Costs--Gen. and Admin. Expense	0.26	0.28	0.28	0.29	0.29	0.30	0.30	0.31	0.31	0.32	0.32	0.33	0.36
Fixed Costs	0.09	0.10	0.11	0.11	0.12	0.12	0.13	0.14	0.14	0.15	0.15	0.16	0.20
Total Cash Operating Costs	5.03	5.72	6.27	6.68	6.88	6.90	6.84	6.80	6.79	6.78	6.77	6.79	6.78
Depreciation Expense	0.57	0.62	0.66	0.69	0.71	0.72	0.74	0.75	0.76	0.77	0.79	0.80	0.85
Capital Investment per Ton of Annual Production*													
Avg. of all Mines Currently in Production	6.57	7.15	7.57	7.92	8.11	8.29	8.46	8.62	8.78	8.92	9.06	9.20	9.84
Capital Required to Open a New Mine	9.60	10.30	10.77	11.13	11.27	11.39	11.50	11.60	11.69	11.77	11.85	11.91	12.24
Average Value of Coal per Ton f.o.b. Mine	5.82	7.40	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Estimated Value of Coal per Ton f.o.b. Mine													
Value at 10% Rate of Return	6.54	7.36	8.01	8.49	8.74	8.79	8.76	8.76	8.77	8.79	8.81	8.85	8.97
Value at 15% Rate of Return	6.98	7.84	8.51	9.02	9.28	9.34	9.32	9.32	9.34	9.37	9.40	9.45	9.60
Value at 20% Rate of Return	7.51	8.42	9.12	9.65	9.93	10.00	9.99	10.00	10.03	10.06	10.10	10.16	10.35

* Total initial investment required to bring mine up to full production. The amount shown does not include land acquisition, exploration, working capital, or deferred capital expenditures; however, these items are included in the analysis.

value of money and the earning power of individual investments. It measures the rate of return on invested capital in terms of the annual discount rate which equates the future net cash flows from a project to the discounted value of the investment outlays required to bring about the cash flows.

The DCF method measures the profitability of an investment over the entire life of the project. It should not be confused with the book value rate of return which is used to measure the performance of an investment at different periods of time in the life of an ongoing project. Thus, a project's book rate of return may vary over its productive life while there is only one true DCF rate of return associated with any given project.

For a single investment project, the DCF rate, "r," is defined as the discount rate that equates the value of the entire series of cash flows from the project to zero. The DCF rate, "r," is uniquely determined by the configuration (time pattern, volume and duration) of the net cash flows, "At." The rate, "r," has to be determined by trial and error if the configuration, "At'" varies over the life of the project. The rate, "r," can be determined directly for a level pattern of cash inflows, "At," a year for "n" years as follows:

$$A_t = C_0 \left[\frac{r(1 + r)^n}{(1 + r)^n - 1} \right]$$

where

A_t = the net cash flows from the project at the end of year "t"
t = the time during years 0, 1, 2, ... , n.
n = the project life
r = the project's internal rate of return
C_0 = the capital investment at time, $t = 0$

Capital expenditures are not restricted to the initial period but are distributed over the life of the project. For example, the total deferred capital expenditures over the average life of a coal mine are on the order of 1.0 to 1.5 times as great as the initial capital investment required to open the mine. The above equation has been expanded so it can be used to analyze such investments. The coal model was also constructed so that such items as depletion, depreciation and income taxes could be examined.

The concept of a DCF rate for a single project is well known and widely used by industry to assess the profitability of a project. It probably is the most common criterion used to measure rates of return for theoretical purposes as the configuration of net cash flows per unit of capital expenditures is either known or can be estimated. On the other hand, the concept of a DCF rate for an ongoing company or industry is not generally well understood. At least the corresponding DCF rate is generally not known. The problem is that the profitability of an industry tends to change with time. Also, an ongoing industry has no specific beginning or end. As a result, there is the problem of determining the time period to which the cash flows should be discounted and the cutoff point beyond which the cash flows of future and past projects should not be considered to affect the industry's current rate of return. This problem as it relates to the concept of a DCF rate of an ongoing industry will be examined in the following paragraphs.

First, consider the case of an industry made up of many companies or projects, each of which yields the same DCF rate of return (for example, 10 percent). Logic tells us that the industry as a whole will make this same rate of return. The industry as a whole will yield this 10-percent rate of return regardless of any differences in the configuration of the net cash flows from the individual projects. This rate will be realized regardless of the time pattern at which the projects are acquired or the practices used in accounting for capital and income. None of these items will change the industry's overall DCF rate so long as the rate of return remains the same for each project.* In this special case, the average rate of return for the industry would remain constant over time.

The next case to be considered is that of an industry or company made up of individual projects each generating a different internal rate of return. This industry or company is considered to be an ongoing concern. The problem is how to determine the industry's DCF rate of return at a given point in time. The overall profitability of the industry is constantly changing as the mix of the companies and their various projects change.

The status of each project of which the industry is composed falls into one of three classes--active, future and completed--during any given period or point in time over the life of the corporation. An active project is defined as one whose project life intersects the time period for which the industry's rate of return is being determined. Such a project contributes to a change (either positive or negative) to the industry's cash flow and net worth during the time period being considered. A future project is one for which the investment outlays required to bring about certain net fund flows will not be committed until after the time period for which the company's DCF rate is being calculated. Such a project does not affect the configuration of the industry's cash flows during the period considered and consequently does not affect its DCF rate of return. A past project that no longer has an affect on an industry's overall cash flow is classed as being completed. Because it no longer affects the industry's cash flow, a completed project will not affect the industry's rate of return during the period considered. Consequently, an ongoing industry's DCF rate is determined only by those projects that are active during the time period considered.

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* E. Solomon, "Alternative Rate of Return Concepts and Their Implication for Utility Regulation," *The Bell Journal of Economic and Management Science*, Vol. 1, No.1 (1970).

Every industry or company generates some DCF rate of return. In most cases this rate is not known as it tends to change with time as the mix of the industry's individual projects change. Nevertheless, an industry's DCF rate can be determined for a given point or period in time if the configuration of the net cash flows for each of its active projects can be calculated or estimated.

A complete analysis of calculations required to determine the DCF rate for an ongoing industry or the average unit "value" needed to yield a given rate of return is beyond the scope of this paper. However, an algorithm that can be used to analyze the DCF rate of return for an ongoing industry and a simplified example are presented in the section of this Appendix entitled "DCF Rate for an Ongoing Industry."

The theory of a DCF rate of return for an ongoing industry was applied to the coal model in the following manner. It was assumed that the average coal mine has a life of 33.3 years. As a result, the structure of the industry during any given year can be described by 30 surface and underground mines.

The model is structured so that the initial capital costs per ton of annual production reflects the state of technology and costs which were estimated to exist during the year the mine was developed, Deferred capital expenditures over the life of each mine reflect the real costs for the year in which the equipment was purchased. On the other hand, the model was designed so that operating conditions and cash operating costs would be the same for each mine during the same year. As a result, the overall configuration of the cash flows from each of the active projects (mines) were calculated for each year covered by the study. In this manner, the average unit "values" needed to yield the three specified DCF rates of return (10, 15 and 20 percent) were calculated for each of the supply cases (3.0-, 3.5- and 5.0-percent annual growth) over the life of the study (1970-1985).

MODEL DEVELOPMENT AND CONSTRUCTION

Model Development

The coal model was developed in three sections. The first part is primarily concerned with estimating the average costs of producing coal in the United States during the period covered by the study. The average value of coal per ton (f.o.b. mine) is calculated in the second section of the model. The third part of the model consists of a regression program that is used to calculate the average coal values in each of the major coal producing regions.

Producing Costs

The cost of producing coal can be broken down into cash operating costs and capital costs. Production costs were estimated separately for the underground and surface mines. The coal model was designed so that the cash operating costs are the same for each of the active projects (mines) during a given year. The capital costs reflected the unit costs of the capital equipment during the year it was purchased.

Operating costs were broken down as follows for estimating purposes: (1) total cost of hourly labor (operating and maintenance), (2) supervision, (3) maintenance and operating supplies, (4) power, (5) reclamation costs at surface mines, (6) indirect costs, and (7) fixed costs. The projections of the average cash operating cost for underground and surface mines are presented in Tables 1-3 and 1-4.

Capital costs were broken down as follows for estimating purposes: (1) the cost of land acquisition, (2) exploration and development costs, (3) working capital, (4) initial capital investment, (5) deferred capital expenditures over the life of the project, and (6) salvage value at the end of the project life. The configurations of the capital investments used in the coal model are described as a function of the initial capital investment (see Tables 1-5 and 1-6).

In order to estimate the average cost of producing coal at underground and surface mines during a given year, it is necessary not only to determine the unit costs of labor, capital equipment, power and supplies during that year, but also to estimate the average operating conditions against which the unit costs are to be applied. The operating conditions used in the model to estimate production costs at the "average mine in production" and the "average new mine opened" are given for the base year--1969 (see Tables 1-7 and 1-8).

It should be noted that the values of the variables used in this study to describe the coal industry are estimated to change each year over the life of the study to account for the changing average mine size, the state of technology and a number of other factors. For example, the productivity of labor at underground mines was 15.61 tons per man per day in 1969. It decreased to 13.76 tons per man per day in 1970.* Productivity was estimated to continue to decline to 12.60 tons per man per day in 1972 before rising to 17.80 tons per man per day in 1985. Likewise, estimates were made for future changes in the other major independent variables where there was a rationale for making such estimates.

The total capital expenditures required each year to satisfy several different supply schedules were calculated. First, the average capital investment required to maintain a constant volume

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* This is the actual productivity figure for 1970 as released by the Bureau of Mines. Since 1970 information was not available when the coal model was formulated, an estimated figure of 13.70 tons per man per day was used for the "price" calculations. (See Table 1-4).

TABLE 1-5

CAPITAL COSTS AT SURFACE COAL MINES
(Percent of Total Initial Capital Investment per Ton Annual Capacity)

Malor Capitalized Items	Average Life (Years)	Total Initial Capital Investment	Initial Capital Investment by Yr. (Yrs. Before Startup) -4	-3	-2	-1	Replacement Capital (Yrs. After Startup) 5	10	15	20	25	Salvage Value 30 Years After Startup
General Mine Plant												
Site Preparation	30*	0.75		0.75								0.00
Mine Buildings and Shop Equipment	30*	5.43		1.20	1.20	3.03						0.48
Water Supply and Sewage	30*	1.31		1.31								0.00
Surface Vehicles	5	2.25		0.75	1.50		2.25	2.25	2.25	2.25	2.25	0.23
Crushing, Cleaning and Loading												
Crushing, Cleaning and Sampling	30*	4.68			1.56	3.12						0.47
Storage and Loading Facilities	30*	9.37			3.12	6.25						0.94
Electrical Power System												
Main Overhead System, 69KV	30*	1.87		1.87								0.19
Dragline and OB Drill System	20	3.75				3.75				3.75		0.38
Stripping Equipment												
Dragline (50 Cubic Yards)	30*	47.77			15.92	31.85						9.55
Tractors and Dozers	5	2.34			1.17	1.17	2.34	2.34	2.34	2.34	2.34	0.23
Drilling and Shooting OB Equipment	15	1.59				1.59			1.59			0.16
Loading Equipment												
Front End Loader	5	1.45				1.45	1.45	1.45	1.45	1.45	1.45	0.15
Dozer with Ripper	10	1.17				1.17		1.17		1.17		0.12
Pumping Equipment	10	0.19				0.19		0.19		0.19		0.02
Haulage Equipment												
Trucks (3 at 120 Tons)	10	5.28				5.28		5.28		5.28		0.53
Road Construction and Equipment	15	3.49				3.49	0.47	0.47	3.49	0.47	0.47	0.30
Reclamation	10	1.17				1.17		1.17		1.17		0.12
Communication, Safety and Miscellaneous	10	0.47				0.47		0.47		0.47		0.05
Total Construction Cost		94.33		5.88	24.47	63.98						
Engineering at 1%	30*	0.95		0.50	0.25	0.20						0.00
Contingency and Sales Tax at 5%	30*	4.72		0.30	1.22	3.20						0.00
Total Initial Capital Investment		100.00		6.68	25.94	67.38						
Replacement Capital		57.47					6.51	14.79	11.12	18.54	6.51	
Less 10% Trade-in Value		(19.66)					(0.65)	(1.48)	(1.11)	(1.85)	(0.65)	(13.92)
Total Initial and Deferred Capital Expenditures		137.81	0.00	6.68	25.94	67.38	5.86	13.31	10.01	16.69	5.86	(13.92)
Land Acquisition and Exploration†												
Working Capital for Two Months‡												
Total Capital Coata Over Life of Mine												

* These items are depreciated over the total life of the operation.

† 85% of the land will be allocated to the mine three years before startup; the remaining 15% will be acquired over the life of the mine.

‡ A sum equal to the total cash operating costs for two months will be needed for working capital.

TABLE 1-6

CAPITAL COSTS AT UNDERGROUND COAL MINES
(Percent of Total Initial Capital Investment per Ton Annual Capacity)

Malor Capitalized Items	Average Life (Years)	Total Initial Capital Investment	Initial Capital Investment by Yr. (Yrs. Before Startup)				Replacement Capital (Yrs. After Startup)					Salvage Value 30 Years After Startup
			-4	-3	-2	-1	5	10	15	20	25	
Mine Plant-Surface												
Site Preparation	30*	1.00		1.00								0.00
Mine Openings												
Belt and Track Slopes	30*	7.48			3.74	3.74						0.00
Intake and Exhaust Air Shafts	30*	7.81			3.90	3.91						0.00
Equipment	10	6.06			3.03	3.03		6.06		6.06		0.61
Mine Buildings	30*	4.98		1.24	1.25	2.49						0.50
Water Supply and Sewage	30*	1.85		1.85								0.00
Surface Vehicles	5	1.52		0.52	1.00		1.52	1.52	1.52	1.52	1.52	0.15
Crushing, Cleaning and Loadout												
Crushing, Cleaning and Sampling	30*	4.98			1.66	3.32						0.50
Storage, Reclaiming and Loadout	30*	9.97			3.32	6.65						1.00
Electric Power-Surface	30*	2.99		0.99	2.00							0.30
***Face* Equipment**	5	24.92			9.97	14.95	24.92	24.92	24.92	24.92	24.92	2.49
General Underground Equipment												
Trans. (Coal-Main Belt)	10	3.59				3.59		3.59		3.59		0.36
Trans. (Men and Supplies-Track)	10	2.99				2.99		2.99		2.99		0.30
Rock Handling	15	1.40			1.40				1.40			0.14
Rock Dusting	15	0.90				0.90			0.90			0.09
Communications Equipment	10	0.11				0.11		0.11		0.11		0.01
Safety and Miscellaneous Equipment	10	1.18				1.18		1.18		1.18		0.12
Electrical Power-Underground	10	3.82				3.82		3.82		3.82		0.38
Total Direct First Cost		87.55		5.60	31.27	50.68						
Field Indirect at 2%		1.75		0.11	0.63	1.01						
Total Construction Cost		89.30		5.71	31.90	51.69						
Engineering at 2%		1.78		1.00	0.39	0.39						
Contingency and Sales Tax at 2%		8.92		0.57	3.19	5.16						
Total Initial Capital Cost		100.00		7.28	35.48	57.24						
Replacement Capital		170.00					26.44	44.19	28.74	44.19	26.44	
Less 10% Trade-in Value		(23.94)					(2.64)	(4.42)	(2.87)	(4.42)	(2.64)	(6.95)
Total Inital and Deferred Capital Expenditures		246.06	0.00	7.28	35.48	57.24	23.80	39.77	25.87	39.77	23.80	(6.95)
Land Acquisition and Explorationt												
Working Capitalf												
Total Capital Costs Over Life of the Mine												

----* **These items will be depreciated over the total life of the operation.**

t 85% of the land will be allocated to the mine three years before startup; the remaining 15% will be acquired over the life of the mine.

‡ **A sum equal to the total cash operating coats for two months will be used for the working capital.**

TABLE 1-7

COAL MODEL PARAMETERS FOR
SURFACE MINES IN THE BASE YEAR--1969

General Summary	Average Mine in Production During 1969	New Mines Opened During 1969	Units
Coal Reserves			
Amount of Coal in Place	16,667,000	33,333,000	Tons
Average Thickness of Coal Seam	5.0	5.0	Feet
Tons per Acre--Foot	1,800	1,800	Tons
Total Amount of Land Needed	1,875	3,750	Acres
90% Recovery Factor	(1,667,000)	(3,333,000)	Tons
Amount of Recoverable Coal	15,000,000	30,000,000	Tons
Mine			
Productive Life of the Mine	30	30	Years
Annual Production	500,000	1,000,000	Tons
Average Number of Working Days per Year	247	247	Days
Stripping			
Stripping Ratio	12.4	12.4	Cubic Yards: Tons
Equipment--Dragline Size	25	50	Cubic Yards
Number of Days Worked per Year	350	350	Days
Number of Shifts per Day	3	3	Shifts
Haulage			
Haulage Distance	5.3	5.3	Miles
Equipment--Truck Size	30	120	Tons
Number of Days Worked per Year	240	240	Days
Number of Shifts per Day	2	2	Shifts
Productivity of Hourly Labor	40.7	34.2-57.0	Tons/Man/Day
Total Productivity of All Personnel	35.7	30.0-50.0	Tons/Man/Day
Coal Preparation			
Mechanically Cleaned	60	60	Percent
Mechanically Crushed	45	45	Percent
Loadout for 7,000 Ton Unit Train	2,500	2,500	Tons/Hour

of coal production was estimated (O-percent annual growth). To sustain a constant volume of coal production, an annual replacement rate of 3 percent of the total productive capacity is needed to compensate for those mines depleted each year. This replacement rate reflects the fact that the average coal mine has an estimated life of 33.3 years. Additional yearly capital investments of 4.9 percent of the initial capital investment at underground mines and 3.1 percent at surface mines are required to replace the capital equipment depreciated each year at the producing mines Next,

TABLE 1-8

COAL MODEL PARAMETERS FOR
UNDERGROUND MINES IN THE BASE YEAR--1969

General Summary	Average Mine in Production During 1969	New Mines Opened During 1969	Units
Coal Reserves			
Amount of Coal in Place	30,000,000	60,000,000	Tons
Average Thickness of Coal Seam	5.0	5.0	Feet
Tons per Acre--Foot	1,800	1,800	Tons
Total Amount of Land Needed	3,350	6,700	Acres
Assumed 50% Extraction	15,000,000	30,000,000	Tons
Amount of Recoverable Coal	15,000,000	30,000,000	Tons
Mine			
Productive Life of the Mine	30	30	Years
Annual Production	500,000	1,000,000	Tons
Number of Working Days per Year	224	240	Days
Number of Shifts per Day	2	2	Shifts
Daily Production	2,300	4,200	Tons
Number of Production Units	3	4	Units
Number of Spare Units Needed	0	1	Unit
Number of Production Unit Shifts per Production Day	5	8	Shifts
Productivity of Hourly Labor	17.8	17.1-28.6	Tons/Man/Day
Total Productivity of All Personnel	15.6	15.0-25.0	Tons/Man/Day
Coal Preparation			
Mechanically Cleaned	60	60	Percent
Mechanically Crushed	45	45	Percent
Loadout for 7,000 Ton Unit Train	2,500	2,500	Tons/Hour

the new capital investment required to produce the incremental coal tonnage needed to yield several different growth rates was calculated. The incremental capital investment was determined for three cases--namely, 3.0-, 3.5- and a S.O-percent annual growth in coal production. Then the total weighted average capital investment required to sustain each of the specified growth cases was determined.

The annual capital expenditures required to achieve the projected production levels are estimated to grow from $435 million in 1970 to between $807.3 million and $1,370.9 million per year in 1985. This increase means that the coal industry must invest between $9.8 billion and $14.8 billion during the 1970-1985 period if it is to supply the quantity of coal that will be needed. A summary of the annual and total capital requirements is presented in Table 17, Chapter Five.

Cash Flow Model

A discounted cash flow model was developed to calculate the average per ton "value" of coal, f.o.b. mine, needed to yield rates of 10, 15 and 20 percent. The "value" of the average ton of coal is calculated by the model in such a manner that the increment between the unit "revenues" and the unit production costs remains constant over the life of each project. An infinite number of slopes to the unit "price" line (the line created by the unit "price" of the coal for each year over the life of the project) can be calculated which satisfy the DCF rate of return equation. By calculating the unit revenue in this manner, it is sensitive to yearly changes in production costs.

It is felt that a uniform stream of income over the life of each project more nearly represents the economic structure of an ongoing industry that does a model in which the unit revenues required to yield a given DCF rate are calculated such that they remain constant over the life of the project or industry. If the unit revenues are calculated in this manner, the result will be a decreasing unit income pattern as the real costs of production increase over the life of the industry. A declining unit income pattern does not realistically represent the conditions which exist in a healthy, ongoing industry composed of many companies. The more logical pattern would be that of the level or uniform stream of income as an industry's supply curve tends to approximate its curve of average costs over the long term.*

Regression Model

A regression model was developed to estimate the f.o.b. mine value of coal produced in each of the major coal producing regions of the United States. This analysis was done on a regional basis for six underground and three surface mining regions for which historical data are available. The estimated values have been shown in Table 1-2.

The regional values were determined in the following manner. First, the historical values for the coal produced in each region and the United States as a whole were collected for the 1960-1970 period. Next, a regression program was developed. This program initially calculates the normal equations and generates a least squares estimate of the coefficients based on a method generally known in statistics as Doolittle's method.† The regression program was then used to determine the normal equation for each of the nine mining regions as a function of the U.S. average f.o.b. mine value of coal.

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* William J. Baumol, *Economic Theory and Operations AnaZysis* (1965), p. 316.

† Margenau and Murphy, *The Mathematics of Physics and Chemistry* (1965).

The normal equation and the multiple correlation coefficient "R" are calculated for each mining region. The equations are given in Table 1-9.

TABLE 1-9

REGRESSION EQUATION
(Estimated Values per Ton by Major Mining District)

Mining District		$\hat{Y}_{it} = ai + bi\ (X_{nt})$	R_i
Underground Mines			
Region 1	$\hat{Y}_1$	-0.0703 + 1.0461 (X_{1t})	0.9984
Region 2	Y_2	-2.2604 + 1.6548 (X_{1t})	0.9967
Region 3	Y_3	1.1490 + 0.5778 (X_{1t})	0.9896
Region 4	Y_4	1.0580 + 1.0761 (X_{1t})	0.9956
Region 5	Y_5	3.6578 + 0.4646 (X_{1t})	0.7268
Region 6	Y_6 =	1.0622 + 1.4067 (X_{1t})	0.9404
Surface Mines			
Region 1	$\hat{Y}_1$	-2.7502 + 1.6780 (X_{2t})	0.9933
Region 2	Y_2	1.0764 + 0.7285 (X_{2t})	0.9944
Region 3	Y_3 =	-2.1114 + 1.5910 (X_{2t})	0.9879

Where: $\hat{Y}_{it}$ = the best estimate of the per ton mine value of coal in region "i" during year "t."

ai = the Y-intercept of the regression line for mining region "L"

= the increase in $\hat{Y}$ (the value of coal in region "i") for each unit increase in $\hat{X}_{nt}$.

X_{nt} = the U.S. average f.o.b. mine value or coal for underground mines (n=l) or for surface mines (n=2) during year "t."

Ri = the coefficient of correlation for region "L"

Model Construction

The process of constructing this model can be broken down into four stages--defining, specifying, estimating and predicting.

First, the purpose of the model was defined. The model was used to estimate the "price" and the cost of producing coal in the East and Midwest. The coal industry in these parts of the country is described best as a mature industry. On the other hand, the coal model is not used to estimate the cost of producing coal in the West for a number of reasons.

In order to determine the range of "prices" *VB.* DCF rates of return for coal produced by surface mining in the West, a typical surface (area) mine was defined by the Coal Task Group. "Prices" of coal were calculated as a function of overburden/coal ratio and are shown separately in the task group report itself.

During the second stage, the most important factors which affect the supply and the cost of mining coal were specified. This simply means identifying the variables which were thought to be important to the industry's economic system. Refer to the causal flow diagram (Figure I-I) to see how the different variables are related.

The initial specification was made in the form of a number of verbal and written concepts about different aspects of the industry. For example, the main variables of which the capital and operating costs were found to be a function fall into one of the following classes: (1) economic, (2) physical, (3) technological and (4) governmental policies. Finally, each of the verbal and written concepts that were formulated about the coal industry's economic structure had to be translated into the form of a number of mathematical equations.

The third stage of developing the model consisted of estimating the coefficients of the variables that were used in the mathematical equations. Most of these values were obtained from published historical data or developed from basic engineering principles. Others were based upon empirical relationships which have been developed and proved useful in the coal industry. In certain cases regression analysis was used to estimate the numerical parameters. At this stage, a distinction must be made between those variables whose values are determined from within the model (endogenous).

Next, the model and data were developed and refined to the point where the average f.o.b. mine "prices" could be estimated for the base period (the years for which the values of the exogenous variables and the average coal "prices" are known).

The final step in constructing the model was to make the projections themselves. Values were assigned to the future levels of the exogenous variables and the average "price" of coal in the United States was determined for each year over the period covered by the study. After the average U.S. "price" was determined a regression program was used to estimate the projected coal "price" in each of the major producing regions (see Table 1-2).

In summary, this is the process that was used to construct the coal model. It consisted of a number of equations which describe the most important aspects of the coal industry. The model contains at least one equation for each of the unknown (endogenous) variables. Considering the diversity of mining conditions existing in the United States, it is not surprising to find a wide range of "prices" projected for the different producing regions.

SENSITIVITY ANALYSIS

For part of the Coal Task Group's use of the economic model, it was necessary to perform a number of sensitivity calculations to evaluate the effect of different assumptIons concerning certain input factors (exogenous variables). A sensitivity analysis was performed on the following factors: productivity of labor, income tax rates, productivity of capital, average stripping ratio at surface mines, average haulage distance from the mine to the tipple, the cost of certain supply items, depreciation method, and rate of return. Results of some of the sensitivity analysis are discussed in the task group report.

DCF RATE FOR AN ONGOING INDUSTRY

In order to determine the DCF rate for an ongoing industry or the "price" needed to yield a given rate of return, the following algorithm can be used:

Step 1. Specify the exact period or point in time for which the industry's rate of return is to be calculated. For example, it might be a year or a period of years.

Step 2. Determine which projects are active during the specified period of time.

Step 3. Calculate or estimate the configuration of the net cash flows for each of the active projects. The configuration of the cash flows for a single project, "P," can be written in set notation as follows:

$$P = [a_0, a_1, a_2, \ldots, a_t]$$

where

= the net cash flows generated by the project at the end of year "t"

t = the time period during years 0, 1, 2, ..., n.

Step 4. Calculate the overall configuration of the industry's net cash flows. The total volume, time pattern and duration of the industry's net cash flows can be found by adding together the sequence of cash flows generated by each of its active projects. Symbolically:

$$P_1 = [a_{11}, a_{12}, a_{13}, \ldots, a_{In}]$$

$$P = [a_{21}, a_{22}, a_{23}, \ldots, a_{2n}]$$

$$P_m = [a_{m1}, a_{m2}, a_{m3}, \ldots, a_{mn}]$$

$$T = [A_1, A_2, A_3, \ldots, A_n]$$

and

$$A_j = \sum_{i=1}^{m} a_{ij} \qquad \text{for } j = 1, 2, 3, \ldots, n$$

where

a_{ij} = the net cash flow generated by the active project "i" during year "j" of the industry's life

p_i = the i-th project of an ongoing industry that has a total number of "m" active projects during the time period for which its rate of return is being calculated.

n = the time period in years that is covered by the industry's active projects.

A_j = the sum of the cash flows generated by all of the active projects during year "j"

T = the total configuration of the industry's net cash flows in set notation.

Step 5. As the configuration of the industry's net cash flows have been determined, the industry's true DCF rate of return can be determined as follows:

EXAMPLE

Date: An industry is comprised of five projects. The cash flows of each project is shown in the following table:

Cash Flows
(Dollars per Year)

Project No.	1	2	3	4	5	6	7	8	9
P1	-762	300	350	250	a	a	a	a	a
P2	a	a	-317	100	60	75	102	a	a
P3	a	a	a	-200	100	60	61	40	a
p4	a	a	a	a	-97	68	40	63	a
P5	a	a	a	a	a	-50	100	125	150

Objective: Compare the DCF rate of return that the industry is making during year 5 with the DCF rate that is generating over its entire life (years 1 through 9).

Analysis: Only projects P2, P3, and P4 are active during year 5. The industry's overall sequence of cash flows produced by each of the active projects is determined and put into set notation.

$$T_S = [-317, -100, 63, 203, 103]$$

Next, calculate the industry's DCF rate of return during the fifth year given its composit configuration of cash flows, "TS." The rate of return, "r," is found to be 10 percent.

On the other hand, the industry's overall configuration of cash flows for its entire life (years 1 through 9) are given in set notation by Tl-9.

$$T_{1-9} = [-762, 300, 33, 150, 63, 153, 303, 228, 150]$$

It can be determined that the industry is generating a DCF rate of 15 percent over its entire life.

This example points out three facts: (1) there is only one true DCF rate of return for an individual project, (2) the DCF rate of return for a company or an ongoing industry can be calculated or estimated for a given period or point in time if the configuration of its net cash flows can be determined or estimated for this same period or point in time, and finally, (3) the DCF rate for an industry or company may change with time as the overall mix of its individual projects change.

APPENDIX J

RAIL TRANSPORT OF COAL

INTRODUCTION AND SUMMARY

In 1969, some 560 million tons of bituminous coal and lignite were mined in the United States. Of that total, 376 million tons, or 67 percent, moved by rail. Forecasts of 1985 consumption of domestically mined coal in U.S. and export markets imply a production of 950 million to 1 billion tons. If the railroads were to retain their historic market share, they could expect to originate approximately 600 to 650 million tons of coal in 1985. Such growth implies a 3.5-percent average annual increase.

Over the past decade, annual growth of rail coal traffic has averaged 2.4 percent. Thus, there appears to be little question as to the railroads' ability to handle this tonnage. Moreover, the trend toward increased use of unit trains will facilitate and encourage the shipment of increasing coal volumes by rail.

Although the railroad industry currently suffers from serious financial problems, it is fundamentally viable. Moreover, the railroads are so basic to the economy that the Federal Government must find ways to underwrite their physical capabilities if such action is required in special cases.

THE COAL-RAIL SYMBIOSIS

Coal and railroads are critically interdependent. The rails are the leading transporter of coal, and coal is the most important commodity moving by railroad.

In 1969, the average value of a ton of coal, f.o.b. mine, was $4.99 while the average rail freight revenue per ton of coal originated was $3.11, or 62 percent of its pit-head value. Figure J-1 details the trend of coal value and rail freight revenue since 1960. Although the rail costs of coal transport may appear high in relation to value, they have in fact declined significantly over the long run. In 1928, rail revenues stood at 122 percent of coal va1ue.* Recent trends in coal prices and increased use of bulk shipments and rates should reduce this margin still further. However, transportation costs are obviously a most significant factor in the ultimate price of coal, and they playa central role in determining coal's competitive position in many energy markets.

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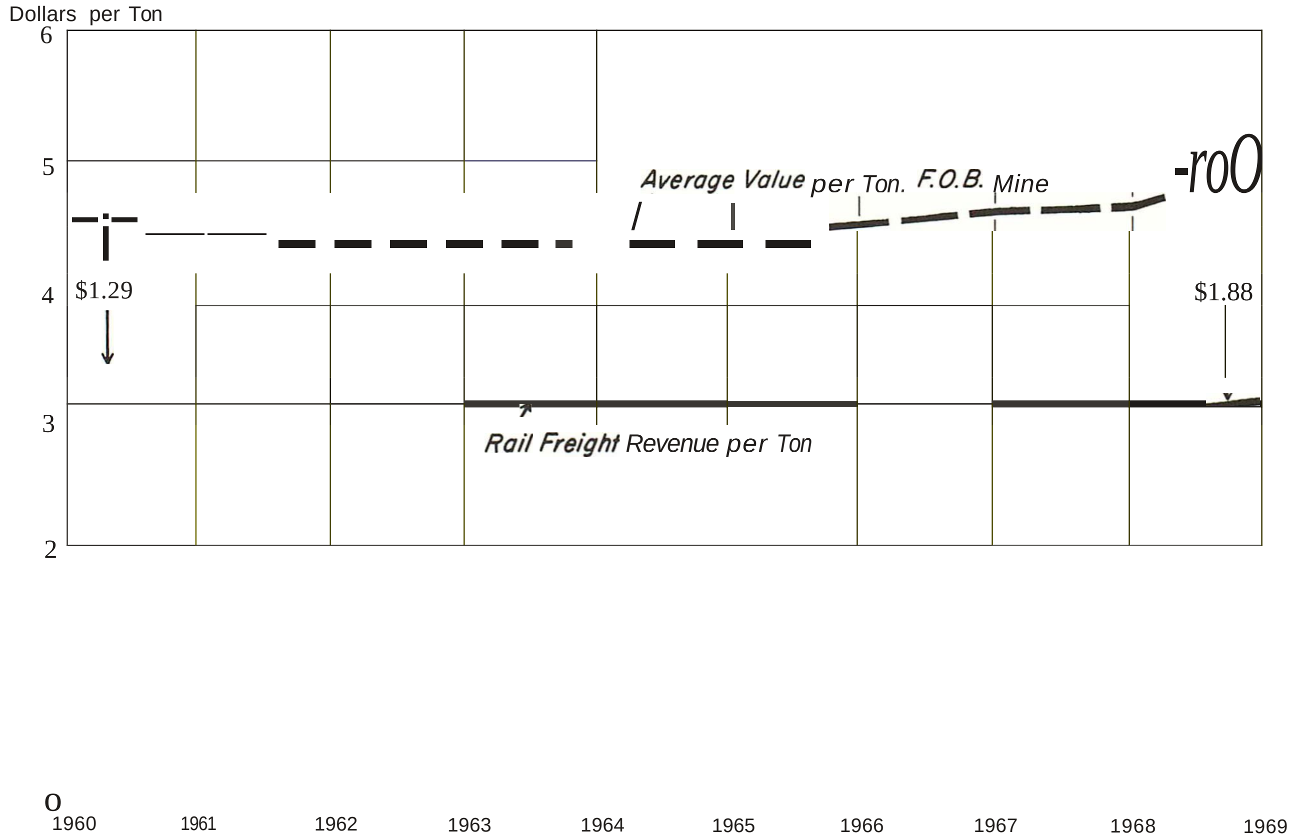
* Interstate Commerce Commission (ICC), Finance Docket No. 23832 et a1., Witness G. A. Sandmann, Exhibit No. A-16, Appendix 42.



Source: Bureau of Mines, Minerals Yearbook, 1966 and 1969; Interstate Commerce Commission, Freight Commodity Statistics, 1960-69.

Figure J-1. Comparison of Bituminous Coal and Lignite Rail Freight Revenue and Value (Mine) per Ton.

The economics of rail transportation favor the high volume carriage of bulk commodities such as coal. In 1969, labor costs accounted for $0.59 of the total railroad expense dollar. Because the input of railroad labor relative to tonnage is very low for coal, especially if shipped in unit trains, it is an attractive traffic to railroad management, and the service can be offered at a relatively low cost. Furthermore, nearly all railroads suffer from excess capacity of fixed plant. To the extent that coal traffic can alleviate this excess and in the process provide revenues adequate to cover the out-of-pocket cost of the coal shipment plus some contribution to fixed costs, it is also welcomed by the railroads.

Over the past decade, Class I railroads have originated an average of 70 percent of all U.S. coal production, as shown in Table J-1.* Although the rail share has fallen slightly because of water and truck competition, large-scale diversion to other modes appears economically infeasible. However, mine-mouth generation, which obviates the need for coal transportation, is expected to rise.

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* Data on Class II railroads are unavailable; their inclusion would increase the rail share above that shown in Table J-1.

TABLE J-1

COAL ORIGINATIONS ON CLASS I RAILROADS
AS A PERCENT OF TOTAL DOMESTIC PRODUCTIONS
1960-1969*

	Million Tons: Production of Bituminous Coal and Lignite	Million Tons: Rail Tons Originated	Rail as Percent of Production
1960	415.5	304.5	73.3
1961	403.0	296.9	73.7
1962	422.1	312.2	74.0
1963	458.9	331.7	72.3
1964	487.0	345.0	70.8
1965	512.1	352.6	68.9
1966	533.9	367.5	68.8
1967	552.6	376.7	68.2
1968	545.2	371.7	68.2
1969	560.5	376.3	67.1

* Bureau of Mines, *Minerals Yearbook*, 1966 and 1969; Interstate Commerce Commission, *Freight Commodity Statistics*, 1960-1969.

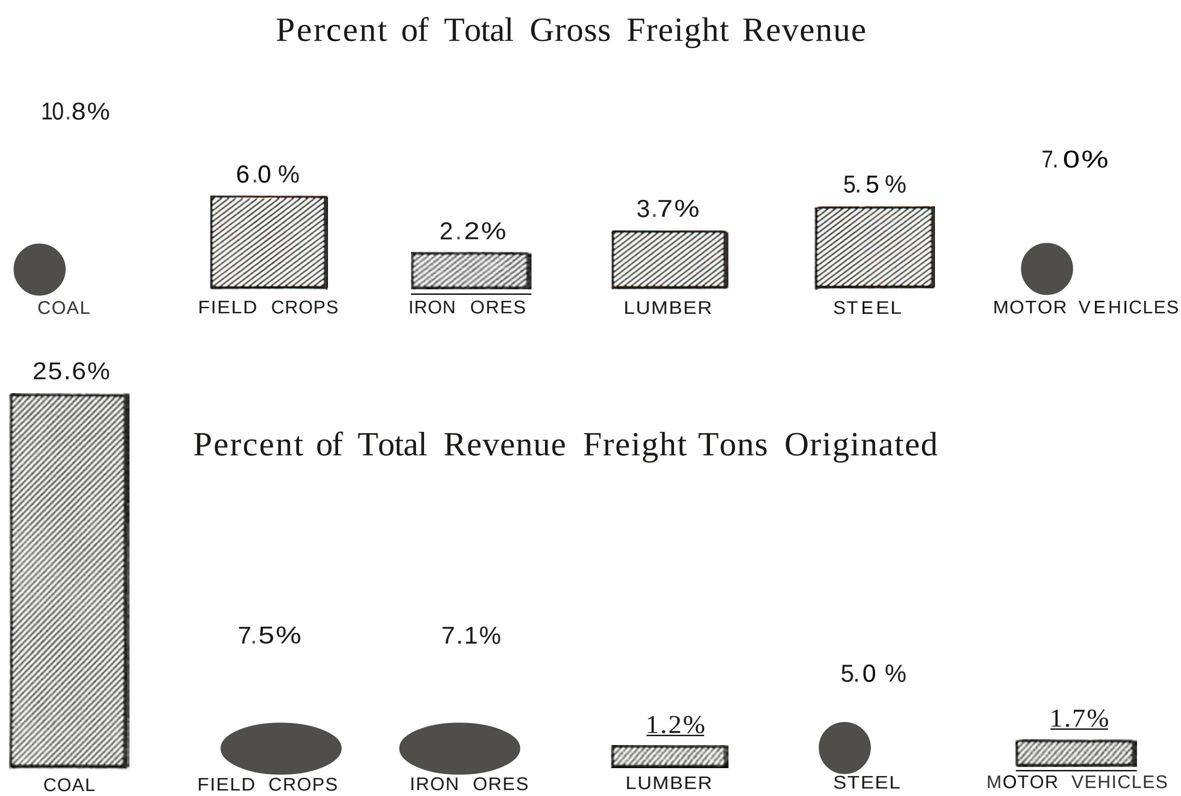
For many years, coal has ranked first among all commodities in rail traffic and revenues. Its importance is contrasted with the contributions of other leading commodities in Figure 3-2, which shows that in 1969 coal contributed 10.8 percent of total rail freight revenues and 25.6 percent of all freight tons originated.

TRENDS IN COAL TRANSPORT BY RAIL

Both carloads and originated tons of rail coal declined between 1948 and 1961, as depicted in Figure 3-3. Subsequently, originated carloads remained nearly constant, while tons originated increased, so that by 1969 the 5 million carloads and 376 million tons of rail coal represented increases of about 6 and 27 percent, respectively, over 1961.

Export Markets

Overseas and Canadian markets have increased from 30 million tons in 1960 to over 65 million tons in 1970 (Table 3-2). In 1970, over 11 percent of all coal shipments were exported. Highly intensive distribution systems have been established from the coal fields to Hampton Roads for overseas exports and to the lower



Source: Interstate Commerce Commission, Freight Commodity Statistics, 1964-1969

Figure J-2. Contribution of Coal and Other Selected Commodities to Total Rail Freight Revenues and Traffic--1969.

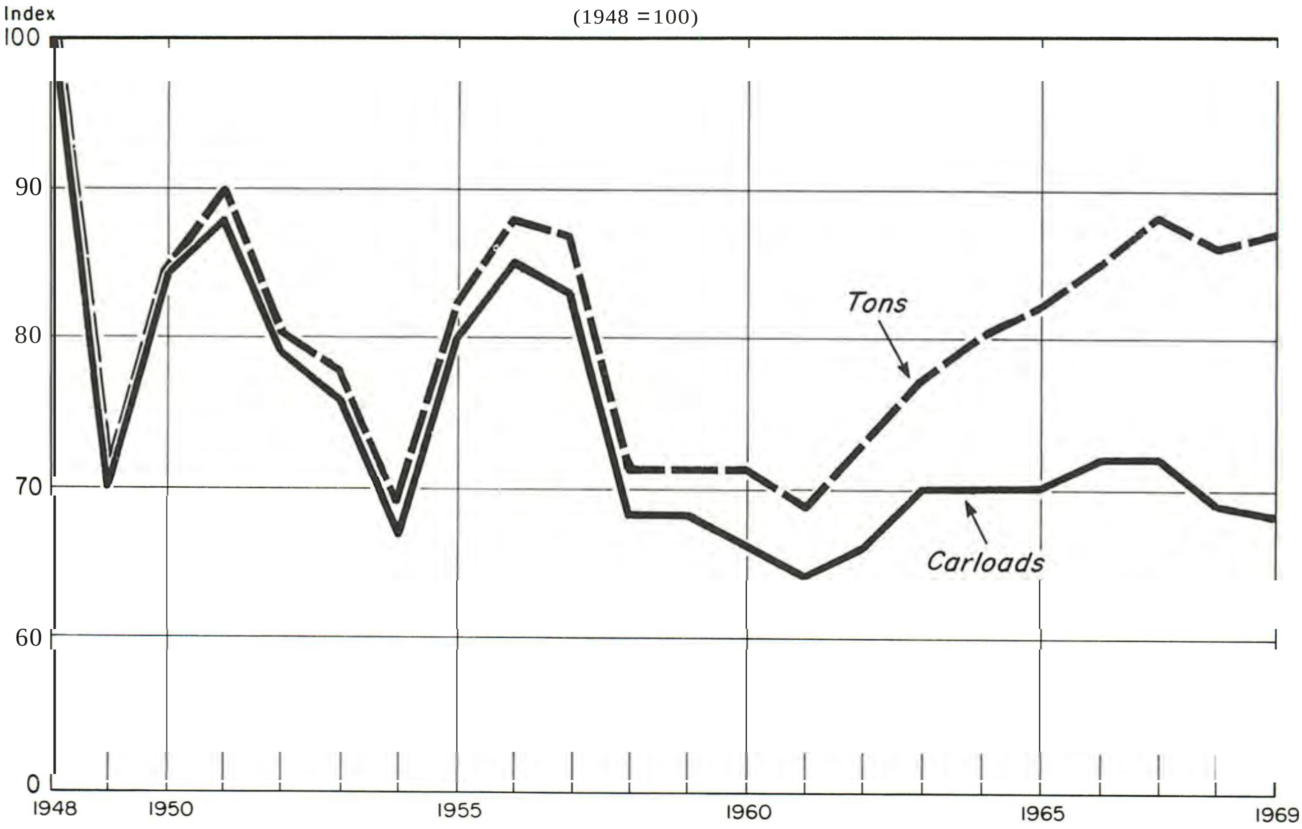
Great Lakes ports of Ashtabula, Conneaut, Sandusky and Toledo for Canadian exports. In the case of Conneaut, Ashtabula and Sandusky, the presence of modern ground storage, reclaiming and transshipment facilities has brought above near maximum realization of bulk transport potential. On the other hand, the situation at Hampton Roads, discussed later in this Appendix, presents a different picture.

Unit Trains

Locomotives and cars exclusively devoted to coal which move in regularly scheduled operations between one origin and one destination--in conjunction with bulk rate tariffs, typically specifying minimum annual tonnages and often providing for inverse price variation with volume--have considerably enhanced coal's competitive posture over the past decade.*

The benefits of unit train operation are widespread:

* Bureau of Mines, *Unit Train Transportation of Coal*, Information Circular 8444 (1970).



Source: Interstate Commerce Commission, Freight Commodity Statistics, 1948-1969.

Figure J-3. Indices of Bituminous Coal Originated by Class I Railroads--1948-1969.

TABLE J-2

U.S. EXPORT COAL--OVERSEAS AND CANADA*
(Thousands of Export Tons)

	Overseas	Canada	
		Electric Utility	Metallurgical
1960	24,818	174	4,715
1961	23,780	122	5,257
1962	27,041	1,169	5,042
1963	33,317	2,483	5,652
1964	33.733	3,175	5,547
1965	34,746	4,001	5,292
1966	33,527	4,506	5,854
1967	34,174	4,932	5,513
1968	33,998	5,661	6,698
1969	39,361	6,577	6,449
1970	51,766	8,310	7,220

* Bureau of Mines, *Mineral Industry Surveys*, "Bituminous Coal and Lignite Distribution," 1960-1970.

- For coal producers, long-term contracts permit larger capital investment, cutting production costs

- For railroads, better equipment utilization and more intensive use of plant enhance competitive position *vis-a-vis* other modes

- For the coal consumer, unit trains lower fuel costs and provide for a more stable fuel supply.

It has been estimated that unit train coal shipments have a rate advantage from 25 to 40 percent under conventional trains (the larger reductions have been attained with shipper-owned equipment) and that the savings in fuel costs to electric utilities due to unit train use may be as much as $100 million per year.*

Reliable statistics on the amount of coal that moves in unit trains are not available. Estimates provided the Bureau of Mines by coal producers are set out in Figure J-4 and indicate that unit train shipments of coal have increased by 20 million annual tons in the 1967-1969 period. Other estimates put unit train participation in the haulage of coal at 50 percent or more.† Divergence in estimates rests mainly on differing definitions of unit train operations.

TRENDS IN RAIL PRODUCTIVITY

Some significant gains in railroad productivity have been made during the past decade.

Operations

Since 1960, car utilization as measured by average daily freight car-miles per car, has increased over 20 percent, from 45.7 in 1960 to 55.3 in 1969. Only a small fraction of this improvement is attributable to higher freight train speeds, which increased only 3 percent from 19.5 to 20.1 miles per hour between 1960 and 1969.

In rail coal, specific productivity gains have centered on the operation of unit trains and ancillary shipping and receiving facilities. Larger capacity cars with higher payload/tare ratios

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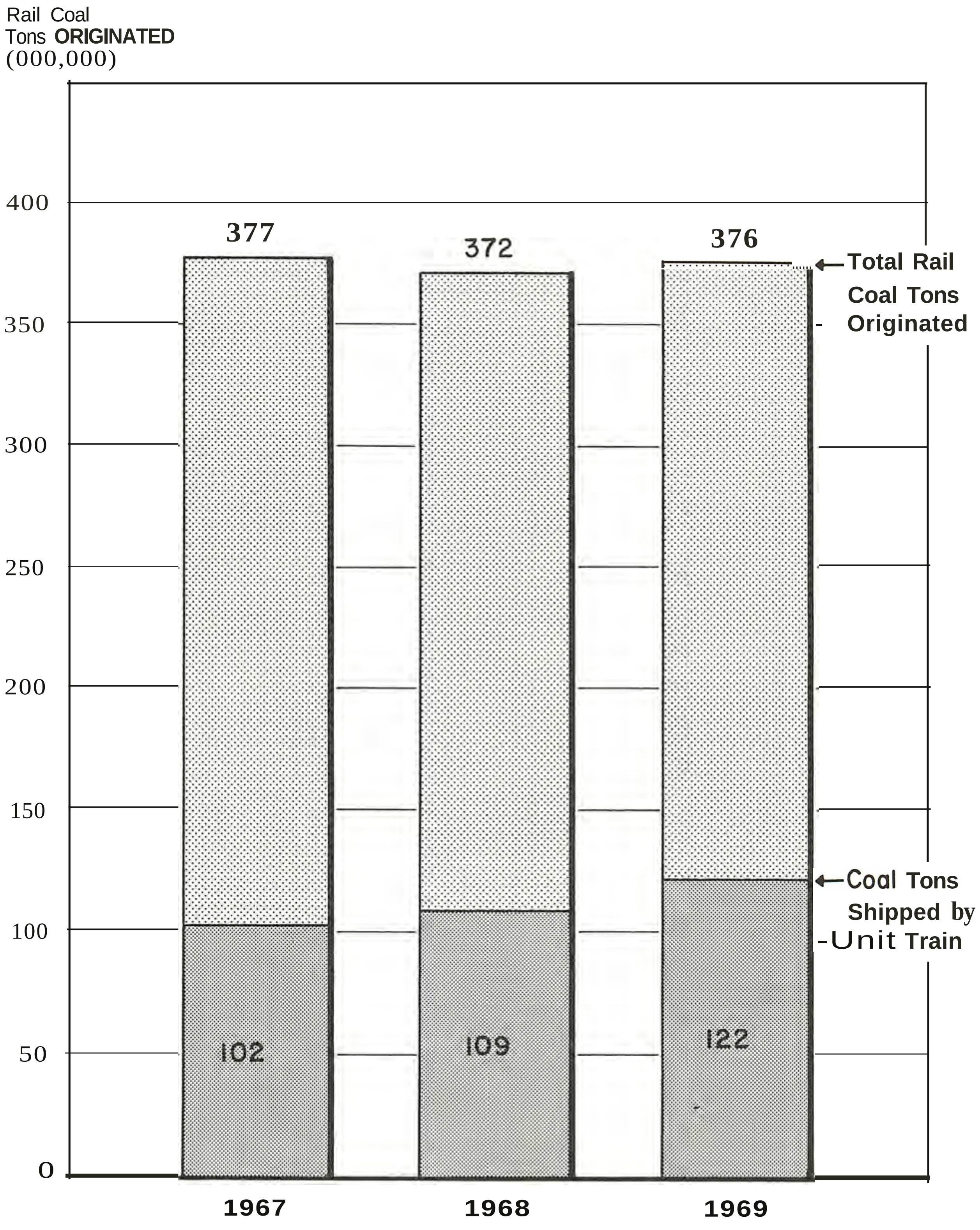
* "To Eat and Keep Warm," *Transportation and Distribution Management* (March 1971).

† Lewis K. Sillcox, "Establishing Railway Excellence," Speech Presented Before Northwestern University, Chicago, Illinois, March 19, 1970; "To Eat and Keep Warm," *Transportation and Distribution Management* (March 1971).



Source: Bureou of Mines, Minerals Yearbook, 1968 and 1969.

Figure J-4. Unit Train Participation in Rail Coal Movements.

have been designed especially for coal shipments. Automated loading and weighing facilities have been built at coal origins. Rotary car dumpers or rapid discharge hopper cars transfer coal to ground and silo storage complexes from which coal is reclaimed as needed. The importance of efficiency gains in other than line-haul rail transport weighs heavily.

In terms of increased car utilization, "[I]t is not unusual in unit-train operations today to obtain 10 to 15 and even more loads a month from a single car when the handling of the same commodity in regular service produced only two to three loads a month and sometimes not even that."*

Labor Performance

Enhanced utilization of railroad labor has resulted from improved operating practices and new investment. Table J-3 indicates that revenue ton-miles per employee had risen over 80 percent between 1960 and 1969 for railroads in general and had gained 66 percent on the coal-carrying roads. Although the *percentage* gain for the latter is less than that for all railroads, the coal roads actually, had a larger *absolute* gain in revenue ton-miles per employee in the 1960-1969 period.

Plant

Another gain in railroad productivity relates to the use of plant, as measured by miles of track and net investment. Between 1960 and 1969, revenue ton-miles per mile of track grew 42 percent, and revenue ton-miles per dollar of net investment rose 33 percent (see Table J-4).

RAIL INDUSTRY ASSESSMENT

Economics

Railroad economics is grounded in sunk costs. Although new mine spurs may be built, they are implicitly justified only by the existence of a national network with rail access, as need arises, to extant and foreseeable markets. The continued ability of the rail industry to serve an expanding coal market rests upon this national system *in being,* which has a pervasive influence upon railroad costs and pricing.

As constituted, the system has a substantial amount of investment that serves no present economic purpose. In the last decade, total track-miles have been reduced by some 14,000, with

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* American Association of Railroad Superintendents, *Advantages and Disadvantages of Unit Trains,* Report of Committee No.5, Washington, D.C., June 17-19, 1969.

TABLE J-3

TREND OF LABOR PRODUCTIVITY
ALL CLASS I AND SELECTED COAL RAILROADS*

	Revenue Frt. Ton-Miles (Thousand)	No. of Employees	R.T.M. per Employee Number	R.T.M. per Employee Indext
		All Class I Railroads		
1960	572,309	780,494	733,265	100
1961	563,361	717,543	785,125	107
1962	592,862	700,146	846,769	U5
1963	621,737	680,039	914,267	125
1964	658,639	665,034	990,384	135
1965	697,878	639,961	1,090,501	149
1966	738,395	630,895	1,170,393	160
1967	719,498	610,191	1,179,136	161
1968	744,023	590,536	1,259,911	172
1969	767,847	578,302	1,327,796	181
		Selected Coal Railroadst		
1960	116,505	120,696	965,276	100
1961	111,419	110,149	1,OU,530	105
1962	119,157	108,839	1,094,801	113
1963	129,772	107,405	1,208,249	125
1964	132,747	105,307	1,260,571	131
1965	148,099	102,648	1,442,785	149
1966	152,825	102,022	1,497,961	155
1967	150,425	100,735	1,493,274	155
1968	151,683	98,894	1,533,794	159
1969	155,754	97,142	1,603,364	166

* ICC, *Transport Statistics in The United States*, 1960-1969, and *Wage Reports (Form A and B)*

t 1960=100

‡ Baltimore and Ohio, Chesapeake and Ohio, Chicago and Eastern Illinois, Clinchfield, Louisville and Nashville, Norfolk and Western Maryland.

concurrent improvement in efficiency of the remainder by wider installation of Centralized Traffic Control (CTC), an advanced signal system, as detailed in Table J-5.

TABLE J-4

PRODUCTIVITY OF RAIL PLANT*

	Revenue Freight Ton-Miles per Mile of Track†		Revenue Freight Ton-Miles per Dollar of Net Investment	
	Number	Index‡	Number	Index‡
1960	1,596,310	100	21	100
1961	1,583,151	99	21	100
1962	1,680,719	105	23	110
1963	1,770,962	111	24	114
1964	1,897,510	119	25	119
1965	2,020,363	127	27	129
1966	2,146,491	134	27	129
1967	2,106,882	132	26	124
1968	2,189,713	137	27	129
1969	2,271,719	142	28	133

* Association of American Railroads, *Statistics of Railroads of Class I in the U.S., Years 1959-1969* (August 1970); *Yearbook of Railroad Facts* (1970).

† Total miles of track, including multiple main tracks, yard tracks and sidings, owned by both line-haul and switching and terminal companies.

‡ 1960=100

TABLE J-5

IMPROVEMENT OF EFFICIENCY OF TRACK MILES*

	Total Miles of Main Track	Miles of CTC	Ratio CTC to Total
1960	254,860	35,997	0.14
1965	243,869	44,025	0.18
1966	243,220	44,758	0.18
1967	242,465	48,891	0.20
1968	241,870	48,984	0.20
1969	240,982	50,000	0.21

* Association of American Railroads, *Yearbook of Railroad Facts* (April 1970); Interstate Commerce Commission, *Transport Statistics in the United States*, (1960 and 1965-1969).

However, excess capacity remains a serious problem, and the current trend is towards accelerated disinvestment. Nevertheless, retention to 1985 and beyond of economically justified rail plant, including most trunk routes and branches serving active coal sources and markets, is certain.

Railroad survival and prosperity are hinged on several factors, which are discussed in the following sections.

New Investment

Poor earnings in recent years have limited the ability of the railroads to make needed investment in new plant and equipment. This development has not, however, had any noticeable effect on investment related to coal shipments. In numerous cases, new investment in coal cars and in shipper/receiver rail related facilities has come from non-railroad sources, principally electric utilities.*

Investment in facilities for loading export rail coal has been intensive at the Ports of Conneaut, Ashtabula and Sandusky. Their automated plants feature stacking-reclaiming to and from ground storage and high-speed vessel loading. Taken together with older ports, the rail/Great Lakes interface should be adequate to serve forecast Great Lakes export coal tonnage.

At Hampton Roads some new investment has been made, but the exclusion of the larger bulk carriers from the port apparently precludes further large-scale new investment.

Because of the large increases in overseas sales of U.S. export coals as projected to 1985, there is concern as to the adequacy of Hampton Roads to handle the growIng coal traffic. A possible solution to this dilemma is the proposal to construct a deepwater bulk cargo transshipment port at Lorneville, New Brunswick, Canada. This port would receive U.S. export coal from Hampton Roads in 75,000 ton shuttle ships and discharge it into 250,000 ton bulk carriers for onward movement to Japan.t Another possibility is the proposed construction of an island in Delaware Bay which would permit loading and unloading of giant ships of the new ore, bulk, oil (O.B.O.) class. These vessels require up to 75 foot minimum depths for their 250,000 deadweight ton (DWT) size.+

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* " Unit Trains: The Reason for Coal's Comeback," *Railway Gazette International* (February 1971).

t "Decision Is Likely on Transshipment Port Project," *The Globe and Mail (Toronto)* (January 15, 1971).

‡ "New Island Urged as Giant-Ship Port in Delaware Bay," *The New York Times* (February 1, 1971).

Productivity

Productivity has recently improved, but the comparison in Table J-6 suggests that much more could be accomplished, especially with respect to open top hopper (coal-carrying) cars. In 1968 all such cars, in both carrier and shipper ownership, spent only 28 days per year (7.7 percent of the time) in line-haul service (loaded and empty movement in trains), as opposed to 49 days for other freight cars. The data on hopper car use reflects, of course, 1968 unit train operations; increased use of unit trains is expected to improve hopper car utilization in the years ahead.

TABLE J-6

FREIGHT CAR UTILIZATION
OPEN TOP HOPPER VERSUS ALL OTHER FREIGHT CARS
1968*

	Open Top Hoppers (General Service)	All Other Freight Cars
Cars in Service (12/31/68)	371,749	1,082,134
Car-Miles (Thousands)	4,293,259	25,531,917
Average Freight Train Speed in Line-Haul Service (mph)t	17.4	20.4
Days per Year in Line-Haul Service	28	49
Percent of Time in Line-Haul Service	7.7	13.4

* Association of American Railroads, *Statistics of Railroads of Class I in the United States, 1959-1969* (August 1970) and *Yearbook of Railroad Facts* (April 1970); ICC, *Ratios of Empty to Loaded Freight Cars-Miles by Type of Car and Performance Factors for Way, Through and All Trains Combined, Class I Line-Haul Railroads, Calendar Year 1968*, Statement No. 6-69 (September 1969).

t Eastern District Average used for Hopper Cars to approximate average coal train speeds; U.S. average used for all other freight cars.

A substantial portion of existing coal cars are older SO and 70 ton hoppers, which are not only expensive to maintain but also have a high tare (empty weight) to net ratio. The trend in new equipment is toward the use of lightweight, maintenance free material, 100 ton capacity, and designs for automated, high speed unloading.

Locomotive manufacturers are producing units with greatly increased horsepower ratings at less than proportionate increases in price. A decade ago the typical locomotive unit was rated at 1,500 to 1,800 horsepower. Today 3,000 to 3,300 horsepower units are common and 3,600 horsepower units are not unusual. Such locomotives are particularly attractive for the line-haul movement of coal involving heavy loads at moderate speeds.

Productivity gains from replacement of old equipment are expected to continue, with particular impact on coal traffic from increased use of unit trains.

Among the other influences and forces which are now at work to project into the future the efficiency trends already experienced are--

- Reduction in the number of separately operated companies by merger, acquisition of control or directed inclusion
- Introduction of automatic freight car identification
- Interline transmission of electronic computer data
- More widespread use of interdivisional runs and reduced crew consists.

Car Supply

Most coal is shipped in open top hopper cars and, conversely, coal is the leading commodity, as to tonnage and revenue, loaded in such cars. Since 1960 the number of these cars and their aggregate capacity has declined. Table J-7 indicates that the decline in the number of open top hoppers in the 1960-1969 period has been largely offset by an increase in average car capacity, with many newly built cars having 100 ton payloads.

The recent shortage of coal cars is considered to be temporary, a situation flowing from an unprecedented and unanticipated surge in coal demand, created in turn by shortfalls of other energy sources. In the long run, aggregate car supply is not expected to be a problem in the railroads' future ability to handle projected coal shipments. The process of providing a satisfactory car supply will, however, be an uneven one. It may, at almost all times, be expected that the railroads will be unable to fully satisfy the car supply requirements of individual coal shippers or of classes or groups of such shippers. Continuing litigation on ramifications of this issue will characterize the future as it has the past. Examples of pertinent current litigation are Interstate Commerce Commission Docket No. 12530, "Assigned Cars for Bituminous Coal Mines" and No. 35188, "Harlan County Coal Operators' Association, et al *vs.* Louisville and Nashville Railroad Company." In any short-term shortage, the railroads could face a dilemma in allocation of available cars between domestic and export consignments. It is likely that, in common with coal producers, the rails will make every effort to accommodate both markets, avoiding the painful choices forced by inadequate car supply.

TABLE J-7

OPEN TOP HOPPER CAR FLEET AND CAPACITY*
CLASS I RAILROADS

		Open Top Hopper Cars (Capacity)		Index (1960=100)		
		Aggregate	Per Car		Capacity	
	Number	(Thousand Tons)	(Tons)	Number	Aggregate	Per Car
1960	480,445	29,105	60.6	100	100	100
1961	462,149	28,075	60.7	96	96	100
1962	440,368	26,981	61.3	92	93	101
1963	431,712	26,755	62.0	90	92	102
1964	431,791	27,719	64.2	90	95	106
1965	425,236	27,894	65.6	89	96	108
1966	422,546	28,404	67.2	88	98	111
1967	415,275	28,787	69.3	86	99	114
1968	403,201	28,454	70.6	84	98	117
1969	388,609	27,954	71.9	81	96	119

* Association of American Railroads, *Statistics of Railroads of Class I in the United States, Years 1959-1969* (August 1970).

Hampton Roads

A relatively heavy cost is borne by shipments of export coal to Tidewater because of the meticulous demands of the overseas customers of U.S. exports for particular blends of metallurgical coal. Neither shippers nor carriers have developed ground storage facilities to cope with these demands. Hence, many cars are detained at port to serve as storage until particular orders are filled. Recent action has alleviated this problem. On September 1, 1970, the Norfolk & Western and Chesapeake & Ohio instituted a "Permit System" which requires export coal shippers to name a vessel and its estimated time of arrival at the port *before* cars are made available. The success of this program can be illustrated by the fact that the number of hoppers free on line (ready for loading) on the Norfolk & Western has increased from 13,000 to 18,200 cars during the past year.*

Competition

Intermodal competition has eroded much of the railroads' historic traffic base, especially of high rated commodities. Although

* Interview with Lawrence T. Forbes, Vice President, Coal & Iron Ore Traffic, Norfolk & Western Railway Company, March 23, 1971.

this trend has subsided in recent years, experienced losses have impaired the financial viability of many roads. The emergence of extra high voltage (EHV) transmission lines and solids pipelines will divert substantial additional coal tonnages from the railroads. In the past, the railroads have made a number of successful rate concessions to counter competition.

The trend of intermodal competition is set out in Figure J-5, with no significant change expected through 1985. The most severe threat to the railroads will be from mine-mouth power plants, which eliminate coal transport altogether. The use of these plants is expected to rise primarily due to the increasing need to reduce air pollution in major urban centers. Coal slurry pipelines, used in special situations which preclude economic railroad operation, will have a more limited impact.

Regulation

Railroad regulation was designed to check monopoly power. Today the monopoly has evaporated but regulation remains. Regulatory relaxation is a popular concept. Various proposals have been offered:

> The Interstate Commerce Commission's efforts to eliminate price cutting among truckers, railroads, and bargelines is a classic example of the attempts to curb competition through regulation. The original justification for regulation-- that railroads were monopolistic-- has lost much of its validity since there is now considerable competition from other modes of transportation, although the shippers of some bulk commodities are still heavily dependent on rail transportation. Yet the ICC must continue to operate under the mandate of past transportation acts. Greater reliance on the market would be beneficial to transportation, but, in view of long established practices, this would have to be approached gradually. Except for predatory pricing to drive competitors from a market, which is prohibited under antitrust law, many transportation rates could safely be allowed to find their own level through competition. A policy of permitting and encouraging competition of all kinds would, if general economic experience is any guide, make the industry more efficient as well as benefit the public.*

Total deregulation is generally opposed by the railroad industry which is said to favor combining the existing regulatory agencies--the Interstate Commerce Commission (ICC), the Civil Aeronautics Board (CAB) and the Federal Maritime Commission (FMC)

* Economic Report of the President, Washington, D.C., 1970.

1/ Excludes overseas exports.
2/ Includes Conveyor and private railroad.

Source: Bureau of Mines, Mineral Industry Surveys, "Bituminous Cool and Lignite Distribution," 1960-1970

Figure J-S. Method of Movement of U.S. Production of Bituminous Coal and Lignite

--into a single entity.* It is important to stress that deregulation is being urged primarily where competition prevails. Coal and other commodities captive to rail transport can doubtless rely on relevant regulatory protection throughout the foreseeable future, with all which that implies as to rate structure stability.

It was once widely believed that mergers held the key to railroad improvement, but recent experience has not supported that view.

Seasonality

Except for the annual effect of the United Mine Workers vacation-based mine shutdowns each July, seasonality exerts relatively little influence on coal shipments. Figure J-6 graphically portrays monthly coal carloadings in 1969 and 1970. To some extent, seasonality has affected Great Lakes markets where lake vessel operations cease during winter months. However, two or three important lower Lake Erie ports have adequate ground storage; they can and do receive year-round rail shipments.

ABILITY TO SERVE THE PROJECTED 1985 COAL MARKET

As estimated in Table J-8, approximately $7 billion will be required for coal-carrying cars and associated motive power by 1985.

The railroads contend that their capital needs cannot be generated from internal sources even when supplemented by heavy borrowing. They call for increased government involvements as follows:

- Railroads must be exempted from local property taxation.
- Federal safety assistance programs for highway-rail grade crossings must be materially stepped up.
- Federal funds are necessary to help modernize the railroads' right-of-way.
- Congress should assist in the railroads' efforts to assure an adequate equipment supply.†

If present railroad financial difficulties continue, the Federal Government will undoubtedly provide some assistance. It

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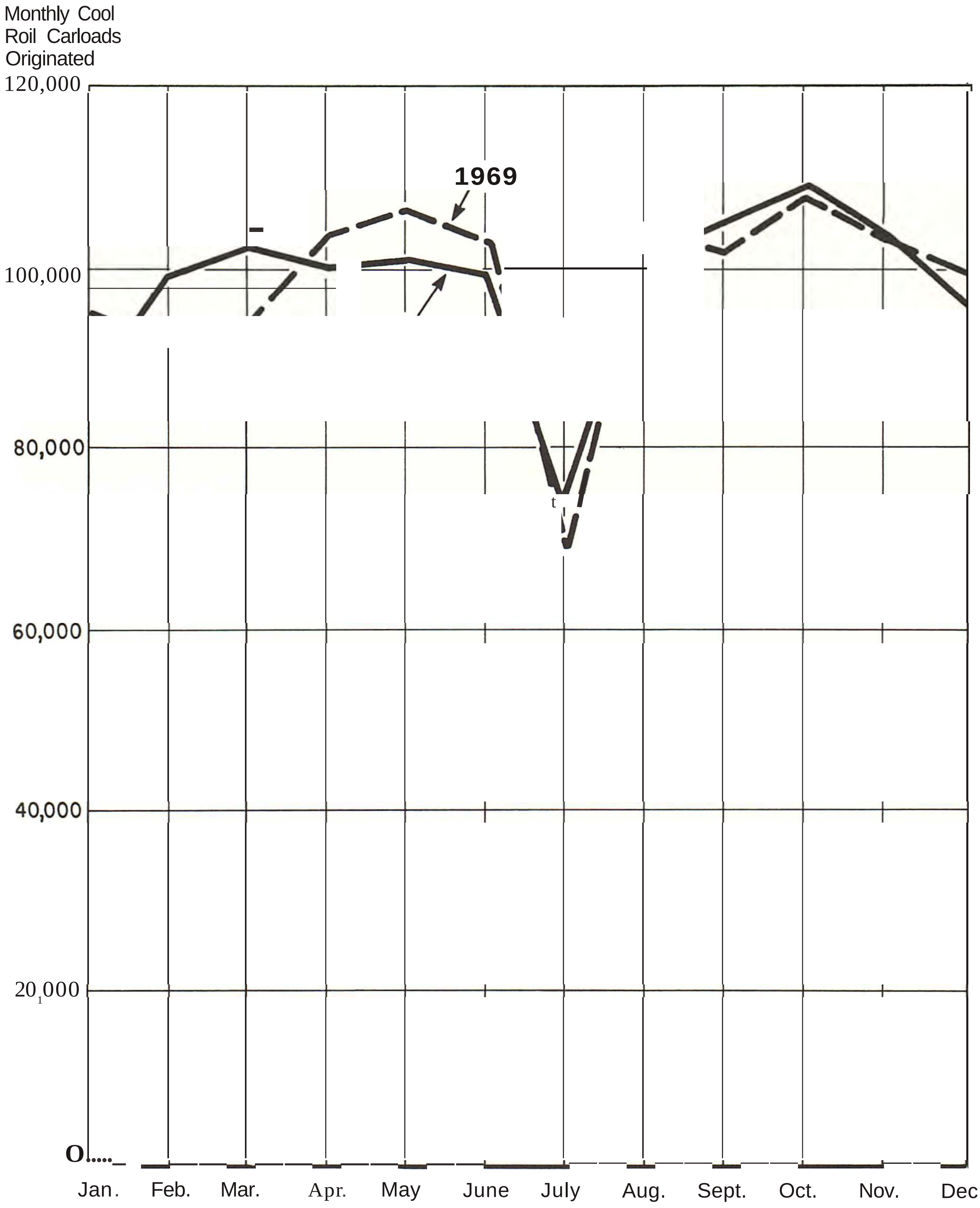
* "Rails Generally Opposed to Total Deregulation," *The Journal of Commerce* (February 8, 1971).

† America's Sound Transportation Review Organization (ASTRO) *The American Railway Industry: A Prospectus* (June 30, 1970).



Source: Association of American Rai/roads, *Revenue Freight Loaded by Commodities And Toto/ Received from Connections,* *Statement CS-54A.*

Figure J-6. Seasonality of Rail Coal Shipments.

TABLE J-8

ESTIMATES OF EXPENDITURE
FOR COAL-CARRYING CARS AND ASSOCIATED LOCOMOTIVES
BY CLASS I U.S. RAILROADS

Line No.		Amount	Source or Derivation
1	Projected Rail Movement of Coal in 1985 (Tons)	600,000,000	Estimated
2	Rail Coal Carloads	6,000,000	100 Tons Average per Car
3	Assumed Average Turn of Largely Unit Train Traffic (Days)	10	Estimated
4	Days per Year After Allowance for Mine Vacations, etc.	330	Estimated
5	Number of Turns per Year	33	Line 4 ÷ Line 3
6	Number of Cars Required	182,000	Line 2 ÷ Line 5
7	Number of Cars Including 10-Percent Spares	200,000	1.10 x Line 6
8	Cost of Cars	$4,000,000,000	$20,000 x Line 7
9	Number of 100 Car Train Sets Including Spares	2,000	Line 7 ÷ 100
10	Number of Locomotive Units	10,000	Line 9 x 5
11	Cost of Locomotive Units	$3,000,000,000	$300,000 x Line 10
12	Cost of Cars and Locomotives--1985	$7,000,000,000	Line 8 + Line 11

has no practicable alternative but to assure the continued railroad transportation of coal. Coal supplies are an absolute necessity for the generation of electricity, and the contemplation of widespread blackouts is unacceptable. A policy of uninterrupted service has been manifest from several governmental responses to railroad strike threats.

There seems no reason to doubt that modern rail plant and equipment, adequate to meet projected coal transport requirements, will be available. Rail transport will be generally satisfactory through 1985 not only for existing coal consumers but also for new markets which may develop, as recently demonstrated in several western coal fields.

APPENDIX K

WATER TRANSPORT OF COAL

Water transportation of bituminous coal has developed into a major component of the U.S. energy distribution system. As the gateways and channels in the U.S. energy supply during the remainder of the 20th century, waterways and harbors will be able to accommodate the rising demands being placed upon them only by enlargement and modernization of channels and navigation works. While this necessity is equally urgent with respect to the supply of crude oil, gasoline, fuel oil and other petroleum fuels, this paper confines attention to bituminous coal.

MAGNITUDE AND IMPORTANCE OF WATER TRANSPORTATION OF COAL

Projection of Tonnage of Waterborne Coal

An increase in domestic waterborne carriage of bituminous coal from 153.0 million tons in 1969 (the latest year reported) to over 220 million in 1980 appears a reasonable expectation. Most of this increase will consist of the rapidly growing movement on rivers and canals, which now constitutes most of the waterborne total and the most rapidly rising segment. Table K-l summarizes waterborne coal movements from 1955 through 1969, with projections for 1980 and 1985. The projections of U.S. consumption are those of the Demand Group of the NPC's Coal Task Group.

It will be noted in Table K-l that in 1969 domestic waterborne movements constituted 30.2 percent of total U.S. coal consumption. While coastwise, lakewise and local harbor tonnages had all undergone some net reduction from the 1955 level, they amounted in 1969 to an aggregate of 49.6 million tons.* On the other hand, internal (river and canal) movements rose by 44.6 percent from 1955 to 1969, amounting in the latter year to 103.4 million tons.†

With respect to lakewise and local movements, the projections of Table K-l may be moderately on the high side. However, total coastwise movement may be sustained or increased in the future by the rising tonnages carried coastwise from the New Orleans area to other Gulf ports. The Gulf coastwise movement rose from 0.6 million tons in 1960 to 3.1 million in 1969. With respect to internal movements, the projections may be well too low. They as-

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* *Coastwise* denotes deep-draft domestic movements on the open oceans; *Lakewise* denotes deep-draft domestic movements on the Great Lakes.

† *Internal* denotes shallow-draft barge movements on rivers, canals and intracoastal waterways.

TABLE K-1

U.S. CONSUMPTION OF BITUMINOUS COAL AND
BITUMINOUS COAL WATERBORNE IN U.S. DOMESTIC COMMERCE

	Total U.S. Domestic Consumption--Tons† (Thousand)	Waterborne Coal--Long-Haul*								Local Coal Movements		Total Waterborne Coal	
		Coastwise		Lakewise		Internal		Total Long-Haul					
		Tons (Thousand)	%	Tons (Thousand)	%	Tons (Thousand)	%	Tons (Thousand)	%	Tons (Thousand)	%	Tons (Thousand)	%
1955	423,412	9,784	2.3	39,612	9.4	71,505	16.9	120,901	28.5	18,913	4.5	139,814	33.0
1960	380,429	7,622	2.0	36,099	9.5	73,345	19.3	117,066	30.8	15,164	4.0	132,230	34.8
1965	459,164	10,048	2.2	39,847	8.7	92,424	20.1	142,319	31.0	14,326	3.1	156,645	34.1
1969	507,275	7,648	1.5	30,882	6.1	103,400	20.4	141,930	28.0	11,105	2.2	153,035	30.2
1980‡	734,000	14,700	2.0	44,000	6.0	149,700	20.4	208,400	28.4	16,100	2.2	224,500	30.6
1985‡	863,000	17,300	2.0	51,800	6.0	176,000	20.4	245,100	28.4	19,000	2.2	264,100	30.6

* U.S. Department of the Army, Corps of Engineers, *Waterborne Commerce of the United States*, Part 5 (Respective Years).

† U.S. Department of the Interior, Bureau of Mines, *Minerals Yearbook, 1969* (Preprint--1971) p.1. Projections by the Coal Task Group.

‡ Projected.

sume that the internal movements will remain at 20.4 percent of total U.S. consumption. This percentage, however, rose from 16.9 in 1955 to about 20.0 percent in 1962, and since 1962 it has continued to rise although more gradually. Should the rise in the percentage of internal movements in the U.S. total continue, the tonnage carried internally in 1980 would, of course, exceed the 149.7 million tons projected--a development which is not unlikely.

Waterborne Coal as a Contributor to Railroad Haulage

The capability of the navigation system also influences the coal-carrying potential of U.S. railroads. In 1969, about 63.4 million tons of coal--18.5 percent of the railborne total destined for domestic consumption--was joint rail and water movement.* This excludes tidewater and lake exports, practically all of which also move via rail connections at deepwater ports. Including exports, the rail and water tonnage was 29.8 percent of the total carried by rail.

Virtually all of the Atlantic coastwise movement of coal originates by rail, the largest portion transshipped at Hampton Roads, Virginia, for New England and other coastal destinations. In addition, most of the coal shipped on the Great Lakes to Michigan, Wisconsin and Minnesota ports originates by rail, and at the upper lake ports large tonnages are transshipped by rail to inland consuming destinations.

The largest tonnages shipped jointly by rail and water, however, move on the rivers and canals. In 1969, the joint rail and river barge movement amounted to about 34 million tons, out of a total of 103 million tons carried by barge. All of the coal shipped by barge from the Illinois shore of the Mississippi River originates inland by rail. The average rail distance to the river is about 50 miles. This movement grew from 4.9 million tons in 1960 to 6.4 million in 1969, an increase of about 31 percent.†

Again, since 1960, a growing portion of the metallurgical coal used in the Pittsburgh steel district is delivered by rail-barge from the area southeast of Huntington, West Virginia. Rail distances to the Ohio River are as much as 150 miles. This upstream movement grew from 3.5 million tons in 1960 to 6.8 million in 1969.

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* Calculated from: U.S. Department of the Interior, Bureau of Mines, "Coal--Bituminous and Lignite, *Minerals Yearbook, 1969,*" (Preprint--1971), p. 47; U.S. Department of the Army, Corps of Engineers, *Waterborne Commerce of the United States* (1969 and 1971).

† Unless otherwise indicated, waterborne tonnages cited herein are as reported by U.S. Department of the Army, Corps of Engineers, *Waterborne Commerce of the United States* (Respective Annual Issues).

Coal originated on the Monongahela River rose from 22.1 million tons in 1960 to 28.4 million in 1969. While a portion of this increase is accounted for by rising consumption of riverbank electric generating stations in the Pittsburgh area, another large portion consists of coal transshipped by rail to inland destinations in northern Pennsylvania and Ohio and to lake ports. Other illustrations of the rising portion of internal waterborne coal originating or terminating by rail could be cited. It should be emphasized, therefore, that the prospects for railroad coal haulage rest to a significant and growing degree on navigation capability of rivers and harbors.

The Influence of Unit Trains and High Voltage Transmission on Water Carriage

Improvements in railroad efficiency restrain the growth of waterborne movement in some instances and enhance it in others. Unit train movement from southern Illinois, for example, displaces a portion of the growth of waterborne tonnage on the Illinois River. On the other hand, unit trains connect with barge terminals to render feasible certain rail-water coal movements which would otherwise be less competitive.*

Similar observations may be made with respect to long-distance transmission of electric energy. In some instances, high voltage transmission from mine-mouth generating stations directly to service areas may displace what would otherwise be an expansion in waterborne coal tonnage. On the other hand, high voltage transmission induces the location of new generating capacity on navigable rivers for receipt of coal by barge and transmission of energy to inland service areas.

The 1962-1967 period may be taken as one of increased long-distance transmission of electric energy. However, during this 5-year interval, the coal received annually by barge at generating stations on the Ohio River and its navigable tributaries (excluding the Tennessee and Cumberland Rivers) increased by 3.6 million tons.† Generating stations on the Ohio River between the city of Louisville, Kentucky, and the Ohio-Pennsylvania border have a total capacity of 17,000 MW, of which 12,000 MW are used to serve remote load areas. A large portion--probably most--of the coal consumed by these stations is waterborne.

Therefore, it may be concluded that the media of unit trains and high-voltage transmission are both a stimulus and a restraint to the waterborne movement. In net effect, these media do not

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* See, for example, U.S. Department of the Interior, Bureau of Mines, *Unit Train Transportation of Coal*, IC8444 (1970), p. 90.

† The Ohio Valley Improvement Association, Cincinnati, Ohio, Survey of 1968.

appear to alter substantially the outlook for growth of waterborne coal tonnage.

Waterborne Coal as a Medium for Conserving Less Abundant Fuels

Water transportation of bituminous coal is especially valuable to the U.S. energy supply because it permits economical long-haul movement. On the one hand, coal is the only primary energy source available in abundance. Reserves of petroleum and natural gas are relatively more limited, and large quantities are imported.

However, offsetting this abundance, coal is the most expensive fossil fuel to transport. In 1968, the average railroad freight charge per ton of coal was $3.01, equal to 64.5 percent of the mine value.* The country's readily available coal reserves of high quality are concentrated in the Ohio River Basin and southern and central Illinois. In 1969, this region produced 82.9 percent of all the coal in the country.† In consequence, most of the remainder of the country, including all coastal regions and the entire west beyond the Missouri River, is deficient in economical access to this most abundant of fuels excepting where low cost water transportation connects the consuming areas with the Illinois-Ohio River Basin (not considering coal gasification or liquefication).

Costs for water carriage of coal are much less than for rail or truck. The 1965 average rail charge for coal haulage was 9.9 mills.‡ Large-volume, steady coal movements on the inland rivers, by contrast, commonly cost only 2.5 mills per ton-mile, and the average is probably about 3.0 mills.§ The service characteristics of water transportation are well suited to bulk commodities such as bituminous coal, and all U.S. navigable waterways, excepting the Mississippi River north of Alton, Illinois, the Missouri River, and the Great Lakes are fully navigable for 12 months every year. In consequence, the waterway system provides for low cost

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* National Coal Association, *Bituminous Coal Data (1970)*, p. 73.

† U.S. Department of the Interior, Bureau of Mines, *Minerals Yearbook*, 1969, (Preprint--1971), p. 9.

‡ U.S. Department of the Interior, Bureau of Mines, *Transportation of Mineral Commodities on the Inland Waterways of the South-Central States*, IC 8431 (1969), p. 18.

§ The charges for barging coal on certain tributary rivers where congestion in obsolete navigation facilities is serious are privately reported to be as high as 7.0 mills per ton-mile, the highest reported. These charges may be expected to decline substantially as modern navigation facilities are brought into service.

delivery of coal to distant markets which are beyond economical reach by rail or truck. It is noteworthy that barge movement of coal is less costly in terms of cents per million BTU's per mile than pipeline movement of natural gas and is comparable to pipelining of petroleum.

Growth in Long-Haul Movement to Coastal and Upper Midwest Markets

Regions thus served by water include New England and the states of Florida, Michigan, Wisconsin and Minnesota. Coal from the Ohio River Basin and southern Illinois is transported by river barges in continuous movement to major consuming centers, such as Chicago, Minneapolis, western Florida and Galveston, Texas. In the absence of water carriage, these markets, in view of their great distance from the coal fields, would have to rely on more costly rail transport, on the more limited reserves of oil and natural gas and, in some instances, on imported fuels.

One of the more notable long-haul water movements is the carriage of Ohio Basin coal by combined internal and coastwise haulage to Gulf Coast destinations. This coal is transported from the lower Ohio Valley by river barge to the New Orleans area and thence by oceangoing vessels to coastal consuming areas. Transshipment in the New Orleans area grew from 0.6 million tons in 1960 to 3.1 million tons in 1969. The principal destination is Tampa, Florida, where coastwise receipts of coal in 1969 amounted to 2.3 million tons. The movement is strengthened by a backhaul of phosphates from the Florida coast and by innovations in transshipment technology.

Long-haul movements are the most rapidly growing portion of internal waterborne coal carriage. An analysis of length of haul in 1965 and 1969 from Ohio Basin and Illinois origins appear herewith in Table K-2. It will be noted that, of the aggregate waterborne tonnage increase during the four years, 55.5 percent was for distances exceeding 250 miles, and 17.8 percent was for distances exceeding 1,000 miles. The waterways thus make coal available to markets otherwise beyond economical access, serving to economize on less abundant fields.

Role of Waterway Extensions and Connections in Long-Haul Movements

The long-haul service of waterway transportation, of course, is limited by the extent of the system. In other words, only coal fields and markets which have waterway access can be served, and some of these are less accessible because of the circuitry of the present navigation routes. This is a forceful reason for expeditious progress in the construction of new waterway connections and extensions. For example, the new Arkansas River Waterway makes the exceptionally high grade Oklahoma coal (in addition to petroleum fuels) more readily available to distant markets. Similarly,

TABLE K-2

GROWTH IN LONG-HAUL WATERBORNE MOVEMENTS OF BITUMINOUS COAL--
BITUMINOUS COAL ORIGINATED BY BARGE
IN THE OHIO RIVER BASIN AND SOUTHERN ILLINOIS
INCREASES IN TONNAGES SHIPPED BY LENGTH OF HAUL--1965 to 1969*

	Net Tons (Thousand)		Increase (1965-1969)	
Distance of Movement	1965	1969	Net Tons (Thousand)	Percent of Increase
Over 1,000 Miles	2,376	4,359	1,983	17.8
750-1,000 Miles	115	1,035	920	8.2
500-750 Miles	1,202	2,530	1,328	11.9
250-500 Miles	7,227	9,194	1,967	17.6
Under 250 Miles	75,493	80,459	4,966	44.5
Totals Originated	86,413	97,577	11,164	100.0

* Calculated from U.S. Department of the Army, Corps of Engineers, *Waterborne Commerce of the United States*, Part 5 (Respective Years); The long-haul waterborne tonnages of bituminous coal tabulated here represent continous movement via connecting waterways as far as Minneapolis-St. Paul, Chicago, Apalachee Bay, Florida, and Galveston, Texas. In 1969 3.1 million tons recieved by barge at New Orleans were transshipped by coastwise movement to other Gulf Coast destinations, principally to Tampa, Florida.

the waterway connection between the Tennessee and Tombigbee Rivers will open up new access to coal reserves and shorten distances of carriage. Ohio Basin coal now moves by water to the Gulf Coast of Florida but no farther. The Cross-Florida Barge Canal would constitute a new connection to South Atlantic coastal markets. While justification of these connections and extensions rests on a variety of commodity movements in addition to coal, the accessibility of this abundant energy source to markets now beyond economical reach emphasizes the urgency of progress.

Role of Rail-Water Coordination in Long-Haul Movements

The accessibility of coal to distant communities lacking waterway connections is likewise impeded by lack of sufficient rail-water coordination. We have cited previously the importance of rail-water movements. These might be considerably extended by the encouragement of rail-water and water-rail joint rates and through routes. Railroads have been highly enterprising with respect to their connections at deepwater harbors on the Great Lakes and Tidewater. However, the tendency remains in some instances to regard shallow-draft barging as inherently rail-competitive. By maintaining rates higher than necessary to and from river connections, joint movement by river and rail is discouraged.

In recent years, a growing number of railroads have participated in the "Willing Partner" program of arranging joint rates and through routes with water carriers to the common benefit of railroads, water carriage and shipping and receiving interests. The encouragement and extension of this program will tend to enlarge the geographical scope of the coal-based energy supply.

<u>Summary as to Magnitude and Importance of Waterborne Coal</u>

The waterborne transportation of coal is a substantial segment of the energy supply. River and canal movements have been growing rapidly, and this growth shows every promise of continuing. The low cost of waterborne carriage dramatically enlarges the geographical scope of economical availability of this abundant fuel, and the long-haul movements constitute the larger portion of the growth increment. In view of these considerations, policies conducive to a very substantial expansion and to sustained high efficiency in the waterborne coal movement are crucial to the country's long-term energy supply program.

<u>Managerial Latitude as a Stimulus to Technological Progress</u>

The first sector of public policy should be directed towards encouragement of the vigorous technological progress which has characterized water carrier operations and associated functions since before World War II. This means a latitude of managerial operating discretion and freedom from regulatory restraint on operations at least as broad as that which has prevailed in the past. In other words, past and existing regulatory policy with respect to private enterprise in water transportation has proved highly successful and should be continued.

Private enterprise in water transportation and in such related functions as vessel design, vessel construction and terminal operations has displayed over many years an immense competitive vitality. Particularly on the rivers and canals, the industry has been characterized by continuing and thoroughgoing technological progress. The central thrust of technology has been the rising productivity of labor and capital.

In the days when steamboats were handling most of the tonnage on the rivers, crews of 20 to 25 men on a towboat were common. In 1971, crews of only 9 to 12 men are most usual, moving twice the tonnage or more, approximately a four-fold increase in productivity per man. "In 1940, the towboat *Peace* moved an average of 250,000 ton-miles (of cargo) per towboat operating day. In 1966, a 3,200 horsepower towboat moved an average of 1,154,000 ton-miles per towboat operating day while a 6,400 horsepower towboat averages 2,269,000 ton-miles per towboat operating day."*

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* U.S. House Congress, Testimony of L. P. Struble, Jr., Executive Vice President, Dravo Corporation, before the Transportation and Aeronautics Subcommittee of the Interstate and Foreign Commerce Committee, October 3, 1967.

New technologies include the medium speed diesel motor (displacing the steam engine), a hydraulic mechanism known as the "Kort Nozzle" for effective multiple screw propulsion, multiple rudder systems, radar, radio communications, depth finders and bow thrusters. Modern towboats have a power capability comparable to oceangoing ships and high degree of maneuverability, essential to negotiating the circuitous and shallow channels of the rivers in swift and changing currents. Research with large-model waterway systems, both in the United States and abroad, continues the refinement of vessel contours, propeller design and control systems. At the end of World War II, a tow of barges carrying 10,000 tons of cargo was unusually large. In 1971, tows of 40,000 tons are becoming increasingly common, especially on the lower Mississippi, and tows of 36,000 tons have moved on the Ohio River.

Technological Progress, Competition and Low Charges

Carrier operations are highly competitive, with the result that economies are transmitted promptly into lower charges to shippers. It should be borne in mind that costs of operating factors, especially of labor, have been rising rapidly and continuously over many years. Yet, in the face of this inflationary pressure, the industry has actually reduced charges during the 1960's. In 1964, the average revenue per ton-mile of Class A and B Water Carriers on the Mississippi River and its tributaries was 3.5 mills In 1969, this was down to only 2.9 mills.* The traffic of this group of carriers constitutes about 38 percent of the total on the Mississippi River System and, because it includes the entirety of the higher rated component moved under ICC regulation, rates per ton-mile for the nonregulated sector are lower. It can therefore be stated with confidence that average charges per ton-mile by all carriers are now significantly less than 3.0 mills. This remarkable achievement is due in no small measure to avoidance of regulatory restraints which would have limited the latitude of managerial discretion. Such restraints should continue to be minimized or avoided.

The Private Capital Requirements of Inland Water Transportation

Inland water transportation shares with other modes the challenge of raising sufficient capital to meet the demands being placed upon it by the mounting volume of freight. As Commissioner Willard Deason of the ICC stated, transportation capacity "must double by the end of the 1970's if demands on the system continue at present rates."

Shallow-draft internal water carriage will probably require private long-term investment funds during the 5-year period, 1971-

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* ICC, Bureau of Accounts, *Revenue and Traffic of Class A and B Water Carriers*, Statement No. Q-650 (Respective Years).

1975, in the neighborhood of $500 million. An analysis of the property and depreciation reportings of 16 Class A water carriers on the Mississippi River and its tributaries for the years 1964 through 1968, indicates that their property and equipment acquisitions during the 5 years approximated $67 million. This amounted to about $0.48 per 1,000 ton-miles of cargo moved by these carriers.*

If this rate of investment were applied to the ton-miles projected in Figure K-l for all shallow-draft carriers, the necessary 1971-1975 investment would amount to $419 million. However, this makes no allowance for other capital needs, especially for working capital. Furthermore, the estimate is derived from the lower construction cost levels of the 1964-1968 period.

The provision of funds of this magnitude is a serious challenge. While the physical volume of freight handled by shallow-draft barging is very large, in financial terms the industry is small. A 5-year investment requirement of $500 million may be compared with estimated 1969 gross revenues of $477 million.[t] As another comparison, the property and equipment of the 16 Class A carriers mentioned above had a depreciated value at the beginning of 1964 of only $93.5 million compared to the estimated subsequent 5-year property acquisitions of $67 million.

The $500 million estimate may be conservative for still an additional reason. Vessel replacements may be expected to run higher than previously. Approximately one-half of the shallow-draft barges now in service are either already overage or will become so before 1975. A substantial portion of the fleet needs prompt replacement with the most modern equipment available to facilitate the larger tows and higher speeds required to hold down operating costs and shipping rates.

Growth of Shallow-Draft Water Transportation Since World War II

Positive action is required with respect to the modernization and enlargement of the navigation system. Technological development and the resulting low charges of carrier operations have induced a growth in traffic which has already reached the economic capacity of certain central gateways which are crucial to the growing long-haul movement of bituminous coal. Mounting congestion will forestall continued growth pending completion of modernized facilities. Modernization is required, not only for adequate capacity, but also to take full advantage of new navigation technologies.

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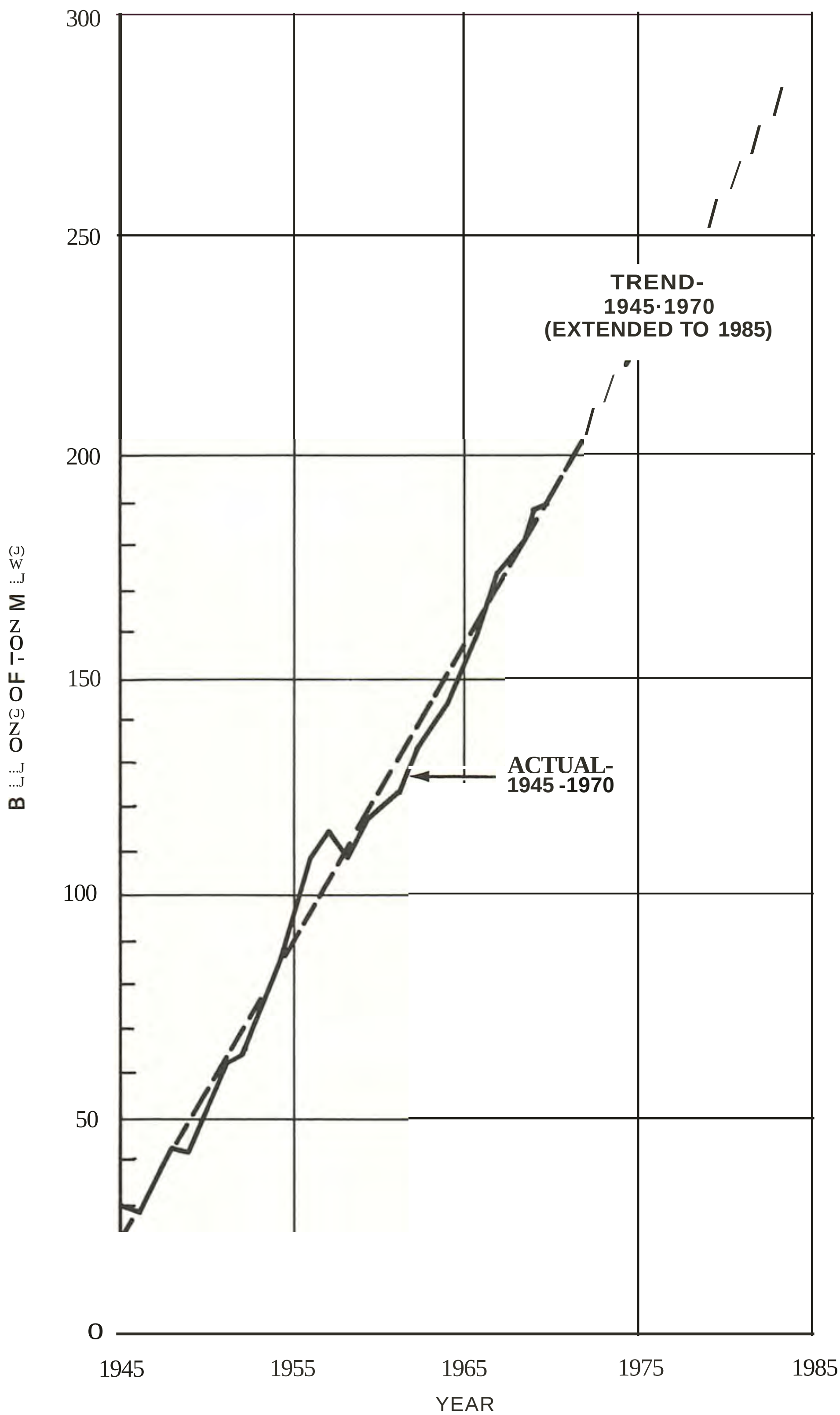
* Calculated from ICC, *Transport Statistics in the United States, Part 5, Carriers by Water,* and *Revenue and Traffic of CZass A and B Water Carriers,* Statement No. Q-650 (Respective Years).

[t] Revenue estimate by Transportation Association of America, *Transportation Facts and Trends*, Quarterly Supplement (January 1971), p. 4.



* Includes oceangoing movements in sheltered coastal waters.

SOURCE: U.S. Department of the Army. Corps of Engineers.

Figure K-l. Internal and Local Ton-Miles of Cargo Carried on U.S. Rivers and Canals--1961-l969 (Trend Extended to 1975).*

Figure *K-2* depicts the growth of transportation on U.S. rivers and canals since the end of World War II, an expansion from 30 billion ton-miles in 1945 to 190 billion in 1970. While this includes deep-draft oceangoing shipping moving in sheltered coastal waters, about 90 percent of the year-to-year increment consists of shallow-draft domestic movements internal to the country. The internal movements have been separately reported only since 1960 and appear as Figure K-l, representing an 8-year expansion from 86.5 billion ton-miles in 1961 to 145.4 billion in 1969.

The growth shown in Figure *K-2* has been projected statistically to 1985 at about 290 billion ton-miles. In Table *K-1*, the movement of bituminous coal on rivers and canals was projected for 1985 at 176.0 million tons. These projections, however, are those for traffic demand, and they cannot be realized without modernization of the navigation system.

Traffic Crisis at the Central Interchange of the River System

The bottleneck most seriously adverse to the growth of long-haul coal movements is situated at the central interchange of the inland river system on the boundary of southern Illinois. In this limited area, six navigable rivers converge, affecting traffic for many hundreds of miles in all directions, from Pittsburgh on the east to Omaha and Sioux City on the west, from Chicago and Minneapolis on the north southward to the Gulf of Mexico.* The most crucially overloaded facilities are the four Locks numbered 50 through 53 on the lower Ohio River and Locks numbered 26 and 27 south of Alton, Illinois, on the Mississippi.

Conditions in these two reaches are very similar. Because the congestion most crucial to coal movement is on the lower Ohio River, this will be treated here in some detail as approximating, also, the navigating conditions on the central Mississippi.

Figure *K-3* depicts the growth in all-commodity traffic through the reach of Locks 50 and 51 in the lower Ohio River from 19 million tons in 1960 to 43 million in 1970, a growth which accelerated considerably towards the end of the decade. This includes most of the rising long-haul coal movement from the Ohio Basin to destinations such as the Twin Cities and Florida incorporated in Table *K-2*. Industry sources project an increase in the coal traffic demand through this reach by 1975 in the neighborhood of 20 to 25 million additional tons (for a total possibly exceeding 40 million). A portion of this projected increment is already under contract to serve utility stations now programmed or under construction.

The economic capacity of Locks 50 and 51 on the Ohio River is calculated at about 40 million tons per year. As shown in Figure

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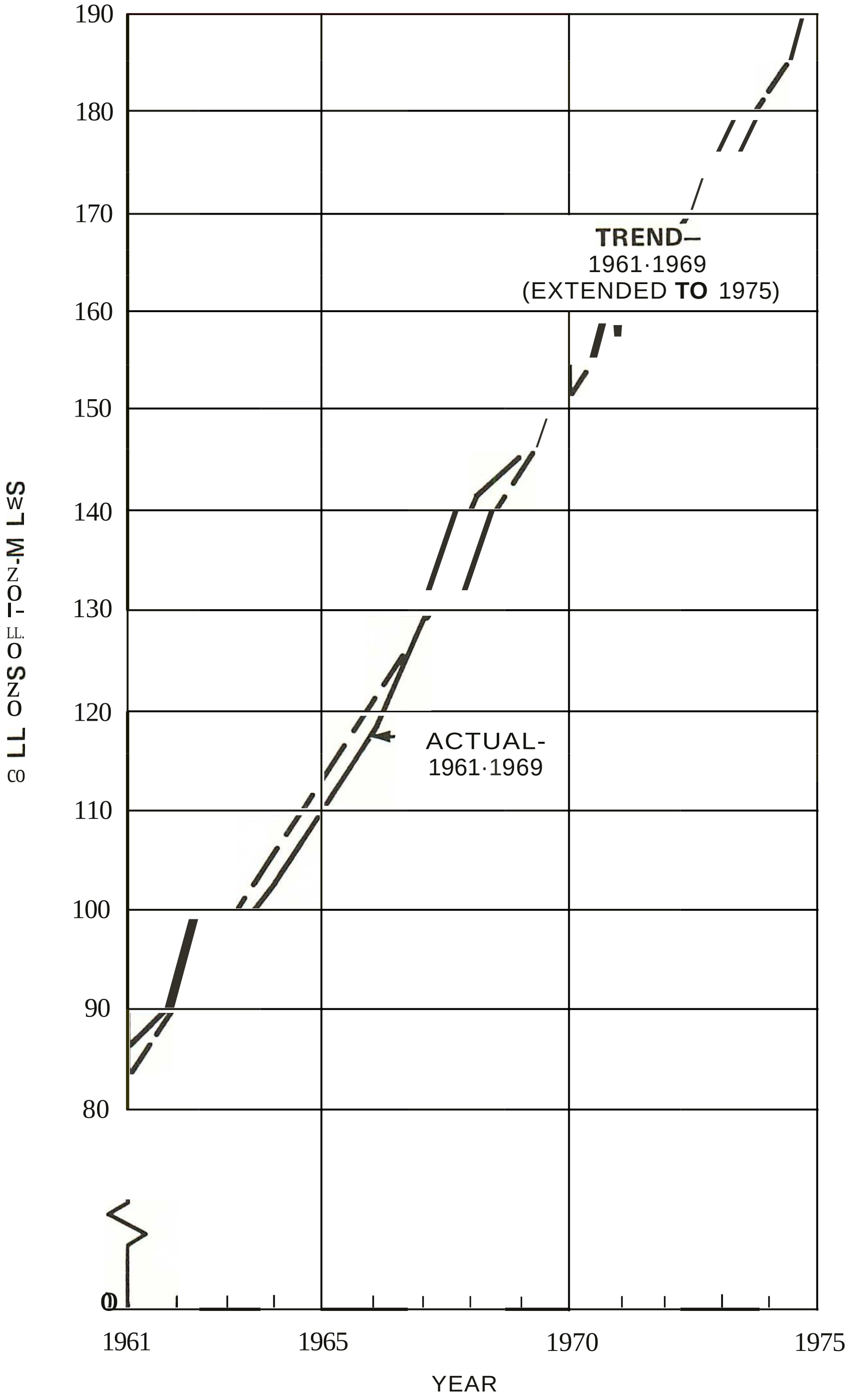
* The six rivers are the Mississippi, Illinois, Ohio, Cumberland, Tennessee and Missouri.

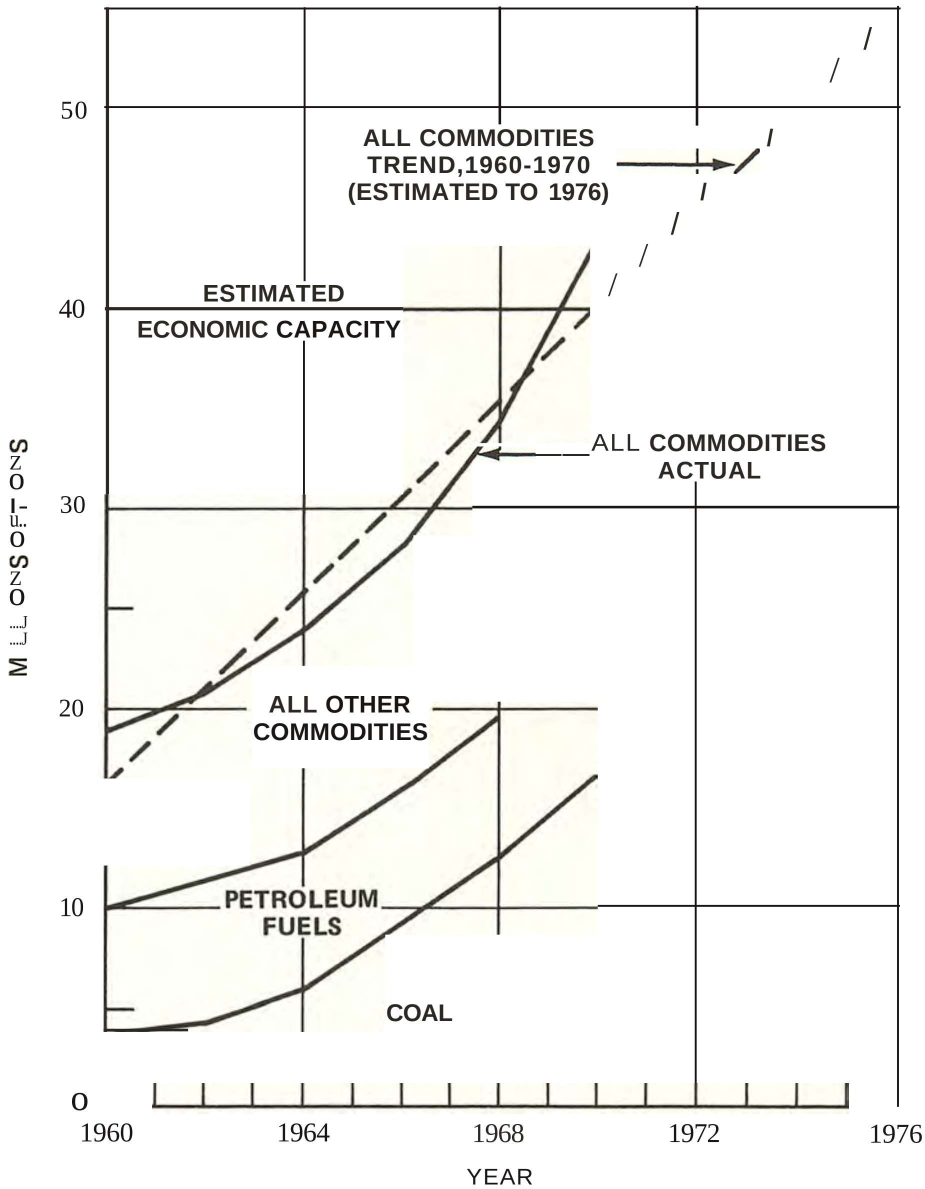


* Excludes oceangoing movements in sheltered coastal waters.

SOURCE: U.S. Department of the Army. Corps of Engineers.

Figure K-2. Ton-Miles of Cargo Carried on U.S. Rivers and Canals--1945-1970 (Trend Extended to 1985).*

K·3, traffic in 1970 exceeded this quantity. Waiting periods for lock access in the range of 12 to 16 hours are common, at a cost for the individual tow of barges falling between $75 and $100 per hour. Delays exceeding 24 hours occur from time to time. The



SOURCE: U.S. Department of the Army, Corps of Engineers.

Figure K-3. The Ohio River Annual Tonnage Transiting the Reach of Locks 50 and 51--1960-1970.

problem is accentuated by the inadequate dimensions of the old locks which impose on large modern tows of barges the time-consuming and costly process of double-locking.

Construction of new facilities of adequate dimensions and capacity has now been initiated. These, however, cannot be completed for about 5 years at minimum. Therefore, it is clear that a substantial portion of the projected growth in the coal movement through this reach will be forestalled until the latter 1970's. In short, the Nation's energy supply, in particular that portion now served by coal, will be constricted for some years by this bottleneck. It is urgent that construction proceed expeditiously.

The lockage system of the central Mississippi River likewise has an estimated yearly capacity of about 40 million tons.* The all-commodity tonnage through this reach rose from 20.2 million tons in 1960 to 41.8 million tons in 1969, and the coal tonnage rose from 3.3 million to 8.4 million tons.

Projections of coal traffic on the Mississippi are difficult. The *Upper Mississippi River Comprehensive Basin Survey,* using data through 1964, projected for the entire reach from Minneapolis to Cairo, Illinois, a coal tonnage of 10.0 million for the year 2000.† This has already been exceeded in 1969 at 10.5 million tons. The outlook for the coal movement through this reach is obviously much greater than past experience would indicate. As in the case of the lower Ohio River, however, realization of this potential will have to wait the completion of modern navigation facilities. This is particularly true if large tonnages of low-sulfur coal from PAD District IV should move to the Midwest to help alleviate the severe air pollution problem in that area. Construction should proceed without avoidable delay.

Timely Action with Respect to Foreseeable Future Traffic Crises

If action on these critical reaches of the river system had been taken some 5 years sooner, serious impediments to the U.S. energy supply would have been avoided. Furthermore, construction costs would have been less. Nothing is gained, and much is lost by delaying action until a foreseeable crisis occurs. This serves as a lesson for other requirements, less immediate, but which will certainly become as critical in the course of time.

Other rivers on which crises of comparable proportions are now foreseeable include the Illinois, the Mississippi between Alton and the Twin Cities, the Upper Ohio River, and sections of the Gulf Intracoastal Waterway. All of these are important coal-carrying streams, controlled by navigation systems now 30 to 50 years old and moving volumes of traffic rapidly mounting toward system capacity. Economic evaluations and planning and design work should proceed in the immediate future so that construction can be undertaken in adequate time.

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* For an analysis of economic capacity of major U.S. inland waterways, see Eric E. Bottoms, F. ASCE, "Practical Tonnage Capacity of the Canalized Waterways," *Journal of the Waterways and Harbors Division*, Proceedings of the American Society of Civil Engineers, Vol. 92, No. WW1, Proc. Paper 4644, (February 1966), pp. 33-46.

† U.S. Army Engineer Division, North Central, *Upper Mississippi River Comprehensive Basin Survey* (Prepared under the Supervision of UMRB Coordinating Subcommittee), Appendix J, "Navigation," (1971), p. J-124.

The Advantages of Deeper Channels and Harbors

Other steps, in addition to new navigation structures, offer high promise for raising the capacity of the inland waterway system. These include the deepening of channels and extension of the navigation season in northern waters.

On most of the navigable reaches of the Mississippi River and its tributaries, deeper channels are now feasible. The present prevailing depth limitation is 9 feet. This limitation is encountered only at occasional shallows. Over most of the mileage, depths now substantially exceed 9 feet. Therefore, the work required to establish a limitation of 12 feet or more would be only at selected points on the system.

The increase in capacity and the potentials for cost cutting technology of a 12 foot channel would be very great. Tows of barges exceeding 60,000 tons would become feasible, without a corresponding increase in horizontal dimensions. In the individual lock chamber, each vessel transit would move a tonnage of cargo increased by about one-third, an increase in lock capacity without investment in physical enlargement. Safety would be increased for both commercial and recreational traffic by a smaller number of vessel tows than otherwise required for any given aggregate tonnage of movement.

A 12-foot channel would introduce new potentials into navigation technology. Wage rates and other cost factors of carrier operation continue their upward momentum. Under the 9-foot limitation, the most vigorous pursuit of technological improvements will inevitably begin to yield diminishing returns. Thus, if the hold-down on charges which has characterized inland water carriage since the end of World War II is to continue towards the end of the century, the deepening of river channels will prove an unequivocal necessity.

Ocean and lake harbors likewise need to be deepened. Bulk commodities are being moved in ever larger ships. For example, on October 12, 1970, the *Chikugu Maru,* with a draft of 52 feet, loaded 110,000 tons of Canadian coal at Robert Banks, British Columbia, for shipment to Japan.* Considering the higher levels of American wages and other costs, the urgency of large loadings such as this is even greater in U.S. commerce. Yet, present draft limitations in U.S. harbors are inadequate for vessels as large as the *Chikugu Maru.* The deepest draft in the Upper Bay of New York Harbor is 45 feet; in Chicago Harbor it is 29 feet.† If American industry is to be served by an energy supply which will keep it competitive

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* *Skillings' Mining Review* (January 16, 1971), p. 21.

† U.S. Department of the Army, Corps of Engineers, *Waterborne Commerce of the United States,* 1969 (1970), Part 1, p. 59, and Part 3, p. 24.

with Japanese and other foreign production, harbor deepening will be necessary. This problem is particularly severe in the Hampton Roads port system.

Extension of the Navigation Season in Northern Waters

Extension of the navigation season in northern waters will likewise increase capacity and reduce costs. This applies especially to the Mississippi River between Alton, Illinois, and the Twin Cities and to the Great Lakes. Each month added to the navigation season by ice control is an increase in yearly capacity, an improvement in employment security, and a reduction in overhead per ton of cargo. Initial action might best be taken where traffic density is greatest, notably on the Great Lakes and the Mississippi between Alton and the Rock-Island-Davenport area.

COAL SLURRY PIPELINING IN THE WESTERN UNITED STATES

It is well-known that the western states have enormous coal reserves and that much of this coal has the distinct advantage of being very low in sulfur content. Slurry pipelines may playa strong role in developing these reserves since they can provide a low cost and environmentally attractive mode of transport.

Coal slurry pipelines transport a mixture of finely-ground coal and water, usually about 50 percent of each. Except for the coal preparation plant at the mine site and a pumping station every 60 to 80 miles, all of the system is beneath the ground and out of sight, giving no visual evidence that energy is being transported continuously.

Slurry pipelines are not a recent development. As far back as 1891 a patent was granted for a method of pumping coal with water, and in 1914 an operating system employing an 8-inch line was constructed to transport coal into London. A 108 mile, 10 inch diameter Consolidation Coal pipeline entered service in 1957. The most recent development in slurry pipelining is the Black Mesa Coal Slurry Pipeline owned by the Southern Pacific Railroad. This 273 mile system, which began commercial operation in November 1970, is capable of transporting over 5.5 million tons of coal annually, all through an 18 inch diameter pipeline. This coal will supply all of the energy requirements for the two 750 MW generating units owned by the West Group at the Mohave Power Plant near Davis Dam in Nevada. Figure L-l is a map of this system. The system requires four pumping stations--one at the mine/site preparation plant and three booster stations spaced along the line. This system is about three times the length and four times the capacity of the pioneer Consolidation Coal pipeline in Ohio.

Technology currently exists for even longer and larger lines. One thousand mile pipelines carrying 10, 20 or even 30 million tons of coal per year are considered feasible. This would be sufficient energy to meet the power requirements of two cities the size of Los Angeles. The economy of scale enjoyed by pipelines makes such systems attractive. Figure L-2 shows the potential markets within 500 and 1,000 miles from the western coal "axis." As shown, tremendous markets are well within reach. The primary market for western coal is for power generation, which is ideal for slurry pipeline application.

Coal pipelines, however, are certainly not a panacea, and each specific transport decision must be made on its own merits. In selecting the power plant location and transport mode -- e.g., railroad, pipeline or extra high voltage transmission -- there are certain key factors which must be considered. These factors include water availability, protection of the environment, reliability, inflation and economics.

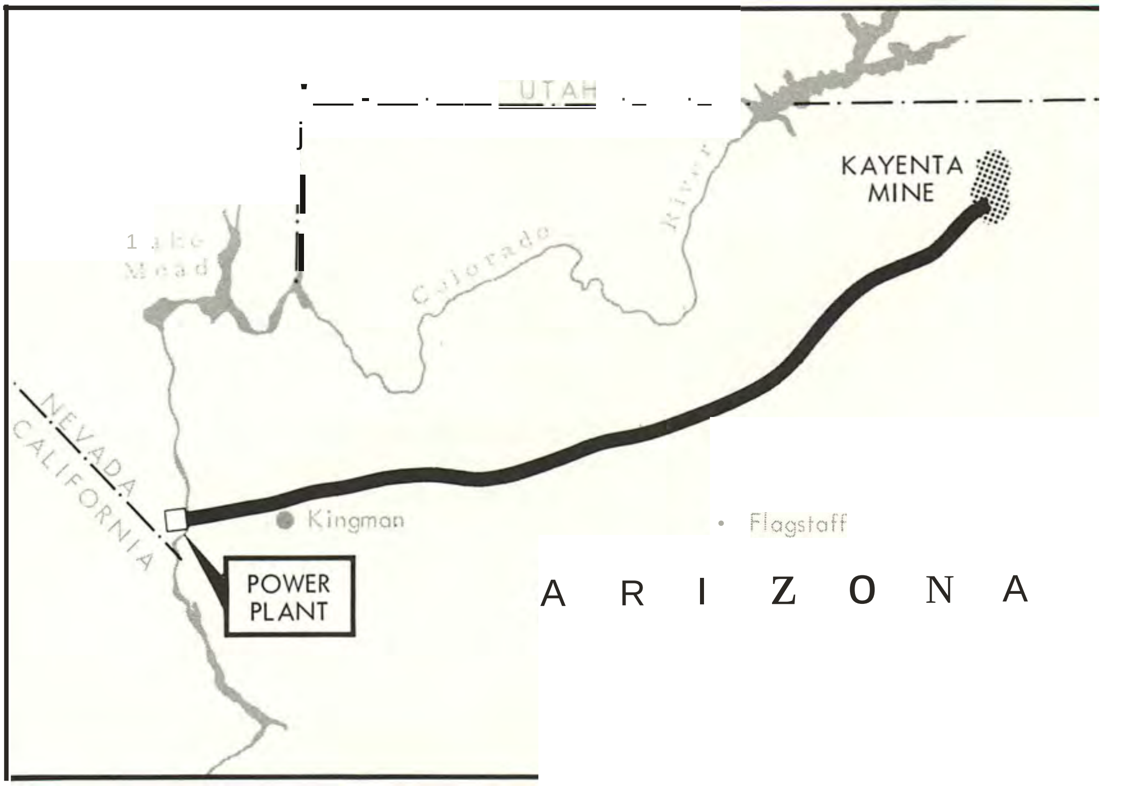
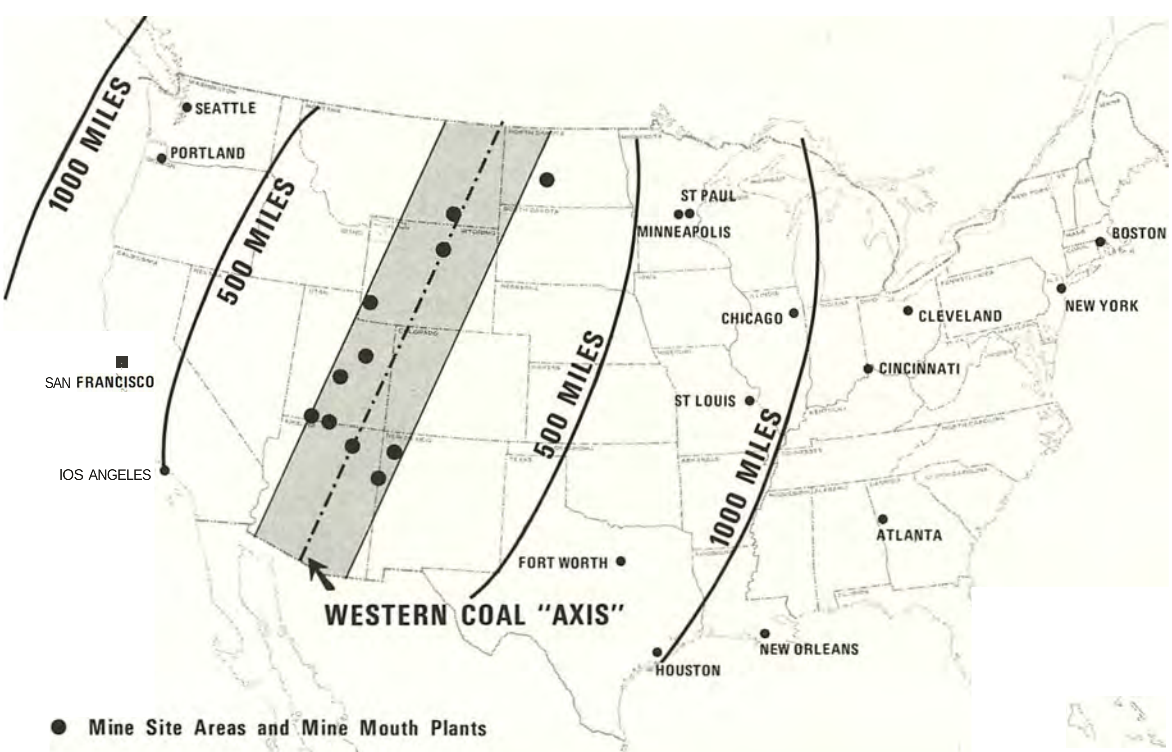


Figure L-1. Black Mesa Pipeline.



SOURCE: *Adapted from Robert R. Nathan Associates,* The Potential Market for Far Western Coal and Lignite, *U.S. Department of Interior Report, Contract No. 14-01-001-475 (December* 1965).

Figure L-2. Western Coal Distance to Major Markets.

WATER AVAILABILITY

Probably the most significant factor regarding power plant site selection is the availability of water. Coal-fired plants require large amounts of makeup water. In the case of a 1,500 MW plant such as Mohave, about 20,000 acre-feet per year are required. Water availability then, because of the large quantities required, has strong influence on the power plant location. Frequently, the question is raised as to how much water is required for coal slurry pipe1ining. In the case of the Black Mesa pipeline, the water requirement for pipe1ining is some 3,000 acre-feet or about 15 percent of the power plant's total requirement--20,000 acre-feet. Again, in the case of Black Mesa, after relatively simple treatment, the water is suitable for cooling tower makeup with quality about the same as clear Colorado River water.

ENVIRONMENTAL CONSIDERATIONS

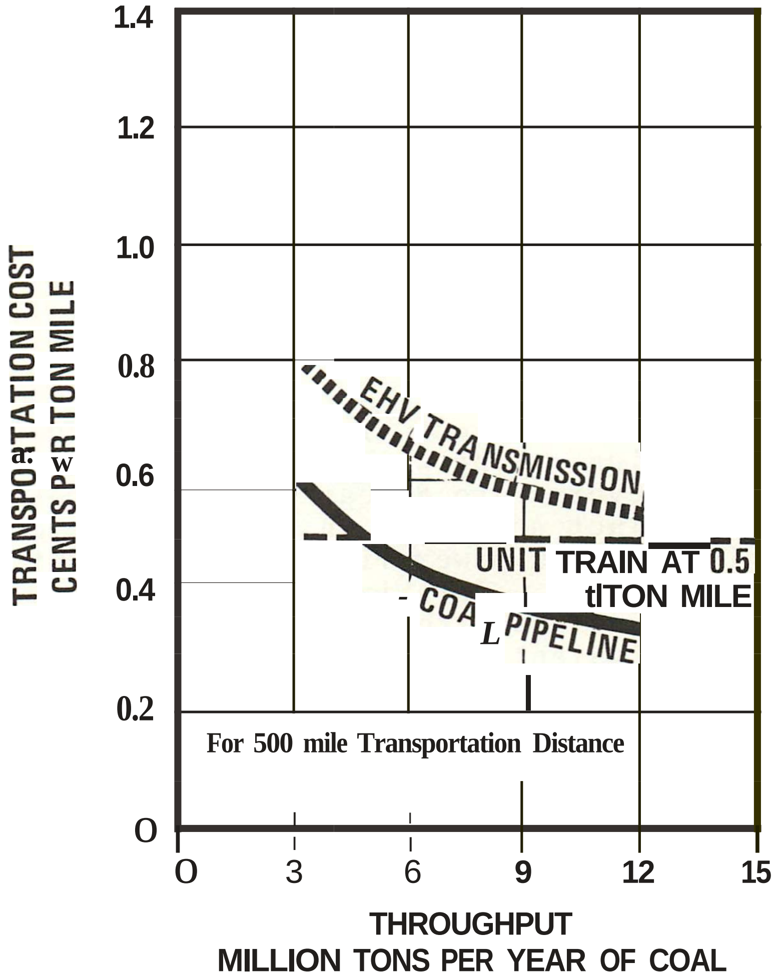
Environmental considerations are becoming increasingly important in utility decision-making with the doubling of the U.S. electric generating load every 7 to 8 years. In this regard, slurry pipelines have a distinct advantage in that they do not offend those who view high tension power lines or railroad tracks as a source of visual pollution. In Arizona, one can stand directly over the Black Mesa pipeline without perceiving visual or audible evidence that the equivalent of 160 rail cars of coal per day is flowing only 3 feet below.

RELIABILITY CONSIDERATIONS

Reliability is another key factor to consider in selecting means of energy transport. The utility companies demand an extremely reliable transport system, as insensitive as possible to interruption from weather, labor disputes, etc., in order to minimize exposure to blackouts. Slurry pipelines meet this requirement since they are not affected by severe weather or very low ambient temperatures. The degree of automation possible also makes them relatively insensitive to labor disputes. The Consolidation Coal pipeline, for example, has had an availability factor of 98 percent. The head station for the pipeline and coal preparation plant was operated by just one man, and only day personnel were utilized at the booster stations. The four-station Black Mesa system is operated similarly. Usually the most important factor in determining a coal pipeline's reliability is the reliability of the pump station power supply. In this regard, techniques such as station bypassing and alternate power sources can be used to further improve reliability.

ECONOMIC CONSIDERATIONS

The economics of a 500 mile pipeline system as compared with other modes of energy transport are shown in Figure L-3. It can be seen from this figure that coal pipelines for all cases with capacity in excess of 3 million tons per year are more economical than EHV transmission. Unit trains, however, are somewhat more competitive. For a unit train of 0.5 cents per ton mile, capacity must be in excess of 5 million tons per year for the coal pipeline to be competitive.

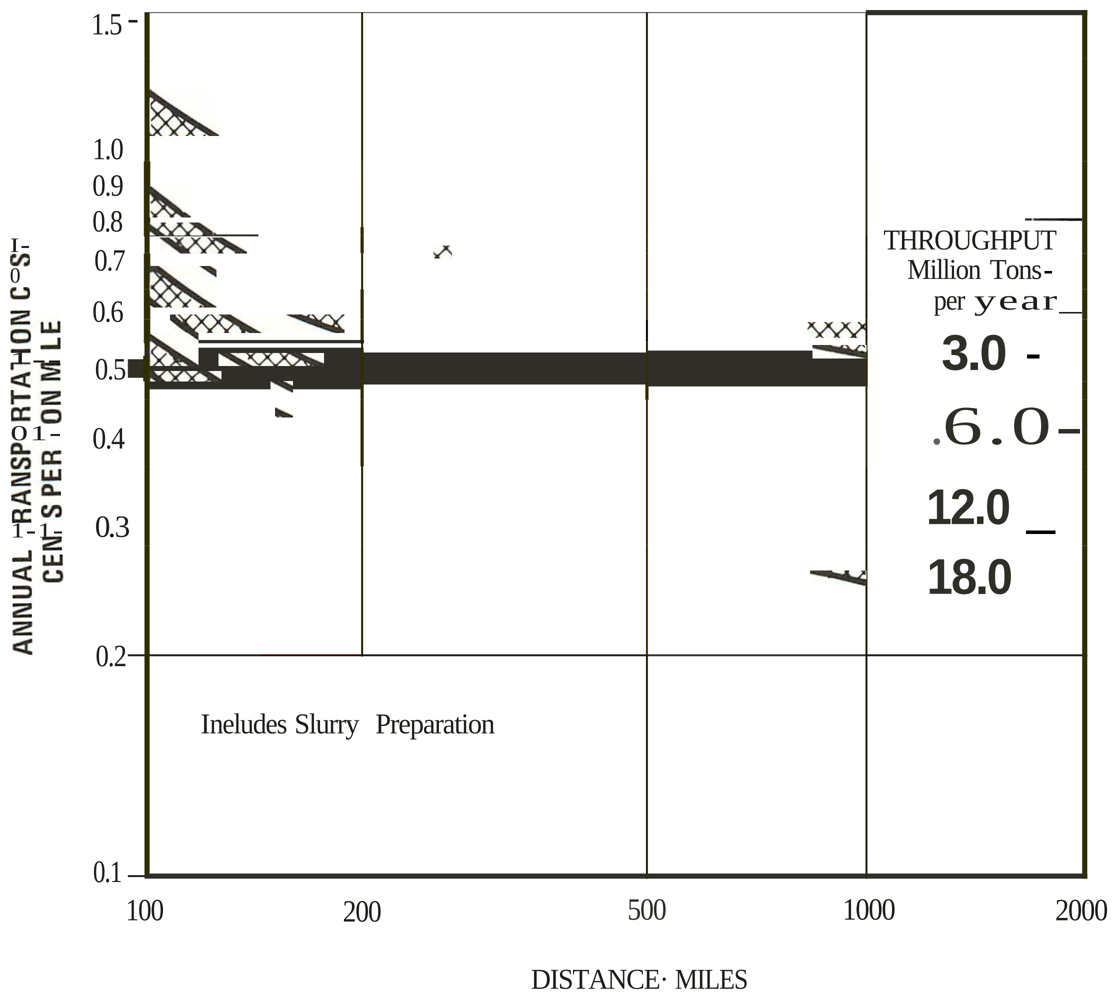


SOURCE: Adapted from T. L. Thompson and E. J. Wasp, "Coal Pipelines--A Reappraisal," Pipe Line News (December 1968), pp. 12 – 16.

Figure L-3. Comparison of Alternate Modes of Energy Transportation.

The cost of transportation of coal slurry by pipeline is a function of the tonnage transported, distance, physical characteristics of the coal, conditions of terrain, and the annual capital charges of the pipeline. The two most significant factors are the annual tonnage and the distance transported. Figure L-4 shows unit costs of pipeline transport as a function of these two variables for annual throughputs ranging between 3 and 18 million tons. The costs include both the costs of slurry preparation and pipeline transportation, but exclude any allowance for utilization cost at the delivery terminal.

Analysis indicates that the utilization costs of coal slurry are very close to those of dry coal (as delivered by a unit train).



SOURCE: Adapted from E. J. Wasp, "The Importance of Slurry Pipelines for Western Coal Development," Proceedings of Montana Coal Symposium, Billings Montana, January 1970.

Figure L-4. Coal Slurry Pipeline Transportation Costs.

Thus, while there is a thermal penalty as a result of firing wetter material and somewhat higher costs due to providing long-term emergency wet storage, these factors are offset by (1) the greater ease and lower cost of handling coal in slurry form, (2) the lower cost of tanks as compared to bunkers, (3) the lower labor requirements of slurry, and (4) the fact that a substantial portion of the crushing required prior to firing has been carried out in preparing the coal for pipelining.

Examination of Figure L-4 shows that, for 100 mile systems transporting between 3 and 18 million tons per year, costs range from approximately 1.2 cents to 0.5 cents per ton mile. Similarly, for 1,000 mile systems, they range from approximately 0.6 to 0.25 cents per ton mile.

UNIT TRAINS

Unit trains represent the major long-distance transportation alternative to coal slurry pipelines when the energy is transported in the form of coal, except for those instances when existing waterways are available for barge transport.

Where new transportation facilities must be installed, a new pipeline is generally more economical than a new railroad. However, railroads may be quite competitive where existing trackage can be employed to a large extent. However, even in this case the benefit of using existing facilities may be offset by the fact that the rail distance may be greater than the straight-line (or pipeline) distance between the source and delivery point.

Whereas slurry pipelines enjoy a rather marked economy of scale, i.e., reduced unit cost with increased tonnage, unit trains do not exhibit this to the same extent. In general, for distances of 300 miles or more and tonnages in excess of 1 million tons per year, unit train costs in cents per mile are relatively constant. Unit trains do, however, have the advantage of more flexibility in expanding or contracting system capacity.

EHV TRANSMISSION

Extra high voltage transmission of energy is increasing rapidly in North America. As with pipeline systems, the unit cost of transportation of energy by EHV is strongly related to the quantity and distance. However, beyond 300 miles unit costs per KWH become relatively constant on a per mile basis.

It should be noted that EHV transmission does possess a unique advantage over other forms of energy transportation when connected to an integrated grid system. In such cases there is an increase in the firm power capacity of the system, and the system reliability is increased by the interconnection. While no dollar amount can be directly attributed to this factor, it does represent an intangible benefit of EHV transmission.

APPENDIX M

ELECTRIC POWER GENERATION FROM COAL

INTRODUCTION

The demand projection of the Coal Task Group indicates the predicted future use of coal in power generation. For quick reference, this demand is summarized in the following tabulation to point up the scope of this segment of coal utilization.

	Total BTU Input to U.S. Power Generation (BTU x 10^{12})	Power Generation as % of U.S. Total Energy	Coal BTU Input to Power Generation (BTU x 10^{12})	Coal BTU's as % of Total Power Generation
1970	16,614	24.0	7,728	46.5
1985	44,161	35.0	15,696	35.5

This projection was based on power stations currently existing, new stations already committed which will operate by 1976, and those to be committed between now and 1980 which will come on-stream between 1980 and 1985. (The figures assume nuclear capacity in actual operation to be 50, 128, and 251 million KW in 1975, 1980 and 1985, respectively.)

Whether this coal use prediction can be achieved depends, predominately on solutions to the pollution problems associated with the use of coal in steam boilers.

SUMMARY

The most important matter bearing on the success of coal in competition with gas, oil and nuclear energy is the future impact of the Clean Air Amendments of 1970 (Public Law 91-604) as administered through the combined activities of the Environmental Protection Agency (EPA) and the state and local agencies working with EPA. Low-sulfur oils, while beneficial where obtainable, are too scarce to constitute a national answer to making power plant stack discharges acceptable. With a tightening moving target criteria to be met, it is unlikely that fuel with even as low as 0.5-percent sulfur will suffice without S02 removal from stack gas. *Consequently, the very highest level of importance attaches to the prosecution of research, development and demonstration testing of large scale 302 removal apparatus applied ahead of the stacks of coal-burning and oil-burning power plants.* The Air Pollution Control Office (APCO), formerly the National Atmospheric Pollution Control Administration (NAPCO), has been and is working--with a 1971 budget of $11 million and a 1972 budget of $20 million--on a program to demonstrate the success of promising S02 abatement apparatus in several power plant test installations of the country. Private industry is spending an even larger amount on the same objective.

The commercial success of such apparatus is psychologically of highest importance bearing upon new plant decisions. Despite the level of federal and private development work, until a commercial S02 removal apparatus is successfully operating in the country's power plants, the pollution troubles associated with existing coal-burning plants will be an obstacle to utility operations and managements and could produce a "snow-balling" of decisions against use of coal in new installations to escape future pollution problems.

Source Material

This Appendix considered as basic material and drew very heavily on the reports of the six Regional Advisory Committees of the 1970 *National Power Survey* of the FPC. These survey reports were made by well-chosen U.S. utility executives and engineers; they constitute an excellent source where the non-specialist in utility engineering practice can develop knowledge of current practices and philosophy as spelled out by electric utility industry management and engineering leaders. Despite the fact that several of the regional reports were prepared in 1967 and 1968, their currency is evidenced by the fact that three of them are still in typewritten form and only three have been printed to date, with the finalizing report of the FPC not yet available in April 1971.

A 1970 report on S02 abatement by an ad hoc committee of the National Academy of Science-National Academy of Engineering (NAS-NAE) is also used as basic reference. This report constitutes the most comprehensive summary of this field out of tremendously voluminous literature on pollution effects and control.

General Outlook

Looking forward to 1985 and even to the end of this century, the fossil-fueled (and nuclear-fueled) processes for making electricity which have evolved over the past 50 years will continue to be used, and further nominal plant efficiency improvements will be made in these processes. Few new plants will be built in cities, and in the coal-burning class there will be an increasing number of mine-mouth plants, located near mines for economy and in order to remove their stack discharges from the energy-using urban areas to the more rural coal supply areas. The designation "mine-mouth" covers plants which may be located as much as 25 miles from the actual mine in order to gain access to the large quantities of water needed for a major power plant. The large natural draft (hyperbolic shaped) cooling towers recently introduced here from Europe will be used increasingly because of inability to find large enough water supplies. Also, "dry-type" cooling towers which cool the condenser circulating water with air instead of water will come into use where adequate water is lacking to replace the evaporation from wet-type cooling towers. The relatively recent development of EHV transmission has been conducive to the economy of locating power plants near the coal source and transmitting the generated energy to cities.

It is possible that, by the time this paper is published, the criteria for acceptable stack gas discharge without stack sulfur oxide removal apparatus will require the burning of coal (or oil) with less than O.S-percent sulfur content. This paper therefore is written in that context. Incidentally, this virtually eliminates the use of coal cleaning as a practical answer to the SOZ emission problem. (Note that the six reports of the Regional Advlsory Committees of the 1970 National Power Survey were written in the context that 1.0-percent sulfur in coal and oil would satisfy the criteria for stack discharge without stack sulfur oxide removal equipment.) It also appears that NO_x criteria which would be difficult to meet are "just around the corner," despite the lack of known combustion processes or control equipment which will permit compliance.

Decisions for New Power Plants

Generating stations have a useful life of approximately 30 years, requiring huge capital expenditures and involving very large lifetime operating costs. But at the immediate present, utility system engineers are greatly handicapped in making developmental studies for future plants by being unable to predict with any reasonable accuracy essential factors such as the following to use in their economic comparisons of alternative generation and transmission systems: (1) the escalation rates to use for equipment, materials and construction labor, (2) the availability and future costs of fuels of different types and qualities, (3) the cost of transporting fuels, (4) the environmental protection standards to which they will be required to conform in their designs, and (S) the type and cost of stack gas cleaning apparatus which will become commercially available for coal (and oil) burning plants. All of these current uncertainties add to the difficulty of assessing the relationship between electricity production and the use of coal or any other particular fuel.

Site Selection

In connection with Presidential interest in power plant siting, the Office of Science and Technology issued a report during the Johnson Administration titled, *Considerations Affecting Steam Power Plant Site Selection*, and another under the Nixon Administration titled, *Electric Power and the Environment*. The first is primarily informational. The second presents a practical, sound approach to recognizing a distinction between old and new plants. Parts of these reports which deal with pollution and equipping plants with apparatus to control sulfur discharge are quoted in the section of this Appendix concerning pollution control legislation.

Pollution Abatement

Sulfur control or emissions abatement is discussed in the section entitled, "Abatement of Sulfur Oxide Emissions," mainly by excerpts from the 1970 NAS-NAE Committee report. It contains several important comments appropriate for this summary:

> There is a possibility that a number of newly created air quality control regions will adopt (control) plans ... in the next few years. *Care must be exercised at the local, regional, and national levels to assure that realistic criteria and plans are adopted which can be implemented in concert with the development of technology and the systematic use of our energy resources.*
>
> There is a real danger that the public may be led to expect environmental improvements at a rate that cannot be realized. This is not to say that high goals should not be established, but rather that realistic and coordinated implementation plans must be adopted.
>
> Even if additional cooperative funding by the coal industry, equipment manufacturers, utility companies, and process developers can be arranged, government support will be needed for many years to encourage development, demanstration, and application of sulfur oxide control technology. *Unless the necessary technology becomes available, the country may have to choose between clean air and electricity.*

New Power Cycles

A concept which merits an early careful engineering evaluation is that of coal gasification to produce hot, clean, low heating value gas to supply first a gas turbine and then the steam boiler of a combined-cycle gas turbine/steam turbine generating plant. Natural gas-burning combined-cycle gas turbine/steam turbine plants have been built, operated and proved successful as a highly efficient type of generating plant. However, the scheme has to date been used only with natural gas fuel. If coal is converted under pressure to a low heat value gas, and if the gas is scrubbed of particulate matter and the S02 removed prior to further combustion, it is then possible to burn such gas in a combined-cycle gas turbine/steam turbine station.

The coal is gasified under pressure with the result that the particulate removal and the S02 removal from the resultant gas would also be performed under pressure, with very much lower volumes of gas than for stack gas at atmospheric pressure. This concept is further reviewed in the section concerning combined-cycle systems. At present, a 172 MW plant of this type is under construction in Germany.

For the immediate future, where no choice for alternate power cycles exists, the most urgent technical problem remains the solution of the stack gas scrubbing problem. However, beyond this period, no other technological improvement in coal-based power generation has the combined potential attraction of the gas turbine/steam turbine cycle in terms of investment savings, higher efficiency, outstanding cleanliness and, most important, of being within practical reach in the IS-year period under study. The coal-burning combined-cycle gas turbine/steam turbine process deserves maximum support from the coal and power industry in the form of adequate development funds for testing the system with American coals.

LOW-SULFUR COAL, COAL CLEANING, ETC.

This subject has raised considerable interest and requires brief comment. Most important in this regard is what will be established by new regulations as the acceptable level of sulfur in fuel to be burned in plants having no stack sulfur oxide removal systems. If O.S-percent sulfur maximum eventually prevails, as the Coal Task Group believes it will, compliance will be impossible, for neither existing coal reserves nor any commercial "washing" process will achieve this goal.

However, the bulk of western coal reserves have sulfur contents between O.S and 1.0 percent, and substantial tonnages are currently burned in areas where 1.0-percent sulfur is presently considered an acceptable fuel, particularly in the West Central region.

Most eastern coals are too high in organic sulfur to obtain a satisfactory sulfur content by removal of pyrite only (washing). NAPCA, with the assistance of the U.S. Bureau of Mines and Bituminous Coal Research, Inc., has completed a very thorough study of this subject. It concluded that possibly 2S percent of eastern steam coals could yield I-percent maximum sulfur. This 2S percent included low-sulfur coals already used in steam raising and would require cleaning of coal after crushing to fine sizes (less than 14 mesh). This would cause large losses of coal in refuse and prevent shipment of the fine clean coal by rail.

The NAS-NAE report suggests that, from an overall national point of view, it appears desirable to reserve the limited supply of low-sulfur coal for small industrial and commercial users who cannot afford to install the complex cleaning devices which can be used in large central power plants. However, such a marketing program would be difficult to administer.

For deep desulfurization to the O.S-percent sulfur level or lower, the organic sulfur in the coal substance proper must be at least partly removed. The NAS-NAE ad hoc panel states: "It appears that organic sulfur may be removed only by hydrogenation, liquefaction, and gasification processes."

To the extent that coal can be converted to low-sulfur fuel oil or pipeline gas for subsequent use in power plants, the subject is dealt with in the appendices on synthetic liquid and gaseous fuels. The use of gasification as a source of low-BTU producer gas for so-called combined-cycle plants is discussed under that heading in a later section.

ABATEMENT OF SULFUR OXIDE EMISSIONS

The single most important factor bearing on the future use of coal relates to the abatement of sulfur oxide emissions from stacks. That subject in this paper, therefore, surpasses all other parts in importance.

Bibliographical Material

The number of technical articles which have accumulated on the subject of abatement of sulfur oxide emissions has grown tremendously. Writing as early as December 1940, Johnstone and Singh listed 106 references and reported "...numerous patents have been issued on processes for sulfur dioxide elimination from combustion gases. The patent survey made in connection with this work has shown over two hundred United States and foreign patents relating to sulfur dioxide removal and recovery from waste gases. None of these is known to be in commercial operation. The problem has evidently been of interest to inventors for at least ninety years."*

In a March 1970 report of HEW to the Senate, it was stated: "To maintain an up-to-date store of technical information, NAPCA has about 1,000 scientific and technical journals screened. About 400 are published in English, and others in various languages. Pertinent articles and abstracts are microfilmed and stored in a data bank. By the end of 1969, there were about 12,400 articles and reports in the data bank. New items are being added at a rate of about 1,000 per month."

Report of NAS-NAE

After studying a great many references pertaining to abatement of sulfur oxide emissions from power plants, it was decided to report on this subject by quoting selected paragraphs and sentences from a 1970 report titled *Abatement of Sulfur Oxide Emissions from Stationary Combustion Sources*, prepared by a NAS-NAE Ad Hoc Panel on Control of Sulfur Dioxide from Stationary Combustion Sources. The verbatim quotations from the report have been resequenced for conciseness.

Abbreviated Preface of the NAS-NAE Report

In this report of a study on the control of sulfur oxide emissions into the atmosphere, primarily from electricity

*Johnstone and Singh, "The Recovery of Sulphur Dioxide from Dilute Waste Gases," 38 University of Illinois Bulletin, No. 19 (December 31, 1940).

generating stations, an effort has been made to place the findings of the study in perspective with the entire problem of environmental quality management.

On the basis of problem definition, a study of need, a study of engineering constraints, and an analysis of technological requirements and alternatives, this report outlines a government-industry program for research, development, and demonstration of potential control processes.

It is hoped this report will provide a basis for increased governmental and public understanding of the problems of sulfur oxide abatement and control, and will direct attention and adequate assignment of resources to the orderly and expeditious solution of this portion of the nation's problems of environmental quality management.

Extracts from NAS-NAE Report

Controlling and improving the quality of our environmental resources is a growing concern of the nation. National and regional goals and standards for air quality management are being defined. Capital investments of billions of dollars will be required to install processes to meet these standards. Keeping these costs within bounds, while still attaining an acceptable level of control within the shortest practical period of time, will call for the best efforts and most careful planning at all levels from individuals, civic groups, and companies through local, regional, state, and Federal agencies.

The emission of SO_2* from combustion of sulfur-bearing coal and oil, primarily for the generation of electrical energy, is second only to the emission of pollutants from internal combustion engines in quantity of pollutants discharged to the national air environment.

During the next 20 years, the national requirement for electrical energy is expected to more than triple. The supply of natural gas, a low-sulfur fuel, is expected to decrease in about 10 years, and petroleum products may reach their maximum availability in about 30 years. To supply the needed electricity, the use of coal is expected to triple by the year 2000, when it is expected that the use of nuclear energy will about equal the use of coal, after which the requirement for coal will start a downward trend.

Sulfur oxides emission data and projections for the United States are shown in Table M-l.

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*The symbol SO_2 is used in this report to designate the sulfur oxides in stack gases (SO_2 plus 1 percent to 2 percent of SO_3).

TABLE M-1

ESTIMATED POTENTIAL SULFUR DIOXIDE POLLUTION WITHOUT ABATEMENT*

United States	Annual Emission of Sulfur Dioxide (Millions of Tons) 1967	1970	1980	1990	2000
Power Plant Operation (Coal and Oil)	15.0	20.0	41.1	62.0	94.5
Other Combustion of Coal	5.1	4.8	4.0	3.1	1.6
Combustion of Petroleum Products (Excluding Power Plant Oil)	2.8	3.4	3.9	4.3	5.1
Smelting of Metallic Ores	3.8	4.0	5.3	7.1	9.6
Petroleum Refinery Operation	2.1	2.4	4.0	6.5	10.5
Miscellaneous Sources†	2.0	2.0	2.6	3.4	4.5
Total	30.8	36.6	60.9	86.4	125.8

* Taken from NAS-NAE, *Abatement of Sulfur Oxide Emissions from Stationary Sources* (1970); February 1970 estimates by NAPCA, excluding transportation.

† Includes coke processing, sulfuric acid plants, coal refuse banks, refuse incineration and pulp and paper manufacturing.

...The panel members considered these data to be realistic, based on authoritative sources, and interpreted rationally and conservatively; and the members were impressed with the magnitude and urgency of the problem of sulfur oxides emission to the atmosphere. *The data and projections gave rise to the conclusion that positive action will be required to prevent the emission of sulfur oxides into the ambient air from more than quadrupling by the year 2000.*

A review of sulfur oxide abatement and control technology gives rise to concern as to the future supply of electricity and the future availability and use of fuels. There are important matters of policy and management regarding future energy conversion and consumption that bear directly and importantly on environmental problems, such as: Emission of sulfur oxides, nitrogen oxides, particulates, carbon dioxide, carbon monoxide, and other pollutants from fossil fuels combustion; thermal pollution; siting of generating facilities and distribution systems; fuel policy and availability; radioactive pollution and disposal of radioactive wastes; and technological, political, jurisdictional and economic limitations and constraints.

Electricity generation, sulfur oxide emission control, and other environmental factors are closely interrelated and require an integrated systems approach. The objective of providing for the nation's growing power needs is subject to the constraints of maintaining environmental quality, fuels availability, and technical developments. Within this framework lie the trade-offs of shifting generation, improved transmission, and the development of control processes. Overriding all of these is the long-term consequence of each alternative.

Electricity generation in 1970 was 1,518 billion KWH, and it is expected to be of the order of 9,000 billion KWH in the year 2000, roughly a doubling every 10 to 12 years.

Most of the new generating capacity installed between now and 1990 will be provided by some 250 large power plants of greater than 1000 MW capacity.* The siting problem will generally be one of assuring that the relatively small number of large plants are adequately planned and located to meet the goals of providing low-cost, reliable power and minimizing the adverse effects on our environment. With an onsite investment of about $200 million to $400 million each, these new plants will be among the larger industrial establishments in the nation. Including support and auxiliary activities, they will represent approximately $80 billion of capital investment, which will be profoundly affected by the public interest.

The demand for electric power is increasing so rapidly that sulfur oxide emissions may increase even allowing for: (1) Projected construction of nuclear power plants; (2) substitution of gas or low-sulfur fuel oil at locations where they are available; (3) use of coal of reduced sulfur content to the extent that can be expected; (4) introduction of improved combustion methods; and (5) application of improved stack-gas treatment and sulfur recovery processes.

Even if additional cooperative funding by the coal industry, equipment manufacturers, utility companies, and process developers can be arranged, government support will be needed for many years to encourage development, demonstration, and application of sulfur oxide control technology. *Unless the necessary technology becomes available, the country may have to choose between clean air and electricity.*

The crux of the problem is its urgency with respect to lead time and degree of applicability of any single process. The schedule for abatement of the emission of

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* The same applies to past the year 2000, excepting number of plants and dollars of capital investment will vary.

sulfur oxides reduces the lead time to a very short period. In order to demonstrate a variety of processes which might be applicable to specific conditions, *the reduction of lead time and the diversity of processes required, demand an intensive and concerted effort substantially greater than normal industrial process development.*

Although the panel is optimistic that acceptable sulfur oxides control technology will be developed, it concludes that this technology is not yet commercially proven. Moreover, a rapid pace must be maintained in pursuit of the technical objectives, if only to prevent conditions from getting worse. Even when the expected technology becomes available, it will be too late to prevent a significant rise in total sulfur emissions during the next several years.

Five general approaches might be made to sulfur oxides control problems:

1. Undertake a crash program to build nuclear power plants

2. Remove sulfur from fuels before they are burned

3. Remove sulfur from fuels during the combustion process

4. Remove the 502 from the combustion gases before emission to the atmosphere

S. Employ very high stacks and remote siting so that the gases are dispersed and diluted to an acceptable level.

Therefore, *the reduction of* 802 *emissions from stationary combustion sources, in the next* 5 *to 20 years, will depend very largely on the development, demonstration, and application of a combination of technologies designed to prevent the sulfur in coal (and petroleum) products from reaching the atmosphere through the combustion processes.*

The preferred use of naturally occurring low-sulfur or cleanable (to low-sulfur levels) coal is in those fuel uses, other than power generation, where the flue gas treatment processes to reduce 802 *are not economically feasible.*

At another point it is stated "*...the panel believes that, from a national point of view, the most logical use for the low-sulfur coal is in commercial and indus-*

trial plants, small power plants, space heating, and for production of metallurgical coke.

In addition to joint support by groups of utilities, a number of industrial organizations have committed significant funds to research, development, and demonstration of sulfur emission control processes and equipment. An increase in these activities, together with increased support by the Federal Government, is needed.

At the present time, the Federal Government is actually supporting research, development and demonstration at levels of $11 million in 1971 and $20 million in 1972 budgets.*

The panel reviewed the status of United States and foreign sulfur oxide abatement and control processes and firmly concluded that, *contrary to widely held belief, commercially proven technology for control of sulfur oxides from combustion processes does not exist.*

Efforts to force the broad-scale installation of unproven processes would be unwise; the operating risks are too great to justify such action, and there is a real danger that such efforts would, in the end, delay effective SO_2 emission control. *A high level of government support is needed for several years to encourage research, engineering development, and demonstration of a variety of the more promising processes, as may be suited to specific local and regional conditions, to bring these processes to full-scale operating efficiency at the earliest practical date. This can be done most expeditiously if Federal support, in addition to industry commitments, is provided at the appropriate time and in the needed amounts.*

Federal support for the development of the following control approaches is suggested:

1. Throw-away processes for removal of SO_2 from stack gases, such as limestone injection, which produce a presently non-marketable product

2. New combustion concepts, such as fluidized bed combustion (FBC), which fixes the sulfur as a sulfate during combustion and prevents its release as SO_2 to the stack

3. Chemical recovery processes, which produce salable SO_2, sulfuric acid, elemental sulfur, or fertilizers

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**Electrical Week*, (February 1, 1971), p.3.

4. Coal gasification processes, which produce sulfur-free fuels

5. New concepts in engineering and chemical approaches to the desulfurization of coal.

The limestone injection processes, with adequate particulate control, should be commercially demonstrated within the next one to three years and, if successful, can be installed in many existing plants.

Several sulfur-recovery processes appear to be ready for scaleup to commercial demonstration size (100,000 kWor larger boilers). Full-scale demonstration of the industrial reliability of these processes is four to ten years away. Some of them can be installed in a portion of existing plants or engineered into future plants.

New combustion technology may be available for industrial application in five to ten years. Efficient coal gasification processes, which are five to ten years away, have the potential for producing pipeline quality, low-sulfur gas for supplementing existing supplies of natural gas or for producing a product of less than pipeline quality, but adequate for power generation. Such fuels seem likely to become increasinlgy competitive for use in power production as the cost for controlling all pollutants (SO_2, NO_x, and fine particulates) increases the costs for conventional systems.

These time estimates are reaZistic only if there is dedication and a positive commitment on the part of government agencies, utilities, fuel suppliers, and equipment manufacturers to support the orderly development and timely application of the more promising processes.

In recommending a five-year plan for future work, the panel places special emphasis on the following:

1. Complete development of the limestone process should be given high priority because it is applicable to many existing boilers and is closer than others to demonstrated industrial application.

2. For new power plants and some existing plants, it is expected that sulfur-recovery processes will be necessary to keep costs for future control within reasonable limits.

3. NAPCA should continue to support the development and demonstration of new con-

cepts in combustion technology, sulfur recovery, and coal desulfurization processes.

4. Research should be supported on ways to combine the abatement of nitrogen oxide and particulates with sulfur oxide control.

5. Elemental sulfur is a more desirable by-product than sulfuric acid or sulfur dioxide. The conversion of sulfur dioxide to sulfur is not a well-established process, and it is important that the technology and costs of this conversion be thoroughly studied.

The NAS-NAE committee interviewed and corresponded with many companies, as shown in Table M-2. They wrote:

> Many ways of removing S02 from stack gases are being actively investigated--all involving some means of contacting the gas with a substance that removes 502' At least 25 such processes are under development in this country by industry and by NAPCA (see Table M-3), and others are under development in Japan and Europe (see Table M-4). Most are bench-scale laboratory projects, but several have reached the pilot-plant stage (10- to 2S-MW equivalent gas streams). Only the limestone-wet scrubbing process has been installed in sizable operating power plants. Several of these processes will probably be technological successes, but the efficiencies are not yet well established for even the most advanced. Projected costs range up to 1 mill per KWH and, in some cases, higher, depending upon method of financing.

Tables M-3 and M-4 help the reader grasp both the extent of the Committee's engagement in the problem and the extent of international activity on the sulfur control problem.

It is apparent that the recommendations of the NAS-NAE report are being closely followed. The impact of new legislation and the magnitude of private and government research and development efforts is shown by the list of major developmental 502 control installations which are currently underway in the United States (see Table M-5) •

Economics of S02 Abatement

The removal of sulfur from coal to levels of O.S percent or lower involves either gasification or liquefaction. The costs associated with these conversions are considered in later appendices.

TABLE M-2

COMPANIES USED BY NAS-NAE FOR
REPORT ON SO_2 ABATEMENT

<u>List of Presenters*</u>

Babcock & Wilcox
Bituminous Coal Research, Inc.
Black, Sivalls, & Bryson, Inc.
Chemical Construction Corporation
Combustion Engineering, Inc.
Continental Oil Company
  (Consolidation Coal Company, Inc.)
The Dow Chemical Company
ESSO Research and Engineering Company
Institute of Gas Technology
Ionics Incorporated/Stone & Webster
The M. W. Kellogg Company
McNally Pittsburgh Manufacturing Corporation
Monsanto Company
National Air Pollution Control Administration
North American Rockwell Corporation
  (Atomics International Division)
Office of Coal Research
Pope, Evans and Robbins
Princeton Chemical Research Company
Roberts & Schaefer Company
Tennessee Valley Authority
Tyco Laboratories, Inc.
Wellman-Lord, Inc.
Westvaco

<u>List of Correspondents†</u>

Abcor, Inc.
The Air Preheater Company, Inc.
Air Products and Chemicals, Inc.
American Petroleum Institute
Basic Chemicals
The Carborundum Company
The Detroit Edison Company
Edison Electric Institute
Institute of Gas Technology
Joy Manufacturing Company (Western
  Precipitation Division)
Kaiser Aluminum & Chemical Corporation
  (Kaiser Chemicals Division)
The Kansas Power and Light Company
Nalco Chemical Company
Pennsylvania Electric Company
Precipitair Pollution Control, Inc.
Research-Cottrell, Inc.
Reynolds Metals Company
Reynolds, Smith and Hills
Slick Industrial Company (Pulverizing
  Machinery Division)
Union Electric Company
United International Research, Inc.
Universal Oil Products Company (Air
  Correction Division)
The Wheelabrator Corporation

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*These organizations made presentations to the Panel on Control of SO_2 from Stationary Combustion Sources.

†These companies sent material to the panel describing their activities and experience on control of SO_2 from stationary combustion sources.

TABLE M-3

UNITED STATES S02 POLLUTION CONTROL RESEARCH AND DEVELOPMENT *

Company	Type of Work
Abcor, Inc.	Aqueous absorption systems for 502
Air Products and Chemicals, Inc.	Dry process for 502 removal
American Iron and Steel Institute	Studies of sulfur pollution control from various iron and steel manufacturing steps
Argonne National Laboratory	Reduction of atmospheric pollution by the application of fluidized bed combustion
Babcock & Wilcox	Magnesium oxide scrubbing system and other 502 removal processes
Basic Chemicals	Magnesium slurry scrubbing (in conjunction with Chemico)
Bituminous Coal Research, Inc.	Use of limestone or dolomite for 502 removal from coal-burning boiler flue gases
Bituminous Coal Research, Inc.	Removal of pyritic sulfur from coal
Black, Sivalls, & Bryson, Inc.	Coal gasification in molten iron; sulfur removal in slag
The Carborundum Company	Limestone injection with wet scrubbing or bag filtration
Chemical Construction Corporation	Various projects for 502 control from sulfuric acid plants and power plants
Combustion Engineering, Tnc.	Limestone injection-wet scrubbing process
(Kansas Power and Light Company)	Demonstration of combustion engineering limestone injection-scrubbing process
(Union Electric Company)	Demonstration of combustion engineering limestone injection-scrubbing process
Consolidation Coal Company, Inc.	Flue gas scrubbing, fluidized combustion in a lime bed, and pyrite removal from coal
The Detroit Edison Company	Limestone scrubbing. ammonia injection
The Dow Chemical Company	Gas-phase removal of 502 with solid alkaline materials
Edison Electric Institute	Dispersion characteristics of stack effluents, development of a formula for stack design
Esso Research and Engineering Company	B&W-Esso proprietary process for 502 removal
General American Transportation Corporation	Catalytic reduction of 502 to sulfur
Hydrocarbon Research, Incorporated	Catalytic hydrogenation of fossil fuels
Illinois Institute of Technology Research Institute	Oxidation and reduction catalysts
Institute of Gas Technology	Coal gasification
Ionics Incorporated/Stone & Webster	Regenerable aqueous scrubbing system for 502 removal and recovery (Stone & Webster-Ionics process)
Kaiser Chemicals	Improved dry sorbent for 502 removal
The M. W. Kellogg Company	Undisclosed process for power plant 502 removal
Monsanto Company	Catalytic oxidation of S02 with recovery of sulfuric acid
(Pennsylvania Electric Company) (Air Preheater Company) (Research-Cottrell)	Development of Monsanto catalytic oxidation process
Nalco Chemical Company	Dry sorbent for S02
Petroleum Industryt	Industry-wide R&D for sulfur oxides control
Pope, Evans & Robbins	Control of gaseous emissions from coal-fired fluidized-bed boilers
Precipitair Pollution Control, Inc.	Gas-phase removal of 502 with solid alkaline materials, and collection with fabric filters (cooperative work with Southern California Edison)
Pulp and Paper Industry±	Sulfur oxides control from sulfite and kraft pulping processes
Research-Cottrell, Inc.	Scrubbing equipment development
Reynolds Metals Company	Dry sorbents for 502 removal
Reynolds, Smith, and Hills	Scrubbing process for flue gas 502 removal
Slick Industrial Company	Dry 502 sorbent development
Southern California Edison Company	Gas-phase removal of 502 with solid alkaline materials, .and collectdon with fabric filters
Stone & Webster	Regenerable aqueous scrubbing system for 502 removal and recovery (S&W-Ionics process)
United International Research, Incorporated	Regenerable scrubbing process removal; S02 converted to H2S04
U.S. Bureau of Mines-Morgantown	Study of corrosion/erosion and of coal type during fluidized bed combustion
U.S. Stoneware Company	Process for S02 control from sulfuric acid plants
Universal Oil Products	Dolomite slurry scrubbing; catalytic hydrogenation of fuels
Wellman-Lord, Incorporated	R&D of regenerable wet scrubbing process at Lakeland, Florida. and Tampa Electric plus direct reduction of 502 to sulfur
Tampa Electric Company	Pilot study of Wellman-Lord process, contributed to Stone & Webster
(Bechtel Corporation)	Demonstration plant of Wellman-Lord process at Baltimore Gas and Electric power station
(Baltimore Gas and Electric Company) (Potomac Electric Power Company) (Delmarva Power and Light Company) (Potomac Edison Company)	Demonstration plant of. Wellman-Lord process at BG&E power station in Baltimore
Western Precipitation Group (Joy Manufacturing Company)	Scrubbing equipment development
Westinghouse R&D Center	Evaluation of the fluidized bed combustion process
Westvaco	Adsorption of S02 by activated carbon
The Wheelabrator Company	Scrubbing equipment development
Wisconsin Electric Power	Lime scrubbing, other aqueous scrubbing systems

* Compiled by NAPCA, March 1970.

t Information from American Petroleum Institute.

Information from NCASI.

TABLE M-4

FOREIGN SO_2 POLLUTION CONTROL RESEARCH AND DEVELOPMENT*

Company	Type of Work
Australia	
Commonwealth Science Industrial Research Organization	Fluidized bed combustion
Czechoslovakia	
Research Institute of Inorganic Chemistry	Ammonia scrubbing of SO_2 effluent
Czech Acid Plant Scrubbing	Ammonia scrubbing on H_2SO_4 plant tail gas
Fuel Research Institute	Fluidized bed combustion
Institute of Mines	Desulfurization of coal
England	
Esso Research Center	Fluidized bed combustion of oil
National Coal Board Coal Research Establishment	Fluidized bed combustion of coal
BCURA Industrial Labs	
LHF Patented Process	Desulfurization of coal
Esso Research	
Bankside and Battersea Process	Alkaline water scrubbing on Thames River
France	
Societe Nationale Des Petroles D'Aquatane (joint project with Halder Topsoe of Denmark)	Catalytic oxidation of flue gas
Ugine Kuhlmann-Weirtam Process	Ammonia scrubbing of flue gas
Societe Anonyme Activit	Fluidized bed combustion
Neyric	Desulfurization of coal
Germany	
Bayer Double Contact Process	Two-stage catalytic oxidation of H_2SO_4 tail gas
Bischoff Process	Lime/Limestone scrubbing of flue gas
Lurgi Sulfacid Process	Wet char sorption of SO_2 from effluent
Activated Carbon Adsorption	Wet char sorption of SO_2 from effluent
Bergbau-Forschung Activated Char Sorption	Dry char sorption of SO_2 from gaseous effluent
Bergbau-Forschung Grillo process	Sorption by proprietary mixture of metal oxides
Holland	
Shell CuO process	Sorption on proprietary mixture of copper based metal oxides
NVCP (Nederlandsch Verkoopkantoor voor Chemische Producten N.V.)	Hydrodesulfurization of oil
Italy	
University of Cagliari	Desulfurization of coal
Japan	
Kiyoura Ammonium Sulfate Process	Catalytic oxidation of flue gas
Nippon Kokan Ltd.	Lime/Limestone scrubbing of flue gas
Japan Engineering and Construction Co. (JECCO)	Lime/Limestone scrubbing of flue gas
Showa-Denko Process	Ammonia scrubbing
Hitachi Activated Carbon Process	Wet char sorption of SO_2 from effluent
Central Research Institute of the Electric Power Industry	Dry limestone injection for SO_2 control of flue gas
Resources Research Institute	Dry limestone injection for SO_2 control of flue gas
Mitsubishi DAP-Manganese Process	Manganese oxide sorption
Kanagawa	Aqueous scrubbing
Poland	
Dry Ammonia Injection	Injection of gaseous ammonia into flue gas
Sweden	
BAHCO Lime-scrubbing Process	Lime/Limestone scrubbing of flue gas
U.S.S.R.	
Wet Limestone scrubbing at Kusnetsk Abagur Plant	Lime/Limestone scrubbing
Ammonia and sodium carbonate scrubbing-Voskresenskij Chemical Industry	Ammonia scrubbing
I.M. Gubkin Institute of Petroleum and Others	Fluidized bed combustion
Academy of Science	Desulfurization of coal
Lensovet Technological Institute	Desulfurization of oil
Yugoslavia	
Institute of Mines	Desulfurization of coal

* Compiled by NAPCA, March 1970.

TABLE M-5

MAJOR SO2 CONTROL INSTALLATIONS IN PROGRESS

	Manufacturers/Engineers
Privately Financed	
Commonwealth Edison Company	
Will County Station--176 MW	Babcock & Wilcox/Bechtel Corp.
State Line Station--Pilot Capacity	Universal Oil Products Co.
Detroit Edison Company	
St. Clair Station--180 MW	Mfg. Open/Bechtel Corp.
River Rouge Station--280 MW	Chemical Construction Co.
Kansas Power and Light Company	
Lawrence Station--125 MW	Combustion Engineering, Inc.
Lawrence Station--425 MW	Combustion Engineering, Inc.
Union Electric Company	
Meramec Station--125 MW	Combustion Engineering, Inc.
Pacific Power and Light Company	
Dave Johnson Station--360 MW	Venturi Scrubber/Ebasco SerVices, Incorporated
Assistance From EPA	
Tennessee Valley Authority	
Shawnee Station--50MW	Alkali Test System/Bechtel Corp.
Widows Creek Station--500 MW	Wet Limestone System/TVA
Boston Edison Company	
Mystic Station--150 MW	Chemical Construction Co.
Illinois Power Company	
Wood River No. 4--100 MW	Monsanto Company
City of Key West, Florida	
Key West Station--40 MW	Fly Ash Arrestor Corp. Scrubber System
Financing Not Settled	
Nevada Power Company	
Reid Gardner Station (2 units)--125 MW	Open/Bechtel Corp.

In reference to cleaning stack gases, it is quite difficult at this time to arrive at cost figures for new stations and even more so for existing stations (retrofit). This is the result not only of the wide variety of systems which are proposed and the claims made by various organizations, but also, principally, the lack of actual construction and operating results. It is, however, very apparent that a great difference will exist between the costs of cleanup systems incorporated in large new stations and the costs of retrofitting smaller existing stations.

It is also obvious that the unit cost per million BTU's burned will differ greatly from plant to plant depending on the type of system, the plant size and the plant operating factor. Some feel for the dimension of these costs is given by the following tabulation of capital carrying charges *only*, exclusive of operating labor and materials, in cents per million BTU's of fuel burned, based on IS-percent capital carrying costs and a heat rate of 9,500 BTU's/ per KWH.

Operating Factor	Added Investment for Cleanup System		
	$lO/KW	$20/KW	$30/KW
75%	2.4	4.8	7.2
50%	3.6	7.2	10.8
25 %	7.2	14.4	21.6

To these capital carrying charges must be added 3 to 6 cents per million BTU's of fuel burned to defray the direct operating costs for labor and materials, which also will vary over a wide range for different systems and conditions.

At least 1.5 times stoichiometric amounts of limestone would be required for treatment, and at a delivered price of $4 per ton of stone, the cost of this item alone, for a 4-percent sulfur coal burnet, would be about 3 cents per million BTU's. This cost varies with the sulfur contents in the coal, but the capital charges and most other direct operating costs are less subject to the coal sulfur.

It is, therefore, not possible to quote any specific costs, but for larger, high-load stations, an add-on (retrofit) cleanup system will probably fall in a range between 8 cents and 16 cents per million BTU's of fuel burned. A figure of 20 cents per million BTU's will quite easily be exceeded for older peaking plants and will depend greatly on the complications of installation and the period for amortizing the cost (i.e., remaining length of plant life) .*

The cost of stack cleanup would, however, be substantially lower for large new stations, particularly the investment. Some engineers reason that in addition to the beneficial size effect there should be savings in large new plants from omission of electrostatic precipitators when S02 scrubbers are used, by installing Venturi type wet fly-ash scrubbers ahead of the scrubbers installed to remove the S02' However, there are significant cost and operational arguments favoring the installation of electrostatic precip-

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* Since this material was compiled, additional experimental investigation of stack gas cleanup technology indicates costs may be several fold higher from those indicated above.

itators and the plant induced draft fans ahead of the S02 scrubber. The developmental S02 removal projects now being engineered and installed to gain experience should be very beneficial in settling what is the best practice for various situations. One source suggests that the incremental investment in a new plant designed to scrub S02 (without an electrostatic precipitator) would approximate $6.40 per KW and have a direct operating cost of some 3 to 4 cents per million BTU's of fuel burned.*

TALL STACKS

Recent technical papers representing variant positions of interest with regard to tall stacks have been reviewed. One American paper gives evidence of concern for occasional high ground level concentrations.t The authors state:

> Finally, dispersing the tremendous emissions from many sources through greater and greater volumes of air does not remove one molecule of S02 from the air.... In summary, we feel tall stacks are an unavoidably useful palliative to aid in reducing the more evident effects of emissions of large quantities of S02 to the atmosphere, but the better long-range solution is to reduce the emissions themselves.

Authors of an English paper present views much more extensive than the following excerpted quotations, although these index the stance of the paper.+

> The high chimney is a cheap, reliable, and indeed an indispensible means of reducing pollution by gases. The criticism of chimneys is largely misguided. The critics tend to consider the atmoshpere as a whole and do not consider in sufficient detail the small part of the atmosphere in which we live and breathe. It would be a tragedy for the cause of clean air if the campaign for low-sulphur fuels and for sulphur removal led to an underestimation of the potentiality of chimneys.

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* A. V. Slack, G. G. McGlamery and H. L. Falkenberry, "Economic Factors in Recovery of Sulfur Dioxide, (*Journal of the Air Pollution Control Association)* (January) 1971) , pp. 9-15.

t F. Pooler, Jr. and L. E. Niemeyer, "Dispersion from Tall Stacks: An Evaluation," Division of Meteorology, NAPCA, EPA (on assignment from National Oceanic and Atmospheric Administration, U.S. Department of Commerce).

‡ F. F. Ross, A. J. Clarke and D. H. Lucas, "Tall Stacks--How Effective Are They?"" Central Electricity Generating Board, London, England, Paper Presented at Second International Clean Air Congress of the International Union of Air Pollution Prevention Association, Washington, D. C., December 6-11, 1970.

> No sulfur dioxide removal process--even if 100 percent efficient--can make it possible to dispense with a chimney. A chimney can in most cases do all that a removal process could do at a fraction of the cost to the community.... There may also be a case for avoiding unnecessary nitrogen oxide formation. But a removal process for S02 would only make sense where the adverse circumstances of terrain or a nearby airport, or the social desirability of making the best use of high sulphur fuel, make the highest practicable chimney inadequate. Even then it would only be needed for comparatively infrequent periods, need not be more than partial unless the process cools the gases, and should still not be considered until after potentially cheaper means of reducing pollution during those periods, have been rejected as impracticable.
>
> The authors believe that the toxicity of sulphur dioxide has been exaggerated. Sulphur is present in coal partly because it is essential to plant life. If the ground level concentrations of sulphur dioxide are sufficiently low the gas not only becomes harmless, it may be beneficial.

Stacks have traditionally been the prime accessory to reduce ground level atmospheric pollution. The tendency has been to build higher and higher stacks, with high exit velocity of the discharge gas for the purpose of driving the gas plume even higher into the atmosphere. As a matter of stack cost economy, and also to improve the plume effect, some installations discharge the gas of more than a single electricity generating unit through a single stack--this on the basis that the greater mass of hot gas will rise higher into the atmosphere than if the less mass from individual stacks for each generating unit were used.

The October 15, 1970, issue of *Electrical World* stated:

> In analyzing for trends, however, data from the 11th Stream Station Design Survey are added to those from four preceding surveys. The combined data represent 84% of all utility-owned fossil-fueled stearn plant capacity added or scheduled for completion during the ten years ending in 1973. During this period, marked shifts in several key design factors reflect the utilities' concern about the environment, the most spectacular undoubtedly being the rapid growth of stack heights at coal-burning stations. This trend was first revealed in the 8th Survey, which included one stack of 550 ft. Subsequently, this growth has accelerated rapidly, reaching a record 1,200 ft. in the 10th Survey for units to be completed in 1970 and 1971. The current survey did not break the record, but it did reveal seven more 1,000 ft. stacks and a continuing steep rise in the average height of stacks for coa1- and lignite-burning units. Many of

the very tall stacks, incidentally, will house separate steel flues to serve two units.

It is the opinion of the author that APCO does not attach an adequately high value to tall stacks and that the trend of federal activities has been to treat the pollution problem too "ideally"--i.e., on the basis that the gas emanating from the stack should be S02 free, irrespective of stack height.

POLLUTION CONTROL LEGISLATION

The outline of the pollution problem can be judged by reference to the Clean Air Act (42 U.S.C. 1857 et sequ. as amended by the Air Quality Act of 1967, PL 90-148, and by the Clean Air Amendments of 1970, PL 91-604), by a sampling of various local and state ordinances, and by the proposed National Air Standards for various pollutants. The latter are listed here.*

> National air quality standards for six common classes of air pollutants--sulfur oxides, particulates, carbon monoxide, photochemical oxidants, nitrogen oxides and hydrocarbons--were proposed by the Environmental Protection Agency to meet the deadline set by Clean Air Amendments of 1970, signed into law by President Nixon, December 31, 1970. Standards were published in the *Federal Register*, January 30, and apply to all areas of the United States. They include *primary* standards (designed to protect human health), and *secondary* standards (designed to protect against effects on soil, water, vegetation buildings, animals, etc.)
>
> The standards for which the EPA invites comments, before publishing final standards within 90 days, are:
>
> Sulfur oxides: primary--80 micrograms/cubic meter, annual arithmetic mean; 365 micrograms/cubic meter, maximum 24-hour concentration, no more than once per year; secondary--60/cubic meter, annual, 260/cubic meter, maximum 24 hours.
>
> Particulates: primary--75/cubic meter, annual geometric mean; 260!cubic meter, maximum 24-hour concentration, not more than once per year; secondary--60 and 150, respectively.
>
> Carbon monoxide: primary and secondary--lO milligrams/cubic meter, maximum 8-hour concentration, not more than once per year; 15 milligrams, maximum 1 hour, not more than once per year.
>
> Photochemical oxidants: primary and secondary--125 micrograms/cubic meter, maximum 1 hour, not more than once per year.

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* EPA, *Air/Water Pollution Report* (February 1, 1971), p. 42.

Nitrogen oxides: primary and secondary--100 micrograms/cubic meter, annual arithmetic mean; 250 micrograms/cubic meter, 24 hour, not more than once per year.

Hydrocarbons: primary and secondary--125 micrograms/cubic meter, maximum 3-hour concentration (6-9 a.m.), not more than once per year.

The new legislation took account of the creation on December 2, 1970, of the EPA, reporting to the President. NAPCA was transferred to from the Department of Health, Education and Welfare (HEW) to operate under the new title of Air Pollution Control Office. Also transferred from various departments were functions assigned to new offices titled Water Quality Office, Pesticides Office, Radiation Office, Solid Wastes Office and Noise Abatement Office. In some of the material quoted in earlier parts of this report, references to HEW and NAPCA are used although EPA and APCO now perform the same roles.

The various state legislations and ordinances setting limits on sulfur content of fuels, or requiring equivalent SO removal, are in a state of rapid change towards lower and lower emission. A listing of such regulations showing how they are modified with time is given in Table M-6. It is quite apparent from this table that sulfur levels equivalent to less than 0.5 percent in the fuel will have to be achieved over the next 15 years.

Siting of Power Plants

During the Johnson Administration, power plant siting and problems associated therewith assumed high importance. As a further development, in his February 8, 1971, message, President Nixon stated:

> I propose a power plant siting law to provide for establishment within each State or region of a single agency with responsibility for assuring that environmental concerns are properly considered in the certification of specific power plant sites and transmission line routes.

In consideration of the importance assigned to power plant siting by two Presidents, it seems appropriate to include brief excerpts from two reports of the Office of Science and Technology, the first released during the Johnson Administration and the second released during the Nixon Administration. Both reports are essentially the work of the federal agencies with the most direct interest in the power plant siting problem. Excerpts from the first report follow.*

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* Office of Science and Technology, *Considerations Affecting Steam Power Plant Site Selection* (December 1968), Excerpt from Chapter IV, "Air Pollution Factors in Power Plant Siting."

TABLE M-6

STATE AND LOCAL SULFUR OXIDES CONTROL REGULATIONS
APPLICABLE TO FUEL COMBUSTION SOURCES*

	Area	Maximum Sulfur Content of Fuel (%)†	Effective Date	Maximum Sulfur Content of Fuel (%)†	Effective Date
California	Monterey/Santa Cruz County	0.5	7/1/69	0.5	7/1/69
	Los Angeles County	0.5	5/1/69	0.5	5/1/69
Connecticut	Statewide	1.0	9/1/71	1.0	9/1/71
Delaware‡		1	9/1/70	1	9/1/70
	Utilities	1	1/1/72	1	1/1/72
	Edgemoor	3.5	1/1/72	3.5	1/1/72
	Delaware City	1	1/1/74	1	1/1/74
District of Columbia		1.0	7/1/69	1.0	7/1/69
		0.5	7/1/71	0.5	7/1/71
Florida	Jacksonville	2.0	10/1/68	2.0	10/1/68
		1.5	1/1/69	1.5	1/1/69
		1.0	1/1/70	1.0	1/1/70
	Manatee County			2.0	12/3/68
Illinois	Chicago	2.5	6/23/70	2.5	6/23/70
		2.0	6/23/72	2.0	6/23/72
		1.5	12/23/73	1.5	12/23/73
	For Heating Existing Buildings				
	Outer City§	1x10^6 8TU/hr (1.5)	9/1/71	1.25	9/1/71
	Inner City§	1-10x10^6 BTU/hi' (1.5)	9/1/71	1.5	9/1/71
	New Buildings	1-lOx10^6 BTU/hr (1.0)	None	1.0	None
	Electric Power Generation	2.5 lb 502/106 BTU‖ (1.6)	1/1/72	2.5 lb 502/106 BTU (2.2)	1/1/72
	Industrial Power Plants§	1.5**	11/1/70	1.5**	11/1/70
			2/28/71		2/28/71
		1.5tt	10/1/72	1.5tt	10/1/71
			2/28/71		3/31/72
Indiana‡‡	Statewide	For both coal and oil: Probable effective date--4/1/71. The % S which would give the smaller emission value using the following approaches: (1) dispersion equation with maximum ground level of 200 micrograms/cu. m. and (2) process weight type curve with maximum value of 6 lb 502/106 BTU input.			
Kentucky		1.0	Indefinite	1.0	Indefinite
Maryland	Western Area	1.0§§	7/1/70	1.0	7/1/70
	Central Area	1.0	7/1/70	1.0	7/1/70
	Baltimore Area	1.0	7/1/70	1.0	7/1/70
	Washington Area	1.0	7/1/69	1.0	7/1/69
	Southern Area	1.0***	7/1/70	1.0	7/1/70
	Eastern Shore	1.0***	7/1/70	1.0	7/1/70
	Prince Georges and Montgomery county	1	Indefioite	1	Indefinite
				0.3 (Disto)	7/1/72
				0.5 (R.sid.)	7/1/77
Massachusetts	Boston Area				
	Inner Cities and Towns	0.55 lb 5/10^6 BTU (0.7)	10/1/70	1.0	10/1/70
	Outer Cities and Towns	1.22 lb 5/10^6 BTU (1.6)	10/1/70	2.0	10/1/70
	All Places During Adverse Heteorological Conditions			No. 2	
				0.17 lb 5/10^6 8TU (0.2)	10/1/70
		0.55 lb 5/10^6 BTU (0.7)	10/1/70	0.55 lb 5/10^6 BTU (1.0)	10/1/70
Minnesota	Minneapolis-St. Paul	2.3 lb 502/106 BTU‡‡‡ (1.5)	4/1/72	2.3 lb 502/106 BTU‡‡‡ (2.0)	4/1/72
	Alert Levels §§§	2.0 ‖‖	4/1/70	2.0 ‖‖	4/1/70
Missouri	St. Louis Area	2.0 ‖‖	12/1/68	2.0	12/1/68
		2.3 lb 50$_2$/10^6 BTU‡‡‡ (1.5)	3/24/70	2.3 lb 50$_2$/10^6 BTU‡‡‡ (2.0)	3/24/70
	St. Louis	2.3 lb 502/106 BTU (1.5)	Date of Regulation +3 Yrs.	2.3 lb 50$_2$/10^6 BTU (2.1)	Date of Adopt. +3 Yrs.
		1.0 lb 502/106 BTU (0.65)	1/1/73	1.0 lb 502/106 BTU (0.9)	1/1/73
Montana	Statewide	2.0 lb 5/10^6 BTU (2.6)	7/1/70	2.0 lb 5/10^6 BTU (3.6)	7/1/70
		1.5 lb 5/10^6 BTU (2.0)	7/1/71	1.5 lb 5/10^6 BTU (2.7)	7/1/71
		1.0 lb 5/10^6 BTU (1.3)	7/1/72	1.0 lb 5/10^6 BTU (1.8)	7/1/72
Nevada	Reno. Sparks and Washoe Counties			1.2	9/18/69
New Hampshire	Statewide			1.0	7/1/70
	Existing Sources	2.8 lb 5/10^6 8TU§§§ (3.6)	10/1/70	00.5 (No. 2 Oil)	10/1/70
		2.0 lb 5/10^6 BTU**** (2.6)		0.4 (No.2 Oil)	10/1/72
				1.5 (No. 4&5 Oil)	10/1/70
				1.25 (No. 4&5 Oil)	10/1/71
				1.0 (No. 4&5 Oil)	10/1/72
				2.0 (No.6 "il)	10/1/70
				1.5 (No.6 Oil)	10/1/71
				1.25 (No. 6 Oil)	10/1/72
				1.0 (No.6 Oil)	10/1/73
	New Sources	1.5 lb 5/10^6 8TU§§§ (2.0)	10/1/70		
		1.0 lb 5110^6 BTU**** (1.3)			
New Jerseytttt	Statewide	1.0 (Bituminous)	5/6/68	0.3 (No. 2 Oil)	5/1/68
		0.2 (Bituminous)	10/1/71	0.3 (No.2 Oil)	10/1/70
				0.2 (No.2 Oil)	10/1/71
		0.7 (Anthracite)	5/6/68	0.7 (No.4 Oil)	5/1/68
		0.2 (Anthracite)	10/1/71	0.4 (No. 4 Oil)	10/1/70
				0.3 (No.4 Oil)	10/1/71
				1.0 (No. 5&6 Oil)	5/1/68
				0.5 (No. 5&6 Oil)	10/1/70
				0.3 (No. 5&6 Oil)	10/1/71
New York	Statewide	1.65 lb 5/10^6 BTU (2.1)	6/1/70	1.65 lb 5/10^6 BTU (3.0)	6/1/70
	New York City Metropolitan Area (Nassau. Rockland and Westchester Counties and City of New York)	Purchased for use 1%	10/1/69	1	10/1/69
		New construction Installed or modified. 0.2 lb 5/10^6 BTU (0.26)	4/1/71	0.2 lb 5/106 BTU (0.37)	4/1/71
		Purchased for use 0.2 lb 5/10^6 BTU (0.26)	10/1/71	0.2 lb 5/106 BTU (0.37)	10/1/71
	Utilities				
	Bronx. Kings. N.Y. Co.		10/1/68	1	10/1/68
	N.Y.C. Metropolitan Area		10/1/69	1	10/1/69
	New York City			0.5 (No. 2&4 Oil)	Date of Adopt.
				0.2 (No. 2&4 Oil)	10/1/71
		1.0	Date of Adopt.	1.0 (No.6 Oil)	Date of Adopt.
		0.3	10/1/71	0.3 (No.6 Oil)	10/1/71
North Dakota	Statewide	3.0 lb 502/106 BTU (2.0)	7/1/70	3.0 lb 502/106 BTU (2.7)	7/1/70

TABLE M-6

STATE AND LOCAL SULFUR OXIDES CONTROL REGULATIONS
APPLICABLE TO FUEL COMBUSTION SOURCES*
(CONTINUED)

	Area	Maximum Sulfur Content of Fuel (%)†	Effective Date	Maximum Sulfur Content of Fuel (%)†	Effective Date
Ohio	Cincinnati	1.25	1/22/69	1.2S	1/22/69
	Cleveland				
	Existing Sources	2.0	12/31171	2.0	12/31171
	New Sources	1.0	10/15/69	2.0	10/15/69
	Steubenville	2.0	10/22/68		
	Toledo	2.7 (Avg. in Any Month)	1/1171	1.0 (1.5) if produced and consumed on premises)	1/1/71
Pennsylvania	Allegheny County	2.5 lb S02/1D6 BTU (1.7)	12/17/69	2.5 lb $SO_2/10^6$ BTU (2.3)	12/17/69
	Philadelphia	2.0 (Bituminous)	5/1170	0.3 (No.2 011)	5/1/70
		1.0 (Bituminous)	7/1/71	0.3 (No. 2 Oil)	10/1172
		0.3 (Bituminous)	10/1172	0.2 (No.2 Oil)	10/1173
		0.7 (Anthracitel	5/1170	0.7 (No. 4 011)	5/1/70
		0.3 (Anthracite)	10/1/72	0.4 (No. 4 Oil)	10/1172
				0.3 (No.4 Oil)	10/1173
				1.0 (No. 5&6 Oil)	5/1/70
				0.5 (No. 5&6 Oil)	10/1172
				0.3 (No. 566 011)	10/1/73
	Allegheny Co., Beaver Valley, Monongahela Valley	1.5 lb S02/106 BTU‡‡‡‡ (1.0)	3 Yrs. After Date of Adopt.	1.35	3 Yrs. After Date of Adopt.
		.6 lb S02/106 BTU§§§§ (0.4)	3 Yrs. After Date of Adopt.	0.5	3 Yrs. After Date oC Adopt.
Tennessee	Chattanooga	2.0	3/4/69	2.0	3/4/69
	Nashville	2.0	3/1/70	2.0	3/1170
Vermont ‖‖‖‖		2.2	10/1171	2.2	10/1171
		1.5	10/1/72	1.5	10/1/72
		1.0	10/1/74	1.0	10/1/74
Virginia	Falls Church			1.0	1/1170
	Fairfax County			1.5	7/1/69
	Alexandria	1.0	7/1/69	1.0	7/1/69
	Arlington County			1.0	7/1/69

* Data collected September, 1970, by National Coal Association from lists prepared by Technical Support Branch, Division of Control Agency Development, Environoental Protection Agency.

† Figures refer to maximum allowable amount or percentage of sulfur in fuel, by weight. except as follows: Where limitations are expressed as lb. S02/106 BTU (as in St. Louis area and Allegheny County), they refer to allowable sulfur oxides emissions, by weight, per million BTU's of heat value of the fuel. Limitations are applicable to all fuel combustion sources except as indicated in footnotes. Figures in parentheses are equivalent fuel sulfur contents.

‡ Government facilities, sales for commercial, institutional and industrial use.

Requires agency proof that air quality standards are being exceeded.

3x10^9 BTU's per hour.

** When air quality standards are exceeded.

†† Annually.

‡‡ Fuel burning equipment and incinerators used singly or jointly by occupants of residential dwellings containing four or less apartments are exempted.

§§ Only equipment with capacity greater than 100x10^6 BTU's per hour.

‖‖ Only equipment with capacity greater than 500x10^6 BTU's per hour.

*** Only equipment with capacity less than 500x10^6 BTU's per hour.

††† Combustion fuels containing sulfur in excess of the amount indicated may be used if stack gas desulfurization reduces SO_x emissions equivalent to that resulting from a combustion of approved fuels.

‡‡‡ Only equipment with capacity greater than 2x109 BTU's per hour.

§§§ Effective during alert periods.

‖‖‖ Only equipment with capacity less than 2x10^9 BTU's per hour.

**** Maximum 3-month average sulfur content.

†††† Provisions not applicable to commercial fuel used by oceangoing vessels or in internal combustion engines. Requirements due to become effective October I, 1970, and October 1, 1971, shall not apply to commercial fuel used in Atlantic, Cape May, Cumberland, Hunterdon, Ocean, Sussex and Warren Counties.

‡‡‡‡ 400x106 BTU's per hour.

§§§§ 1000x10^6 Btu's per hour.

‖‖‖‖ Provisions do not apply where stack gas desulfurization reduces emissions of S02 to that which would be emitted by combustion of low-sulfur fuels.

Air pollution control is a vital element in the siting of generating plants because a substantial portion of emissions from stationary sources is attributed to the electric power industry--primarily in the form of particulate matter and sulfur oxides--in and near major population centers. The projected power needs of the Nation, the long economic life of power plants, and the trend toward larger unit size all underscore the importance of including air pollution control as a major siting criteria in planning future plants. As new plants are built and older plants are gradually replaced, cognizance of air pollution control requirements in the location and design phase represents a major step toward meeting national air pollution control objectives while also meeting the Nation's future power requirements at reasonable costs.

Pollution from Power Plants

When fossil fuels are burned, chemical oxidation occurs as combustible elements of the fuel are converted to gaseous products and the noncombustible elements to ash. Typically, more than 95 percent of the gaseous combustion products are not presently known to be harmful (oxygen, nitrogen and carbon dioxide, and water vapor) and, therefore, apparently are not factors in air pollution. The noxious gases (oxides of sulfur, the oxides of nitrogen, and organic compounds including polynuclear hydrocarbons) are harmful to humans, plants, animals, and material. Controls are available for particulates, but there are presently no fully tested commercially available control systems for oxides of nitrogen and sulfur from fuel combustion. Combustion of natural gas yields comparable quantities of the oxides of nitrogen, but is generally very low in the production of particulates and sulfur oxides.

The oxides of sulfur are of immediate concern and extensive research efforts are underway to develop economical control processes adaptable to utility and commercial combustion units. Upon discharge, sulfur dioxide may convert to sulfur trioxide, and sulfur trioxide to sulfuric acid mist, which may cause extensive damage to humans, vegetation, and property. In combination with other pollutants, for example, particulates, sulfur oxides have been shown to exhibit "synergistic" effects several times more severe than comparable exposure to either pollutant alone.

Site Selection Factors

The majority of the new air quality control regions will be centered on major population centers; these areas also represent major electrical load centers. Therefore, in planning new plant sites in these areas, it will be extremely important to take into consideration the intent of new air pollution control standards. A rigorous examination of the site and design features should be made to assure the safety of the surrounding environment and its population as the size of fossil and nuclear plants increases to meet the projected energy requirements of the nation.

From an air quality viewpoint and based on the present level of technology in air quality controls, an ideal site for a generating plant may be characterized as one where no significant air quality problem is present, remote from population or other land use which is particularly susceptible to air quality effects, and free of terrain or meteorological features which might inhibit dispersion of emissions. A mine-mouth plant in remote, undeveloped, flat terrain probably represents the closest approximation to this ideal site. Normally such sites are rare or perhaps nonexistent where the power is needed and other site factors are met. Nevertheless, these characteristics should be sought insofar as practical and compatible with other interests.

Factors related to air quality requiring appraisal are population distribution, expected growth pattern, existing or expected local industrial pollution, terrain over the area where dispersion processes are most significant (say, 30-mile radius), and land-use patterns such as agriculture, forestry, or recreational purposes.

Excerpts from the second report, published during the Nixon Administration, follow below.* This entire report is worth study. However, as pertaining to atmospheric pollution and its effect on future coal use for electricity generation, the following excerpt is included because of its highly practical approach in recognizing a distinction between old and new plants.

Distinction Between Old and New Plants

1. Relative Control Effectiveness. Electric power supply facilities are in a continuing state of transition. New plants become obsolescent rather quickly in an industry which is doubling every ten years. The economies of operation results in the tendency toward much higher use of large new plants, and consequently toward lower and decreasing use of older plants. Over the life of a thermal power plant (25-35 years) the load factor averages only 50-60%. The rate of economic--as distinguished from physical--obsolescence is quite rapid.

The use of older, less efficient generating plants declines rapidly when they are no longer needed continuously to meet the "base loads,"† and are used only to meet daily and seasonal peaks. In a typical power system, most electric generating units over the first ten years of life will produce one-half to two-thirds of their 30-year lifetime output.

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* Office of Science and Technology, *Electric Power and the Environment* (August 1970), pp. 12-14.

† The minimum continuous load over a given period of time.

An interesting fact for our purposes is that without any other remedial action, from any given point in time, the total volume of pollution from all existing plants would be reduced by about 10 percent in 5 years and by about 40 percent in 10 years, merely because they will be used much less in the future. It is true, of course, that peak periods of air pollution could coincide with power system peaks. Nevertheless, with continued growth in the power industry, the environmental effects of older plants diminish rapidly with age.

The environmental effects of plants to be built over the next decade are therefore significantly more important than that of all existing electric power generating facilities combined.

Economic and cost considerations also suggest a distinction between existing and new facilities. The cost per unit of output of backfitting pollution control equipment in older (and also generally smaller) units combined with the shorter period available for amortization of these facilities make pollution control exceedingly more expensive in old units as compared to new ones. At some existing plants, space limitations make it impossible to add control equipment. It is much more economical to install pollution control equipment when the plant is built. Economic improvements due to increases in sizes of units provides another incentive to install the pollution control equipment on the larger units.

As a plant becomes older, it thus becomes less economically justifiable to equip it with environmental control equipment, and at the same time the benefits that accrue from installation of such equipment decrease substantially, since environmental effects for the most part are proportional to plant use. Finally, as a plant nears the end of its life, it becomes economically more attractive to the utility to retire it (which may be a waste of a useful existing resource) rather than utilize the limited capital resources for additional equipment that will not be operated enough to justify the expense.

Of course, there is one major offsetting factor--namely, that many older plants are in urban areas where the pollution problems are most acute and where a greater expense for pollution control may be justified. These are all factors that must be weighed in each particular situation. It is well to understand the clear distinction between existing and new plants and make judgments in light of the costs and benefits in each particular situation.

2. Practicality of Control Measures. The plant emissions of most concern now are fly ash and sulfur dioxide for fossil-fuel-fired plants, radioactive releases from

nuclear plants, and large quantities of low-level heat from both fossil and nuclear plants. In the future for fossil-fired power plants, this concern may extend to oxides of nitrogen as well.

Electrostatic precipitators are now almost universally used for high efficiency removal of fly ash from the newer fossil-fired electric power stations. However, adequate technology for removal of sulfur oxides on a large scale on a reliable basis for the life of a power plant has not yet been demonstrated. Several processes are being investigated, and several are being tested on commercial-size installations. Most of these processes either remove fly ash as an integral part of the process or require high efficiency removal of ash prior to processing the gases for S02 removal. Some of the processes could not be used at existing power stations because they require higher flue gas temperatures than are available at the air preheater outlet which is the only reasonable location for installing S02 recovery equipment at existing power stations. However, one of the processes under consideration involving limestone-wet scrubbing, could accept flue gases at air preheater outlet conditions. Conceivably its cost could be sufficiently low so that it could be utilized at older plants. In the case of some older plants, however, the available space may not permit installation of equipment or disposal of the additional sulfur-containing particulate material.

For still older plants, particularly those with low-use factors, only a low capital cost, simple installation could be considered economically justified unless it was in an urban location that experienced severe air pollution problems. Regardless of the simplicity of the process, more waste product storage would probably have to be provided. The use of low sulfur fuels (to the extent available) may provide the most economical solution when plants are too old to justify sulfur removal equipment.

For discharge of low-level waste heat, the same generalizations can be made regarding the relative impact on the environment of old and new plants and on the economics of adding new environmental control equipment to older power stations as were mentioned for air pollution control. However, the state of technology is different. For the present, the only feasible alternatives to once-through cooling for large plants is use of wet cooling towers and cooling ponds. The technology for large commercial wet cooling towers is well established, but only for fresh water.

Present cooling techniques require large sites for added equipment and present unique environmental problems of their own.

Very little can usually be done about the site itself and the esthetics at existing plants, but a great deal can be accomplished before sites are selected and plants designed and built.

In summary, it may be said that beyond the questions of need and cost, it seems probable that there will be some environmental control techniques that cannot be backfitted to older plants because of technological and design problems. There may also be the problem of physical space limitations that will make it impossible to add control facilities to existing plants, short of rebuilding them; and finally, there may be a lack of disposal areas for unusuable byproducts from the air quality control processes which currently seem most adaptable to older plants.

Thus, in order to control the major sources of future pollution and to obtain the greatest return for our investment in environmental protection, we should concentrate on new installations in which the necessary control equipment can be incorporated initially. Of course, it may be necessary to install control equipment on some existing facilities where problems exist and where there are no better alternatives.

COMBINED-CYCLE SYSTEMS

The failure of earlier attempts to improve power plant efficiency by increasing steam temperatures has set a ceiling on this important variable, at least for the commonly used so-called steam-electric cycle. Attempts to break out from this limitation by other means have been under study for some time. In general, these efforts involve "topping" devices of one kind or another. They are discussed in the report of the New Energy Forms Task Group.* Topics included in that report are magnetohydrodynamics, ionic converters" fuels cells and others.

For the use of coal in power generation, the most important topping concept appears to be the so-called gas turbine/steam turbine combined-cycle. Given increased attention, it could be available for commercial use before 1980 and have a profound impact on coal's future position in power generation.

The importance of this concept relates to the apparent indication that combined-cycle plants could ultimately convert high-sulfur coals to electricity at higher thermal efficiency and with less pollution than any other system, and this might possibly be achieved while lowering the investment in dollars per KWcompared to conventional coal-burning plants.

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* NPC, *U.S. Energy Outlook, an Interim Report by the New Energy Forms Task Group* 1971-1985 (March 1972).

The key to success is clearly the potential advances which appear possible for gas turbines in terms of unit size, inlet temperature, blade life and cost. A second important consideration is the present availability of a reliable gasification system operating at elevated pressure.

This combined-cycle concept as applied to coal has received attention in the United States for some years, both by private industry and by the predecessors of the EPA, but the effort was minor, and no significant advances have been made. However, the concept has recently received a significant support by a 172 MW plant in GermanY,known as the Lurgi-STEAG plant, which is currently under construction. In view of the importance of this project, a brief comment follows.

Lurgi gasifiers have been in operation around the world for a number of years and now number about 60. At present a 172 MW electricity generating unit is being built at the Kellermann Power Station at Lünen by Lurgi G.m.b.H. and Steinkohlen Elektrizitat AG, hence the designation "Lurgi-STEAG." In this particular plant, after coal is gasified in Lurgi gasifiers, the gas is cleaned of particulate matter by being washed with water in a scrubber and is thereby saturated. It then goes to a gas turbine where the steam content benefits the gas turbine capacity. The plant will involve 74 MW of gas turbine capacity and 98 MW of conventional steam turbine capacity. (Note that this plant will require a condenser circulating water quantity of only 98/172 = 57 percent of what would be usual).

The Lunen station will not have sulfur removal because the coal used will contain little sulfur, but Lurgi states: "The H_2S can easily be removed from the gas by conventional washing processes and can be converted either to sulfuric acid by wet catalysis or to elemental sulfur in a Claus kiln. The processes are well known in conjunction with town gas and synthesis gas production." A simplified flow diagram of the Lunen plant is shown in Figure M-l.

This plant should be watched very carefully, and consideration could well be given to the possibility of inducing Lurgi-STEAG to cooperate at U.S. expense in the installation of a sulfur removal plant and testing some typical American coals.

Not only would combined-cycle plants of this type be highly efficient and able to use high-sulfur coals, but they could also be of a size that could be located at the mouths of smaller mine developments. The low water requirement would be quite an asset in this connection.

The Lurgi-STEAG might be considered the forerunner of the coal burning combined-cycle scheme. The ultimate promise inherent in the concept is outlined in a comprehensive study sponsored by EPA and performed by United Aircraft Research. This was an extensive conceptual design study of a combined-cycle plant in which coal would be gasified for combustion in a 1,000 MW power system. "The nominal 1,000 MW system would consist of two 314 MW gas turbines,

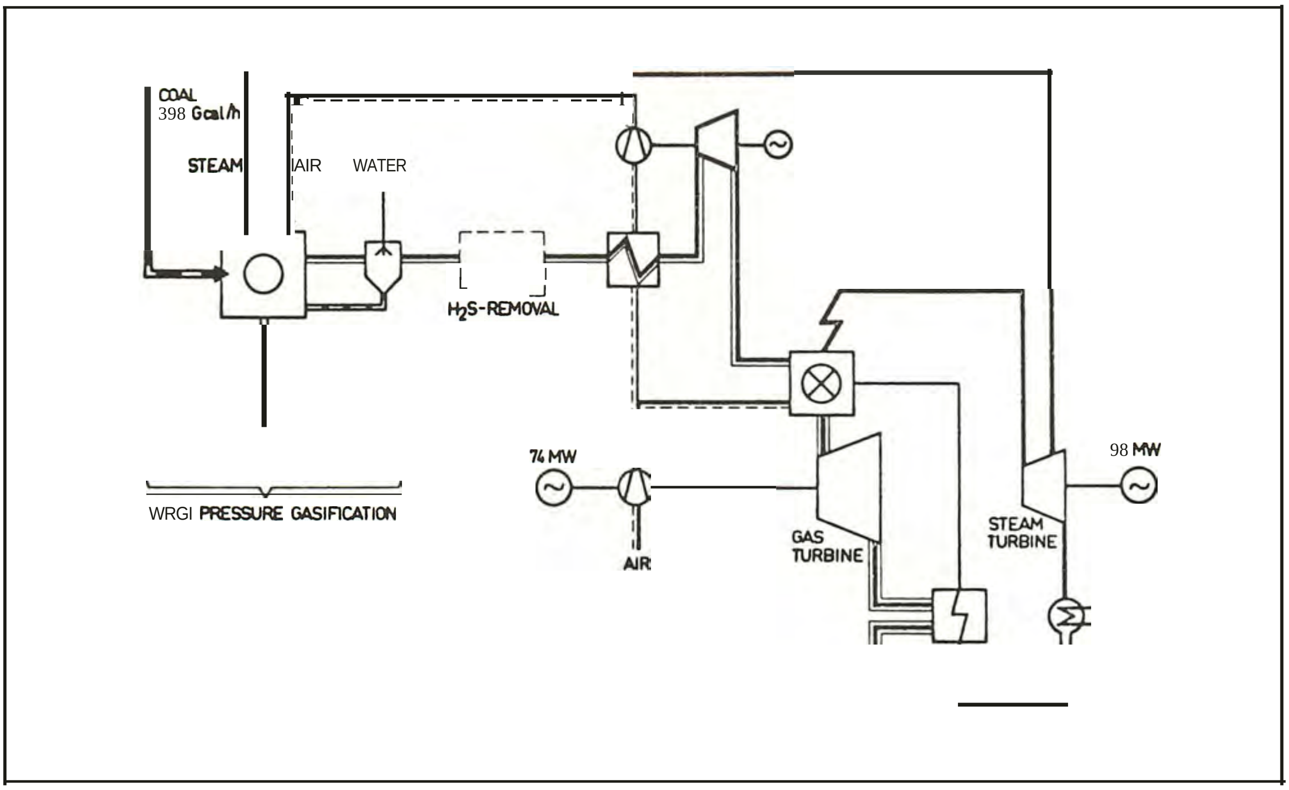

Figure M-l. Combination of Gasification with Gas Turbine/Steam Turbine Power Plant.

operating at 2,800°F turbine inlet temperature, exhausting into a waste-heat boiler which supplies steam for a 318 MW steam turbine (the temperature of 2,800°F sounds startling, but gas turbine blading temperatures have been continuously increasing, with United Aircraft being actively involved). The system efficiency is projected to be 54 percent and the overall station efficiency, including gasification, is estimated to be 47 percent." United Aircraft has published various articles on this work written by F. L. Robson, A. J. Giramonti and others. Also, there will be available the very detailed APCa report.*

All other systems for eliminating air pollution from sulfur in coal-burning power plants involve substantial added costs. This is true whether the coal is desulfurized (by liquefaction or gasification) or whether the flue gases are cleaned at the stack. Solely, the combined-cycle appears to offer an answer to the pollution problem which, at the same time, can yield other advantages. In view of this, it is believed that the successful development of this system could have an important impact on decisions for future coal-burning power plants at the end of the 1970-1980 period.

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* APCa, *Final Report on the Technological and Economic Feasibility of Advanced Power Cycles and Methods of Producing Non-Polluting Fuels for Utility Power Station*, United Aircraft Research Laboratories Report J-970855-l3 (November 1970).

APPENDIX N

MANUFACTURE OF PIPELINE GAS FROM COAL

INTRODUCTION

The purpose of this particular study concerning the conversion of coal to pipeline gas was to assess:

- The probable costs of manufactured pipeline gas
- The effect of major factors on the cost of manufactured pipeline gas
- The status of various processes available or under development
- The potential benefits that could be provided by the processes under development.

The study was based primarily on published information but supplemented where necessary by general background information judged to be appropriate.

PIPELINE GAS TECHNOLOGY

Basic Chemistry

The hydrogen content of coal, averaging about 5 percent by weight, is very low compared to the 2S-percent hydrogen content of methane which must be the major component of pipeline gas. A key problem in conversion of coal to pipeline gas is, therefore, the generation of large quantities of hydrogen which must come from water decomposed by reaction with coal or char. The reaction of coal and steam is highly endothermic, requiring almost 60,000 BTU's per mol of steam at temperatures of about 1,600°F to 1,900°F for acceptable reaction rates. Heat supply of this magnitude and temperature level is expensive and is an important factor in the cost of coal gasification.

At sufficiently elevated pressure, hydrogen will react directly with coal at the steam decomposition temperatures and liberate substantial quantities of heat (about 40,000 BTU's per mol of methane). Since 1 mol of methane is stoichiometrically equivalent to a mol of steam being decomposed, it is clear that the coal hydrogenation reaction can supply a major portion of the heat needed for the steam decomposition reaction if both reactions occur in the same zone. This will result in reducing the endothermic, high temperature heat supply to one-third of the steam decomposition heat in the absence of hydrogenation, thus significantly reducing pipeline gas costs.

To the extent that hydrogenation (i.e., hydrogen consumption) is incomplete, the reactor heat duty increases, and in addition synthesis gas generated at about 1,600°F flows from the high temperature reactor and must be converted to methane in a methanation reactor. This latter reacton occurs at about 600°F; it releases almost 100,000 BTU's per mol of methane formed from synthesis gas and requires a volumetric gas flow through a number of process steps four times as great as the equivalent volumetric flow of methane. Decreasing synthesis gas methanation, consequently, is also important in reducing the cost of pipeline gas.

The various processes for pipeline gas manufacture available or under development differ primarily with respect to the method of gas-solid contact, supply of heat to the stearn decomposition reaction and the extent to which direct hydrogenation of coal to methane is combined with stearn decomposition in the high temperature reaction system.

Table N-l illustrates these key reactions.

TABLE N-l

REACTIONS IN COAL GASIFICATION*

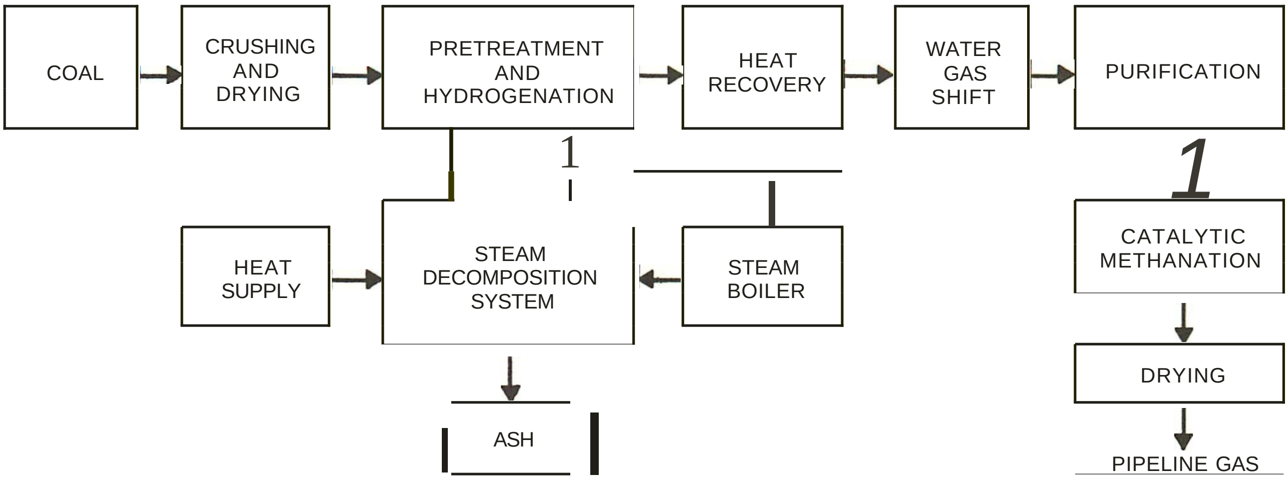
<u>Major</u> <u>Reactions</u>		
Steam Decomposition	C + HZO → CO + HZ	60,000 BTU/lb mol
Hydrogenation	C + ZHZ → CH4	+ 40,000 BTU/lb mol
Methanation	CO + 3HZ → CH_4 + HZO	+ 100,000 BTU/lb mol
<u>Auxiliary</u> <u>Reactions</u>		
Heat Supply	C + 0z → COZ	+ 170,000 BTU/lb mol
Water Gas Shift	CO + HZO → COZ + HZ	+ 14,000 BTU/lb mol

* Heats of reaction at gasification temperature levels.

In addition to these two major process steps, the complete pipeline gas plant requires important facilities to prepare the coal for reaction, to purify and convert the high temperature gases for methanation, and to dry the pipeline gas.

<u>Overall Pipeline Gas Manufacture</u>

A block diagram of the individual operations that must be carried out in sequence to make pipeline gas from coal is shown in Figure N-l.



Source: THE M. W. KELLOGG COMPANY – A Division of Pullman Incorporated

Figure N-l. Pipeline Gas from Coal Integrated Facility.

On being recovered from the stockpile, coal is crushed, ground and dried. The dried, ground coal is then charged to a pretreatment and hydrogenation operation where it is reacted with hydrogen-rich synthesis gas and steam under pressures ranging from 400 to 1,200 pounds per square inch and temperatures from 1,200°F to 1,600°F. In this operation, coal is hydrogenated to yield methane depending in amount on the pressure and coal activity, and the exothermic heat is transferred to the coal-steam reaction decomposing water to generate a hydrogen-carbon monoxide mixture (synthesis gas). The process can be carried out in a commercially proved moving bed process or under fluid bed or entrained solids conditions in several other processes under active development. The products of the pretreatment-hydrogenation step are raw gas and hot char. In general, the pretreatment step is unnecessary for non-caking coals but is necessary for caking coals in some reaction systems such as moving beds or fluid beds.

The hot char is transferred to a final gasification step where it decomposes steam to generate synthesis gas for use in the hydrogenation step. The temperature in this part of the process will depend on the method of heat supply but could rise to above 2,000°F. Various processes available or under development combine the hydrogenation and gasification reactions in different ways.

Returning to the gases leaving the hydrogenation section, this stream is passed through a waste heat recovery section which cools the gases to the temperature required for further processing. Depending on the rank and analysis of the coal and on the balance between the hydrogenation and water decomposition reactions used in a particular situation, the composition of this gas stream will vary and mayor may not be suitable for the stoichiometry of the final methanation reaction (Table N-1). Consequently, the cooled gas may be subjected to water gas shift and purification steps in such combination as is suitable to convert the raw synthesis gas to a composition such that the methanation reaction will provide a final gas having no more CO, H_2 and CO_2 than is permitted to meet pipeline gas specification with good methanation catalyst life.

After composition adjustment and purification, the synthesis gas is converted to pipeline gas in a catalytic methanation step using a nickel catalyst. This reaction is used commercially in removing carbon oxides from ammonia synthesis gas, but its use in pipeline gas processing represents an important extension of the available technology. This is a result of the much higher carbon oxides content of the gas which results in much greater heat release during reaction. Dissipation of this heat and control of temperatures are important considerations in adapting current methanation technology to pipeline use, but this is not considered a major problem in pipeline gas development.

The extreme sensitivity of nickel catalysts requires a very thorough removal of all sulfur compounds in the purification step. Hence, synthetic pipeline gas will stand out as an unusually sulfur-free gas.

After methanation has produced pipeline gas, the water produced by the reaction must be removed in order to meet dryness specifications for pipeline use.

The major areas undergoing extensive development at the present time are the stearn decomposition/coal hydrogenation steps. These are the processes that provide the best potential for cost reduction. On the other hand, a commercially developed process, available from the well-known firm, Lurgi G.m.b.H., is well suited to most western coals and can handle the caking coals of the eastern fields after pretreatment, including agglomeration of the fines, which cannot be used in the Lurgi moving bed reactors. This coal preparation would require some modest development work.

Some development work is also needed for catalytic methanation, but this effort should be substantially smaller than that needed for gasification.

Other steps, such as crushing, drying, water-gas shift and gas purification, are well-known and available commercially. These would require very minor adaptation for pipeline gas operations.

COST OF PIPELINE GAS--LURGI PROCESS

Gasification of coal in Lurgi gasifiers using oxygen to supply the required heat has been practiced in Europe for over 3S years and in South Africa for about two decades.* In the latter

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* Used in South Africa by the South African State Oil Company, the government-owned coal conversion plant near Johannesburg, South Africa. The plant processes some 7,000 tons per day of coal containing up to 30-percent ash.

case, the raw gas is processed to make liquid hydrocarbons, and the overall processing is very similar to the pipeline gas requirements except for the methanation step. Substitution of the liquid-producing catalytic reaction used at SASOL by the nickel-catalyzed methanation reaction makes it possible to provide a plant for converting non-caking (western) coal to pipeline gas based on well-established technology once the relatively simple adaptation of catalytic methanation to pipeline gas conditions is demonstrated. Consequently, the Lurgi process has been used to project costs of pipeline gas from coal, and these costs are considered to be fairly dependable.

A number of publications are available for the cost of the Lurgi process, but none are recent, hence, allowance has been made for the time factor. On this basis, the investment required for a complete gasification plant starting with stockpiled coal and delivering dried pipeline gas is shown in Table N-2. The investments are based on a plant delivering 270 million standard cubic feet per day of gas with a higher heating value of 900 BTU's per cubic foot and include utility and offsite facilities. The process plant investment for caking coals is larger because facilities must be included for pretreatment to overcome the caking characteristic and for agglomeration.

Because the basic process costs are for a generalized location and detailed engineering has not been carried out, an allowance of 15 percent has been added to the process plant investment. In

TABLE N-2

COAL GASIFICATION--LURGI PROCESS--CAPITAL REQUIREMENTS
(270 Million SCF per Day of 900 BTU/SCF Gas)

	Non-Caking Coal	Caking Coal
Process Plants Investment	132,000,000	157,000,000
Utilities and Offsites	23,000,000	23,000,000
Allowance for Detailed Design	20,000,000	24,000,000
Escalation During Construction	15,000,000	18,000,000
Allowance for Process Development	5,000,000	5,000,000
Miscellaneous*	8,000,000	8,000,000
Total	203,000,000	235,000,000
Working Capital	6,000,000	12,000,000
Rate Base	209,000,000	247,000,000

* Startup, spare parts, coordination, etc.

addition, an allowance of 10 percent has been added for escalation during construction, though this will vary depending on the timing of plant construction. A further allowance of 20 percent has been included to allow for unforeseen requirements that may appear in adapting the available catalytic methanation techniques to pipeline gas conditions and for other minor modifications that may develop. Finally, about 5 percent has been added for costs involved in coordination during construction, spare parts and startup expenses.

The resulting investment of $203 million for non-caking, strip-mined (western) coals and $235 million for caking, deep-mined (eastern) coals are judged to be reasonable estimates, which when added to working capital result in the "rate base" for use in gas cost calculations.

The contribution of the individual process steps to the total plant investment is shown in Table N-3. Since methanation is the only step that requires major adaptation from known commercial technology, it may be concluded that the rate bases of $209 million and $247 million for western and eastern coals, respectively, provide a dependable basis for projecting gas costs by means of the Lurgi process.

TABLE N-3

DISTRIBUTION OF PROCESS PLANT INVESTMENT--
LURGI GASIFICATION

	% of Total
Coal Handling (Western Coal)	4
Oxygen Plant	25
Gasification	23
Water-Gas Shift	6
Gas Purification	22
Sulfur Recovery	4
Methanation	16
Total	100

The calculation of gas cost is shown in Table N-4. In this table, the costing calculation follows the procedure used in the ongoing development programs. It was set up to reflect accepted practice in the gas industry. Typical coal prices of 15 and 30 cents per million BTU's are used for western strip-mined and eastern deep-mined coals, respectively. Labor is based on an operating crew of 55 men per shift and a rate of $4.75 per man per hour. The large crew is used in the calculation because multiple trains are needed throughout the plant, including about 30 gasifiers in the gasification section.

TABLE N-4

COAL GASIFICATION--LURGI PROCESS
ANNUAL OPERATING COST AND AVERAGE GAS COST TO CONSUMER
(270 Million SCF per Day of 900 BTU/SCF Gas)

	Annual Costs ($)		Unit Cost (¢/MM BTU's)	
	Non-Caking Coal	Caking Coal	Non-Caking Coal	Caking Coal
Coal (15¢ and 30¢/MM BTU's)	17,900,000	35,800,000	22.2	44.2
Catalysts and Chemicals	1,200,000	1,200,000	1.5	1.5
Raw Water	300,000	300 000	0.4	0.4
Operating Supplies	600,000	600,000	0.7	0.7
Direct Labor	2,300,000	2,300,000	2.8	2.8
Maintenance (Labor and Materials)	6,000,000	7,000,000	7.4	8.6
Supervision	230,000	230,000	0.3	0.3
Payroll Overhead	250,000	250,000	0.3	0.3
General Overhead	4,560,000	5,060,000	5.6	6.2
Plant Overhead Expense	33,340,000	52,740,000	41.2	65.0
Contingencies	700,000	1,100,000	0.9	1.4
Capital Charges on Rate Base (13%)	27,200,000	32,100,000	33.7	39.6
Total Annual Revenue	61,240,000	85,940,000		
Average Gas Cost to Consumer (¢/MM BTU's)			75.8	106.0

As an example of "utility type" financing, capital charges used in calculating gas costs in Table N-4 are set at an average of 13 percent per year of the rate base in Table N-l. This 13 percent figure includes 5 percent of the rate base per year for depreciation, 3 percent of the rate base per year for local taxes and insurance and, in addition, interest on borrowed capital, return on equity invested in the plant and federal income tax. It is assumed that 65 percent of the rate base is supplied by borrowed capital and 35 percent by equity capital. Interest is paid at a rate of 5 percent per year on half of the funds borrowed at the start of the 20-year plant life since depreciation will retire the debt over the 20-year depreciation period. Similarly capital return at about 10 percent, after federal income tax, is earned on half of the equity since this is completely paid back by depreciation over the life of the plant. Income tax is 48 percent of gross return. On this basis, an average gas cost to the consumer is computed for the 20-year life of the plant.

As shown in Table N-4, gas can be supplied to the market at 76 cents per million BTU's from non-caking, western coal at 15 cents per million BTU's. For caking, eastern coal at a typical cost of 30 cents per million BTU's, gas can be marketed at $1.06 per million BTU's.

It would appear that the cost of transporting gas from western sites to the eastern market may well be comparable to the difference in local costs, so that gas from low cost western coal may well be competitive in eastern markets.

The cost of coal in Table N-4 is some 30 percent to 40 percent of the total gas cost and is, therefore, an important cost factor.

The effect of coal cost over a range of 10 to 40 cents per million BTU's is shown in Figure N-2 at 13-percent average capital charge on rate base.

To indicate the major impact of capital charges, Figure N-2 relates the comparable costs if capital charge is taken as 18 percent of rate base per year. On this basis, interest could be paid at 7 percent and equity could earn, after income tax, 23 percent of the averaged undepreciated rate base per year.

The major factors affecting gas cost are thus cost of coal, plant investment and capital charges on investment. Gas costs will range between $0.68 and $1.29 per million BTU's, depending on these factors.

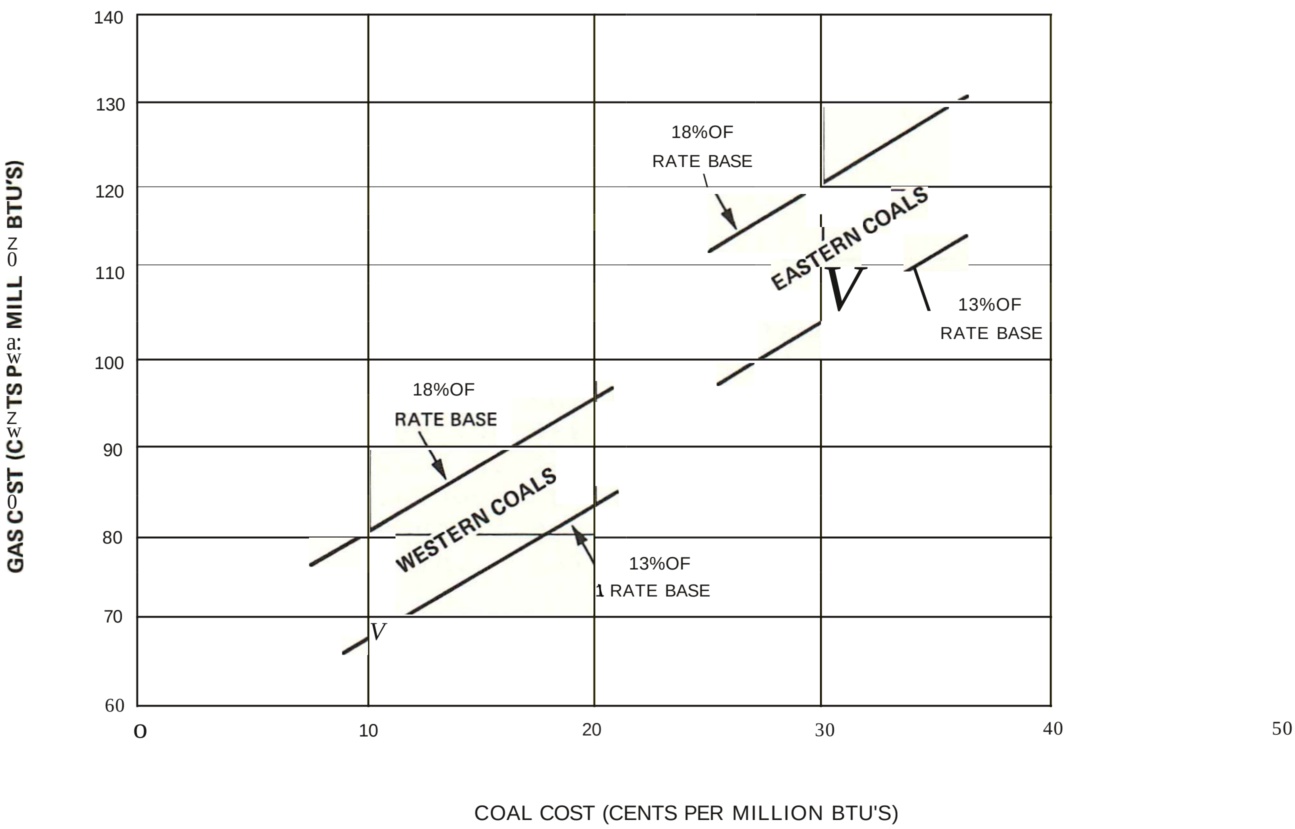

Figure N-2. Projected Cost of Pipeline Gas from Coal (Lurgi Process).

DEVELOPMENTAL COAL GASIFICATION PROCESSES

A number of coal gasification processes are currently under active development. These are concerned largely with the coal gasification and coal hydrogenation reactions and with the method of heat supply.

A pilot plant, currently undergoing preliminary testing using the HYGAS process, has been dedicated in Chicago by the Institute of Gas Technology and the Office of Coal Research. The HYGAS process uses four steps carried out in fluid beds. Caking coal is first pretreated to destroy caking characteristics at moderate conditions. The pretreatment step can be bypassed for coals which will not cake under the conditions of the following steps. The coal is then pumped as a slurry to the second bed at 1,000 to 1,500 pounds per square inch. In this bed, at 1,500°P, coal reacts with gases from the next bed and flows down to the last bed of the hydrogasification reactor where it reacts with gases entering the bed from the electrogasifier. This is fed with char from the preceding bed. Heat is introduced to the reaction system by passage of electricity between electrodes immersed in the electrogasifier bed, which is scheduled for service in mid-197l. It is expected that two-thirds of the methane product will be produced in the high temperature fluid beds leaving only one-third to be produced in the low temperature catalytic methanation. This should decrease the heat requirement for the high temperature endothermic coal gasification reaction and serve to reduce gas costs.

Another pilot plant is under construction at Rapid City, South Dakota, to develop the CSG process of the Consolidation Coal Company under sponsorship of the Office of Coal Research. This process uses three fluid beds. Lignite or subbituminous (non-caking) coal is charged to a first bed where it reacts with gases from the second bed to produce the raw gas for further processing into pipeline gas. Char from this bed flows to the second bed where it reacts with steam in the presence of a stream of calcined dolomite or CO_2 acceptor. Heat is supplied by carbonation of the lime content of the regenerated (calcined) dolomite as well as by sensible heat of the acceptor. Residual char and acceptor flow to a regenerator where char is burned with air producing heat to convert calcium carbonate back to lime for recycle to the second bed. The operating pressure for this process is about 300 pounds per square inch and the maximum temperature about 1,900°P. Heat supply by means of the acceptor circulation is the basic improvement used in this process, but removal of carbon dioxide from the process gas is also expected to enrich the raw gas in hydrogen and to reduce the water gas shift requirement.

Process design of a pilot plant for the BCR Two-Stage Super-Pressure Coal Gasification Process is under way. This process is being developed by Bituminous Coal Research, Inc., under sponsorship of the Office of Coal Research. Coal and steam are introduced to the upper stage to come into contact with hot synthesis gas from the lower section of the reactor. Char is separated from the overhead gas and returned to the lower stage where it reacts with oxygen, to supply heat, and more steam. The pressure used in the process is 1,050 to 1,500 pounds per square inch so that substantial direct hydrogenation of coal to methane is effected and subsequent processing of raw gas is minimized. In addition, the process is operated with coal and char entrained in the gas streams in order to eliminate a pretreating step for caking coals.

A pilot plant is being planned for the Synthane process under development by the Bureau of Mines. Coal, steam and some oxygen are introduced at the top of the gasifier reactor and flow down in dilute phase to destroy caking characteristics and permit direct use of caking coals. The pretreated coal falls on a fluid bed where it is gasified with steam and oxygen, which is used to supply the required heat. The operating pressure is 600 pounds per square inch and the fluid bed temperature is to be 1,650°P to 1,800°F. The conditions are expected to generate about half of the total methane product in the gasifier, thus reducing costs and minimizing oxygen requirements.

Among coal gasification processes not yet committed to the pilot plant stage is the Kellogg Coal Gasification Process which uses molten sodium carbonate to catalyze both coal gasification with steam and direct hydrogenation of coal to methane. In addition, the molten carbonate supplies heat to the gasifier vessel by circulating between this vessel and an air or oxygen supported combustion vessel to supply the necessary heat.

ECONOMIC POTENTIAL OF DEVELOPMENTAL PROCESSES

Estimates of the investment and operating costs of the gasification processes under development have been published. These figures are based on small-scale test data and are quite variable. Until pilot plant verification of the assumptions used in plant designs and cost estimates becomes available, it appears proper to use these estimates primarily to guide the research and development programs. Nevertheless, it is possible to derive an idea of the potential of the cost savings these processes may provide upon satisfactory completion of the work now under way.

The available estimates differ widely and are based on a variety of coals and on a variety of means of carrying out the required reactions. The plant investments for capacities of about 250 million standard cubic feet (SCF) per day, including utility facilities, range from about \$85 to \$150 million as compared to \$155 million for the Lurgi process operating on western coal. Though the first plant of any of the processes under development will cost more because of allowances that will have to be included to ensure dependability, it seems reasonable that some of the new processes should provide savings over the established process. Real savings would appear to be available as a result of the incorporation of increased direct hydrogenation in the gasifier and decreased downstream catalytic methanation, resulting in an important decrease in endothermic heat requirements.

A potential savings in investment of perhaps \$35 million in rate base would appear to be possible. On this basis, savings in total gas costs would amount to about 8 to 12 cents per million BTU's with no credit for savings in coal utilization. If 10 percent of current gas consumption were to be supplied in the future at a savings of 8 to 12 cents per million BTU's below the cost of available coal gasification technology, the annual savings to the consuming market would be about \$175 to \$265 million per year. These annual savings are available to pay for development costs. While the plant investment, around $800 per thousand cubic feet of daily output, is high, it is not out of line with other means of providing supplemental supplies of gas.

Detailed estimates of the cost of the present development programs are not available, but it would seem that the cost could be as high as $80 million. Upon completion of these programs in 3 to 4 years, a semi-commercial unit to confirm pilot plant results and develop commercial-scale technology would be desirable. Such a unit could cost around $100 million if a single full size reactor train were installed. Design, construction and operation of this unit could require 4 to 5 years. In view of the indicated potential savings over established technology (Lurgi process), active encouragement of the development effort would seem to be in the national interest.

INTRODUCTION

MANUFACTURE OF HYDROCARBON LIQUIDS FROM COAL

The study of producing synthetic liquids from coal had three main objectives:

- To assess the probable range of costs for making liquids from coal--synthetic crude oil and deashed coal, as a possible substitute for low-sulfur fuel oil
- To assess the cost and timing to develop the required technology to permit commercialization at normally acceptable industrial risks
- To estimate the possible commercial plant capacities at future dates.

The basic approach utilized a "reference case" by using published information judged most pertinent. The cost of manufacturing liquids was then estimated for the reference case for a range of various raw material costs and possible investment levels. Using experience and judgment, a probable level of commercial plant investment was then estimated, and its impact on the cost of producing coal liquids was defined.

Since most of the experimental work supporting the published designs was done on bench scale equipment, the successful operation of a prototype unit is judged to be required prior to design of a commercial plant. Some of the key elements of a prototype and the attendant ranges of cost and timing are described. Based on this timing, an estimate was made of when commercial plants could be brought on-stream, and a timetable of possible commercial capacity was developed.

SUMMARY AND CONCLUSIONS

The production of synthetic liquid fuels from coal involves the development of technology in two areas:

- Conversion of coal to liquids by hydrogenation
- Production of hydrogen from coal at a lower cost than that available from existing technology.

The "H-Coal" process developed by Hydrocarbon Research Inc. (HRI) was selected to evaluate the costs of producing synthetic crude from coal. The process was judged to be competitive with other processes under development, and published information is available on experimental results and on engineering design of a commercial plant. Typical yields and coal requirements (using coal to make hydrogen) are as shown in the following tabulation:

	H-Coal Syncrude
C4+ Liquid Yield (B/Ton Dry Coal)	Z.3
°API of Liquid Product	3Z
HZ Consumption (MSCF/B C4+ Liquid)	7.1
Percent of Coal Feed Used to Make HZ	35

The investment (on a 1970 basis) and cost for making syncrude from bituminous coal are high, by current standards, as shown in the following tabulation:

	Syncrude from H-Coal
Investment	$6,000-8,000/(B/CD)
Cost of Producing, Including 10% DCF Return on Investment	$7-8/B ($1.ZO-1.35 MM BTU's)

The $7 to $8 per barrel is about $3 per barrel higher than current market values for hydrocarbon liquids with similar properties. Therefore, significant technical improvements and/or increases in current market prices for liquids would be necessary to encourage development and commercialization. This cost is substantially higher than that developed by Amoco (about $5.Z5 per barrel). The increase in cost is (roughly) equally due to (1) escalation of investment and raw materials costs to 1970 levels, (Z) additional investment judged necessary, and (3) the use of coal rather than natural gas to make hydrogen. With regard to liquefaction processes other than H-Coal, it was estimated that some of the other processes being studied throughout industry could probably produce liquids for a cost within about $0.50 per barrel of the cost of H-Coal--e.g., the Consolidation Coal Company's (CONSOL's) hydrogen donor process.

Western coals offer the potential for producing cheaper liquids. The lower mining cost of western coals ($Z per ton total cost) offsets its lower quality and higher hydrogen requirements. The potential savings in coal liquids cost is judged to be $0.50 per barrel at the plant site.

Because pollution regulations have set limits on current and future sulfur contents of fuel oils (as low as O.Z to 0.5 percent S), processes for deriving such fuels from coal were considered. Pittsburgh & Midway Mining Company's (PAMCO's) "Deashed Coal" process, which has the following yields, was evaluated:

	PAMCO Deashed Coal
C4+ Liquid Yield (B/Ton Dry Coal)	2.8
°API of Total Liquid Product	16
HZ Consumption (MSCF/B C4+ Liquid)	1.3
Percent of Coal Feed Used to Make HZ	8

As summarized in the following tabulation, the sulfur content of the fuel oil product (the deashed coal) is still 1 percent or more when feeding a high sulfur coal to the process. Also, the product is very expensive by current standards.

	Deashed Coal from PAMCO
Investment ------------------------	$4-5000/(B/CD)
Cost of Producing, Including------- 10% DCF Return on Investment	>90¢/MM BTU (>$5.40/B)
Sulfur Content, Using High-Sulfur-- Bituminous Coal Feed (>3 wt. % S)	1.0-1.5 wt. %

A better process can probably be developed for producing a fuel oil containing 0.5-percent sulfur by using a catalytic hydrogenation process (e.g., a modified H-Coal process) or by taking a heavy by-product stream from a coal syncrude plant. The cost of such a fuel oil would be roughly $0.75 per million BTU's ($4.50 per barrel).

The technology of coal liquefaction is still in an early stage. With respect to hydrogen manufacture, Lurgi gasification is a proved process. However, other hydrogen processes being investigated throughout the industry offer the promise of cheaper hydrogen. Overall, more pilot plant work and the successful operation of large prototype units are required for both liquefaction and improved hydrogen manufacture to provide acceptable risks for a commercial plant. The *efficient* development of this technology could cost $50 to $80 million and take about 7 years, as shown in the following tabulation:

	Time (Years)	Cost (Million $)
Bench and Pilot Plant Work	1-2	4-8
Prototype (200-400 Tons/D of Coal)		
Design and Construct	2-3	25-40
Operate	2-3	25-40
Overall	5-8*	50-80t

Considering the long time required, it is important to begin this work so as to develop improved technology which could ultimately reduce costs. A buildup of capability by contractors and pressure vessel fabricators is required also if rapid and widespread commercial application is desired following development.

The buildup of commercial capacity for syncrude manufacture would be slow without a special driving force. The first commer-

* Commercial plant construction could then be initiated.

t Includes $30 to $60 million for liquefaction and about $20 million for hydrogen manufacture.

cial plant is estimated to require 1 year for design and 3 years for construction. The design can start after about 1 year of successful prototype operation. Design of subsequent plants would await successful operation of the first. The commercial schedule might be as shown below:

	Time for Syncrude (Years)
Startup of First Plant	10
Total Capacity	
500 MB/CD	18
1,000 MB/CD	>20

A similar and parallel schedule might be developed for producing a low-sulfur fuel oil if either a similar type of liquefaction processing were used or a parallel process development had been carried out.

Coal could play a more immediate role in supplying liquids by its direct use as a fuel in power plants and other heavy industries currently burning liquid fuels or natural gas. The coal might be gasified via the Lurgi process and the sulfur removed to make a clean, low-BTU fuel gas, or the coal could be burned directly in conjunction with flue gas desulfurization facilities. The liquid and gas fuels saved could be used to supplement supplies of those commodities.

TECHNIQUES FOR MAKING LIQUIDS FROM COAL

A Measure of the Problem

The main problem in the conversion of coal to liquids is the transformation of a low hydrogen-content solid into a liquid containing substantially higher amounts of hydrogen. The extent of the hydrogen addition is illustrated in Table 0-1. In normal petroleum refining, the hydrogen consumption may be in the order of 500 to 1,500 SCF per barrel, depending on the specific type of processing used and the properties of the refinery feedstock. Experience in coal liquefaction has shown that much more hydrogen processing is needed, requiring large amounts of hydrogen and severe processing conditions. To convert the organic material in coal to a petroleum-like liquid theoretically requires about 5,000 SCF per barrel. This amount of hydrogen would suffice to remove the sulfur, oxygen and nitrogen compounds and yield a liquid containing about 13-percent hydrogen, without making any substantial amounts of light hydrocarbon gases.

In practice, the hydrogen consumption is much higher, ranging from 6,000 to 10,000 SCF per barrel, due primarily to a substantial production of light hydrocarbon gases and to loss of hydrogen into the unliquefied solid residue. As a result, the production of hydrogen represents a major factor in coal liquefaction and the processing of coal liquids.

Other problems arise from the nature of coal itself. The presence of organic nitrogen compounds inhibits many of the reactions in converting the coal liquids. Further, the presence of ash has several harmful effects. In carrying out catalytic reactions, the ash can cause plugging of the bed, and deactivation and permanent damage to the catalyst. The ash and unconverted organic residues also pose a waste disposal problem, which may be both costly and require substantial anti-pollution measures. A further technical problem arises In separating the heavy liquids from the solid residues. The unconverted solids have a small particle size, many being below 10 microns, requiring appreciable and careful processing to prevent a loss of liquid yield due to sticking or occlusion with the fine solids.

Many of the techniques for processing coal are geared to circumventing various aspects of the above problems. Some of the general techniques are described in the following sections.

Pyrolysis

The general technique of pyrolysis seeks to recover liquids from coal by the application of heat, without the direct addition of hydrogen. In essence, this technique seeks to reject carbon as a solid and recover a liquid containing a substantial amount of hydrogen. Pyrolysis processes, in general, operate at temperatures above 800°F and at atmospheric pressures. The specific temperature used is normally determined by the desired quality and end use of the char product. In the past, many special processes have been developed to carry out pyrolysis and have been aimed primarily at making a high quality char product usually suitable for metallurgical use.* In general, pyrolysis makes a very low oil yield, usually less than about 0.8 barrels per ton of coal. For this reason, pyrolysis was not considered further as a source of liquids from coal.

Fischer-Tropsch Process

The Fischer-Tropsch process was originally developed in Germany for the synthesis of hydrocarbon liquids from gaseous CO and H_2. The synthesis gas could be made from steam reforming of methane or by gasifying coal. The liquid product is a highly oxygenated liquid. If high quality motor fuel is desired, the oxygenated liquid must be further processed with hydrogen to remove most of the oxygen.

Some application of this process was made in Germany in the 1936-1939 period. Also, this process and others were employed in

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* H. H. Lowry, Ed., *Chemistry of Coal Utilization,* Supplementary Volume (1963).

Germany during World War II. Immediately after World War II, a large pilot plant was built in Brownsville, Texas, using methane as the primary feed. Severe technical difficulties were encountered in the synthesis reactions, and the project was abandoned.

Today, SASOL operates a facility, built in 1955, which processes about 10,000 tons per day of soft coal to produce chemicals and fuels. In general, the economics of the Pischer-Tropsch synthesis are considered unfavorable for fuel products.

Catalytic Hydrogenation

The processes which have been studied most extensively for the conversion of coal involve the use of a catalyst. It is possible to react hydrogen directly with coal in the presence of a catalyst and a slurry oil vehicle to produce gas, oil products and a solid residue. Many catalysts were developed in Germany prior to World War II and have been extensively studied in the United States. Early work involved the use of cheap "throw-away" catalysts such as iron oxide and iron oxalate, which were discarded with the solid residue. The general reaction conditions were extremely severe--pressures were generally in the range of 5,000 to 10,000 psia and temperatures were usually 850°P or higher. Immediately after World War II, the U.S. Bureau of Mines built a large demonstration plant for this process at Louisiana, Missouri. In general, the plant operated successfully, but the economics of the process were extremely poor.

Subsequent research into this type of processing has been aimed at (1) developing better catalysts, so as to lower the severity of reaction conditions (with accompanying improvement in yields) and (2) developing new technology for gas/solids contacting. More recent research by CONSOL has centered on the use of zinc chloride as an active hydrogenation/cracking catalyst. In addition, HRI has been developing its ebu11ating bed technique for contacting coal and hydrogen in a fluidized bed of cobalt molybdate catalyst (H-Coal).

Hydrogen Donor Solvents

Another approach to coal liquefaction is to remove the coal ash by dissolving most of the coal in a hydrogen donor solvent prior to the catalytic hydrogenation step. The basis of this process is to heat coal in the presence of a hydroaromatic material, such as tetralin or its analogs, at 700°p to 850°p and 200 to 1,000 psia pressure. The coal gradually dissolves, and the large coal molecules are stabilized by the transfer of hydrogen from the donor solvent to the coal fragments. The unconverted coal and ash are filtered from the solution of solvent and extract. The spent solvent is subsequently recovered from the extract and rehydrogenated for recycle. This process was originally developed in Germany and is known as the Pott-Broche process. It was applied to some extent in Germany during World War II and has been pursued in the United States by CONSOLo In general, the liquid product is an extremely heavy extract--its molecular weight is well above 1,000, thus requiring that the extract be upgraded substantially to make fuel products. This upgrading can be accomplished by adding hydrogen catalytically, e.g., using an ebullating bed of catalyst. A fixed bed can also be used if the extract is essentially free of solid particles.

MAJOR PROCESSES BEING STUDIED BY INDUSTRY AND GOVERNMENT GROUPS

Many coal liquefaction processes are being actively studied by industry and government groups today, using both private and government funds. The same is true for processes aimed at making hydrogen from coal, which are often allied with processes for making synthetic methane. A brief summary of the various programs is presented in the following sections.

Liquids from Coal

The major current work on pyrolysis is being carried out by the FMC Corporation under the sponsorship of the Office of Coal Research (OCR). Work has been carried out in small pilot units, and recently a large pilot unit has been constructed (about 25 tons per day). This process is usually referred to as Project COED (Char, Oil, Energy, Development). In this operation, coal is fed to a multi-stage pyrolysis operation which consists of a number of fluidized bed reactors at different temperatures. Volatiles are recovered by cooling the vapors. The char is finally handled at a high temperature in the last stage where its partial combustion with oxygen produces enough hot gas to provide the required heat for the prior stages. This process produces primarily a solid fuel as well as a liquid product (which requires extensive hydrogenation for upgrading) and gases (which can be used to make hydrogen).

The donor solvent extraction of coal and extract hydrogenation have been investigated by CONSOL under an OCR contract in both bench scale work at Library, Pennsylvania, and at a 75 barrel per day pilot unit at Cresap, West Virginia. This pilot unit includes a hydrogen plant, the coal preparation steps, donor extraction, filtration of the products, and extract conversion processing. Coal is slurried with a donor solvent and heated to about 750°F at about 250 psia in order to dissolve itself, forming an extract. The mixture is passed through hydroclones to remove most of the unconverted solids. The extract is flashed to recover the solvent. The conversion of the extract is carried out in the ebullating bed, using cobalt molybdate catalyst, at 800°F to 850°F and 4,200 psia. Part of the light distillate produced is used as makeup donor solvent. The hydroclone underflow is sent to a low temperature carbonizer to recover liquid products and produce a solid residue. There have been numerous operability problems with this pilot unit, and the unit was shut down in April 1970 for a general review of these problems.

Another major coal liquefaction process being developed is HRI's H-Coal process. Initially, this work was funded by the OCR until about 1967, when budgetary restrictions required that this support be dropped. Since then, Atlantic-Richfield has provided funds for HRI to continue the work. Currently, HRI is developing its process further through agreements whereby it sells its process information to other private companies. In this process, coal is slurried with a heavy oil and fed with hydrogen gas to a reactor containing an ebullated bed of catalyst, whereby the coal is converted to a range of liquid products. The general reaction conditions for HRI's process--about 850° P and 3,000 psia--are the least severe of any process to make the same type of products. HRI has published the economics of producing gasoline from coal using this process, and a critique of this report was made by Amoco.* Amoco, in essence, agreed that the projected economics were reasonable and that there were substantial bench scale data on which to base the general process design. In addition, Amoco outlined the need for further work to verify the process design.

Low Sulfur Puel Oils from Coal

Heavy fuel oils can also be produced from coal. Since a great deal of the sulfur in coal is tied up as inorganic constituents of the ash, it is possible, by liquefaction and removal of the ash, to produce a heavy fuel oil (or deashed coal) from which a portion of the sulfur has been removed. This material has a high melting point (above 200° P). The sulfur content of the deashed coal depends on the coal feed. Por bituminous coals, the product contains about 1.0 to 1.5 weight-percent S; for subbituminous coals, the product is often 0.5 to 0.8-weight-percent S. (When processing subbituminous and lignite coals, the product is very low in oxygen [less than 5 percent], making the product suitable for subsequent upgrading to metallurgical coke. This type of specialty application has not been considered in this paper.) The usual type of processing consists of contacting coal (in a slurry oil vehicle) with hydrogen at 1,000 to 1,500 psia and 750° p to 850° P. Under these conditions, the coal depolymerizes sufficiently so that the total mixture can be filtered to recover the heavy oil product and a solid residue. Such processing has been developed on a proprietary basis by Union Carbide and also by PAMCO under sponsorship of OCR. PAMCO has carried out bench scale work on their process, but a large scale pilot unit has been delayed due to a lack of OCR funds. An economic study of PAMCO's process has been carried out by Stearns-Roger Construction Company.t This process was chosen for this study to evaluate the cost of making deashed coal. Details of the

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* HRI, *Commercial Process Evaluation of the H-Coal Hydrogenation Process*, OCR Contract 14-01-0001-477; American Oil Company, *Evaluation of Project "H-Coal,"* OCR Contract 14-01-0001-1188.

t PAMCO, *Evaluation of a Process to Produce Ashless, Low-Sulfur Fuel from Coal*, OCR Contract 14-01-0001-496.

process are given in the section entitled, "Production of Deashed Coal from the PAMCO Process," but it should be recognized that low-sulfur fuel oil--meeting future pollution regulations as low as O.Z to 0.5 percent S--cannot be produced from high-sulfur coals (greater than 3 percent S) by this deashing process alone. Additional desulfurization steps would be required.

Hydrogen from Coal

In order to convert coal to liquids, substantial amounts of hydrogen are required. On the basis of today's technology, the least expensive way to produce the hydrogen is by steam reforming of methane. However, it is expected that methane will not be available for this purpose in the future, due to its increased cost or possible restrictions on its type of use. Prom the point of view of synthetic fuels from coal, it will therefore be necessary to produce hydrogen from coal or coal byproducts. Some of the processes and techniques for this are summarized in the following paragraphs.

The best defined processes today use high temperature gasification of coal with steam and oxygen. The Lurgi process, which has been used commercially for many years, uses a moving dense bed of coal. The oxygen and steam are injected into the bottom to form a high temperature gasification zone, producing a synthesis gas (CO and HZ, with some CH4 and HZO), which is subsequently converted to HZ' The hot gases flow up the reactor, preheating the incoming coal. The subsequent gas processing consists of converting the methane in the synthesis gas (by secondary reforming or partial oxidation), shifting the CO with water to make more hydrogen, removing the COZ' and removing the remaining carbon oxides by a final purification step (methanation). The removal of traces of carbon monoxide is necessary since CO acts as a severe inhibitor for hydrogenation catalysts, such as cobalt molybdate, used in the hydrotreating of the coal liquids.

Other processes follow a similar pattern of making a synthesis gas from coal or char with similar purification steps. The key feature is the technique of adding heat so as to promote the carbon/steam reaction.

The Texaco Partial Oxidation process using coal utilizes the same basic method as the commercial process that feeds residuum. The partial oxidation process has been commercialized using resid feedstocks, but the use of coal feed has only been practiced in a pilot plant. When adapted to coal, it is necessary to use a coal-water slurry as the feed.

Coal is slurried with water, heated in a furnace and, after removal of excess stearn, fed into a high pressure combustion chamber where it reacts with oxygen to produce a synthesis gas (CO and HZ at about 500 psia and Z,6000P). The hot gases are quenched to remove the ash as a solid slag and sent to downstream processing to remove soot and to convert the synthesis gas to hydrogen.

The Kellogg molten salt process involves the use of a molten salt to circulate between a chamber where the coal reacts with the steam and another chamber where the unconverted coal is burned with air to heat the molten salt.* The ash is removed from the hot molten salt in a separate processing unit. Once the synthesis gas is formed, it is cooled, shifted, scrubbed and methanated to prepare a high purity hydrogen. This process has been tried on a laboratory scale only. It has been used in this study as being typical of a "conceptual cost" of making hydrogen from improved technology that might be developed.

Another technique for making synthesis gas is the fluidized bed gasification of coal or char, which can be used also as a technique for making pipeline gas.† In this process, the fine char is introduced into a fluid bed where steam is injected to provide the fluidization. The steam reacts with the carbon to form the synthesis gas. Heat may be furnished electrically (via electrodes) by the direct injection of oxygen to promote combustion or by some other means. The "Hygas" and "C02 Acceptor" processes are examples of this general approach. Currently, both processes are entering the large pilot plant stage under sponsorship of OCR.

PRODUCTION OF SYNCRUDE FROM THE H-COAL PROCESS

Several factors were considered in choosing a process for evaluating the cost of making synthetic crude from coal:

- Published literature was desired (over proprietary information) to allow a more descriptive and independent assessment of the process potential.

- Showing a process with low cost syncrude and a substantial background of technical development was desired.

The two processes considered were HRI's H-Coal catalytic process and CONSOL's donor process.‡ HRI's H-Coal process was chosen for the following reasons:

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* M.W. Kellogg Company, *Commercial Potential for the Kellogg Coal Gasification Process*, OCR Contract 14-01-0001-380.

† C.L. Tsaros, "Hydrogen: A key to the Economics of Pipeline Gas from Coal," Paper Presented at ACS Meeting, Chicago, Illinois, September 13-18, 1970.

‡ HRI, *Commercial Process Evaluation of the H-Coal Hydrogenation Process*, OCR Contract 14-01-0001-477; CONSOL, *Summary Report on Projected Gasoline*, R&D Report No. 39, Vol. 1, OCR Contract 14-01-0001-310(1).

- An independent critique by Amoco showed substantial agreement with HRI's design. *

- An independent review by the Ralph M. Parsons Company of CONSOL's process showed a significantly different basic design and a higher cost of gasoline than CONSOL's projected design. †

- It is the authors' judgment that a direct catalytic process holds the most promise for ultimate commercial development and lower cost synthetic liquids.

However, the CONSOL process certainly is an alternative approach to the problem of separating the ash.

Process Aspects

The specific process design chosen is that of Amoco, which is essentially the same as HRI's design. For the study, the Amoco design, which produced a 2:1 ratio of naphtha to heating oil, was modified to make a light syncrude. In essence, the hydrocracking and catalytic reforming steps were deleted since no direct experimental data were available to support the yields and process operating conditions that Amoco had chosen for these steps. The process yields for the basic liquefaction steps were kept the same as those used by Amoco, and new yield charts were prepared.

A simplified flow sheet is shown in Figure 0-1, which indicates the processing blocks and key flow rates. A bituminous coal, such as Illinois #6, was used as the feed. The detailed material balance is indicated in Figure 0-2 and Table 0-2. The plant feed is 9,573 tons per day of coal (10-percent moisture), and the product is 30,000 barrels per day of syncrude. The coal is crushed and dried and slurried with a heavy gas oil to make a 50-percent solids slurry. The slurry is preheated and fed to the H-Coal reactors, along with hydrogen. The reaction products go to a separation section--a series of flashes, absorbers and fractionator--to split out the gas, naphtha, heating oil, heavy gas oil (for slurrying) and vacuum bottoms (containing the solids).

The vacuum bottoms are fed to a fluid coker, which primarily recovers the heavy coker gas oil and discharges a dry char. The coker gas oil is fed to an H-Oil unit for further conversion to light products. (An alternate disposition, not used by HRI or Amoco in their design studies, would be to use the coker gas oil for a low-sulfur fuel oil, as discussed later in this report.)

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* American Oil Company, *Evaluation of Project "H-Coal,"* OCR Contract 14-01-0001-1188.

† Ralph M. Parsons Company, 1968 *Feasibility Report--CONSOL Synthetic Fuel Process*, OCR Contract 14-01-0001-255.

TABLE 0-1

HZ REQUIRED TO MAKE CRUDE LIQUID FROM COAL*

Analysis	Weight Percent Bituminous Coal	Petroleum
C	60.0	86
H	4.1	13
O	6.3	
N	1.Z	0.1
S	Z.4	0.9
HZO	16t	
Ash	10	
Total	100	100

* HZ required to make syncrude: (1) theoretical--5 MSCF/B (Z) actual--6 to 10 MSCF/B.

t Moisture varies widely with coal source.

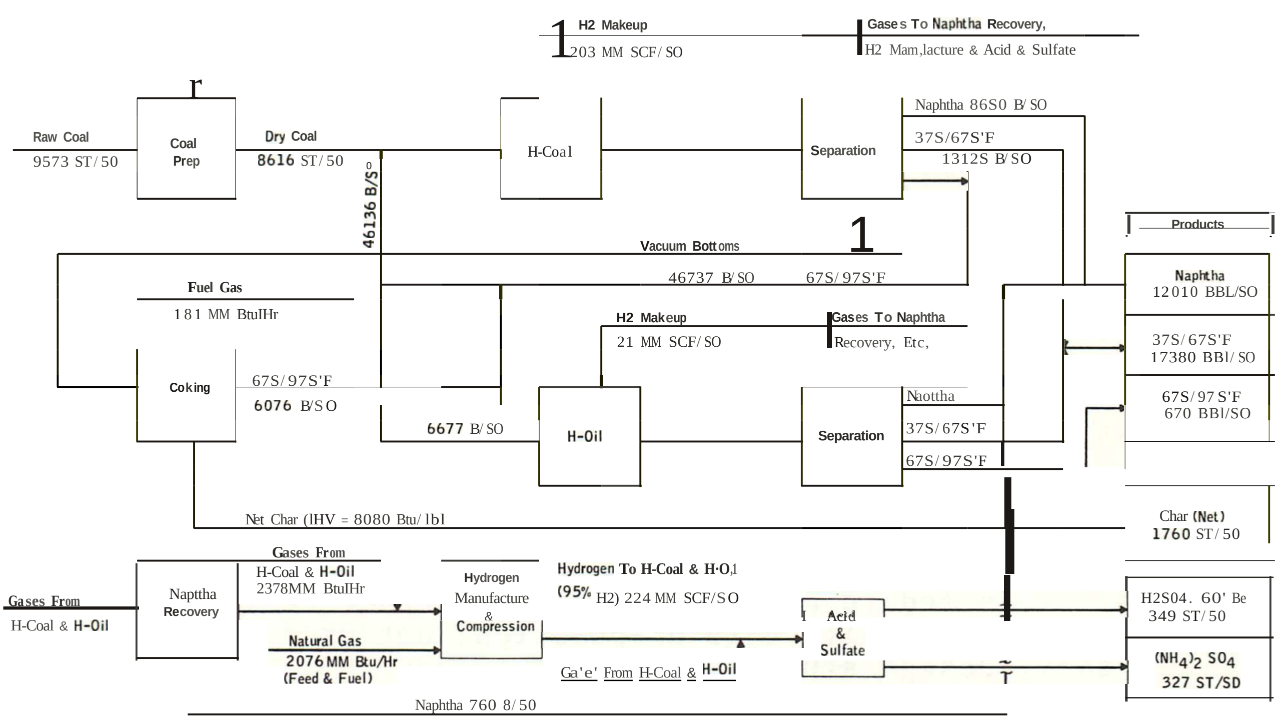


Figure 0-1. Syncrude Manufacture by the H-Coal Process --Simplified Flow Plan.

The plant gases are processed to recover naphtha, H2S and NH and then are fed to steam reformers (along with purchased methane} to make hydrogen. The sulfur and ammonia are recovered as sulfuric acid and ammonium sulfate.

TABLE 0-2

SYNCRUDE FROM H-COAL--OVERALL MATERIAL BALANCE

Stream Number

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
MB/SD	-	-	-	46.14	-	-	-	-	-	8.65	13.12	46.74	-	-	-	6.08	-
M 1b/hr--H_2	-	-	-	-	-	42.35	1.93	2.36	-	-	-	-	-	0.10	-	-	-
C_1	-	-	-	-	-	17.83	8.05	30.38	-	0.22	-	-	-	0.79	-	-	-
C_2	-	-	-	-	-	-	1.65	18.83	-	0.35	-	-	-	0.63	-	-	-
C_3	-	-	-	-	-	-	1.08	19.72	-	2.18	-	-	-	0.93	-	-	-
C_4	-	-	-	-	-	-	0.57	14.50	-	7.18	-	-	-	1.22	-	-	-
H_2S	-	-	-	-	-	-	0.19	4.86	10.62	0.12	-	-	-	0.24	-	-	-
NH_3	-	-	-	-	-	-	-	-	7.18	-	-	-	-	-	-	-	-
H_2O	-	79.75	-	-	-	-	-	-	66.06	-	-	-	-	-	-	-	-
Naphtha	-	-	-	-	-	-	0.11	5.18	-	86.98	-	-	-	-	-	-	-
375/675°F	-	-	-	-	-	-	-	-	-	-	177.70	-	-	-	-	-	-
675/975°F	-	-	-	718.00	718.00	-	-	-	-	-	-	725.18	73.24	-	-	96.72	821.90
975°F Liq.	-	-	-	-	-	-	-	-	-	-	-	-	78.26	-	-	-	-
Coal/Char	797.75	-	718.00	-	718.00	-	-	-	-	-	-	-	151.50	-	202.37	-	-
Total	797.75	79.75	718.00	718.00	1,436.00	60.18	13.58	95.83	83.86	97.03	177.70	725.18	303.00	3.91	202.37	96.72	821.90

Stream Number

	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34
MB/SD	-	-	-	-	-	-	-	4.26	0.67	-	-	-	-	-	-	-	-
M 1b/hr--H_2	-	4.38	0.28	0.36	-	-	-	-	-	2.72	-	2.72	2.21	4.93	-	-	49.06*
C_1	-	1.85	0.91	3.18	-	0.02	0.03	-	-	33.56	-	33.56	8.96	42.52	11.20	-	20.67*
C_2	-	-	0.17	1.92	-	0.01	0.07	-	-	20.75	0.03	20.72	1.82	22.54	-	-	-
C_3	-	-	0.13	1.77	-	0.02	0.36	-	-	21.49	0.33	21.16	1.21	22.37	-	-	-
C_4	-	-	0.08	1.25	-	0.02	1.02	-	-	15.75	1.52	14.23	0.65	14.88	-	-	-
H_2S	-	-	-	0.19	0.42	-	0.02	-	-	5.05	0.01	5.04	0.19	5.23	-	5.23	-
NH_3	-	-	-	-	0.42	-	-	-	-	-	-	-	-	-	-	-	-
H_2O	-	-	-	-	2.08	-	-	-	-	-	-	-	-	-	221.76	-	-
CO_2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	271.06	-
Naphtha	-	-	-	0.96	-	0.02	28.15	-	-	6.14	5.66	0.48	0.11	0.59	-	-	-
375/675°F	-	-	-	-	-	-	-	55.88t	-	-	-	-	-	-	-	-	-
675/975°F	103.90	-	-	-	-	-	-	-	10.39±	-	-	-	-	-	-	-	-
975°F+Liq.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal/Char	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	103.90	6.23	1.57	9.63	2.92	0.09	29.65	55.88	10.39	105.46	7.55	97.91	15.15	113.06	232.96	276.29	69.73±

* Before losses in compression.

t 380/650°F

± 6'0/975°F

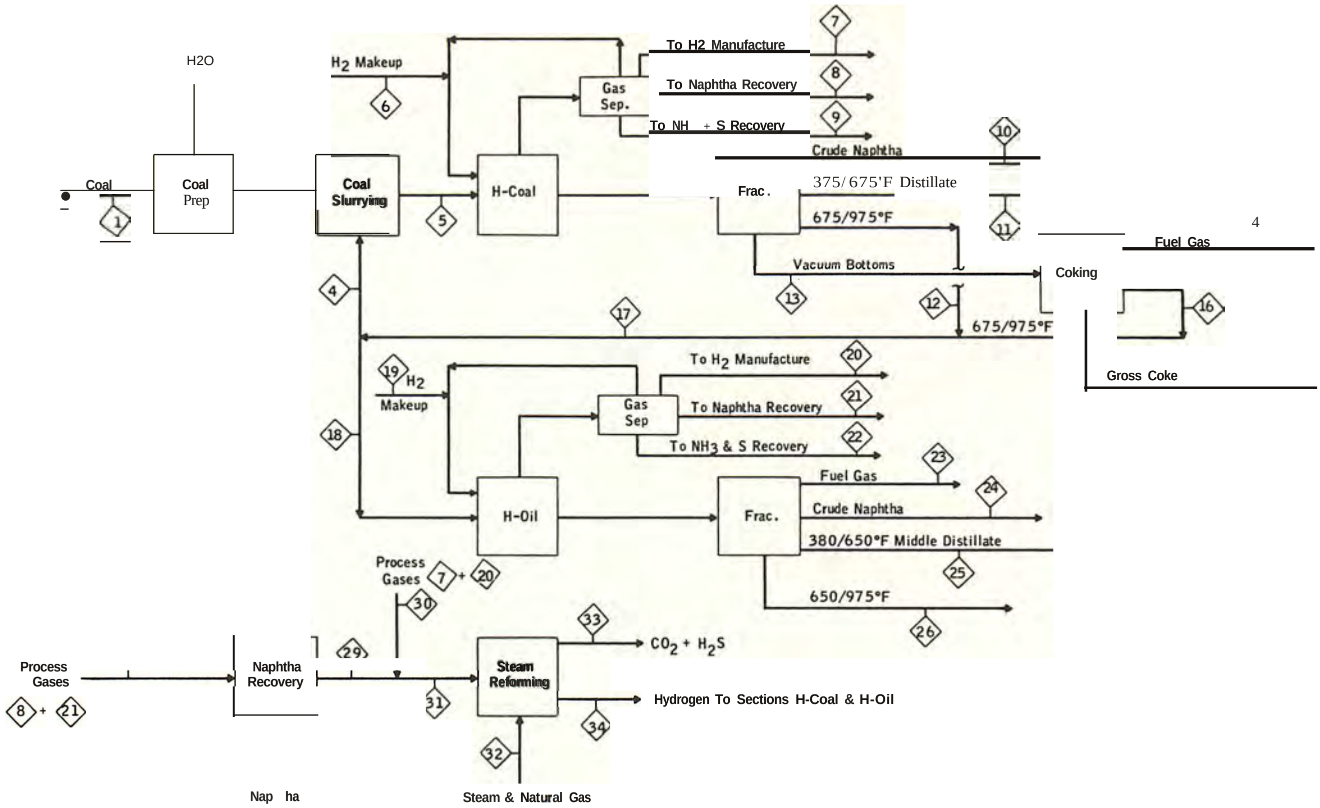


Figure 0-2. Material Balance Flow Plan.

The syncrude produced is mostly naphtha and heating oil, as shown in Table 0-3, and only a small amount of heavy gas oil is made. Some pertinent statistics on yields and process requirements are shown in Table 0-4. Basically, the oil yield is about 3.5 barrels per ton of dry coal. The hydrogen consumption is high--greater than 7,000 SCF per barrel of syncrude. Substantial amounts of gas are produced (0.32 FOEB/B) though it is used, together with natural gas, for plant fuel and HZ feedstock.

The process is also applicable to lower grade coals, such as subbituminous. In this regard, also shown in Table 0-4 are some approximate yields for a subbituminous coal. The higher hydrogen consumption and lower oil yields are caused primarily by the higher oxygen content of this coal.

Investments and Operating Costs

The investments developed by Amoco were adjusted to the new syncrude basis (no hydrocracking and catalytic reforming) as follows:

- Investments for gas treating, offsites, etc., were prorated to account for less gas, hydrogen, etc., when going only to syncrude. Investments for coal preparation and the H-Coal reactors, which were kept at the same capacity, were taken directly as Amoco estimated them.

- Amoco's 1967 investments were corrected to 1970 levels by adding 16 percent to account for inflation.

TABLE 0-3

SYNCRUDE FROM H-COAL--SYNCRUDE PROPERTIES

	C5/375°F	375/650°F	650/975°F	Total
°API	53.0	23.2	3.5	32.4
B/SD	12,011	16,287	1,762	30,060
Percent Total	40.0	54.2	5.8	100.0
Analysis (Weight %)				
C	84.5	88.8	89.4	87.3
H	13.6	11.0	10.2	11.9
0	1.7			0.6
N	0.1	0.1	0.1	0.1
S	0.1	0.1	0.3	0.1

TABLE 0-4

SYNCRUDE FROM H-COAL--SOME PROCESS STATISTICS

H_2 from Methane Reforming	Bituminous	Subbituminous
Syncrude Yield (B/ST--AR Coal)	3.14	1.96
Syncrude Yield (B/ST--Dry Coal)	3.49	2.69
Gross Char Yield (ST/ST--Dry Coal)	0.28	0.33
Net Char Yield (FOEB/B--Syncrude)	0.20	
Internal Gas Yield (FOEB/B--Syncrude)	0.32	0.47
Hydrogen Consumed* (SCF/B--Syncrude)	7080	8670
Natural Gas Purchased (FOEB/B--Syncrude)	0.32	0.30
Equivalent S Yield (LT/B--Syncrude)	0.005	0.001
Equivalent NH_3 Yield (ST/B--Syncrude)	0.003	0.003
Power Consumption (KWH/B--Syncrude)	45.6	
Water Consumption (Gal/B--Syncrude)	270	
H_2 from Coal		
Syncrude Yield (B/ST--Dry Coal)	2.3	
Gas Yield (FOEB/B--Syncrude)	0.31	
Natural Gas Purchased (FOEB/B--Syncrude)	0.0	

* Contained H_2 after compression.

The resulting total plant investment, called the "reference point," was $123 million, as shown in Table 0-5. This is equal to $4,500 per barrel per calendar day. The main costs are in the hydrogenation reactor section and in hydrogen manufacture. This investment is a reference point and does not include any added costs for uncertainties, discussed later in this section.

The factors involving the plant operating costs are given in Table 0-6. The coal and natural gas rates, plus utilities, are those estimated by Amoco. The manning and other costs related to investment are based on other experience and are slightly higher than those estimated by Amoco. The factors are expressed as functions of coal cost, natural gas cost and investment for subsequent study of variations in cost levels.

The basis for calculating revenues is shown in Table 0-7. The char is arbitrarily valued at one-third the coal value, due to its high ash content. The costs for sulfuric acid and ammonium sulfate are felt to be representative of the 1970-1975 period. The cost of the syncrude is left as a variable, being expressed as a function of coal cost, natural gas cost, investment, etc.

<u>Basis for Calculating Economics</u>

The technique for calculating the cost of making synthetic crude has been to relate the cost to the revenues, operating costs and return on investment. The basis for return on investment has been the conventional DCF technique. The main features of calculating the DCF return, shown in Table 0-8, involve the use of a

TABLE 0-5

SYNCRUDE FROM H-COAL--REFERENCE INVESTMENTS

Section	1970 Basis* (Million $)
Coal Preparation	8.5
Coal Hydrogenation	35.2
Heavy Gas Oil Hydrogenation	7.3
Coking	6.0
Naptha Recovery	2.7
Hydrogen Manufacture	30.2
Hydrogen Compression	6.3
Acid and Sulfate Recovery	8.2
Offsites, Utilities and Tankage	18.9
Total	123.3
Call	123

* Based on Amoco numbers adjusted for 16-percent inflation between 1967 and 1970.

TABLE 0-6

SYNCRUDE FROM H-COAL--BASIS FOR ESTIMATING OPERATING COSTS

		Unit Cost	Million $/Year
Coal	9573 ST!SD	A-$/Ton	3.145 A
Natural Gas	2387 MM BTU/Hr	B-$/MM BTU's	18.819 B
Wage Earners	Men = 127 Men + 0.86 x Inv. (MM$)	$13,1OO/Yr	1.66 + 0.011 Inv.
Salaried	Men = 58 + 0.29 x Inv. (MM$)	$16,700/Yr	0.97 + 0.005 Inv.
Utilities			
Power	57,120 KW	0.6¢/KWH	2.70
Water	5,630 GPM	4¢/M Gal	0.11
Catalysts and Chemicals			2.94
Investment Related Costs	3.3% of Investment		0.033 Inv.
Other Costs	20% (Wage Earners and Salaried)		0.53 + 0.003 Inv.
		Total	8.91 + 3.145 A + 18.819 B + 0.052 I

TABLE 0-7

SYNCRUDE FROM H-COAL--BASIS FOR ESTIMATING REVENUES

Item	Amount	Unit Cost	Million S/Year
Syncrude	30,060 B/SD	C-S/B	9.8747 C
Char	1,760 ST/SD	1/3A-S/Ton	0.193 A
H_2SO_4 (60° Be)	349 ST/SD	S20/ST	2.29
$(NH_4)_2SO_4$	327 ST/SD	S20/ST	2.15
			4.44

20-year project life and an investment schedule involving a 3-year construction period. Working capital and startup expense are included in the calculation. The working capital is recovered in the final year of the project. The sum-of-the-year-digits technique was the depreciation method chosen. In addition, there is a delayed production schedu1e--fu11 production is assumed to be achieved in the third year. The results of calculating the DCF return as a function of gross profits are shown in Figure 0-3. This figure can be used to estimate the revenues required for any given level of return. For the purpose of this study, a 10-percent DCF return profits should be 21.6 percent of the plant investment to achieve the 10-percent DCF return. If it is desired to use some other return, the factor of 21.6 percent can be adjusted accordingly. For example, an 8-percent DCF return requires a gross profit factor of 17.5 percent.

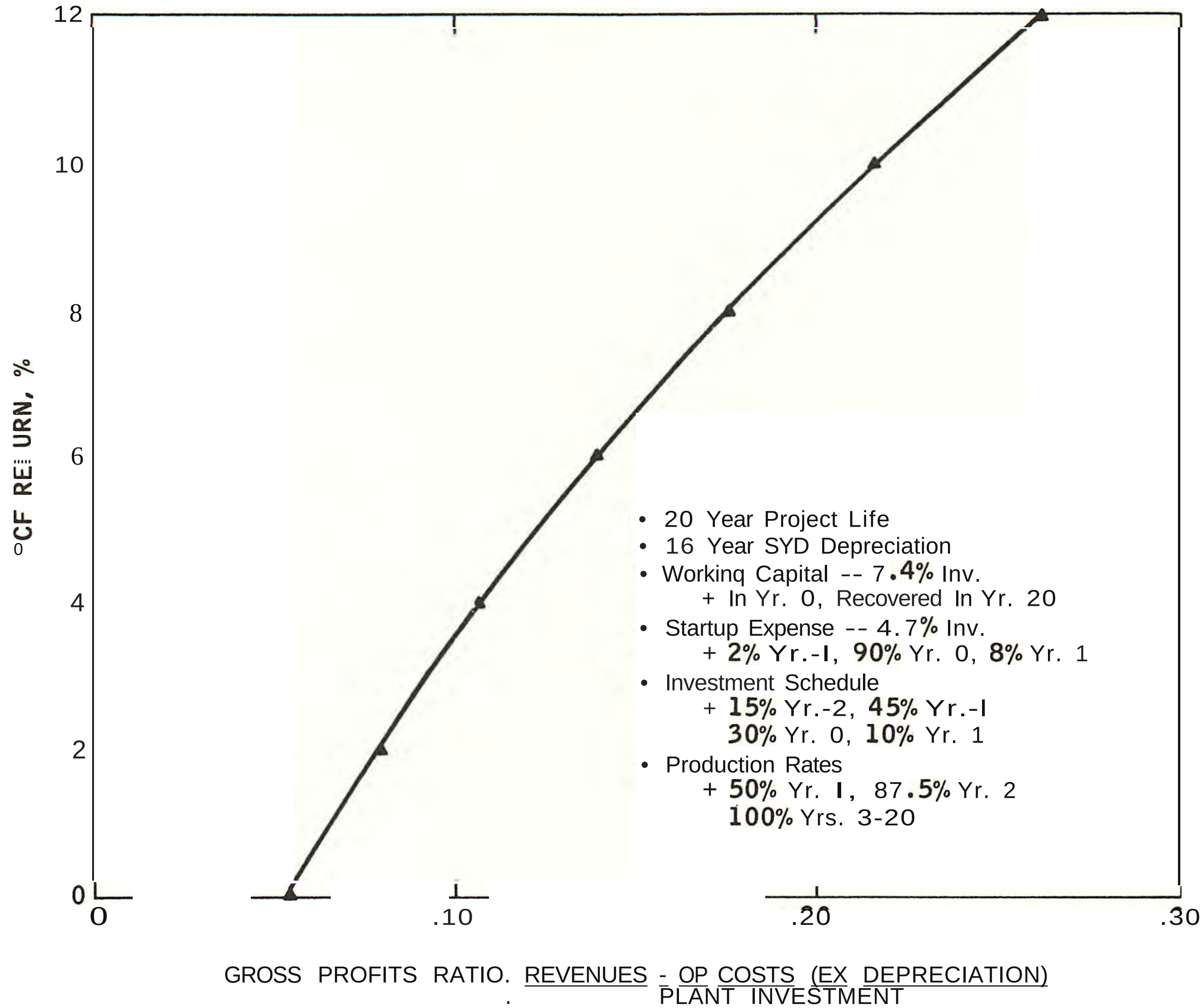


Figure 0-3. DCF Return from Gross Profits and Investment.

TABLE 0-8

SYNCRUDE FROM H-COAL--BASIS FOR CALCULATING DCF RETURN*
(20-Year Project Life--Percent)

	Time Period--Years					
	-2	-1	Q	1	2	3-20
Investment Schedule	15	45	30	10		
Startup Expense		2	90	8		
Production Schedule				50	87.5	100

* 16 years sum of year's digit depreciation; working capital--7.4-percent investment; startup expense-- 4.7-percent investment; working capital is expended in year 0 and recovered in year 20; 50-percent income tax rate.

Using this technique, the cost of making syncrude by the "H-Coal process was calculated as a function of coal cost, natural gas cost and investment level with a 10-percent DCF return. For convenience, in the discussion that follows, a "reference point" was chosen which has the following values:

- Investment: $123 Million
- Bituminous coal cost: $5 per ton
- Natural gas cost: 50¢ per million BTU's.

A sample breakdown of the cost of making synthetic crude is shown in Table 0-9, and typical ranges of costs are illustrated in Figures 0-4, 0-5 and 0-6. At the reference point, the cost of making synthetic crude is $6.23 per barrel. The main cost elements are the cost of coal, natural gas and the capital charges which cover depreciation, return and income tax. For simplicity, the capital charges are broken down into average values over the 20-year project life, even though for any year they are variable. It is apparent from the figures that, over a range of prices which are felt to be currently representative ($4 per ton or more for coal and 40¢ per million BTU's or more for natural gas), the syncrude cost is more than $6 per barrel and may easily exceed $7 per barrel.

The cost of making hydrogen from steam reforming of methane is appreciable, as shown in Figure 0-7. This represents the cost

TABLE 0-9

SYNCRUDE FROM H-COAL--"REFERENCE" POINT FOR SYNCRUDE COSTS
(Reference Investment = $123 Million)

	$/BBL
Coal at $5/Ton	1.59
Natural Gas at $0.50/MM BTU's	0.95
Wages and Salaries	0.47
Utilities	0.28
Catalysts and Chemicals	0.30
Other Direct Operating Costs	0.50
Byproduct Credits	(0.55)
Total	3.54
Average Capital Charges at 10% DCF Return	
Depreciation	0.62
50% Income Tax	1.03
Return	1.04
Total	6.23

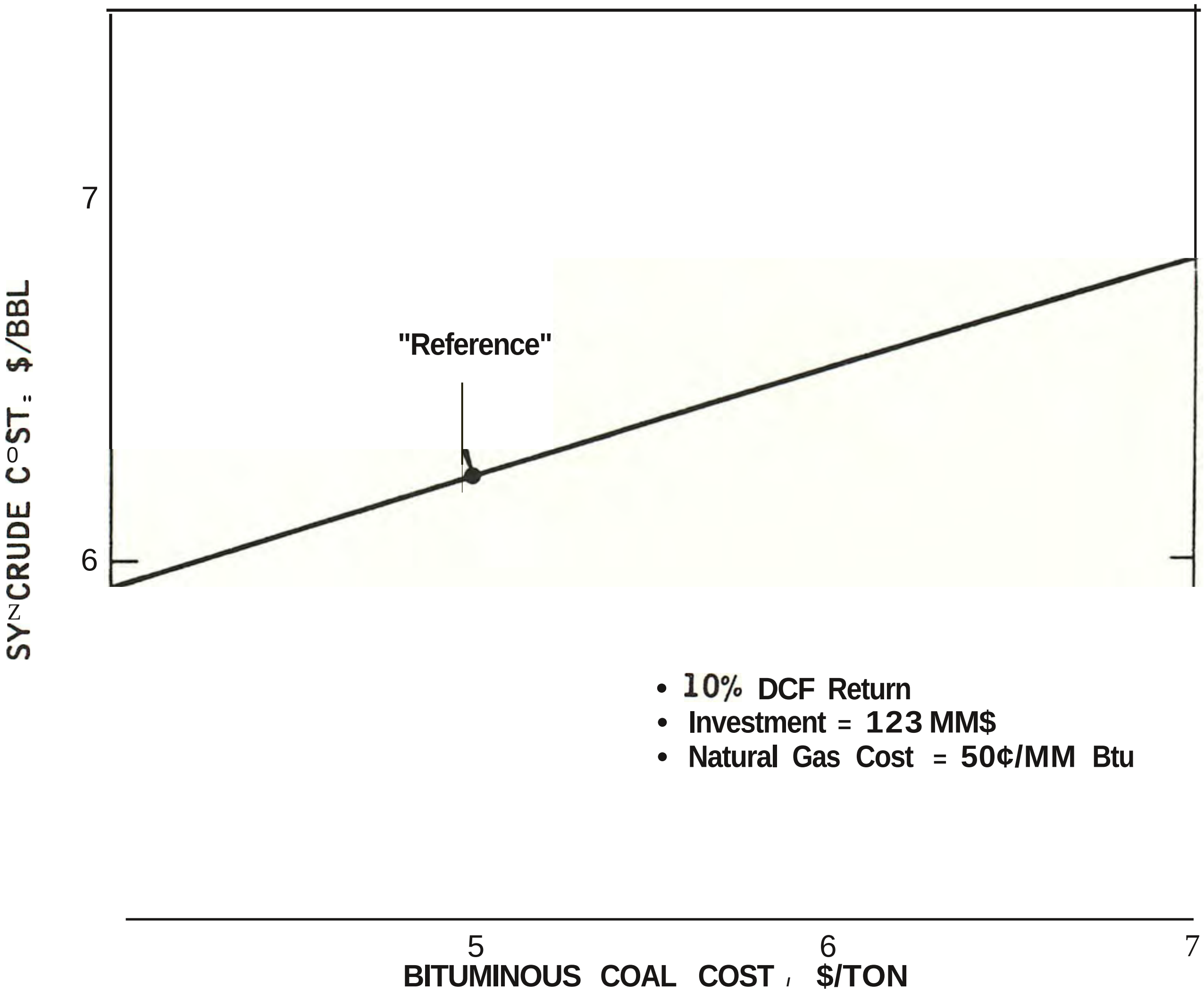


Figure 0-4. Syncrude from H-Coal Effect of Bituminous Coal Cost.

of making hydrogen at approximately 3,200 psia for use in the H-Coal and H-Oil reactors. The investment covers the stearn reforming, hydrogen compression and a prorata share of utilities and offsites. For the assumed natural gas cost of $0.50 per million BTU's, the hydrogen cost is about $0.43 per MSCF (including a 10-percent DCF return). Thus, the effect of hydrogen cost on making syncrude is high. For example, in using 7,080 SCF per barrel, the hydrogen cost alone contributes about $3 to the cost of making a barrel of syncrude.

The investment level also has a major impact, as shown in Figure 0-6. The authors believe that the reference level of $123 million is low. There are several items which we believe should be added to the investment to achieve a more realistic level, and these are outlined in the following section.

<u>Probable Investment Is Higher Due to Added Costs</u>

Several factors need to be added to the reference investment to reflect the status of technology, depth of design, etc., to arrive

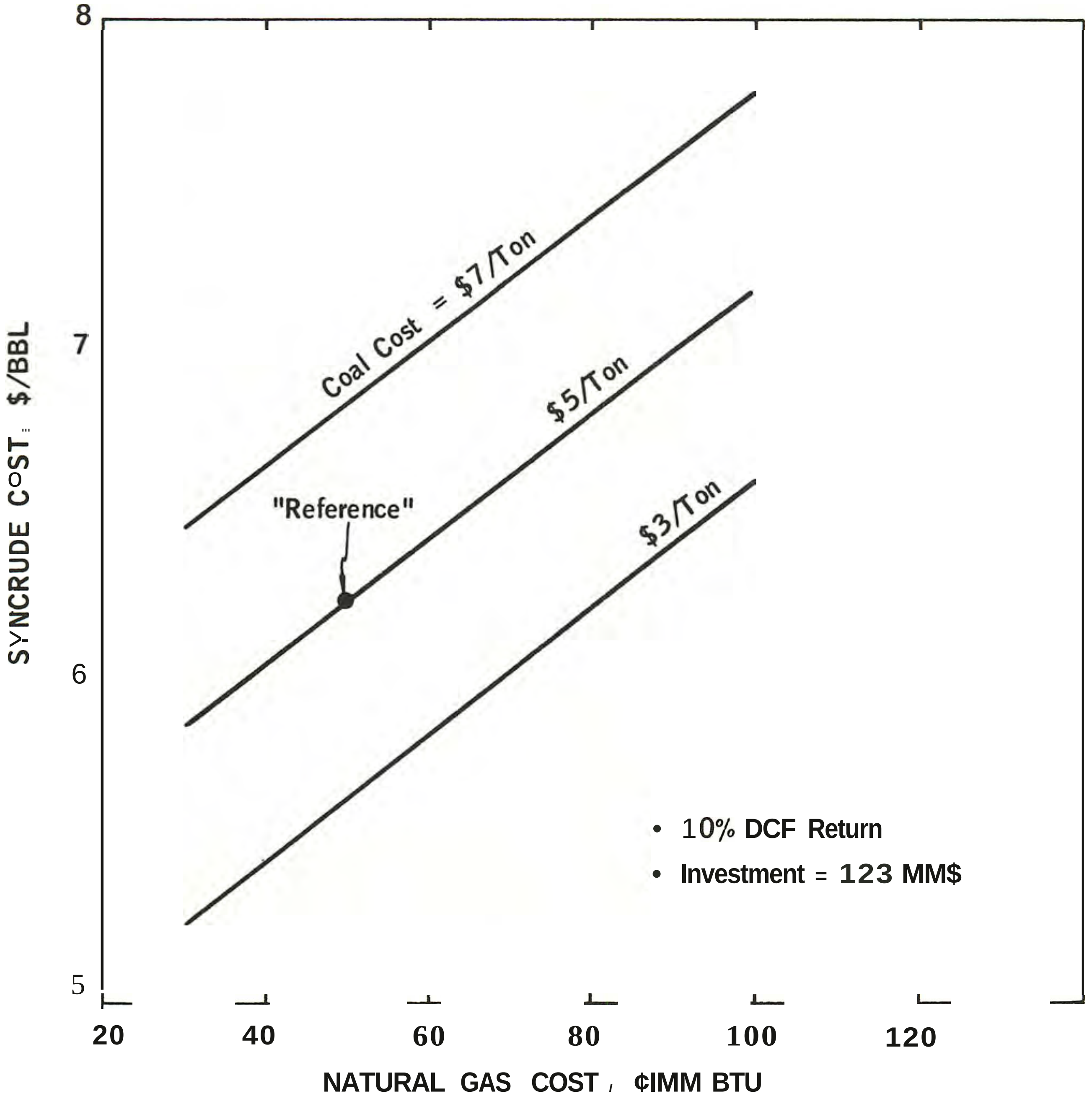


Figure 0-5. Syncrude from H-Coal Effect of Natural Gas Cost.

at a more realistic level of investment. These items, and the reasons for applying them, are as follows:

- There is a lack of detailed engineering design which would include certain key factors (e.g., in the current design, a specific plant site was not chosen; also, water sources, definitive pollution controls, etc., were not specified). In addition, there is no information published or indications given that key pieces of equipment (e.g., the high pressure vessels) were designed in detail. It is

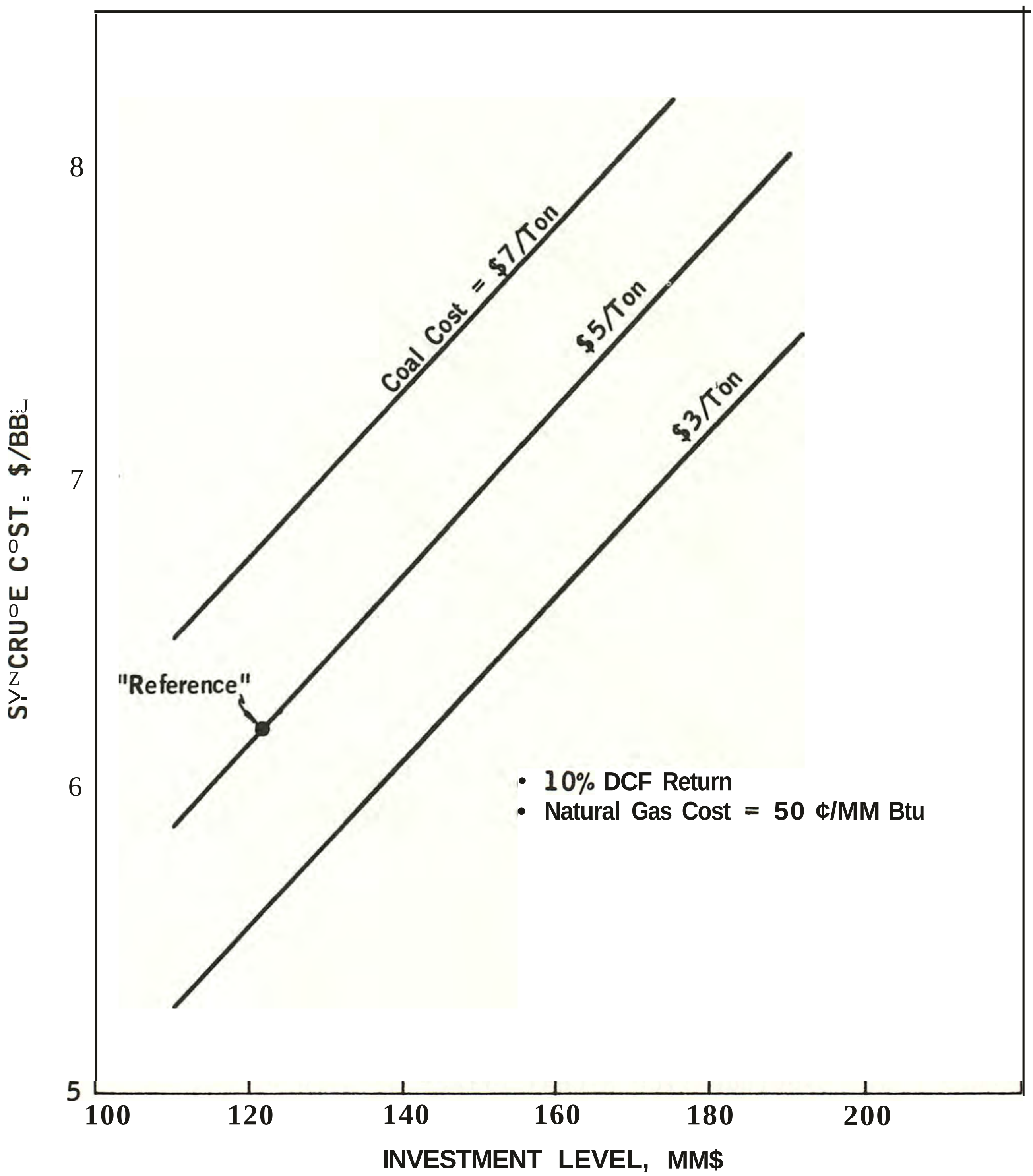
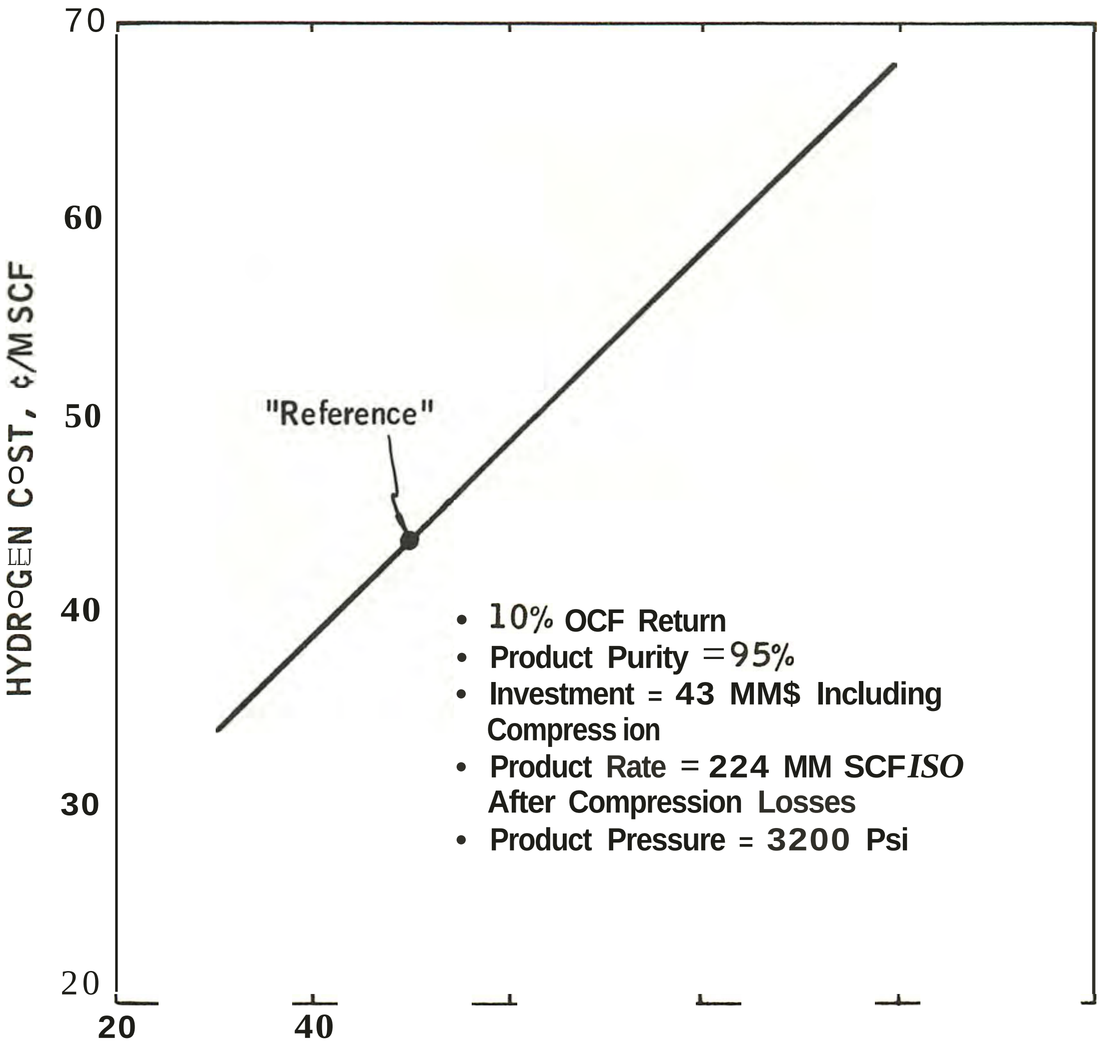


Figure 0-6. Syncrude from H-Coal Effect of Investment.

estimated that the added investment would be at least 15 percent for this lack of a detailed design.

- During construction of a plant over a period of 3 years, labor and material prices have steadily risen in recent history. It is estimated that this effect on investment would be about 10 percent during the construction period.



- The processes for coal conversion coking and H-Oil (on the coal liquids) are not yet well defined. Further work is required to define process yields, product quality, operating conditions and equipment requirements. At this point, it is estimated that 20 percent of the onsite investments for these process steps should be added to reflect the probable cost.

- Other questions are still unanswered. For example, amounts of pollutants, general accuracy of the basic equipment costs, and accuracy of other basic data are unknown, and thus the impact of these factors cannot be estimated in a meaningful way.

Overall, it is estimated that a more reasonable investment for the basic design would be at least $160 million, as shown in the following tabulation:

	Million $
Reference Investment	123
Lack of Detailed Engineering Design	+18
Escalation During Construction	12
Processes Not Fully Developed	10
Lack of Definition of Pollution Requirements	?
Accuracy of Reference Costs Unknown	?
Accuracy of Other Basic Data Unknown	?
Total	163
Call	160

The total impact of these uncertainties--at least $40 million--as assessed from Figure 0-6, amounts to about $1 per barrel. To fill out the full design, it is also necessary to include the effect of making hydrogen from coal, discussed in the following section.

Hydrogen from Coal

Some information is available on the cost of making hydrogen from coal. The M. W. Kellogg Company has presented an estimate based on their molten salt process,* and Tsaros has given an invest ment for making pipeline gas from coal, using the Texaco Partial Oxidation process to generate the synthesis gas.† It has been assumed that 70 percent of this investment would be applicable to the generation of hydrogen. This level of investment is also typical of the cost of the Lurgi coal gasification process when applied to making hydrogen.

The amount of hydrocarbon needed to make the hydrogen is slightly higher when using coal instead of methane, as shown in Table 0-10. A comparison of the costs of making hydrogen (250 MMSCF/SD) by these processes is given in Table 0-11, based on 1970 costs. Typically, the costs of H_2 from coal are 4 to 11 cents per MSCF H_2 higher than from CH_4. A more general relationship is shown in Figure 0-8. The Kellogg process, with its lower cost, may be regarded as conceptual, while the Lurgi process is commercial, and the Partial Oxidation process is "near commercial" technology. However, the lower possible costs of a conceptual process, such as the Kellogg Molten Salt process, indicate a clear incentive for research on other processes to make hydrogen from coal.

The impact of the higher hydrogen costs is appreciable. Since 7,000 SCF per barrel is used, an increase of 5 cents per MSCF is

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* M. W. Kellogg Company, *Commercial Potential for the Kellogg Coal Gasification Process*, OCR Contract 14-01-0001-380.

† C. L. Tsaros, "Hydrogen: A Key to the Economics of Pipeline Gas from Coal," Paper Presented at ACS Meeting, Chicago, Illinois, September 13-18, 1970.

TABLE 0-10

HYDROCARBON USAGE IN H2 MANUFACTURING

	Consumption for 1,000 SCF H2		
	MM BTU's	Tons Dry Coal	MSCF CH4
Steam Reforming	0.47		1.12
Kellogg Molten Salt	0.55	0.022	
Lurgi!Partial Oxidation	0.52	0.021	

TABLE 0-11

TYPICAL BREAKDOWN OF REFERENCE H2 COSTS
(250 MMSCF/SD)

Process	Steam Reforming	Kellogg Molten Salt	Lurgi/ Partial Oxidation
Investment (Million $)	50	90	90
H2 Cost (¢/MSCF)			
Feed			
CH4 at 50¢/MM BTU's	23.5		
Coal at 23¢/MM BTU's		11.2	10.3
Direct Operating Costs			
Labor	1.6	2.4	2.4
Repairs, Supplies, etc.	4.4	5.2	4.8
Oxygen at $7!Ton			9.5
Capital Charges (at 10% DCF)	13.0	23.6	23.6
Subtotal	42.5	42.4	50.6
Compression to 3,200 psia	2*	6	5
Total	44.5	48.4	55.6

* Basic costs include compression to 1,700 psia.

equivalent to about 35 cents per barrel. Regarding investment, the impact is to add about $40 million, which brings the total investment to the level of $200 million.

The effect on the cost of coal liquids is appreciable, as shown in Table 0-12, and summarized in the following tabulation:

	Reference Case	With Added Costs	With HZ from Coal
Investment (Million $)	1Z3	160	ZOO
Approximate Syncrude Cost ($/B--Coa1 @ $5/Ton, 10% DCF Return)	6.Z5	7.Z0	7.45-8.00*

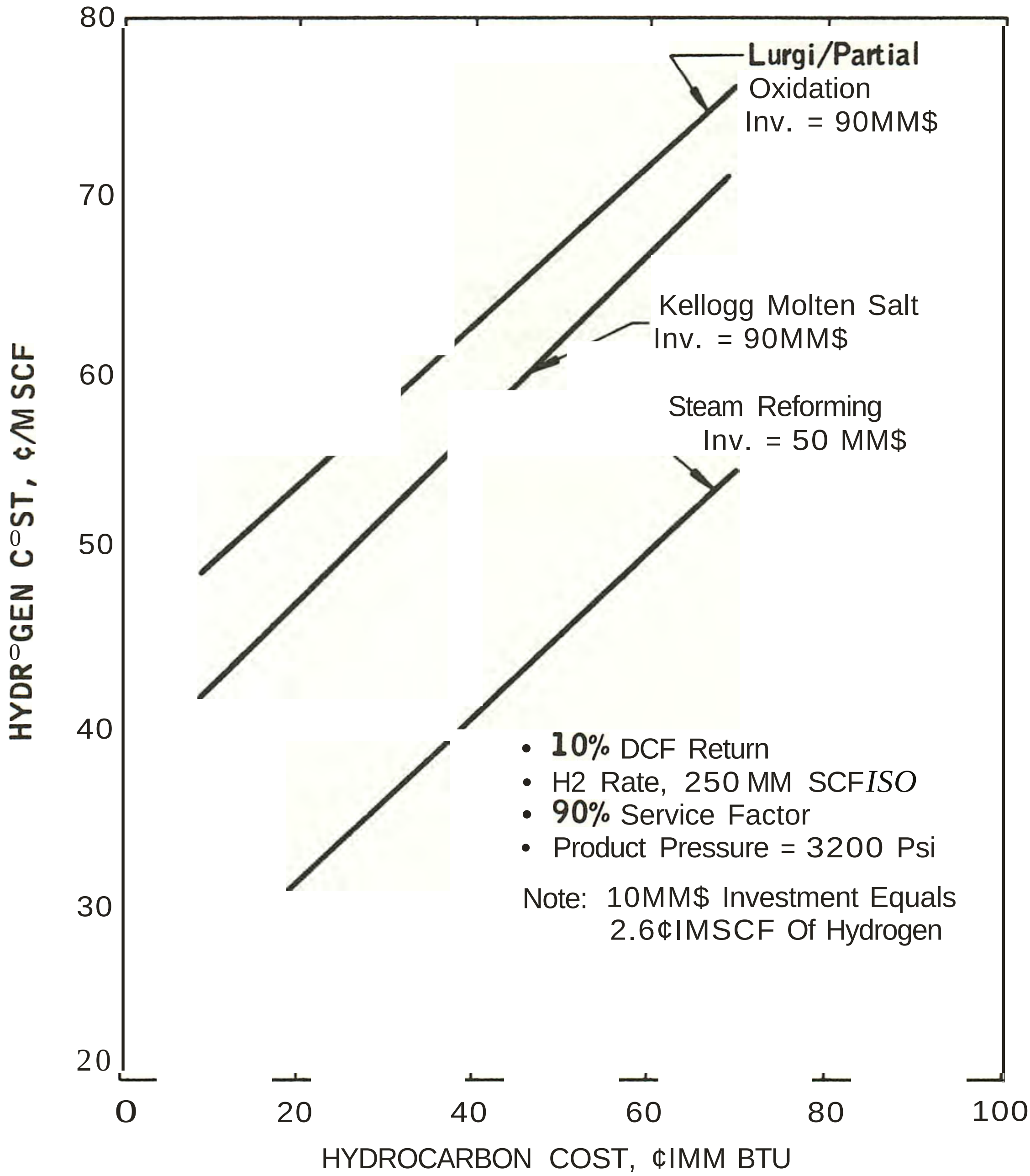

Figure 0-8. Hydrogen Manufacturing Costs from Coal and Methane.

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* Range reflects different HZ-from-coa1 processes.

On this basis of using coal to make all the hydrogen and selling the excess gas, the process yields would typically be:

- Syncrude yield (barrels per ton dry coal)--2.3
- Net gas yield (FOEB per barrel syncrude)--0.31.

The relation of syncrude cost to coal cost is shown in Figure 0-9 for the case of using coal to make all the hydrogen.

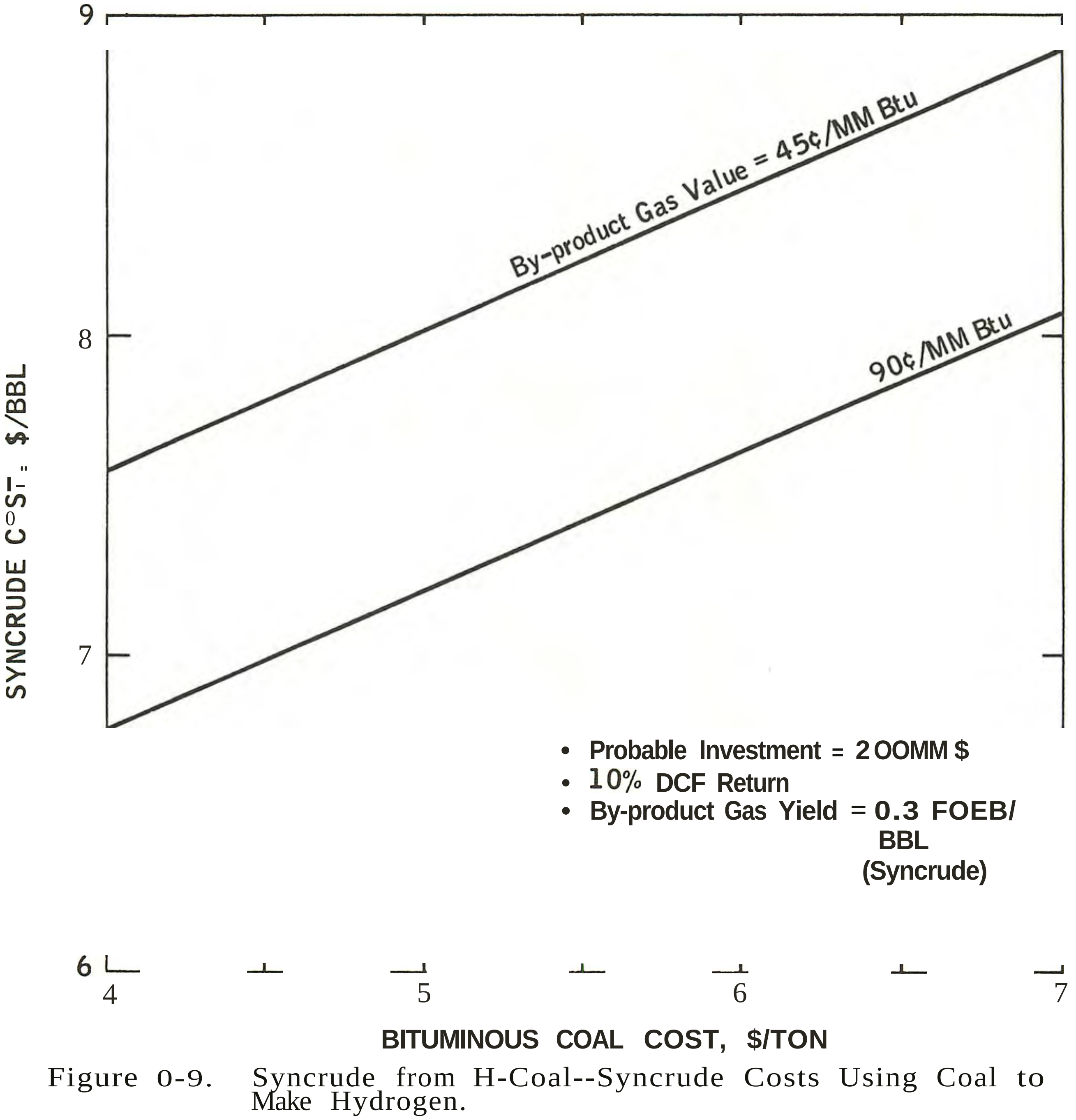

Figure 0-9. Syncrude from H-Coal--Syncrude Costs Using Coal to Make Hydrogen.

The current syncrude cost is about $2 to $3 per barrel higher than the equivalent cost reported by Amoco (about $5.25 per barrel). The higher costs arise primarily from the following:

TABLE 0-12

SYNCRUDE FROM H-COAL--ECONOMICS FOR PROBABLE INVESTMENT

	Reference Case	Reference Case Plus Added Costs	Reference Case Plus H_2 from Coal: Molten Salt	Reference Case Plus H_2 from Coal: Lurgif Partial Oxidation
Investment (Million $)	123	160	200	
Cost of Syncrude ($/B)				
Coal at $5/Ton	1.59	1.59	2.45	2.41
CH_4 at $0.50/MM BTU's	0.95	0.95		
Direct Operating Costs	1.55	1.74	2.10	2.71
Byproducts	(0.55)	(0.55)	(1.43)*	(1.43)*
Average Capital Costs (10% DCF)				
Depreciation	0.62	0.81	1.01	1.01
Income Tax	1.03	1.33	1.66	1.66
Return	1.04	1.34	1.66	1.66
Total	6.23	7.21	7.44	8.01

* Plant gas sold at $0.45/MM BTU's.

	Added Cost ($ per Barrel)
Escalation	
Higher Coal Cost ($5.00/Ton vs. $3.61/Ton)	0.50
Increase "Reference" Investment to 1970 Basis	0.40
Added Investment ($37 Million)	1.00
HZ from Coal	0.Z5-0.80
	Z.15-Z.70

Other Factors Influencing Syncrude Manufacturing Costs

The cost of making syncrude will vary with other factors, such as plant size and coal type. Some rough estimates have been made to see what the potential effects might be.

Increasing plant size to 100 MB/SD will reduce the plant investments (expressed as $/(B/CD)). However, the reduction is not great because most of the onsites are multiple units, even at 30 MB/SD, though the separation equipment and offsites offer some economy of scale. Overall, we would calculate investment to rise as the 0.9 exponent of size and the cost of syncrude might decrease about $.50 per barrel for the larger plant, as shown in the following tabulation:

Size (MB/SD)	Investment ($) Total (Million)	Investment ($) Per B/CD Syncrude	Cost of Syncrude
30	ZOO	7,400	Base
100	600	6,700	-50¢ bbl.

Western subbituminous coal, which is cheaper to mine than eastern bituminous coal, offers potentially cheaper liquids at the plant site. Although the low rank coal shows poorer liquid yields, it also can produce cheaper hydrogen, as a compensation. For example, assuming the total plant investment is about the same for the two coals, the raw materials cost favors the western coal by about $.55 per barrel, as shown in the following tabulation:

	Raw Materials for 1 Barrel of Syncrude: Bituminous Coal	Raw Materials for 1 Barrel of Syncrude: Subbituminous Coal
Coal for Liquefaction (Tons)	0.314	0.51
HZ for Processing (MSCF)	7.08	8.67
Coal Cost for Liquefaction ($)		

Bituminous at 30¢/MM BTU's*	1.89	
Subbituminous at 15¢/MM BTU's†		1.02
H_2 Cost		
Bituminous at 58¢/MSCF	4.11	
Subbituminous at 51¢/MSCF		4.43
	6.00	5.45

The incentive may be larger than that indicated in the tabulation since some high-oxygen coals may use less hydrogen if much of the oxygen can be eliminated as CO_2 rather than H_2O.

PRODUCTION OF DEASHED COAL FROM THE PAMCO PROCESS

With the growing restriction on sulfur contents of fuels, particularly heavy fuel oils, processes have been investigated for producing liquid fuels from high-sulfur coals. Heavy, low-sulfur fuels can be produced as byproducts in several processes, such as H-Coal and CONSOL's donor process. PAMCO has worked on a specific process, funded by the OCR, to make a deashed coal.‡ A conceptual plant design, based on the PAMCO process, was made by Stearns-Roger and has been reviewed and adapted for this study.§

Process Aspects

The flow plan of the process is the same as developed by Stearns-Roger. The plant is located near the mine mouth and produces a solidified product for shipment to remote consumers.

Wet bituminous coal from the mine is crushed and dried, slurried with a heavy recycle oil and fed through a preheater to the dissolver. The dissolver operates at 1,000 psig and 825°F with a liquid residence time of 15 minutes. A small amount of hydrogen is added to maintain the pressure and to aid in producing some light liquid which provides a more filterable product. The liquid and solids go to a filtration section consisting of rotary precoat filters. The filter cake is sent to a drier to recover light wash solvent and then burned in a fluid bed boiler, producing steam used to generate power.

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* $6/ton.
† $2/ton.

‡ D. L. Kloepper et al., *Solvent Processing of Coal to Produce a Deashed Product,* OCR Contract 14-01-0001-275.

§ PAMCO, *Economic Evaluation of a Process to Produce Ashless, Low-Sulfur Fuel from Coal,* OCR Contract 14-01-0001-496.

The clear filtrate is sent to a series of flashes and a vacuum tower to recover solvent. The net production is a heavy fuel, which has been claimed to have the following properties:

	Weigh % Sulfur
Carbon	88.4
Hydrogen	S.2
Oxygen	3.7
Nitrogen	1.8
Sulfur	0.8
Moisture	0.0
Ash	0.1
	100.0
Melting Point	>200°F
High Heating Value	lS,673 BTU/lb

The product is solidified and shipped as a granular solid.

The sulfur content of 0.8 percent is suspect. The PAMCO data show values of 1.0 to 1.S-percent S from bituminous coal, which is in line with other liquefaction experience. Hence, the assumption that such a deashed coal would be an acceptable substitute for low-sulfur heating oil (less than O.S-percent S) would appear incorrect.

The plant processes 10,7S2 tons per SD of raw bituminous coal and produces about 30 MB/SD of heavy fuel oil, plus 3,934 B/SD of light oil. The overall yield statistics for PAMCO deashed coal are given in the following:

- Deashed coal yield ST/ST (feed coal)*--O.SS
- Deashed coal yield, FOEB/ST (feed coal)--2.82
- Oil yield, bbl/ST (feed coal)--0.37
- H_2 consumed, SCF/ST (feed coal)--4,6S0
- Natural gas purchased, FOEB/ST (feed coal)--0.28
- Sulfur yield, LT/ST (feed coal)--0.02
- Power produced, KWH/ST (feed coal)--67.

Investments and Operating Cost

The investment was updated to a 1970 basis, uSlng the same procedure as in the syncrude case. The filtration section was re-sized to use a much lower filtration rate (100 pounds per hour per

* Feed coal has la-percent moisture.

square foot based on lab data) than that used in the Stearns-Roger design (400 pounds per hour per square foot). The Stearns-Roger estimate appears to be on a 1967 basis, so the 1970 investment would be about 16 percent higher. The updated investment for the PAMCO design is $93 million for the 30 MB/SD plant.

For operating cost factors, the raw materials and utilities reported by Stearns-Roger were used, together with our own estimates of manning, as in the syncrude case.

Cost of Producing Deashed Coal

The cost of producing the deashed coal product was calculated using the same procedure described for syncrude (see the section on the H-Coa1 process). A sample breakdown of the product cost for the 1970 reference point is shown in the following tabulation. The reference point cost of 73.4 cents per million BTU's (or $4.50 per barrel is highly influenced by coal cost and capital charges).

	¢/MM BTU
Coal	29.3
Natural Gas	5.0
Other Operating Costs	17.6
Byproduct Credits	(11.2)
Capital Charges (Return, Depr., etc.)	32.7
Total	73.4

Estimation of More Probable Investment and Product Cost

In reviewing the Stearns-Roger remarks on their design, it is evident that they feel (and our judgment agrees) that many parts of the design are not firm. For example:

- The mineral residue burners require rotary valves which operate under pressure.
- The boilers are fluid bed boi1ers--not yet commercial--and require that a stoichiometric air-fuel rate be used.
- The process for recovery of cresylic acids from water is "somewhat unknown."
- Suitability of a modified Claus plant to remove low levels of S02 is dubious.

Coupled with process uncertainties, e.g., filtration rates and effectiveness of simple vacuum flashing to recover solvents, the following *minimum* costs should be added to the reference investment:

- Lack of detailed engineering design (15 percent)--$15 million
- Escalation during construction (10 percent)- $10 million.
- Process not yet fully developed (ZO percent of major elements)--$15 million
- Accuracy of many costs suspect (phenolic, cresylic recovery and flue gas desulfurization)--Not Estimated.
- Accuracy of basic data suspect (fields and filtration rates)--Not Estimated
- Added costs--$40 million.

In addition, if the hydrogen is made from coal, there will be an additional $10 million needed. The total investment is then about $145 million and is broken down in the following tabulation:

		Million $
Reference Investment		93
Added Costs		+40
HZ from Coal		+10
	Total	143
	Call	145 MM

The impact on the cost of making the deashed product is appre ciable, as shown below:

		¢/MM BTU
Reference Case		73
Added Costs		19
HZ from Coal		Z
	Total	94 ($5.70/B)

Since pollution regulations project future sulfur levels as low as O.Z-to 0.5-percent S, it is doubted that this particular process merits serious consideration as a potential source of low-sulfur heavy fuel. To attain this low level of sulfur in heavy coal liquids, some form of catalytic hydrodesulfurization will be needed. An alternative would be to use the heavy gas oil products from an H-Coal syncrude plant (which are below I-percent S) rather than convert them to light distillates in an H-Oil Unit. Similarly, the H-Coal process might be run at milder conditions (lower pressure, higher throughputs, etc.) to increase the yield of heavy liquid materials. The cost of such heavy fuels made by H-Coal might be roughly 75 cents per million BTU's ($4.50 per barrel).

This estimate is based on making rough adjustments for added costs, hydrogen from coal and other factors to a heavy fuel *oil* coal operation described by HRI in a paper presented at the Chicago Meeting of the American Chemical Society (ACS) on September 14, 1970.

TIME AND COST TO COMMERCIALIZE COAL LIQUIDS

There has been no published work showing a thorough and reliable estimate of the time and effort needed to develop any of the coal liquefaction processes to commercial readiness. There are no hard, quantifiable rules for such estimates, and substantial amounts of judgment are required to satisfy certain critical questions, such as the following:

- At what time will a given coal liquids process become economically acceptable?
- How much work is required in the various stages of development to provide sufficient data to make the risk of investing in the first (and subsequent) commercial plant acceptable?
- How much bench scale and pilot plant work will be required?
- How is the equipment technology to be developed?
- Is a prototype or demonstration unit required prior to the first commercial plant, and what are the size and cost of such units?

Our estimate of how the technology might be developed is based on a few key assumptions, listed in the following section. These estimates have been expressed as a range of time and costs, indicating judgment of both the general level of effort required and how much uncertainty is involved in these estimates.

Base Assumptions

The development of the process technology is geared towards minimizing the risks inherent in early "pioneer" plants. It has been assumed that the processes will be developed by private industry using some level of economic return on investment as the criterion for viability. In addition, it has been assumed that such economic viability can be foreseen at the start of the development work to serve as the basic driving force for initiating the major development expenditures. As a result, the assumed commercialization strategy is one of all deliberate speed, but guided by process economics and moderate risk.

The main features involved in the development of a coal liquids system are--

- Identification and definition of desired processes, together with the preferred operating conditions, to cover (1) coal liquefaction to syncrude (or low-sulfur fuel oil); (2) conversion of syncrude to lighter products, e.g., gasoline; and (3) improved methods for hydrogen manufacture from coal or char

- Development of technology for critical pieces of equipment, e.g., pressure vessels, reaction systems; slurry pumps, heat exchangers and furnaces; flow and pressure control methods and equipment; filters and centrifuges (if needed)

- Demonstration of operability and efficiency of combined processes and equipment on a sufficiently large scale prior to commercial plant design: (1) proved process operability and equipment integrity, (2) obtain large samples of products; and (3) confirm economics of process.

<u>Timing Set by the Need for Large Scale Prototype Plant</u>

The investigations of the processes that make up the overall coal liquids system, the best operating conditions, catalysts, etc., can be accomplished in bench units or small pilot plants. Some equipment can be developed in conjunction with equipment manufacturers. However, the high investments for commercial plants will require that the main processes and equipment elements be demonstrated on a large scale such as a prototype or demonstration plant prior to commercial application.

Basically, a prototype should be large enough to prove many commercial features such as--

- Providing reliable scale-up data for key process elements

- Proving mechanical operability using at least semi-commercial equipment

- Testing long-term process performance, including steady state yields, startup and shutdown procedures and process upsets

- Making large samples of products for further evaluation

- Testing safety and special pollution controls

- Training operating personnel.

Typically, a prototype might be 0.5 to 0.2 percent of the size of a commercial plant, depending on the risk that is considered acceptable. Overall, the capacity of a coal liquids prototype (for syncrude or heavy fuel oil) would be about 200 to 400 tons per day of dry coal. For the H-Coal process, this size range would involve high pressure reactors of at least 3 feet in diameter and would probably test our commercial high pressure pumps, heat exchanger tubes, furnace tubes, etc., on slurry service. Other process elements in the prototype, such as fluid cokers, centrituges or filters, would be of sufficient size to confirm projected commercial design and operation. The hydrogen prototype would also be sized for about 200 tons per day, corresponding to about 9 to 10 MMSCF per day of hydrogen. It is believed that this size would provide adequate scale-up data for commercial plant design.

Judging from the limited literature on the basic processing and from personal experience in large pilot units, the following schedule was estimated:

	Coal Liquids		H2 from Coal	
	Time (Yrs.)	Cost (MM$)	Time (Yrs.)	Cost (MM$)
Bench Scale Work	1-2	3-5	1-2	1-3
Prototype (200 to 400 tons/day)				
To Design & Construct	2-3	15-25	2-3	10-15
To Operate	2-3	15-25	2-3	10-15
Overall	5-8	30-60	5-8	20 - 30
Liquids + H_2	5-8	50-80		

The lower end of the time and cost range would represent a smooth, relatively trouble-free set of experiences. The 8-year period is probably more reasonable, reflecting an "average" number and severity of problems in development work. The range of $50 to $80 million should encompass the total amount since there is enough flexibility in the size of prototype, length of operation, etc., to keep within a given range of expenditures. In addition, as discussed in the next section, there is the possibility of overlapping some time schedules to reduce the total elapsed time. The costs listed in the tabulation above represent the cost for one company developing one process. If other processes are pursued, or if other companies carry out parallel efforts, the total cost to industry would be some multiple of the above value shown in the tabulation.

POSSIBLE COMMERCIAL CAPACITIES BY FUTURE DATES

Projections of possible commercial capacities depend on the basic assumptions made and the general optimism (or pessimism) of the estimator which is related to the risks thought acceptable. A commercial timetable was projected for the buildup of syncrude capacity based on the following assumptions:

- There will be no unusual limitations on acquiring commercial equipment due to other industry activities such as other synthetic fuels projects (e.g., synthetic methane and shale oil). Current estimates of delivery times have been used for special high pressure equipment.

- Contractors will be available to handle coal projects.

- Development of mining capabilities will not be limiting.

- The foreseeable economics will be sufficiently attractive to encourage the initiation of major expenditures for process development work 8 to 10 years in advance of the first commercial plant startup.

- A prototype design will commence after about 2 years of bench and pilot plant work. One year of design effort is needed, followed by 2 years of field construction to reach mechanical completion of the unit.

- One year's operation of the prototype is sufficient to verify the essential merits of the liquefaction and hydrogen processes and to obtain enough data for starting the design of a commercial plant.

- The design of the commercial plant takes 1 year. Combined with 2 years of prototype experience, the plant's economics are re-evaluated and still look viable so that approval for funds is made for construction.

- Construction of the first commercial unit requires 3 years to reach mechanical completion.

- The first plant operates sufficiently well so that subsequent plants can be designed promptly for larger capacities or multiple plants built.

To estimate the capital outlays for plant construction, it has been assumed that some improvements in technology and the construction of larger plants can reduce the plant investments per barrel of capacity, resulting in the following size/investment relations for syncrude plants:

MB/SD	Investment (Million $)
30	200
50	320
100	600
200	1,100

Following the timetable illustrated in Figure 0-10, the build-up of capacity and the required investment was developed and is illustrated in Table 0-13. (For simplicity and clarity, each plant has been shown at full capacity at the end of the first year of production, whereas for the DCF calculation a more extended period to reach full capacity was used.) Overall, the capacity buildup is slow. Production from the first plant is 10 years from the starting date, and another 8 years is required to obtain about 500 MB/SD total syncrude capacity. Capital outlays are large--$600 to $1,100 million per year. In addition, many technical people would have to be committed to design, construction and operation of the plant. (Since almost any type of syncrude process can be adapted to making a heavy fuel oil, the general production buildup for a heavy fuel oil might follow the same pattern as outlined previously for syncrude. However, because of reservations about the suitability of the PAMCO process, a separate projection of possible commercial capacity has not been developed.)

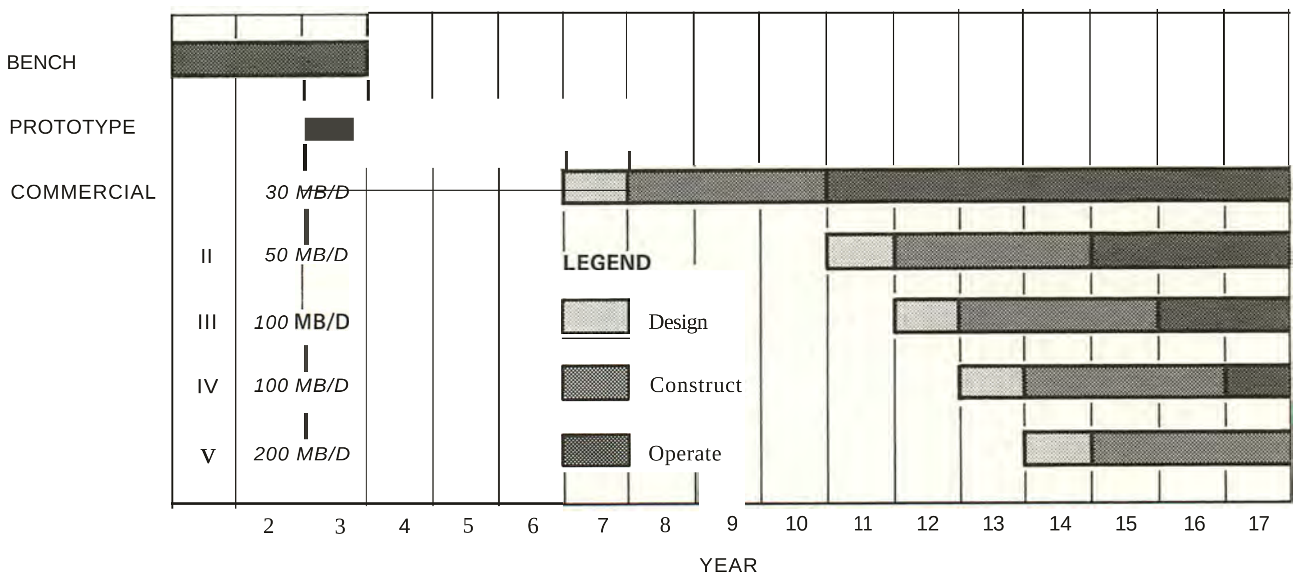

Figure 0-10. Syncrude from H-Coal--Possible Schedule for Commercial Development.

The first commercial plant may not be started successfully much sooner than shown in Figure 0-10 since the main limitation is the development of technplogy. Even if a special driving force existed to accelerate the development program--e.g., to omit the prototype step and proceed directly to a commercial plant--the potential time saving might well be lost due to the long down-times that would be required to make changes in a commercial plant to overcome technical deficiencies. Also, these changes would be very expensive. Therefore, an approach such as bypassing the prototype would involve very high risks.

For coal to playa more immediate role in supplying liquids, the best approach might be to use coal to replace liquid petroleum fuels (or natural gas) in power plants and industrial furnaces. This would require some form of desulfurization technique--either

TABLE 0-13

SYNCRUDE FROM H-COAL--POSSIBLE BUILDUP OF COMMERCIAL CAPACITY

Years from Startup	Capacity (MB/D) Δ	Capacity (MB/D) Total	Investment (Million $) Δ	Investment (Million $) Total
11	30	30	200	200
12	0	30	0	200
13	0	30	0	200
14	0	30	0	200
15	50	80	320	520
16	100	180	600	1,120
17	100	280	600	1,720
18	200	480	1,100	2,820
19	200	680	1,100	3,920

manufacturing. low-BTU gas from coal with sulfur scrubbing or direct burning of coal with desulfurization of the flue gas. No estimates have been made of the quantities of clean fuels being used by utilities, refineries or other manufacturers which might be allotted to other uses and replaced by coal.

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