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DEPARTMENT OF REGISTRATION AND EDUCATION

Gasification and Liquefaction—Their Potential Impact on Various Aspects of the Coal Industry

Hubert E. Risser

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Topographic mapping in cooperation with the United States Geological Survey.

GASIFICATION AND LIQUEFACTION—THEIR POTENTIAL IMPACT ON VARIOUS ASPECTS OF THE COAL INDUSTRY

Hubert E. Risser

ABSTRACT

Coal is recognized as one of the potential sources of liquid fuels and gas to supplement supplies of these fuels available from natural sources. Projections indicate that the demand for gasoline in the year 2000 will be 2.95 billion barrels per year higher than in 1980 and the demand for pipeline gas will be 10.4 trillion cubic feet higher. These quantities are equivalent to the gasoline output from 983 million tons of coal and the gas output from 554 million tons. The cumulative growth in gasoline and gas during the 20-year period would be equivalent to the output from 8.5 billion tons and 5.1 billion tons of coal, respectively. The magnitude of the factors involved in supplying such quantities of coal is phenomenal.

A billion tons of coal per year will require the output of 333 modern mines (3 million tons per year each), employing 100,000 workers. Mine investment would be 10 billion dollars. In the production of a billion tons of coal, from underground mines in 6-foot coal, an area of 185,000 acres would be mined out.

The location of coal conversion plants will be governed by a number of factors including proximity to the areas of demand for the products and the availability and thickness of coal. Huge reserves of thick, cheaply mined coal are available in the western United States; however, coals east of the Mississippi River are more favorably situated with regard to the market demand for fuels of all types. Illinois, possessing the largest reserves of bituminous coal in the nation, lying adjacent to one of the largest energy consuming areas, and producing coal from the greatest average seam thickness east of the Mississippi, is in an especially favorable position to contribute to and benefit from the development of a coal conversion industry.

INTRODUCTION

Among the topics receiving special attention from resource economists, government officials, and fuel producers in the United States is the question of how the rapidly growing demand for energy will be met in coming decades. Projections indicate that by 1980 the domestic supplies of natural gas and petroleum, which now supply 76 percent of the nation's fuel needs, will not be adequate to meet requirements. Anticipated deficits will be made up to some extent by imports. It has been predicted, however, that liquid fuels and gas produced from tar sands, oil shale, and coal will fill most of the needs.

This study examines projections of demand for natural gas and gasoline and the estimated reserves available to meet these demands. Projections for the period 1980 to 2000 are studied in terms of coal equivalent, and estimates are made of the tonnages of coal, number of mines, employees, investment, and coal acreages that would be required if the growth were to be supplied by gas and gasoline produced from coal.

Geographic, geologic, and market factors that will influence the location of future coal liquefaction and gasification plants also are considered.

The conversion of coal to gas and liquid fuels has been technically feasible for many years, but the products of such operations have been too expensive to be competitive with natural gas and petroleum-based liquid fuels. Current research, aimed at improving the economics of the processes, now appears to be nearing success.

ENERGY TRENDS

In the half century ending in 1965, the estimated total annual consumption of energy from mineral fuels in the United States grew from 16,163 trillion Btu to 51,703 trillion Btu. Table 1 shows that although total energy consumption was tripled during this period, petroleum consumption in 1965 was 15 times the 1915 level, and natural gas, almost 25 times. Meanwhile, bituminous coal consumption had increased less than 4 percent, and anthracite consumption dropped 85.5 percent during the same period. In effect, then, the increase in energy provided by liquid fuels and gas was equal to the total growth in fuel energy consumption.

The selection of a fuel depends on numerous factors. Among the strongest determinants are suitability, cost, and desirability. The expansion in the use of liquid fuels and gas demonstrates the extent to which they have met these requirements.

Energy requirements in which only one fuel can perform satisfactorily are few in number. One such example is in blast-furnace operations where coke made from coal is used almost without exception although other fuels can be partially substituted. Another is in transportation, where liquid fuel provides nearly all the energy. The energy from gasoline and diesel fuel used in transportation in the United States in 1965 was approximately 12,184 trillion Btu (U. S. Bureau of Mines, 1967a, p. 16) compared to about 150 trillion Btu 50 years earlier (Schurr et al., 1960, p. 117; Putnam, 1953, p. 384).

Except for the few specialized applications, the energy provided by one fuel can perform a service equally as well as the energy from another. For most

TABLE 1 - TOTAL CONSUMPTION OF ENERGY FROM MINERAL FOSSIL FUELS IN THE UNITED STATES

	Quantity			Trillion Btu		
	1915*	1965**	2000†	1915	1965	2000
Bituminous coal, million tons	442.6	459.2	718	11,597	12,030	18,000
Anthracite, million tons	89.0	12.9		2,260	328	
Oil, million barrels	281.1	4,202.4‡	11,590‡	1,630	23,209‡	61,600‡
Natural gas, billion cubic feet	628.6	15,590.5	32,780	676	16,136	33,800
				16,163	51,703	113,400

* Schurr et al., 1960, p. 492, 497.
** U. S. Bureau of Mines, 1967a, p. 9, 16.
† Landsberg, Fischman, and Fisher, 1963, p. 290.
‡ Includes natural gas liquids.

industrial and utility purposes, the fuel selection hinges largely on the over-all cost. It is on this basis that coal has been able to gain much of the rapidly growing electric utility market.

In residential, commercial, and some industrial uses, cost becomes secondary to cleanliness and convenience as a factor in fuel selection. Oil and natural gas have been steadily increasing their share of these markets.

Coal in solid form has not been able to compete in some of the largest and most rapidly growing energy markets, even though it has a lower cost than other fuels in many locations. However, if it can be converted to liquid and gaseous forms, at a suitable cost, it has a prospect not only of gaining a share of future energy growth, but of competing for existing markets as well.

GASOLINE

General

The consumption of liquid fuel grew 15-fold from 1915 to 1965 and is projected to more than double during the period 1965 to 2000 (table 1). The output of refineries in the United States during 1965 consisted of 44 percent gasoline, 23 percent distillate fuel oil (including diesel fuel), 8 percent residual fuel oil, and 5.8 percent jet fuel. The remaining 19.2 percent consisted of products such as asphalt and road oil, petrochemical feedstock, petroleum coke, and lubricants. In the liquefaction of coal, a number of products can be produced, including gasoline, certain grades of fuel oil, various chemical products, and a solid char.

For many stationary uses of fuel, coal in its natural solid form can provide the energy to perform the task equally as well as the liquid fuels produced from crude oil, although perhaps not quite as conveniently. At present, liquefying coal merely to replace or compete with solid coal now being used appears to be of no particular advantage to the coal industry. For this reason, conversion of coal is most likely to be first concentrated primarily on those fuels and uses with which coal cannot presently compete. In the future, however, tighter restrictions on sulfur emission will make liquefaction or gasification necessary or desirable in those uses for which solid coal now is consumed.

In transportation, coal is almost completely excluded because in its solid form it is unsuitable for use within internal combustion engines. Yet, this market, which is presently closed to coal, consumes nearly all of the gasoline and 24 percent of the total energy consumed in the United States each year (U. S. Bureau of Mines, 1967a, p. 14). Transportation, therefore, appears to offer the greatest potential market for liquid fuels produced from coal.

More than 2 billion barrels of liquid fuels, three-fourths of which is gasoline, is consumed in transportation in the United States each year. For this reason, gasoline and its markets are the principal topics that will be covered in the following discussion of coal liquefaction.

Costs and Factors of Conversion

According to the U. S. Bureau of Mines, the average wellhead value of crude oil produced in the United States in 1965 was $2.86 per barrel, compared to $2.58 per barrel in 1948. The cost of gasoline produced at refineries in Oklahoma rose to an average of 12.21 cents per gallon in 1965 from 11.19 cents in 1948, an increase of about one cent per gallon (U. S. Bureau of Mines, 1950, p. 985; 1967a, p. 403).

While the cost of both crude oil and gasoline from crude oil has been increasing, that of gasoline from coal has been decreasing. Processes under investigation in 1967 gave estimated costs of 10.5 to 13 cents per gallon for gasoline from coal, with after-tax return on investment ranging from 8 to 12 percent and payout period of 6 to 7 years (Chem. and Eng. News, 1967, p. 96-104). This is a distinct improvement over estimated costs of conversion in the late 1940's. In 1949, a report of the U. S. Bureau of Mines, in describing results of research underway at that time, stated the following:

> "Based on conditions in 1948, it is estimated that a plant with a capacity of 30,000 barrels per day could produce gasoline at a cost ranging from 12 to 15 cents per gallon if credit is taken only for by-product liquefied petroleum gas. If credit also is taken for phenols, these costs would be reduced to a range of 8 to 11 cents per gallon. These costs include amortization in 15 years but no return on investment."

With research steadily lowering the cost of producing gasoline from coal, while the difficulty of finding and the cost of producing crude oil are increasing, the time when commercial-scale conversion plants may be constructed to produce gasoline in competition with oil refineries appears to be approaching rapidly.

A second factor that will affect the relative competitive positions of gasoline from oil and gasoline from coal is the geographic locations at which oil and coal occur. Coal deposits are widely distributed throughout the nation and major reserves exist relatively near large centers of population and industry. By contrast, about 67 percent of the known oil reserves lie in Texas, Oklahoma, and Louisiana, which contain only 8.5 percent of the nation's population.

Because a large portion of the crude oil is produced and much of it is refined at locations several hundred miles from most of the major consuming centers, transportation becomes an important factor of cost to the consumer. For example, the average wellhead value of crude oil produced in Oklahoma in 1966 was $2.91 per barrel. The reported cost of pipelining crude oil from Oklahoma to Chicago that year was 22 cents per barrel. From eastern Wyoming to Chicago the cost was 33 cents. Piping refined products from Baytown, Texas, to Chicago during the same year cost 36 cents per barrel (U. S. Bureau of Mines, 1967b, p. 384). This is equivalent to 0.86 cents per gallon.

In the conversion of coal to gasoline it is estimated that 3 barrels of gasoline will be obtained per ton of coal. Coal-to-gasoline conversion plants currently under consideration by researchers range in size from 30,000 to 100,000 barrels per day. Such plants would have daily coal requirements of from 10,000 to more than 30,000 tons, or annual requirements that might approach 10 to 12 million tons of coal.

Supply and Demand Factors Influencing Conversion to Gasoline

Up to the present time, the petroleum industry has supplied the ever-increasing demand for its products and should be able to continue to do so for some time into the future. The United States, however, became a net importer in 1949 and varying quantities of imported petroleum and petroleum products have supplied part of the nation's requirements since that time.

In 1966, imports provided about 20 percent of the total oil consumed in the United States and 13 percent of the crude oil processed by United States refineries. These imports are not altogether the result of an inability of the domestic industry to increase production. Much of the importation of crude oil results from the fact that foreign oil, in general, is available at a lower cost than oil from domestic sources. The reported average wellhead value of domestic crude oil in 1966 was $2.88 per barrel (U. S. Bureau of Mines, 1967b, p. 851). The value of crude oil imported from foreign sources, other than Canada, is about $1.25 per barrel less (Wall Street Journal, 1968, p. 9).

With foreign oil available at such low costs, a larger share of the United States' requirements would be supplied from foreign sources were it not for restrictions on the import of such oil. These restrictions serve, in part, as a protection for higher cost domestic producers. Also, for defense purposes and other reasons, it is undesirable for the United States to become too dependent upon outside sources for its oil. Imports may be interrupted through political or other action, and there has been a tendency in recent years for nations in which United States oil-producing firms are operating to demand increased payments in taxes or other forms of revenue. If the United States were to become almost totally dependent on outside sources of oil, there would be little defense in the future against higher prices that might equal or exceed the costs of domestic production.

Regardless of future United States policy established in importation of oil, the growth in fuel and energy use in other parts of the world is progressing at a rate about twice that of this country. This eventually will affect both the availability and the cost of foreign oil.

The United States currently possesses greater oil-producing capacity than is being utilized. During the 1967 Middle East crisis, domestic production was increased to help supply oil for areas normally dependent on the Middle East. Existing surplus capacity cannot, however, be relied upon to provide for any significant share of the 260 percent increase in demand projected to occur between 1965 and the year 2000.

At present, the prospects for liquefaction of coal are strictly a matter of economics. A decline in domestic petroleum reserves and in availability of foreign sources could make the production of liquid fuels from sources other than crude oil a necessity, whatever the relative costs might be. In such a circumstance, availability would be of much more significance than economic factors.

Coal will have two strong rivals in the synthetic liquid fuel market. These are the tar sands in Alberta, Canada, and the oil shales of the western United States.

A commercial plant is already in operation, producing oil from the Athabaska tar sands, and processes have been developed for retorting the oil shales. However, coal appears to have a distinct advantage over both of these from the standpoint of proximity to the market.

Coal is reported to have a number of advantages over oil shale (Oil and Gas Jour., 1967, p. 41). One advantage is in yield, or the quantity of product that can be obtained from processing a given amount of raw material. To supply a 100,000 barrel per day (36.5 million barrels per year) oil shale plant would require the mining, handling, processing, and waste disposal of roughly 125,000 tons of shale per day or about 45 million tons per year. About 70 million tons of tar sands per year would be required for an equivalent plant processing tar sands. A coal processing plant would require only 12 to 15 million tons of coal input per year.

Coal has advantages, too, because of its wide geographic distribution and predominantly private ownership. The concentration of oil shale in relatively limited geographic regions means entire new networks of pipelines may be required if large quantities of oil are produced. A major share of the oil shale exists on public lands, which makes it subject to political problems and controls. The limited availability of water also is a factor.

Partly offsetting some of the disadvantages of oil shale is the fact that other valuable minerals may be recovered during shale mining and processing. Valuable chemical by-products, however, also can be recovered from coal, although the output from operations of the size under consideration might quickly flood the market for these.

Figure 1 shows the past consumption of gasoline as motor vehicle fuel in the United States and projections of future consumption. For purposes of discussion, the medium projection will be used.

A doubling of consumption is expected from 1960 to 1980, and a further doubling is anticipated from 1980 to the year 2000 (medium projection, fig. 1). This market growth will present a huge target for gasoline from coal.

It is unlikely that gasoline from coal will supplant gasoline from oil in the foreseeable future. It does appear likely, however, that it will begin to supplement oil-based gasoline within the next few years. With pilot-scale liquefaction plants already under construction and gasoline production costs trending in favor of liquefaction, a limited number of commercial-scale liquefaction plants are likely to be in operation in specially favorable local situations in the early to mid-1970's. During the last two decades of the century, gasoline from coal should be able to gain a significant share of the expanding market.

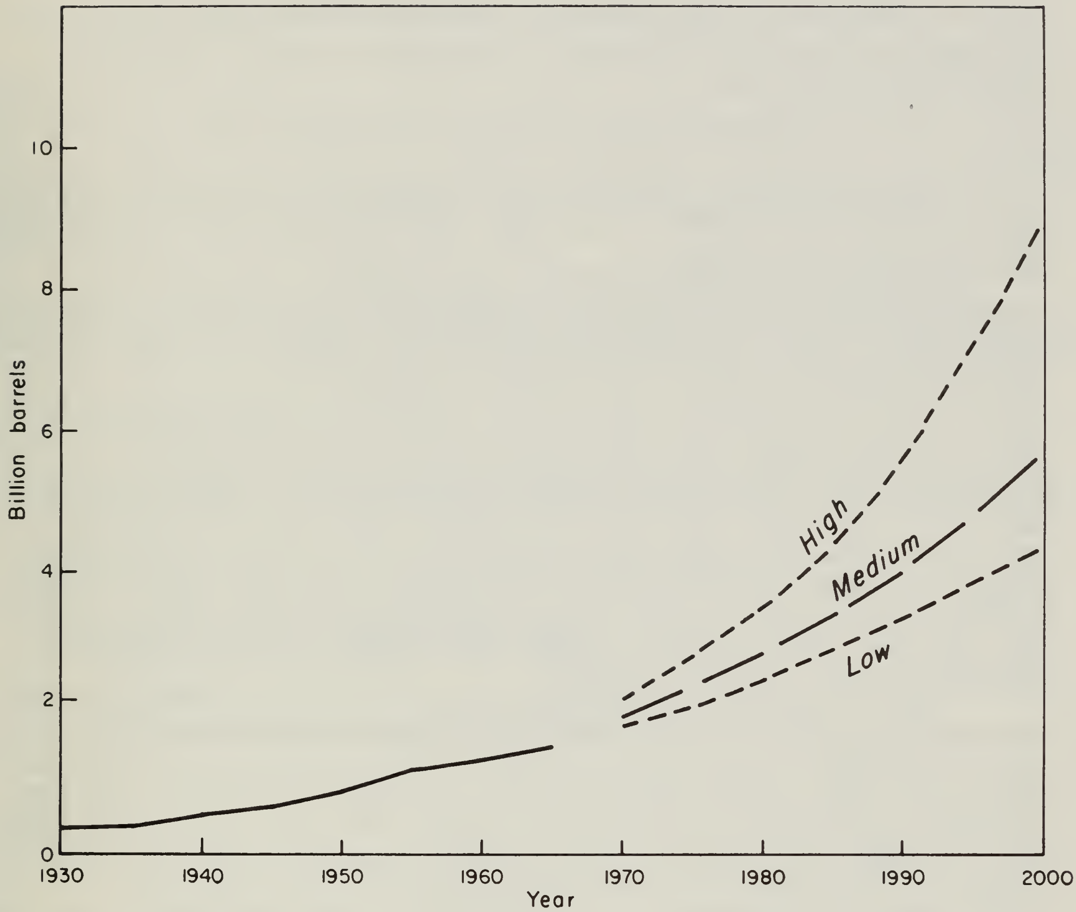

Figure 1 - Past and projected consumption of motor vehicle fuel in the United States, 1930-2000. (Source: Landsberg et al., 1963, p. 668).

PIPELINE GAS

General

Natural gas has been the fastest growing of the three major fuels in recent decades. While total energy consumption from fuels grew 82 percent from 1946 to 1966, gas consumption rose 324 percent, or almost four times as fast. In 1966, natural gas provided 30.4 percent of total energy compared to only 14.4 percent 20 years earlier.

Growth in natural gas' share of the energy market came both through absorbing a significant share of the total energy growth and through penetrating markets held by coal and oil. It appears that a continuation of the growth pattern can be anticipated for the next several decades. Although the most easily penetrated markets already have been taken, some expansion will continue into regions not yet served by gas. The use of gas for air conditioning and in the so-called "total energy" applications will also increase. Furthermore, natural gas' freedom from the stigma of air pollution will enable it to replace coal and oil in some places where these now are used.

Costs and Factors of Conversion to Pipeline Gas

The cost of natural gas, both at the wellhead and at the point of consumption, has been rising steadily. Meanwhile, research gradually has been reducing the cost of coal gasification.

The average value of natural gas at the wellhead in 1950, at 6.5 cents per thousand cubic feet (Mcf), gave a cost equivalent of approximately 6.5 cents per million Btu; by 1966, the average wellhead value had risen to 15.7 cents, equivalent to a 150 percent increase (U. S. Bureau of Mines, 1967b, p. 769). A study of the economics of producing gas from coal, published in 1950, estimated the cost of producing pipeline gas from coal at $1.06 per million Btu (Foster and Lund, 1950, p. 279). By 1966, the estimated cost of coal-based gas had been reduced to the range of 40 to 58 cents per million Btu (approximately 1 Mcf) depending on plant size, cost of coal, and value of by-products (Bituminous Coal Research, 1967, p. 3). Thus, while the cost of natural gas at the source was more than doubling, research was cutting the cost of gas from coal in half. The estimated cost of producing gas from coal still remains above the wellhead price of natural gas. However, gas from the two sources must compete, not at the wellhead or gasification plant, but at the market.

About 79 percent of the natural gas reserves and 78 percent of the production are concentrated in the West South Central region of the United States, although most of the coal production and reserves occur in the eastern United States. Natural gas moving toward eastern markets must absorb transmission costs that, in general, range from 12 to 18 cents per Mcf per 1000 miles. As a result, natural gas delivered to the "city gate" of some eastern metropolitan areas carries prices equal to or only slightly less than the estimated cost of gas from coal.

The average wellhead cost of natural gas is established from numerous sales in many regions. Large quantities are delivered under contracts negotiated years ago when the demand for gas was slight and the price was considerably below the 15.7 cent average of today. New contracts reported in Louisiana early in 1968 called for prices of 21.5 cents per Mcf, and a price of 30.5 cents per Mcf was recently approved for Canadian gas delivered just inside the U. S. border at Sumas, Washington (Oil and Gas Jour., 1968, p. 55).

The 15.7 cents per million Btu average cost for natural gas at the source is relatively low compared to 48 cents per million Btu for crude oil at the well and 18 cents for coal at the mine. A major reason for this low cost is the regulation of gas prices by the Federal Power Commission. Although this regulation makes gas available to the consumer at a lower price, there is increasing evidence that it is also retarding the search for reserves that are needed to sustain the growth in gas availability.

It has been estimated that with the processes now under development, it will require 53.3 million tons of coal to produce one trillion cubic feet of gas. Thus, a plant producing 250 million standard cubic feet per day (about 90 billion cubic or 90 trillion Btu per year) would consume more than 13,000 tons of coal per day (Linden, 1965, p. 4). To produce the equivalent of the 18.4 trillion cubic feet of natural gas estimated to have been consumed in 1967 would have required the operation of about 200 such plants and the consumption of almost a billion tons of coal.

Supply and Demand Factors Influencing Conversion to Gas

Numerous projections have been made of the future use of gas, all of which indicate that the demand for gas will continue to grow at a strong rate throughout the remainder of the 20th century. A number of the projections are shown in figure 2. For the purpose of discussion, the medium projection of Resources for the Future will be used. This projection indicates a growth in annual consumption to 24.5 trillion cubic feet in 1980 and 34.9 trillion in 2000. Cumulative production from 1966 to 2000 would be about 895 trillion cubic feet.

The projections shown in figure 2 raise questions as to the adequacy of future supplies to meet the growing needs for gas over the next several decades. Available evidence indicates that it will be necessary to supplement natural gas with gas from other sources within the next 15 to 20 years, and perhaps much sooner.

Ultimate Supply of Gas

A number of studies have been made in an attempt to estimate the quantity of gas that ultimately will be discovered in the United States. The estimates range

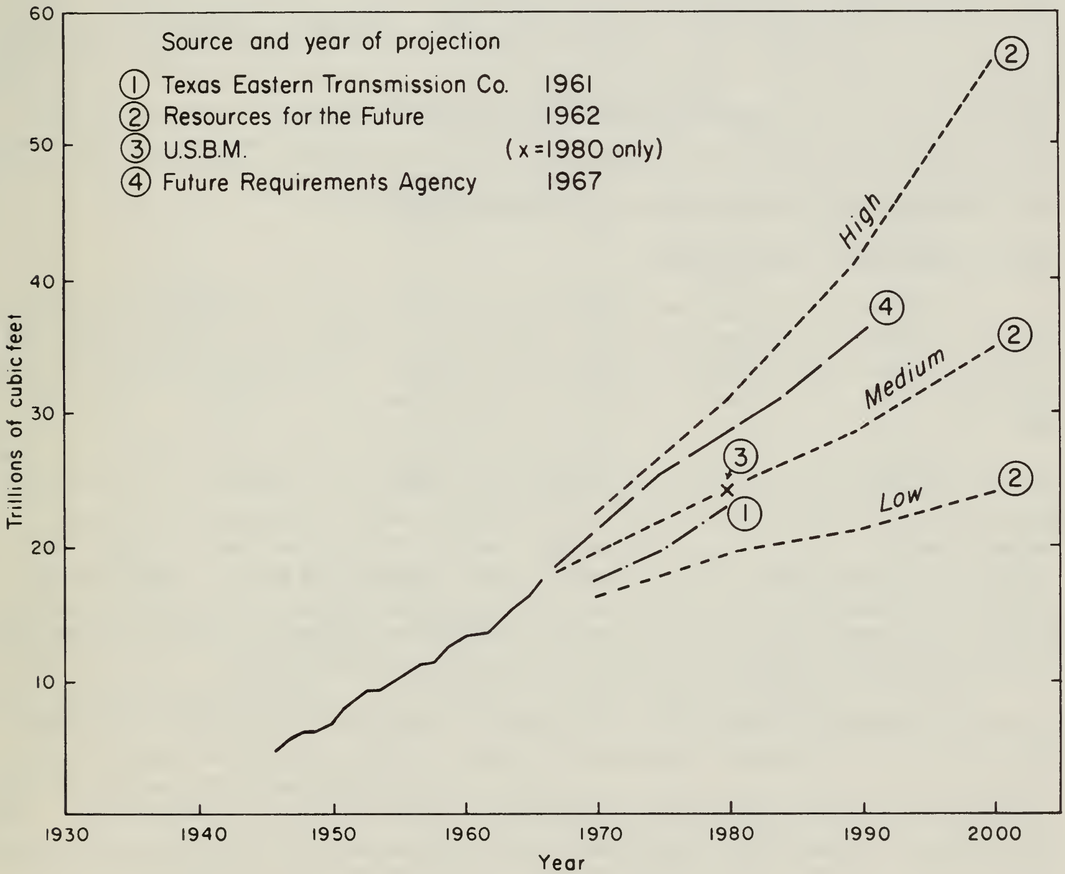

Figure 2 - Past and projected consumption of gas in the United States, 1945-2000.

from 600 trillion cubic feet to 2650 trillion cubic feet (Hubbert, 1962, p. 77). One of the more recent studies is that of the Potential Gas Committee sponsored by the Colorado School of Mines Foundation. This committee estimated the potential supply of gas remaining to be found after December 31, 1966 (Potential Gas Committee, 1967, p. 9).

Classification	Trillion cubic feet
Probable	300
Possible	210
Speculative	180
Total	690

The 690 trillion cubic feet is the estimated undiscovered potential supply. Together with past production of 314 trillion cubic feet and known reserves amounting to 286 trillion cubic feet, total ultimate supply of gas as of December 31, 1966, was estimated at 1290 trillion cubic feet. Of this, 976 trillion remains to be produced.

The medium Resources for the Future projection of gas demand from 1966 to 2000 (fig. 2) would require 895 trillion cubic feet. The gas consumption occurs at an ever increasing rate, with the greatest demand occurring at the end of the period. By 2003, the cumulative demand would have exceeded the total supply. Long before the gas reserves are completely exhausted, however, the rate of production from these reserves will decline, and a need for supplemental gas will arise. How soon this need will arise depends largely upon how rapidly the gas can be discovered and, once discovered, the rate at which it can be produced.

Rate of Discovery, and Reserves

The average rate of new discoveries of natural gas from 1954 through 1965 was 19.4 trillion cubic feet per year. This rate, if continued, would be adequate to discover the total estimated potential gas by 2001. However, it would not provide the reserves that are essential to sustain the annual production in the meantime.

The consumption in 1967 was estimated at 18.4 trillion cubic feet. If past trends in discoveries and production continue, before 1970 we will be consuming more gas than we are discovering, and thereafter will be whittling away at our known reserves. Assuming a further continuation of the same pattern until 1980, reserves will have been reduced from the 1966 level of 289 trillion cubic feet to about 265 trillion, equal to an 11-year supply at that time. Such a supply cannot support the construction of new pipeline facilities to fill growing requirements, nor can the declining reserves long support so high a level of output.

Until the past few years, a ratio of reserves to annual production (R/P ratio) of 20 was considered essential to assure the consumer an adequate future supply and to assure the investor in pipeline facilities a return on his investment. Firms considering the construction of a new pipeline could not obtain approval of the construction unless they could demonstrate that a 20-year supply was available. These restrictions have since been removed. The R/P ratio for the United States fell below 20 in 1961. By 1967, the ratio had fallen to 16 and was still dropping.

Other Problems of Gas Availability

Besides the questions of the over-all adequacy of gas supplies, other problems that exist are related to the location of gas reserves and allocation of the gas produced.

Although the United States' average R/P ratio is 16, the gas reserve available to some regions and some consumers is considerably less. In 1965, 23 interstate pipeline companies held dedicated field reserves of gas totaling 162.6 trillion cubic feet, equal to 56.9 percent of the nation's total reserves (Federal Power Commission, 1967, table 4). This gas, in turn, was dedicated to other transmission lines, distribution systems, and direct consumers. The 162.8 trillion cubic feet provided a reserves to production (or purchase) ratio of 18.8 for these companies in 1965; the over-all national reserve/production ratio was 17.8. On the basis of these ratios, the average R/P for consumers not related to the 23 pipeline companies mentioned above can be estimated at 16.7. At the end of 1967, the R/P ratio for the nation was about 16. No data are available regarding the 23 companies, but if they have been able to maintain their ratio at 18.8, as prudence would dictate, the average ratio for all other consumers can be estimated at about 12.1 by the end of 1967.

Despite gains in actual reserves by some of the states, the R/P ratios of the six major gas-producing states shown in table 2 were falling.

TABLE 2 — NATURAL GAS RESERVES AND RESERVE/PRODUCTION RATIOS FOR SELECTED STATES

State	Reserves, December 31 (trillion cubic feet)		Reserve/Production ratio	
	1956	1966	1956	1966
Texas	113.1	123.6	21.2	18.7
Louisiana	51.4	83.7	26.7	18.2
Oklahoma	14.3	20.1	15.6	15.4
Kansas	19.3	15.9	33.4	19.6
New Mexico	22.3	14.8	34.7	15.8
California	9.0	8.5	18.4	13.6
Subtotal	229.4	266.6	23.2	17.8
All other states	8.3	19.9	10.9	15.9
Total	237.7	286.5	21.8	17.6

Known natural gas reserves grew from 237.7 trillion cubic feet in 1956 to 286.5 trillion cubic feet by 1966, or a gain of 48.8 trillion cubic feet (table 2). During this 10-year period, significant changes occurred in the reserves of a number of states. The reserves (in trillion cubic feet) of Louisiana grew by 32.3, those of Texas by 10.5 trillion, and those of Oklahoma by 5.8, thereby accounting for 48.6 of the 48.8 trillion cubic foot gain of the entire United States (table 2). Among the 10 states with declining reserves during the 10-year period were New Mexico (7.5), Kansas (3.4), and California (0.5).

The gains in reserves from Louisiana and Texas were mainly from the recent large additions in offshore reserves under the Gulf of Mexico. The total gain in United States reserves from 1956 to 1966 would be sufficient to sustain production at the 1966 level for a period of less than 3 years.

EXTENT OF POSSIBLE NEED FOR SUPPLEMENTARY FUELS

The exact time at which gasoline and pipeline gas will be produced on a commercial scale from coal remains uncertain at present. It appears likely, however, that at least some gas and gasoline will be produced from coal commercially during the 1970's. After 1980, such production will increase as demands for both liquid and gaseous fuels tend to exceed availability from domestic sources.

Gasoline

The projected annual demand for gasoline for motor fuel to the year 2000 shown in figure 3 is the medium projection in figure 1. Annual demand is shown to increase from 1.38 billion barrels in 1960 to 5.77 barrels in 2000. The projected 1980 level is shown at 2.82 billion barrels. The bars in the figure show the projected growth before and after 1980. As shown, the annual rate of demand in 1970 is expected to be 0.88 billion barrels less than in 1980. In 1990, it is expected to be 1.20 billion barrels higher, and in 2000, 2.95 billion barrels higher than the

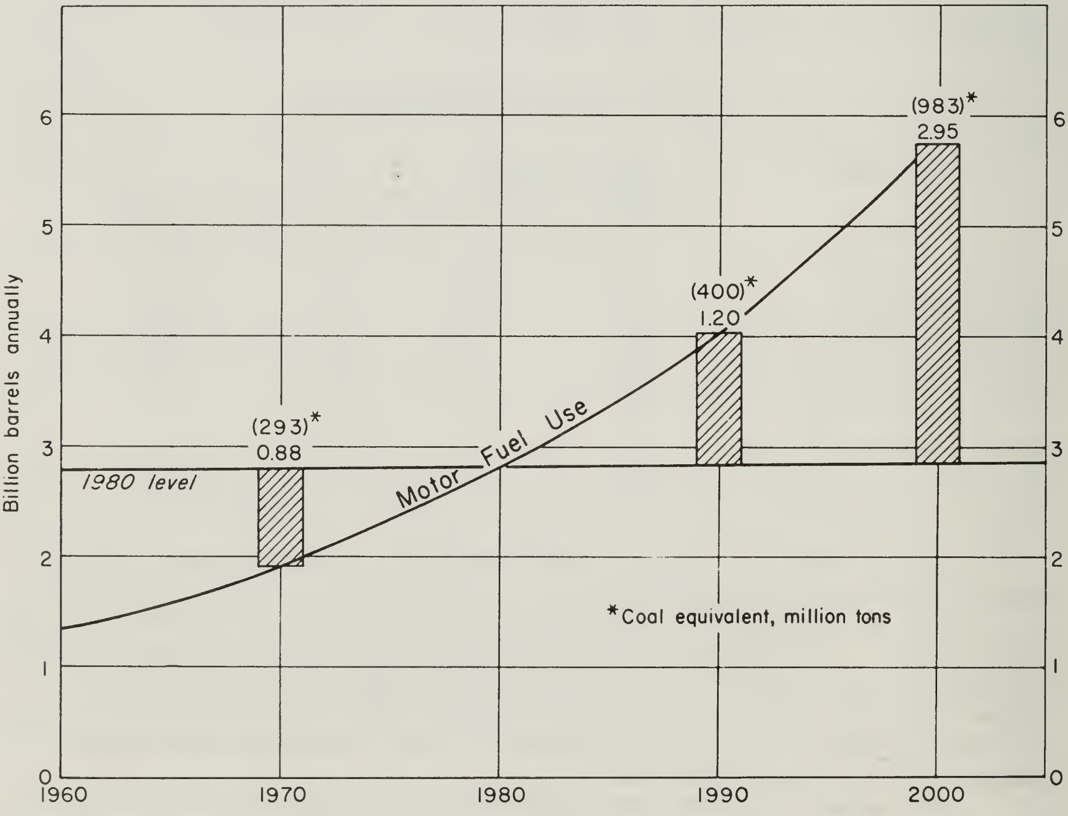

Figure 3 - Projected annual use of motor vehicle fuel to the year 2000. Growth in terms of coal equivalent is based on conversion rate of 3 barrels of gasoline per ton of coal.

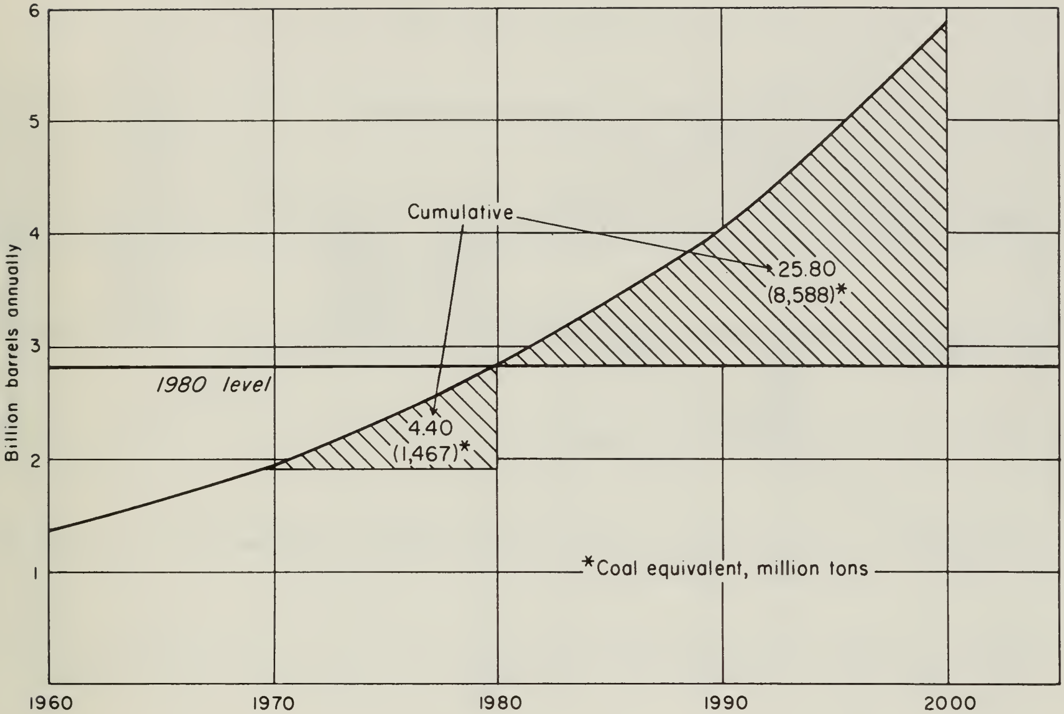

Figure 4 - Projected annual and cumulative use of motor vehicle fuel to the year 2000 with 10- and 20-year cumulative totals before and after 1980. Cumulative values in terms of coal equivalent are based on 3 barrels of gasoline per ton of coal.

1980 level. In parenthesis is shown the amount of coal that would be required to provide the barrels of liquid fuel indicated by the bar. Thus, if the assumption were made that petroleum resources were available to produce motor fuel at the 1980 level of need only, and if coal was used to provide the supplement, an annual input of 400 million tons of coal in 1990, and 983 million tons in 2000, would be required.

Figure 4 shows the annual and cumulative projected use of motor fuel and its relation to the anticipated 1980 level of use. Again, if it were assumed that petroleum resources were sufficient to supply only the 1980 level of need, the cumulative need for supplementary sources of motor fuel during 1980 to 2000 would amount to 25.80 billion barrels. This is equivalent to the output from 8588 million tons of coal. Figure 4 also shows the cumulative growth from 1970 to 1980.

Pipeline Gas

Figure 5 shows the projection of natural gas requirements given in the medium projection of figure 2. Annual demand is shown at 24.5 in 1980, which is assumed, on the basis of reserve estimates and rate of discoveries, to be the maximum rate at which natural gas will be delivered. By 1990, the annual requirement

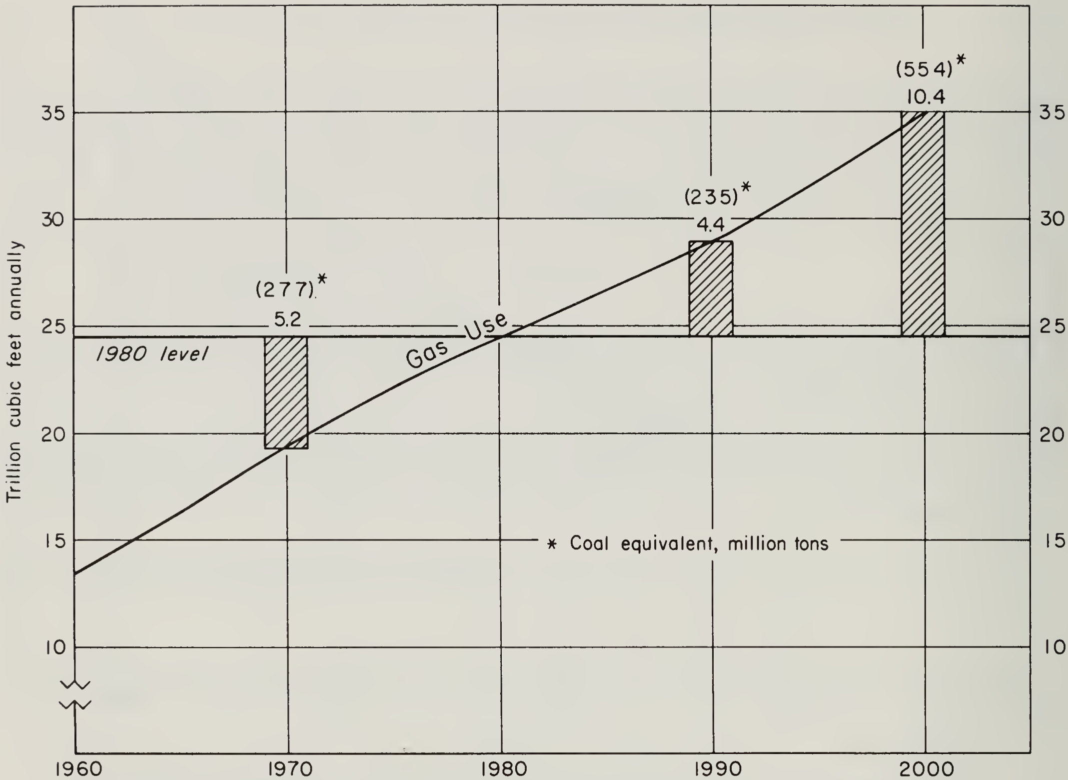

Figure 5 - Projected annual use of pipeline gas to the year 2000. Growth in terms of coal equivalent is based on conversion rate of 53.3 million tons of coal per trillion cubic feet of gas.

will exceed the 1980 level by 4.4 trillion cubic feet, and in 2000, by 10.4 trillion cubic feet. The 1970 level of consumption is shown to be 5.2 trillion cubic feet below the 1980 level. The coal equivalents shown on the chart are based on the use of 53.3 million tons of coal to produce 1 trillion cubic feet of pipeline gas.

Figure 6 also shows the 1980 level of consumption at 24.5 trillion cubic feet. If production of natural gas remains at this level and the requirement continues to grow, as projected, the cumulative need for supplemental gas will reach 96 trillion cubic feet during 1980 to 2000. If, as is predicted by some authorities, producibility of natural gas reaches a peak of 24.5 trillion cubic feet by 1980 and declines thereafter, the deficit to be made up from supplementary sources may be as much as 40 percent higher.

MAJOR IMPLICATIONS FOR THE COAL INDUSTRY

The quantities shown in figures 3 through 6 are not to be considered as the amounts of coal that unquestionably will be consumed in liquefaction and gasification. Rather, they are a measure of the growth in need for these fuels, anticipated

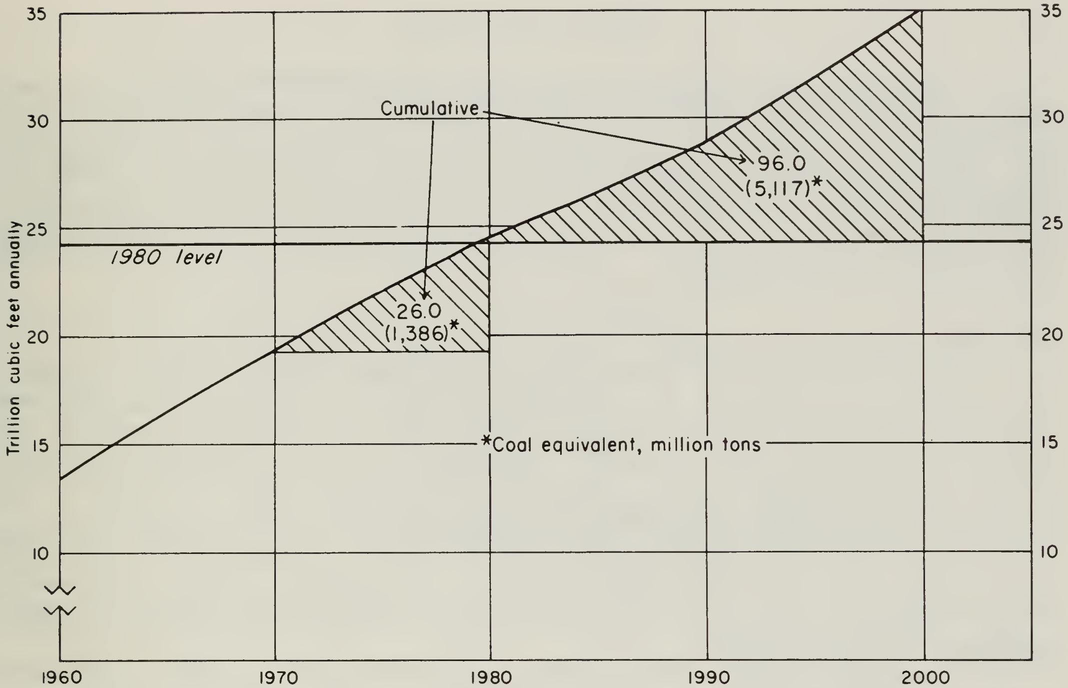

Figure 6 - Projected annual and cumulative use of pipeline gas to the year 2000 with 10- and 20-year cumulative totals before and after 1980. Cumulative values in terms of coal equivalent are based on 53.3 million tons of coal per trillion cubic feet of gas.

at a time when natural sources are declining and coal conversion processes are becoming competitive. They constitute a huge market target for which coal will actively compete against synthetic gas and liquid fuels made from other sources and, to some degree, natural products from foreign sources.

As a target, the annual incremental growth in gas and gasoline use from 1980 to 1990 will be equivalent to more than 63 million tons each year. At the end of the 10 years, the cumulative growth will have amounted to almost 3.2 billion tons. The following 10 years will add a further cumulation of 18.5 billion tons. Coal will be able to shoot at a 20-year cumulative growth target (1980 to 2000) of 13.9 billion tons, equal to the cumulative United States consumption of coal for all uses during 1940 through 1965. This target also represents 4.8 times the cumulative use of coal by electric utilities, coal's fastest growing use in the past, during the 20 years ending in 1965.

Besides the growth beyond 1980, there is a lesser growth target predicted between 1970 and 1980. Cumulatively, this will amount to the equivalent of 2.8 billion tons. Coal will share in part of this growth, depending on local situations with regard to growing demand and the availability of coal, oil, and natural gas.

Among the major implications for the coal industry resulting from the potential market for coal for gasification and liquefaction are those regarding future investment, manpower, and reserves. Figures 7 through 9 indicate the magnitude of these implications.

Mining Requirements

In figures 7 and 8 the quantities of coal required for the production of specified quantities of motor vehicle fuel and pipeline gas are shown. Also shown are the estimated number of mines, capital investment in mines, and the number of mining employees required. Number of mines is based on an assumption of mines of 3 million tons per year, each, at a cost of 10 dollars per ton of annual capacity. The number of workers is based on highly mechanized modern mines with an output of 10,000 tons per man per year.

Gasoline

Motor fuel demand in 1990 is projected to exceed that of 1980 by 1.20 billion barrels and in 2000 by 2.95 billion barrels (fig. 3). If gasoline from coal were to supply only half of this projected demand in 1990 (i.e. 600 million barrels), 200 million tons of coal would be needed. This quantity of coal would require an investment of 2 billion dollars and the employment of 20,000 men (fig. 7). About 67 mines, producing 3 million tons each, would be required.

If gasoline from coal supplied half of the projected increased demand in 2000, 1.475 billion barrels produced from 491 million tons would be needed. This would require the output of 161 mines, constructed at an investment of 4.91 billion dollars, employing 49,000 workers.

The mining requirements for a larger or smaller portion of total growth can be selected from figure 7.

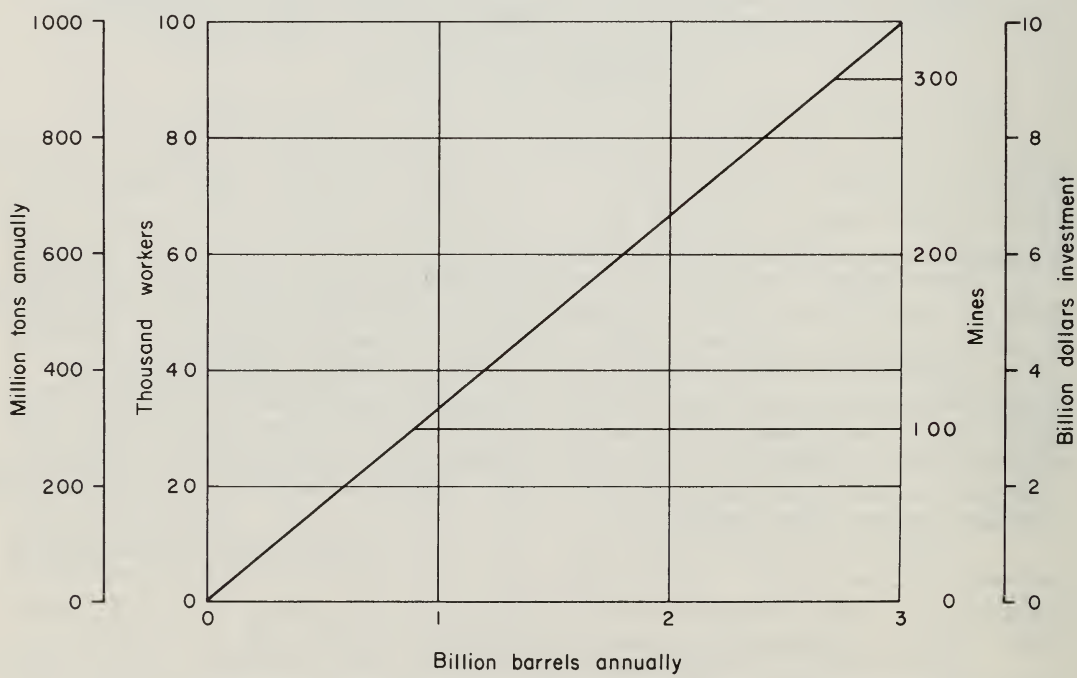

Figure 7 - Mining requirements for production of specified quantities of motor vehicle fuel from coal. Tonnage is based on conversion rate of 3 barrels of gasoline per ton of coal.

Pipeline Gas

The projected growth in pipeline gas consumption after 1980 would require 4.4 trillion additional cubic feet in 1990 and 10.4 trillion in 2000 (fig. 5). It appears that coal is the most likely source of synthetic pipeline gas, although imports of natural gas or liquefied natural gas may supply some of the growing need. However, if only half of the expanded use (i.e. 2.2 trillion and 5.2 trillion, respectively) were supplied by gas from coal, 116 million tons would be required in 1990 and 277 million tons in 2000, as shown in figure 8.

The 116 million tons in 1980 would require 11,600 workers, an investment of 1.16 billion dollars, and the output from 39 mines.

In the year 2000, the output of 92 mines, costing 2.77 billion dollars and employing 27,700 workers, would be required.

Coal Reserves

An acre of coal 1 foot thick weighs approximately 1800 tons. Thus, a 6-foot seam of coal contains 10,800 tons per acre. The percentage of the coal that

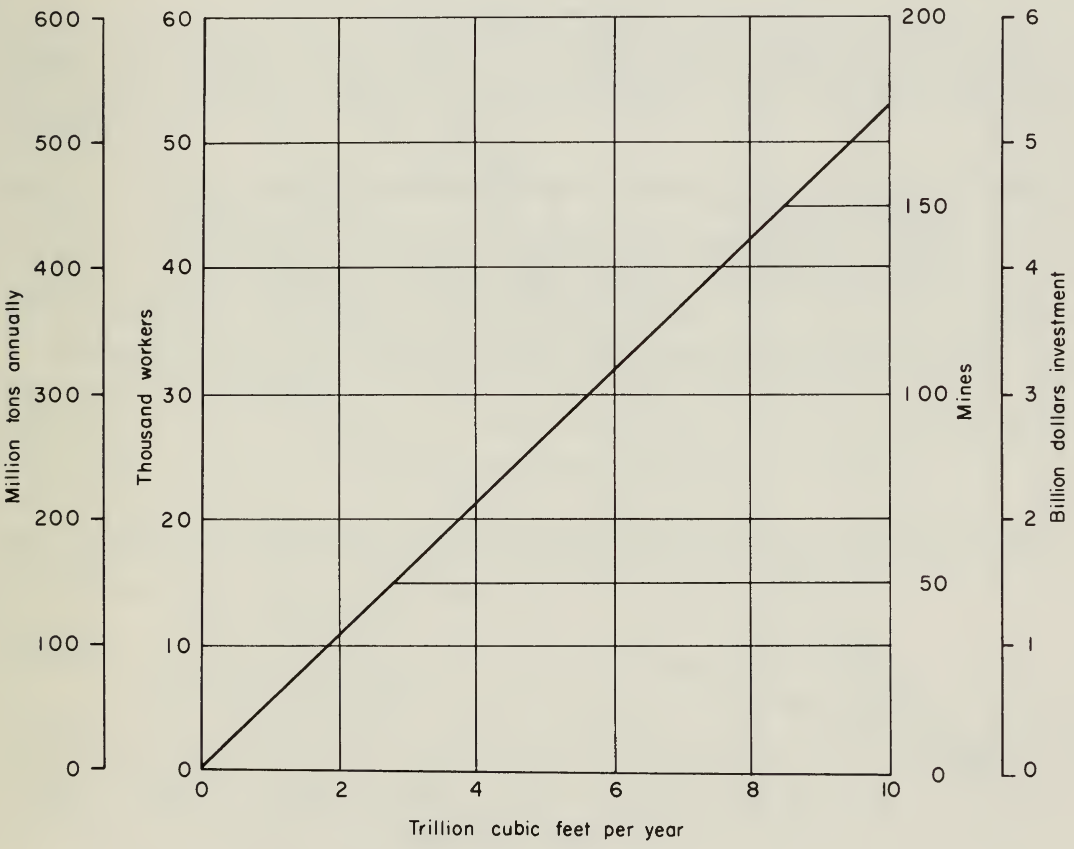

Figure 8 - Mining requirements for production of specified quantities of pipeline gas from coal. Tonnage is based on conversion rate of 53.3 million tons of coal per trillion cubic feet of gas.

can actually be recovered through mining depends on numerous factors including the thickness of the coal seam, the mining method, the strength of material overlying and underlying the coal, and the protection that must be afforded the land surface above the mine. An over-all factor commonly used is 50 percent recovery. Figure 9, on the basis of 50 percent recovery, shows the acres that would be required to produce quantities of coal from coal seams of different thicknesses.

At 50 percent recovery, a 3 million ton per year mine, operating for a period of 20 years, would produce 60 million tons from an in-the-ground deposit of 120 million tons. In a 6-foot seam this would require more than 21,000 acres (fig. 9), and in 4-foot coal would require more than 16,600 acres.

The production of 60,000 barrels of gasoline per day from a coal-to-gasoline plant would require an input of 20,000 tons of coal per day, or 7.3 million tons per year. A 20-year supply would be 146 million tons. To provide reserves for such a plant would require mining 1350 acres of 6-foot coal per year, or a reserve of 27,000 acres for the 20-year life. In 4-foot coal, a reserve of 40,500 acres would be needed.

If 50 percent of the post-1980 growth in motor fuel is provided by coal, the requirement in 2000 would be almost 85,000 acres of 6-foot coal. Cumulative acre-

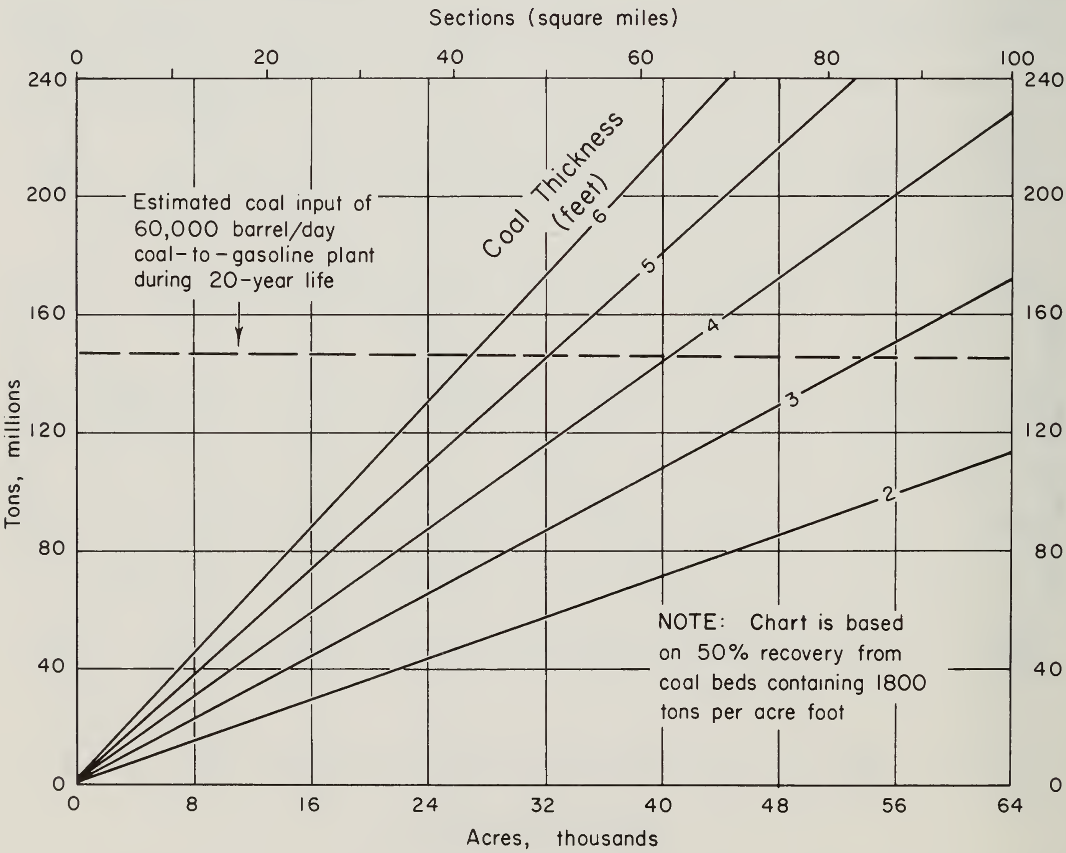

Figure 9 - Coal reserve acreage requirements for production of specified quantities of coal from varying thicknesses of coal.

ages required from 1980 to 2000 would be almost 800,000 acres. Thinner coal would require proportionally larger acreages.

A plant producing 250 million standard feet per day of pipeline gas would require an input of 4.86 million tons of coal per year. A 20-year supply would be more than 97 million tons (fig. 9). In 6-foot coal, a reserve acreage of about 18,000 acres would be required. To provide 50 percent of the indicated supplementary requirement for gas in 2000 would require 51.3 thousand acres of 6-foot coal. Cumulative acreages for the 20-year period would be almost 480 thousand acres.

If it should be necessary to supply all the growth in gasoline and pipeline gas from coal, the combined cumulative tonnages required during the 20-year period would reach 13.7 billion tons and require an acreage equivalent to 2.5 million acres of 6-foot coal. The 13.7 billion tons of coal would be readily supplied from the 850 billion tons of total recoverable reserves estimated for the United States. If concentrated in some states, however, it would have considerable impact on the reserve situation.

THE INFLUENCE OF GEOGRAPHIC FACTORS

When the need for supplemental sources of liquid fuel and pipeline gas arises, the location at which production of these fuels will take place will depend on a number of factors. Among the factors favorable to coal conversion plants are the following:

1. A large demand for gas or gasoline within a short distance of the plant site;
2. Natural gas and petroleum available only from distant sources;
3. Large reserves of coal available nearby, occurring under conditions that permit easy low-cost mining.

A further important factor might be the availability of unused pipeline capacity to carry the products.

Demand Areas for Gasoline and Gas Related to Supply

Most gas and crude oil produced in the United States comes from the western south-central region. Figure 10 indicates the states whose production of crude oil was less than the amount refined.

Gasoline

In figure 10, each full circle represents a net interstate import of 50 million barrels of crude oil per year for refining. In effect, this is a demand not being supplied from in-state sources. Although some of the importing states produce and even export quantities of crude oil, the imports are in excess of exports by the amounts indicated. The estimated equivalent output of gasoline shown is based on the average quantity of gasoline produced through refining a barrel of crude oil in 1965.

Based on a conversion of 1 ton of coal to 3 barrels of gasoline, the amount represented by each full circle would require a daily plant input of 20,000 tons per day of coal. From figure 10, then, it may be estimated that Illinois imported enough crude (net) in 1965 to match the gasoline output from three 60,000 barrel per day coal-based plants. Such plants would have had a combined input of almost 22 million tons of coal per year.

The principal oil deficit states are in heavily industrialized and populous areas: Illinois, Indiana, Ohio, Pennsylvania, and New Jersey. Net interstate crude oil imports of these 5 states during 1965 combined amounted to about 590 million barrels from which approximately 260 million barrels of gasoline was produced. Twelve coal-based plants, each with a 60,000 barrel per day output of gasoline, would be required to match the amount produced from this crude oil.

Most other parts of the United States either are self-sufficient in oil production or import less than enough to match the output of one coal-based plant.

A growth of 260 percent in motor vehicle fuel is projected from 1965 to 2000. If interstate imports into the five states previously mentioned should increase by this percentage, they would reach 1 billion barrels by 2000. Gasoline output from this interstate oil would be equivalent to that of 43 coal-based plants of 60,000 barrels of gasoline per day, each. If, instead of growing, the production of oil from within the states should remain at the 1965 level and imports or supplements provide all of the growth in gasoline, an increase equivalent to the output of 47 such plants would be needed.

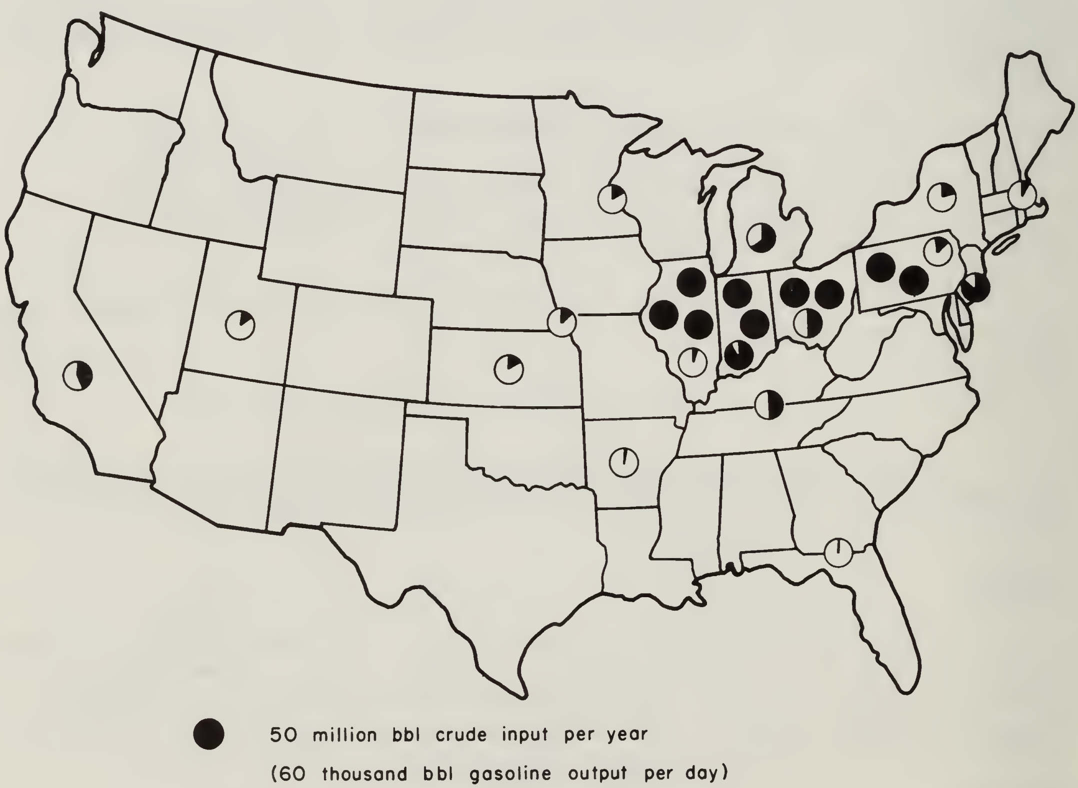

Figure 10 - Net interstate receipts of crude oil at refineries, 1965.

Gas

Figure 11 shows the consumption of interstate imports of natural gas. The concentration of demand over production in the eastern part of the nation is especially notable.

Each full circle represents 100 billion cubic feet per year. This is equal to the output of a coal-based plant of slightly more than 250 million standard cubic feet per day. Assuming plants of a 100 billion cubic foot capacity, the gas imports into Illinois, Indiana, Ohio, Pennsylvania, and New Jersey equal the output of 28 such plants. Michigan and New York are equal to 10 more plants. If the projected increase of 115 percent occurs within these 7 states by 2000, an amount equivalent to the output of 82 such plants will be required.

Resource Locations

The location of plants for gasification and liquefaction will be influenced both by the demand for these fuels and by the proximity to their natural sources. Equally important will be the availability of coal or other hydrocarbon materials from which to produce them.

Oil, natural gas, oil shale, and tar sands are relatively concentrated in the locations in which they occur. About two-thirds of the known reserves of oil

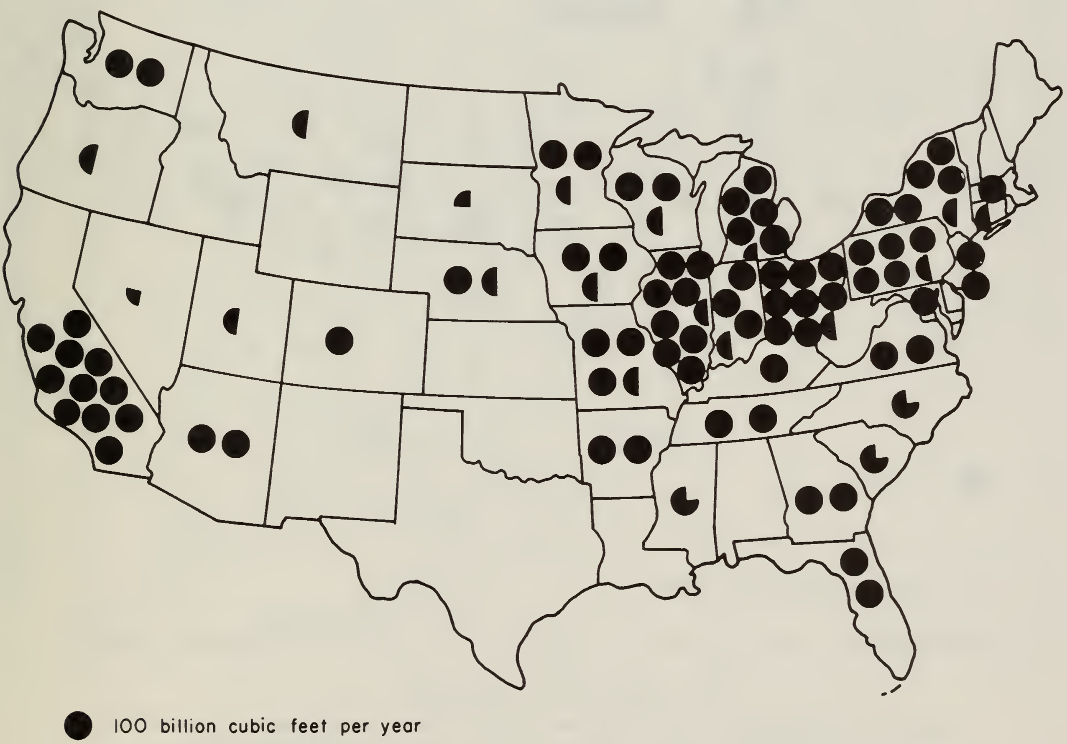

Figure 11 - Excess of consumption over production of natural gas, 1965.

and natural gas lie in the West South Central region. The major reserve of oil shales is in Colorado and Utah, and that of tar sands is in western Canada. All of these regions are remote from most of the major centers of population.

As contrasted to other fuels, coal is more widespread. Figure 12 shows the known reserves, based on 50 percent recovery of the coal in the ground. In North Dakota and Montana, which possess the largest reserves, much of the tonnage consists of lignite and sub-bituminous coal. East of the Mississippi River, Illinois possesses the largest reserves.

Not only must large quantities of coal be available, but they must be producible at relatively low costs. One of the important factors in cost of production is the labor cost per unit of output, which in turn is inversely proportional to the daily production per man.

Among the things greatly influencing the productivity of workers are type of mining and thickness of coal seam mined.

Strip mining, in general, shows a higher productivity than underground mining. For example, in 1965, the over-all average output was 17.52 tons per

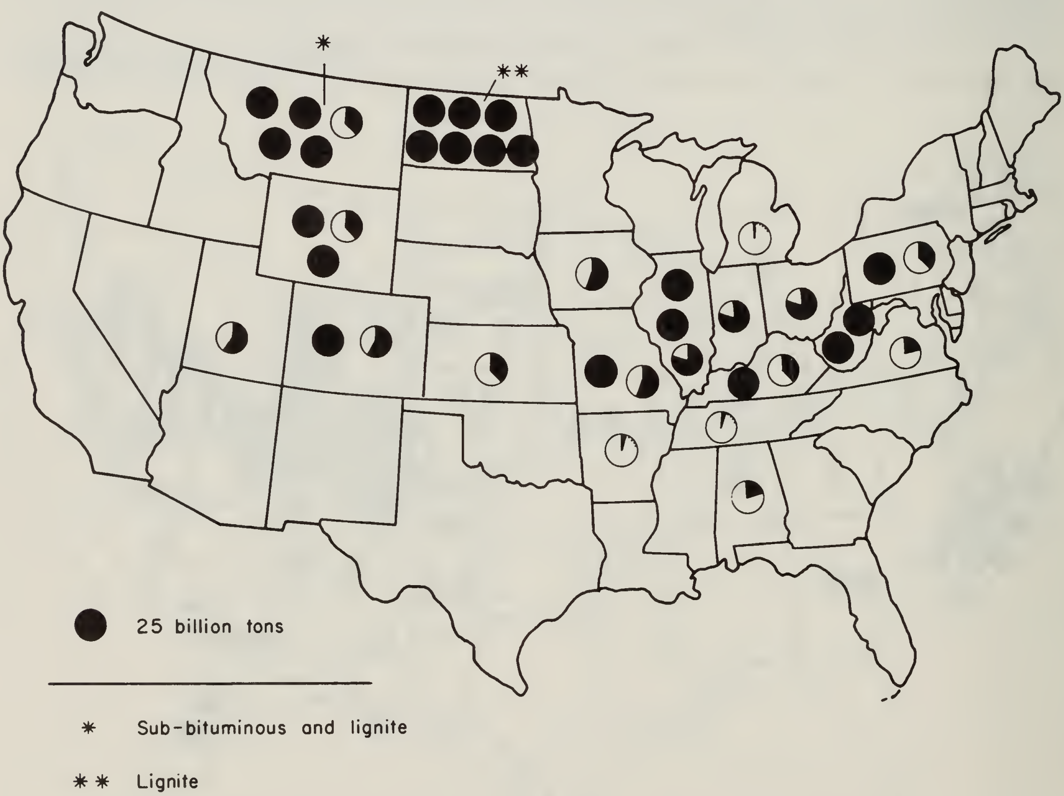

Figure 12 - Location of major coal reserves in the United States. Quantities shown are based on 50 percent recovery and are equal to half of the actual coal in the ground.

man per shift worked; for strip mines it was 31.98, and for underground mines it was 14.00.

The influence of coal thickness on productivity is indicated by the fact that during 1965 the productivity of underground mines in Illinois, where the average seam thickness was 7.7 feet, was 20.98 tons per man day compared to Ohio with an average of 4.9-foot seams and 13.61 tons per man day, and West Virginia with an average of 5.2-foot seams and 15.04 tons.

Figure 13 shows the production by states of coal from both surface and underground mines in various seam thickness. Whereas 51 percent of the West Virginia and 65 percent of the Illinois production came from coal seams more than 5 feet thick, only 13 percent of the Ohio, 32 percent of the Indiana, and 41 percent of the Pennsylvania coal came from such thicknesses.

Nearly all of the North Dakota and Wyoming and 89 percent of the Utah production came from seams more than 5 feet thick, and most of the seams were in excess of 8 feet thick. Because of the remoteness from centers of demand, however,

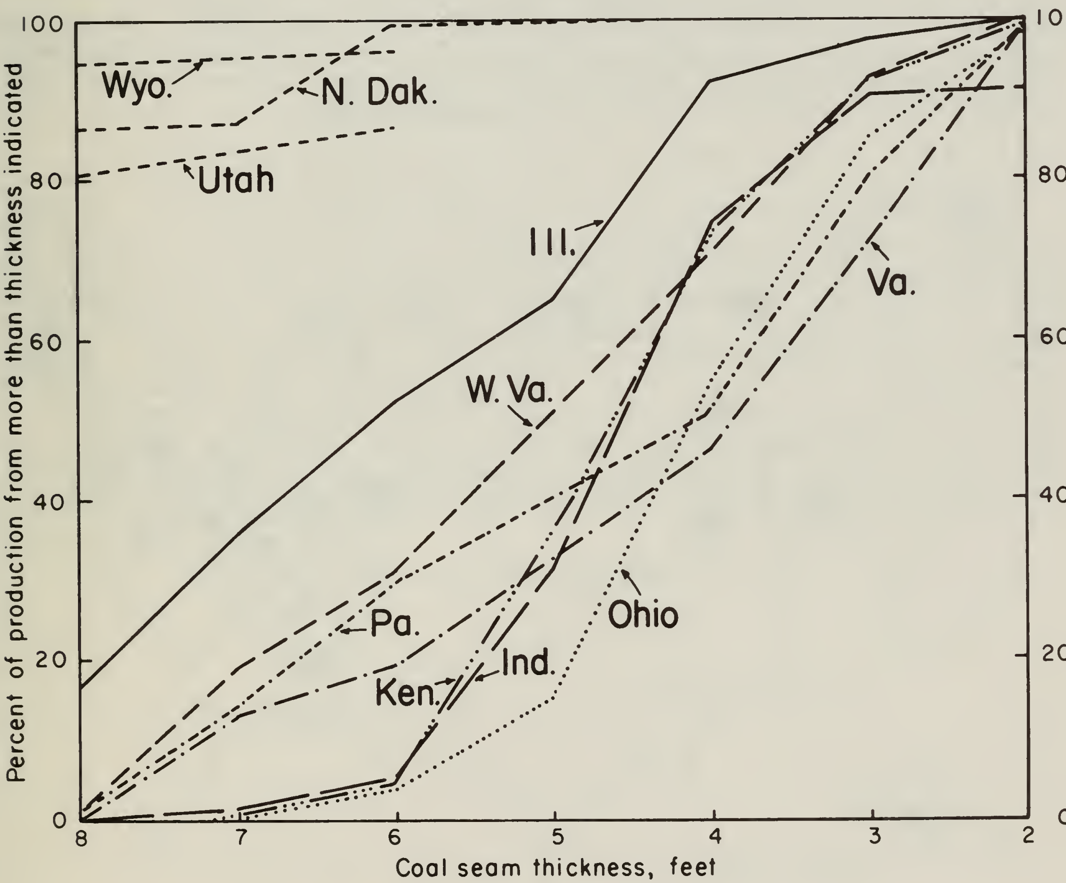

Figure 13 - Thickness of coal seams mined in selected coal-producing states in 1965.

the combined production of these three states in 1965 was only 11 million tons or 2.1 percent of the U. S. total.

Figure 14 shows the average value of coal f.o.b. the mine in various states, as reported by the U. S. Bureau of Mines. The average indicated by the arrow and the amount stated is the state average. The shadowed portion of the circle indicates the range of values reported as county averages.

As would be anticipated, the average values in the thick seams of North Dakota and Montana are the lowest in the nation. East of the Mississippi River, the values shown are somewhat higher, ranging up to more than three times the North Dakota values, as in the case of Alabama. In some states it will be noted that the state average is considerably higher than that of the lowest county of the state. In general, utilities and other large volume consumers will be purchasing coal at, or perhaps even below, the lower range shown.

The cost at which coal is available and the reserve situation would appear to favor gas and liquid fuel production from the western coals. On the other hand, the location of the demand with respect to availability of gas and oil favors the coal regions east of the Mississippi River. Figures 10 and 11 show that the gas and oil deficits of Montana, Wyoming, North Dakota, South Dakota, and Utah combined are not equal to the output of a single 250 million cubic foot per day gasification plant or 60 thousand barrel per day gasoline plant. Output of all such plants in this region would have to be shipped to outside markets.

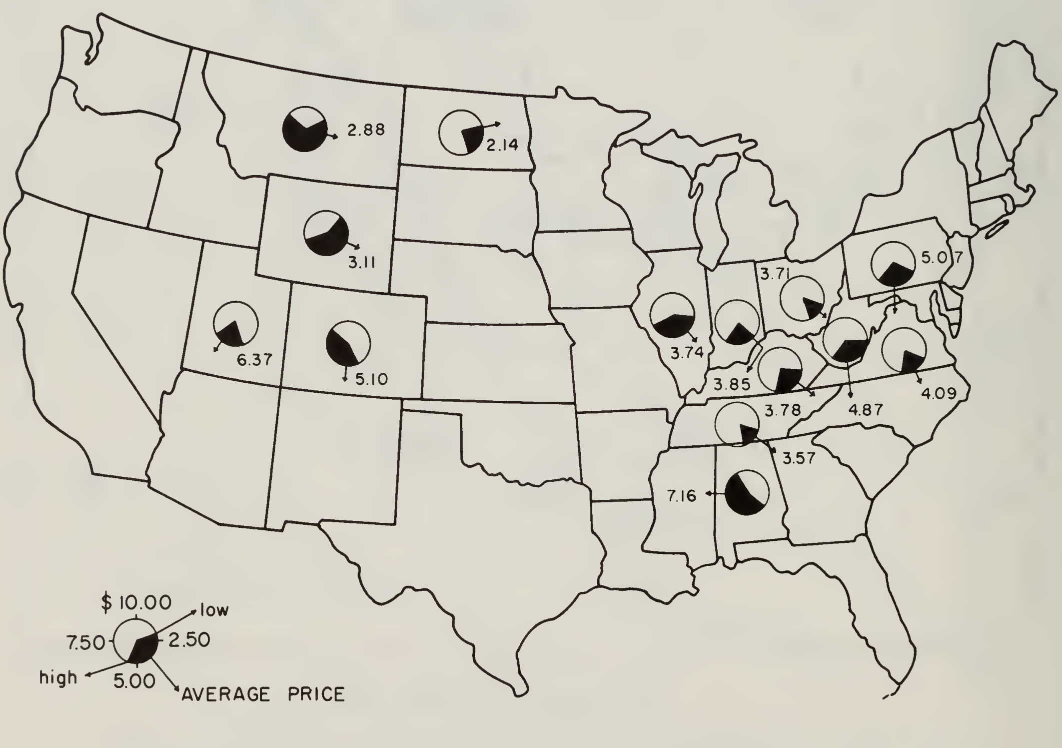

Figure 14 - Reported value of coal produced in 1965 in dollars per ton f.o.b. the mine. (Source: U. S. Bureau of Mines, 1967a, Table 54, p. 118-127).

East of the Mississippi River, the coal reserves are somewhat thinner but they lie in or adjacent to areas of large oil and gas demand and deficits.

The actual location of future gasification and liquefaction plants will be the result of a balance between the numerous factors of geographic location of resources and population and the resulting economic advantage.

SUMMARY

All evidence indicates that by the middle to late 1970's the domestic reserves of oil and natural gas will be inadequate to meet the total U. S. demand at competitive prices. A part of the oil demand is already being supplied from foreign sources at lower prices than domestically produced oil. Virtually all of the natural gas consumed in the United States comes from domestic sources (imports in 1966 accounted for 2.5 percent). Although it is believed that much gas remains to be found, the rate of discovery is lagging behind the growth in demand.

To supplement the supplies of natural gas and crude oil, it is anticipated that gas and liquid fuels will be obtained from oil shale, tar sands, and coal. Each of these possesses its own advantages and disadvantages. Among coal's greatest advantages is its widespread distribution near centers of energy demand; the oil shale and the tar sands are more remote.

Researchers estimate that coal conversion processes can provide gas and gasoline at costs approximately equal to those of natural gas and gasoline from crude oil. The cost of coal is a major portion of the total cost of producing gas and gasoline. The thick low-cost western coals tend to be in an especially favorable position from this standpoint; however, this apparent advantage is diminished in large degree by their remoteness from the major energy markets. It appears likely that the major share of the gasification and liquefaction will take place in the coal-producing regions east of the Mississippi River, where the relatively thick seams of Illinois coal possess an advantage.

The reserves of the nation are adequate to provide all of the coal that may be required for liquefaction and gasification for several centuries. However, tremendous investments and large numbers of men will be involved in the mining of the coal, and large acreages of reserves will be required to make this coal available.

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