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FUELS AND ENERGY SITUATION
IN THE MIDWEST
INDUSTRIAL MARKET

Robert L. Major

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INTRODUCTION

Although much has been written about the current energy crisis, most reports have focused on the national and international situations. The purpose here is to examine the fuels and energy situation in the Midwest Region, with special emphasis on the industrial sector. The "Midwest Region" is defined as the nine-state area that includes Illinois and surrounding states, as shown in figure 1. Coke usage by the iron and steel industry is not covered in this paper, and developments in the electric utility industry are discussed only in so far as they affect the fuels and energy situation in the Midwest industrial market.

TRENDS IN ENERGY CONSUMPTION

The United States

The industrial sector of the economy has traditionally been the largest single consumer of direct energy in the United States, using 28.8 percent of the total energy in 1972. In terms of the current energy crisis, the period since 1967 is the most important, because it was during this time that two previously unrelated trends converged to compound the problems of increasing shortages of fuels. First, the domestic reserves of oil and natural gas

* Adapted from a paper presented at the Industrial Fuel Conference, Purdue University, West Lafayette, Indiana, October 4, 1973.

began to be depleted at a rate faster than new discoveries were being made. Second, the imposition of new environmental protection laws placed restrictions on the amount of sulfur oxides that might be emitted from stationary sources. As most of the currently available coals and many of the oils contain significant amounts of sulfur, and as there has been no way available to remove the resultant sulfur oxides from the flue gases, there was a rush to convert to "clean" fuels such as natural gas and low-sulfur fuel oil. The already developing fuels shortages were consequently intensified.

Between 1967 and 1972, the total consumption of energy in the United States increased 23.7 percent, from 58.3 quadrillion Btu to 72.1 quadrillion Btu. During this period, household and commercial consumption rose by 13.0 percent, electric utilities consumption by 45.4 percent, transportation sector consumption by 27.5 percent, and industrial sector consumption by 14.5 percent. As a result, industry's share of total direct energy consumption declined from 31.1 percent in 1967 to 28.8 percent in 1972. On the other hand, direct consumption of energy in the electric utilities sector increased from 21.8 percent in 1967 to 25.6 percent of the total gross energy in 1972 (U.S. Bur. Mines, 1973b, p. 23; U.S. Bur. Mines, 1973c, p. 4).

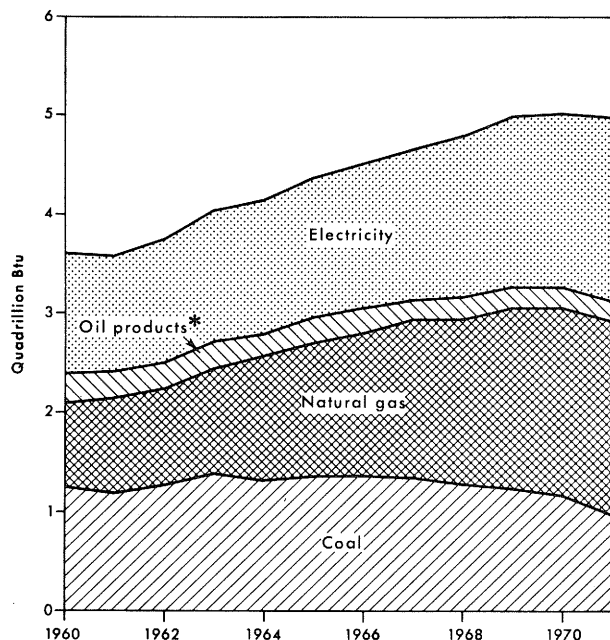
Electricity is, of course, ultimately consumed by other sectors of the economy in the production of goods and services. Between 1967 and 1972, purchases of electricity by the transportation sector increased by 5.9 percent, those by the household and commercial sector by 52.8 percent, and those by the industrial sector by 32.0 percent. Despite this shift by the industrial sector toward greater use of indirect energy in the form of electricity, the overall growth in industrial use of total energy was only 16.1 percent—lower than the 18.9 percent increase in the household and commercial sector and the 27.4 percent increase in the transportation sector (U.S. Bur. Mines, 1973b, p. 23; U.S. Bur. Mines, 1973c, p. 4). Part of this slower increase in the growth of total energy use by industry probably reflects industry's more efficient use of energy and its greater sensitivity to price changes.

The Midwest Region

Trends in energy use (on a heat content basis) in the industrial sector of the Midwest Region are illustrated in figure 2. Although the total use of energy in the Midwest industrial market increased by 38 percent between 1960 and 1971, the use of coal declined by 22 percent and the use of residual oils declined by 52 percent. These declines were offset by increases in the use of natural gas (up 127 percent), distillate fuel oils (up 37 percent), and



Fig. 1 - Boundaries of Midwest Region.



*Residual fuel oil, distillate fuel oil, and LPG.

Fig. 2 - Industrial use of energy in the Midwest Region, 1960-1971, by source. (Source: U.S. Bureau of Mines, Minerals Yearbooks, 1960-1971.)

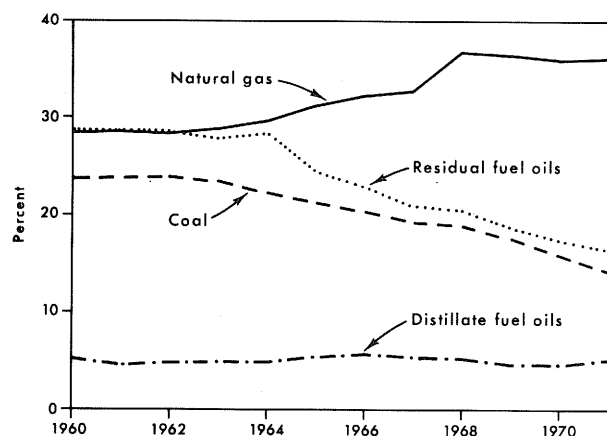


Fig. 3 - Industrial use of various fuels as a percentage of the total consumption of that fuel by all sectors in the United States, 1960-1971. (Compiled from U.S. Bureau of Mines and American Petroleum Institute data.)

liquefied petroleum gases (up 41 percent). Although the share of total energy supplied by all fossil fuels has remained relatively constant at about two-thirds, the relative shares supplied by individual fuels have changed considerably. Coal's share declined from 51 percent in 1960 to only 31 percent in 1971, while the contribution of natural gas increased from 36 percent to 63 percent in the same period. While distillate fuel oil and LPG merely held their own, residual fuel oil's share declined from 9.4 percent to 3.4 percent.

Industrial use of various fossil fuels as a percentage of the total U.S. consumption of that fuel from 1960 through 1971 is indicated in figure 3. Natural gas is the only fuel for which the industrial sector increased its share of the total market, from 28 percent in 1960 to 36 percent in 1971. Industrial use of coal and residual fuel oils declined sharply, while industrial use of distillates remained essentially unchanged.

Figure 4 indicates the percentage of the total industrial use of various fossil fuels consumed by industry in the Midwest Region from 1960 through 1971. Only coal showed an increase, and that increase merely reflects the fact that industrial use of coal has been phased out faster in non-Midwest areas than in the Midwest. Therefore, although the total coal market declined, the larger share of the remaining market lies in the Midwest Region.

Coal

Figure 5 indicates the trends in the industrial use of coal by states of the Midwest Region for 1960-1972. The use of coal by industry is concentrated mainly in Illinois, Indiana, Ohio, Michigan, and Wisconsin, the western end of the so-called "manufacturing belt." Industrial use

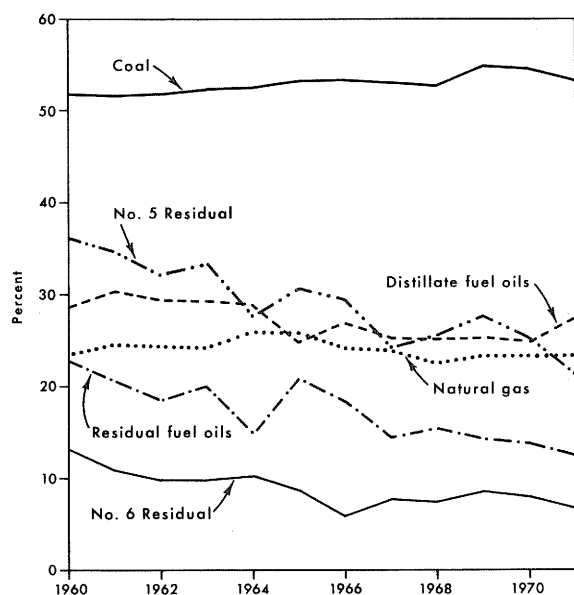


Fig. 4 - Fuel consumption by industry in the Midwest Region as a percentage of the total U.S. consumption of that fuel by all industry, 1960-1971. Curves for Nos. 5 and 6 residual heating oils also reflect large commercial use. (Compiled from U.S. Bureau of Mines and American Petroleum Institute data.)

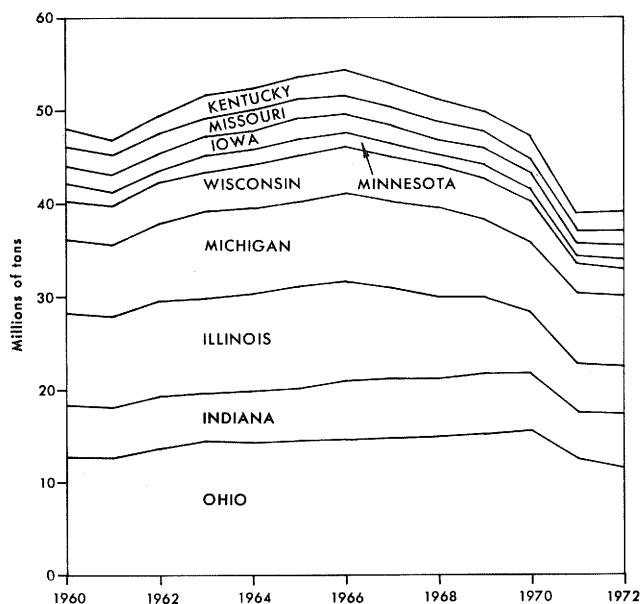


Fig. 5 - Cumulative coal consumption by industry in the Midwest Region, 1960-1972, by state (Source: U. S. Bureau of Mines Bituminous Coal and Lignite Distribution reports.)

of coal in these states showed steady growth from 1961 through 1966, followed by a sharp decline through 1971. For the Midwest Region as a whole, industrial use of coal increased by 13 percent from 1960 through 1966; from 1966 through 1972, consumption declined 28 percent.

These over-all averages conceal widely varying rates of change in the individual states. From 1960 to 1966, all the states of the region except Minnesota and Missouri increased their consumption; since 1966 all states in the region have shown a decline in industrial coal use, ranging from a high of 52 percent in Illinois to a low of 8 percent in Indiana. In terms of tonnage, industrial coal consumption in the Midwest Region has declined from a recent peak of 54.4 million tons in 1966 to 39.2 million tons in 1972.

Ironically, the Midwest Region is blessed with an abundance of coal resources. In recent years the region's mines have accounted for 40 to 45 percent of the total coal production in the United States, and production increased from 166.3 million tons in 1960 to 269.0 million tons in 1972. Most of the growth resulted from the increased demand for coal by the electric utility industry. Although the region is both an exporter and importer of coal, it is essentially self-sufficient in coal. Between 1960 and 1968, it was a net importer, although imports declined from 21.7 million tons in 1960 to 2.0 million tons in 1968. In 1969, the region became a net exporter of coal and has remained so since then. Figure 6 indicates these trends in the coal position in the Midwest Region between 1960 and 1972.

Whereas, traditionally, the region has received most of its coal imports from the Appalachian areas of West Virginia, Virginia, and Tennessee (District 8), in recent years there has been a substantial increase

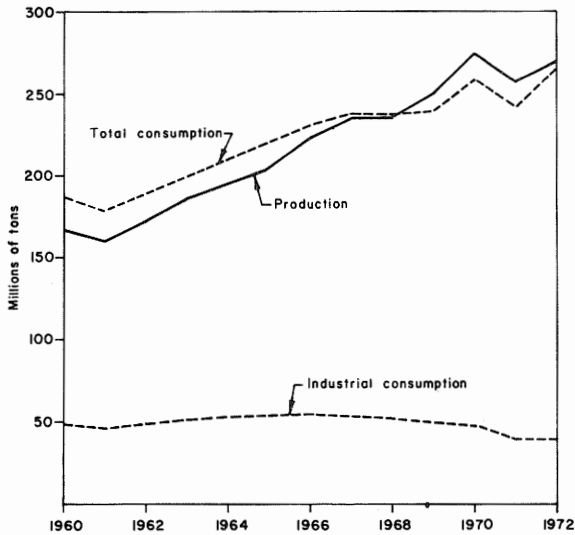


Fig. 6 - Trends in coal production and in total and industrial consumption in Midwest Region. (Source: U.S. Bureau of Mines Minerals Yearbooks and Coal Distribution Reports.)

1970, compliance with air pollution regulations has accelerated the demand for clean-burning gas, although recent shortages have almost stopped any further increases in gas consumption by industry.

While industrial use of gas in the Midwest Region grew at an average rate of 10.8 percent per year between 1960 and 1966, the national growth in industrial gas usage was only 9.2 percent per year. Between 1966 and 1971, gas consumption by industry in the Midwest increased at a slower average rate than the national rate for the industry—7.6 percent versus 9.6 percent per year. However, during both periods, the industrial consumption of gas in the Midwest Region increased faster than the total consumption of gas in the region.

In 1972, because of a national gas shortage, total gas consumption in the United States increased by only 1.2 percent—a much lower annual rate than had prevailed during the preceding decade. Consumption by "electric utilities" and "other consumers" declined by 0.4 percent and 4.4 percent, respectively. Industrial use of gas in 1972 was essentially unchanged from 1971 (up 0.4 percent); only residential and commercial use of gas showed substantial increases.

Figure 8 shows the trends in the production and consumption of natural gas in the Midwest Region between

in imports of coal from the West, especially from Montana and Wyoming. Between 1967 and 1972, imports of western coal (Districts 16-23) increased by 15-fold from 875,000 tons to 12.7 million tons. Despite this large increase, western coal still accounted for only 4.8 percent of the region's 1972 coal consumption, and essentially all of it was used by electric utilities.

Natural Gas

Figure 7 shows the trends in natural gas consumption by industry in the Midwest Region between 1960 and 1972. During that period the use of gas increased substantially, mainly at the expense of coal, because of the superior handling and burning qualities and low price of gas. Since

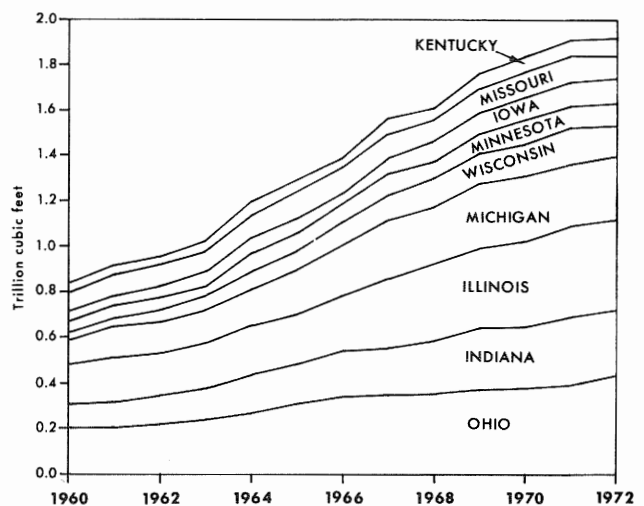


Fig. 7 - Cumulative natural gas consumption by industry in the Midwest Region, 1960-1972, by state. (Source: U.S. Bureau of Mines Minerals Yearbooks, 1960-1971, and Natural Gas Annual, 1973.)

1960 and 1972. Although there was a steady growth in total gas consumption in the Midwest through 1971, the amount of gas produced (the marketed production) from states within the region remained at a low level—144 to 189 billion cubic feet per year. As this represents less than 5 percent of the region's total annual demand, imports from states outside the region and from Canada supply most of the natural gas consumed.

The impact of the gas shortage was also felt in the Midwest for the first time in 1972. Although over-all consumption increased slightly (0.8 percent), consumption of gas by electric utilities declined 22.5 percent, and the use of gas by industry and "other consumers" was essentially unchanged from 1971. Only the commercial and residential sectors showed significant increases in consumption. On a state basis, total gas consumption in 1972 declined 1.8 percent in Illinois, 0.9 percent in Missouri, 7.8 percent in Wisconsin, 0.03 percent in Iowa, and 0.01 percent in Minnesota. During 1972, industrial gas consumption declined in five of the nine states of the Midwest Region—Illinois (-2.0 percent), Michigan (-0.3 percent), Wisconsin (-11.4 percent), Minnesota (-0.8 percent), and Missouri (-8.4 percent).

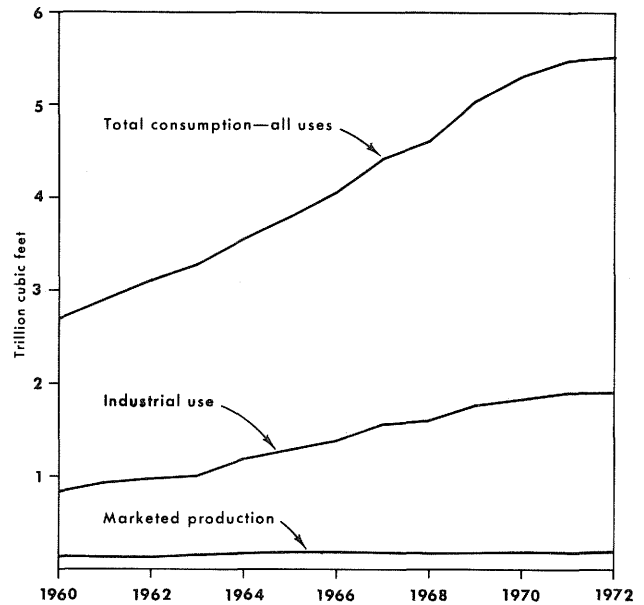


Fig. 8 - Marketed production and industrial and total consumption of natural gas in Midwest Region, 1960-1972. (U.S. Bureau of Mines Minerals Yearbooks, 1960-1971, and Natural Gas Annual, 1973.)

Refined Oil Products

Refined petroleum products contributed only a small and declining share of the fossil fuel needs of industry in the Midwest Region during the decade of the 1960s, falling from 12.5 percent in 1960 to 6.3 percent in 1970. Use of distillate oils generally ranged between 10 and 12 million barrels per year. However, beginning in 1971 there was a sudden upsurge in consumption as other "clean" fuels became scarce in relation to the increased demand. Consumption of distillate oils increased by 24.6 percent in 1971 and by 14.1 percent in 1972, reaching 15.5 million barrels in the latter year. Major increases were reported in Iowa, Ohio, Indiana, and Kentucky.

Use of residual fuel oil by industry in the Midwest Region declined between 1960 and 1971, falling from 35.8 million barrels to 17.1 million barrels. Part of this decline was probably attributable to the increasing competition for residual oil by electric utilities, the high sulfur content of the available oils, and the fact that combustion of residual oils requires preheating and special handling techniques. The downward trend in industrial use was reversed in 1972 as consumption increased by 11.1 percent. The upsurge probably resulted from increased demand from customers who found themselves short of gas and in need of additional fuels.

Although the Midwest Region has been a producer of crude petroleum for over 100 years, current production is low and declining. Between 1960 and 1972, the region's over-all production fell by 45 percent, from 131.9 million barrels to 72.0 million barrels. The estimated demand* for oil products in the Midwest Region in 1960 was about 875 million barrels, but by 1972 it had increased by 60 percent to an estimated 1.4 billion barrels. Because local production was decreasing, dependence on oils imported from outside the region increased from 85 percent in 1960 to 95 percent in 1972. However, because United States crude oil production has essentially peaked, future additions to supply will increasingly have to be imported from foreign sources.

For statistical purposes, the U.S. Bureau of Mines has divided the country into five Petroleum Administration for Defense (PAD) Districts. PAD District II includes the Midwest Region and North Dakota, South Dakota, Nebraska, Kansas, Oklahoma, and Tennessee. Prior to 1972, all foreign crude oil imports into PAD II came from Canada. However, since 1972 the demand has increased so rapidly that imports from Canada have not been sufficient, and oil from more distant sources has been imported into the Midwest. While crude oil imports from Canada during the first six months of 1973 surpassed by 48.2 percent the imports for the same months in 1972 (79,582,000 bbl versus 117,907,000 bbl), imports from other overseas areas increased by 782 percent, from 1.72 million barrels to 15.17 million barrels. The Arab countries of North Africa and the Middle East accounted for 62 percent of these non-Canadian imports (U.S. Bur. Mines, 1973e). As a result, the Midwest Region was rapidly becoming directly dependent on Arab oil, and no diminishing of this trend was indicated until the recent oil embargo on the part of the Arab oil-producing countries. Only time will tell how serious the shortages created by the recently imposed embargo really will be.

Electricity

Energy may be used either directly or indirectly. In the past, direct use of energy in the form of fossil fuels dominated industrial use, but it now appears that the trend in industry is to use more electricity than it has done in the past. Consumption of electric energy by industry in the Midwest Region increased from 112 billion kilowatt-hours in 1960 to 176 billion kilowatt-hours in 1971, an increase of 56.4 percent. This growth rate was faster than that for fossil fuels as a whole (+30.9 percent), with the result that electricity's share of the total energy consumed by industry increased from 33.6 percent in 1960 to 37.1 percent in 1971 (Federal Power Comm., 1960-1971).

PRICE TRENDS

In the past, energy has been one of the greatest bargains available. Industrial consumers have been even more fortunate than other consumers, for most of them were large-volume users and thus qualified for discount rates. For natural gas consumers there were "interruptible" rates, which, combined

* Estimated demand equals gasoline sales + distillate oil sales + residual oil sales + LPG and ethane sales + 15 percent to allow for wax, lubricants, etc., which are not reported on a state basis.

with Federal Power Commission regulation of wellhead prices, made natural gas very cheap despite its being a premium fuel.

Figure 9 shows the trends in the average cost of coal, oil, and natural gas at the point of production (i.e., at the mine or wellhead) from 1960 through 1972 in the United States. The price is given in cents per million Btu so that direct comparison on an equivalent heat-value basis is possible. Clearly, natural gas has been the cheapest of the three major fuels, followed closely by coal. Oil is decidedly a more expensive source of energy, competitive on the basis of its ability to supply energy for special uses (such as transportation) more efficiently and/or more conveniently than coal or natural gas. It is significant that, while the current energy crisis has been reflected in increased prices for both oil and coal since 1968, the

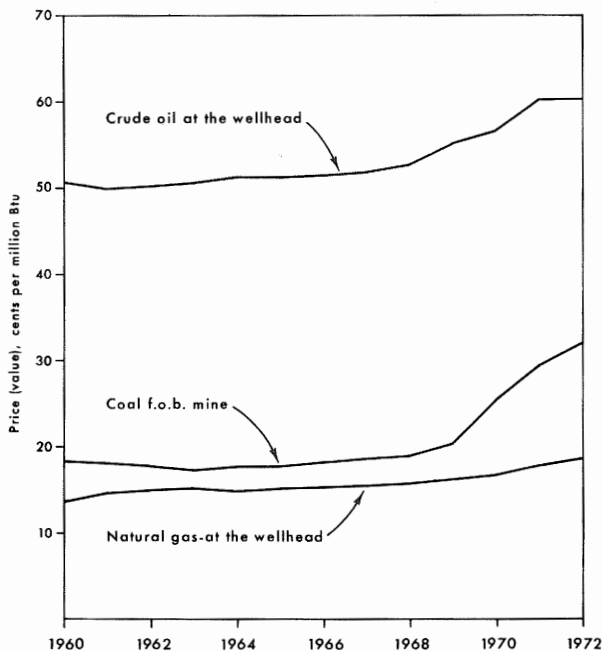


Fig. 9 - Average U.S. fuel price at the point of production for each major fuel, 1960-1972. (Source: U.S. Bureau of Mines Minerals Yearbooks, 1960-1971; Minerals Industry Survey, 1972; pers. comms. from L. W. Westerstrom and Jacob Van Den Berg.)

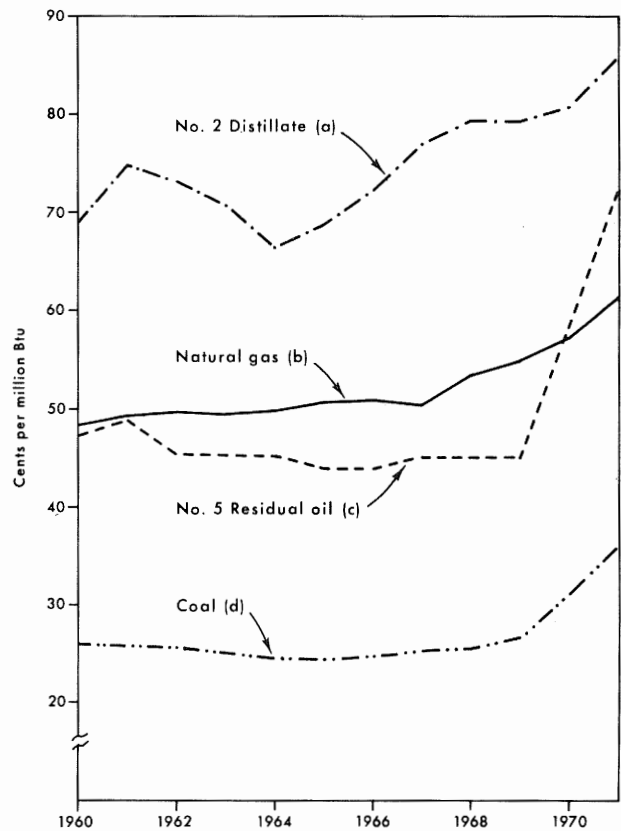


Fig. 10 - Average delivered price for various fuels, 1960-1971.

- (a) Average price for No. 2 distillate oil delivered at New York harbor (U.S. Bureau of Mines Minerals Yearbooks, 1960-1971).
- (b) Average price of natural gas at point of consumption, all uses (U.S. Bureau of Mines Minerals Yearbooks, 1960-1971).
- (c) Average price for No. 5 residual oil delivered at New York harbor (U.S. Bureau of Mines Minerals Yearbooks, 1960-1971).
- (d) Average delivered price for utility coal (National Coal Association, Steam-Electric Plant Factors, annual issues).

increase in gas prices has been almost negligible—reflecting the "hold down" effects of the Federal Power Commission regulations. Even within the confines of the present price controls, however, the Federal Power Commission has allowed substantial increases in the prices for new gas from certain fields (Wall Street Jour., 1973b).

However, the cost of fuels at the point of production is not really the crucial factor. More important is the relative cost of these fuels delivered at the market. Figure 10 indicates the trends in delivered prices for various fossil fuels. On a delivered basis, coal has a decided price advantage compared with oil and gas, even despite the sharp increases in recent years. Coal for the industrial market probably will have a higher delivered price than the average price for coal delivered to the utility market. The average small industrial consumer often is not in a position to take advantage of the discounts offered by unit trains and long-term, large-tonnage contracts. However, even allowing for additional transportation charges and other expenses, coal still should be competitive with other fuels in the Midwest industrial market on a strictly price basis.

As can be seen from figure 11, the average price, f.o.b. the mine, for coals mined in the Midwest Region has consistently been less than the average for all bituminous coal and lignite mined in the United States. Because of their relatively high Btu content and favorable location with regard to market, coals of the Midwest Region can absorb considerable transportation and handling charges and still remain competitive with refined petroleum products and natural gas.

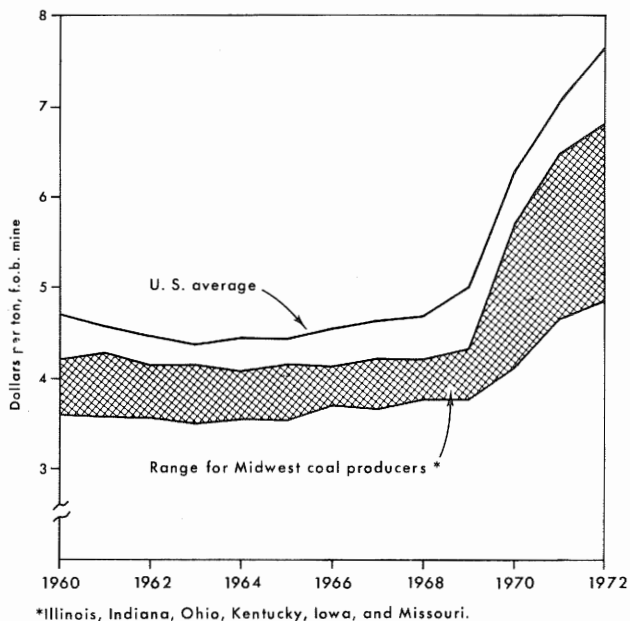


Fig. 11 - Average U.S. coal price, f.o.b. mine, compared with range of average price for coal produced in Midwest Region, 1960-1972. (Source: U.S. Bureau of Mines Minerals Yearbooks, 1960-1971; Minerals Industry Survey, 1972; pers. comms. from L. W. Westerstrom and Jacob Van Den Berg.)

The average 1972 price for coals produced in the Midwest Region (fig. 11) ranged from a low of \$4.86 per ton in Iowa to a high of \$6.81 per ton in Kentucky. If we assume that the maximum transport costs for moving such coals to markets within the Midwest Region is \$2.00 per ton, then the upper limit on delivered costs should be around \$8.80 per ton. If the coal has a heat value of between 10,000 and 11,000 Btu per pound, the maximum delivered cost for Midwest coals should be around 40 to 44 cents per million Btu. This would be a maximum upper limit; many "local" coals are delivered for considerably less. Since the average 1972 price for natural gas delivered to industrial consumers in the Midwest Region was 59.1 cents per million Btu and the delivered prices for refined petroleum products were even higher, it is obvious that midwestern coals are priced competitively.

Western coals in comparison with other fuels delivered to the Midwest

industrial market do not compete so favorably. The average values, f.o.b. the mine, for coals produced in Wyoming and Montana—the leading suppliers of western coal to midwestern consumers—were \$3.74 and \$2.03 per ton, respectively, in 1972 (personal communication from L. W. Westerstrom, Fossil Fuels Dvn., U.S. Bur. Mines, Oct. 30, 1973). However, although the mine prices are lower than midwestern coal prices, the combination of longer shipping distances—up to four times as long as midwestern local hauls—and a heat content 10 to 20 percent lower than that of midwestern coals makes the cost of western coals delivered to Illinois and Indiana almost double that for local coals. According to the Federal Power Commission, electric utilities in Illinois and Indiana during December, 1972, paid 62.76 and 59.83 cents per million Btu, respectively, for low-sulfur western coals. The prices for the higher sulfur local coals ranged from 31.38 to 36.33 cents per million Btu, delivered to the same utilities. The differential in Iowa, Minnesota, and Missouri was much less (Federal Power Comm., 1973).

Despite recent price increases, natural gas is still competitively priced, but projected curtailments make it unlikely that gas will be available to meet all current and projected demands for it. The alternative is oil, but the prices for most oil products are currently higher on a cents-per-million Btu basis than even western coals and are expected to rise higher as the fuels shortage intensifies.

Whereas price was a key factor in determining the fuel used by industry in the past, price in the future will be secondary to other considerations, such as fuels availability and environmental considerations. These latter two considerations are inter-related to varying degrees.

AVAILABILITY OF FUELS IN THE UNITED STATES

The fuels situation in the United States can be summed up in three brief statements. First, most of the coal currently being mined has a sulfur content too high to meet proposed air quality standards, and no technology is currently available to remove this sulfur economically from the coal itself or from the gases produced during combustion. Second, domestic reserves of oil and natural gas are inadequate to sustain sufficient production to meet all of the rapidly increasing demand for these fuels, including the demands for "clean" fuels being made by former coal users. Third, imports of crude oil and refined petroleum products offer the only short-term option for alleviating our energy crisis because "new" sources of energy such as liquefied natural gas (LNG), synthetic natural gas (SNG) made from petroleum feedstocks and/or coal, solar energy, and geothermal power will not be ready to make any significant contribution to the over-all energy supply for at least a decade.

Coal

Coal and lignite are the most abundant fossil fuels, accounting for about 90 percent of the world's known recoverable energy (Hubbert, 1971, p. 66). Current estimates of the known reserves ("identified resources") of coal remaining in the ground in the United States amount to some 1.59 trillion tons, of which 390 billion tons is considered to be recoverable with current tech-

nology (Theobald, Schweinfurth, and Duncan, 1972, p. 3). Unfortunately, the continued and expanded use of this resource is being threatened by new air pollution regulations.

Practically all fossil fuels naturally contain sulfur in various amounts. During combustion, most of this sulfur is converted into sulfur oxides, which are discharged out the stack with other combustion gases. If the ground-level concentrations of these oxides exceed a certain level, plants, animals, and human beings subjected to prolonged exposure to the oxides can be adversely affected. Because no stack-gas cleaning device has yet proved effective, the Federal Environmental Protection Agency, as a means of reducing the sulfur oxides level in the ambient air to a desired lower level, has set maximum levels of sulfur content for fuels burned by stationary sources. The Federal and Illinois regulations (Illinois EPA, 1973) currently set a maximum limit for all new solid-fuel-fired units of 1.2 pounds of sulfur dioxide emissions per million Btu of heat input. This amount is equivalent to only 0.6 percent sulfur in a coal with a heat content of 10,000 Btu per pound. Any unit that has been significantly modified since the law became effective is classified as a new source. The standards for existing plants are also being made more restrictive. After May 30, 1975, old plants located in the Chicago, St. Louis, and Peoria metropolitan areas of Illinois may not emit more than 1.8 pounds of sulfur dioxide per million Btu of heat input. This is equivalent to only 0.9 - 1.1 percent sulfur in typical midwestern coals (assuming 10,000 to 12,000 Btu/pound). Old units located outside of the above-mentioned metropolitan areas may not emit more than 6.0 pounds of sulfur oxides per million Btu of heat input after May 30, 1975. For a coal with a heat value of 10,000 Btu per pound, the 6-pound limit would be equivalent to 3 percent sulfur in a coal.

The problems in meeting these standards are that very few of the coals currently being mined contain such a low percentage of sulfur. Essentially all of the coals occurring in the states lying east of the Mississippi River, where 90 percent of the current production occurs (U.S. Bur. Mines, 1973b, p. 330-334), are of the bituminous variety, and, unfortunately, only 8 percent of them contain 0.7 percent or less sulfur. Moreover, 97 percent of the coals that are very low in sulfur are located in eastern Kentucky, West Virginia, and Virginia (Federal Power Comm., 1971, p. I-4-9). Because of their favorable combination of low ash, low sulfur, and strong coking characteristics, these coals are particularly suited for coking and for use in blends for the manufacture of coke. As a result, many of the best reserves of these coking coals are tied up by steel companies for their own (captive) use. Others are reserved by the mining companies for sale under long-term contract to steel companies in both the U.S. and overseas. These are premium coals and traditionally have commanded higher than average prices. Although these low-sulfur coals could be a possible source of "clean" fuel for industrial consumers in the Midwest who seek to replace their high-sulfur coals, there is little surplus mine capacity in the low-sulfur area to supply them, and the cost of using these premium coals may be prohibitive.

Even the more lenient standards for existing plants in nonmetropolitan areas would eliminate a large part of the coal currently being mined in the Midwest Region. If 3.0 percent is assumed to be the maximum sulfur allowable, 81 percent of the coal reserves in Illinois would be disqualified, as would 54 percent of Indiana's coal, 85 percent of the coal in western Kentucky,

69 percent of the coal in Ohio, and all of the coal in the states of Michigan, Iowa, and Missouri. On a national basis, 43 percent of all bituminous coals have sulfur contents in excess of 3.0 percent (DeCarlo, Sheridan, and Murphy, 1966, p. 19).

While approximately 70 percent of the coal reserves of the United States lies in states west of the Mississippi River (U.S. Bur. Mines, 1973b, p. 330), western coals thus far have been developed only marginally because they were far from the major markets and generally lower in grade than the more favorably located eastern and midwestern coals. However, in the light of the current energy shortage and the critical need for low-sulfur fuels, many producers and consumers have begun to re-evaluate these western resources, and a number of large new mines have already been developed in the West.

Estimates show that in states west of the Mississippi River 26 percent of the bituminous coals, 66 percent of the subbituminous coals, and 77 percent of the lignites contain 0.7 percent sulfur or less (Federal Power Comm., 1971, p. I-4-9). Although these low-sulfur coal resources seem a promising source of energy, several problems are associated with their use and with any attempt at rapid large-scale switching from currently available high-sulfur fuels to low-sulfur western coals.

First, the heat contents of the lignites are so low that they must be burned at or very near the mine because transport costs per million Btu of heat energy is prohibitive. Even the abundant higher Btu subbituminous coals may have heat contents as low as 8300 Btu per pound. Although most western coals have a low sulfur content, they also have low heat values that may still make it impossible for them to meet a 1.2 pound sulfur oxides limit. It is difficult to determine just how much of these coals would be eliminated from use without flue-gas desulfurization facilities. Risser (1973, p. 41) has indicated that a preliminary examination of available data from the North Central Power Study reveals a substantial portion of the coals reported on could not meet the standard.

Second, the ash fusion characteristics of many of the western coals are quite different from those of the coals now being used by Midwest consumers. These differences can cause clogging and ash discharging problems in the boilers (Wall Street Jour., 1970).

Third, the distance from the western coal fields to the Midwest industrial markets is 700 to 1000 miles. As a result, transportation costs can double or triple the cost of the coal f.o.b. the mine. The cost of western coals delivered to the Chicago area is reportedly twice as much as the delivered cost of the local (Illinois), higher sulfur coals formerly used (Rifakes, 1971, p. 13).

Fourth, there is at present no surplus mine capacity in the western coal fields. Any customer wishing to use western coals must first make a contract with a mining company to develop a new mine or expand capacity at an existing mine. The time required between initial commitment and first deliveries is likely to run from a minimum of 1 year for expansion of an old mine to as much as 2 or 3 years for development of a new mine.

Last, there is the question of environmental regulations. Most of the projected output of western coal is scheduled to be strip mined, both be-

cause of cheaper production costs and because many of the coals lie too close to the surface for underground mining to be feasible or safe. Consequently, questions arise about strip mine reclamation and potential air and water pollution from such mining operations. Environmentalists argue that proper reclamation of much of the strip mined land in the more arid areas would be extremely difficult. The conclusions of a study by a special panel of the National Academy of Sciences would seem to agree with this assessment (Gillette, 1973). If new laws banning or severely curtailing strip mining are passed (Science, 1973), large quantities of low-sulfur coal from the West will be essentially unavailable. Air pollution is not normally a major problem for strip coal mines located in humid climates because there is adequate water to keep dust under control; however, in the arid areas of the West such a problem can be severe. A new mine near Rock Springs, Wyoming, was reportedly abandoned last year by its developers when it became apparent that there was no economic way to solve the problems of dust created in the loading and storing of coal at the mine (Wall Street Jour., 1972b).

Another approach to solving the sulfur problem is to continue to burn high-sulfur coals but clean the sulfur oxides from the combustion gases before discharging them into the outside air. Several different approaches to the problem have been tried, both here and overseas. Many of the proposed systems have been designed primarily with the electric utility market in mind, and their economics and technical characteristics may limit or prohibit their use on small industrial units. Although a number of systems are currently being installed in industrial plants in this country for testing purposes, only a few have been operated in a plant long enough for their success to be adequately judged.

One notable success has been the "Double Alkali" system, developed by the General Motors Corporation. In this system, a solution of caustic soda is used to remove the sulfur from the flue gases. The system was installed at their plant in St. Louis, Missouri, in the fall of 1972 and has operated successfully for more than a year, achieving 90 percent removal of the sulfur dioxide (SO_2). However, the system as used in St. Louis had one drawback. The waste sulfite liquor in the scrubber effluent was being disposed of by discharging it, with approval of local authorities, into the city sewer system. Since such an option is not likely to be widely available elsewhere, General Motors has since modified the system to eliminate the potential water pollution problem by treating the sulfite liquor with lime. The lime causes the sulfur to precipitate as a solid, and a clear caustic soda solution results. This solution can then be re-cycled in the system. The precipitates can be collected as a solid waste cake and disposed of in a landfill (General Motors Corp., 1973).

Several other systems, such as the "Bahco" and the "Citrate" processes, are currently being installed on industrial-sized units at various places in the country, and the developers are optimistic about their chances for success. Even if these and other systems prove successful, it will take several years to equip all plants that are currently burning high-sulfur fuels.

Natural Gas

Natural gas is an ideal fuel; it burns cleanly, is easy to handle and transport, and is cheap. In a normal market situation, it would be considered

a premium fuel and would carry a premium price. However, the wellhead prices of natural gas have been controlled by the Federal Power Commission since 1954, under the assumption that reserves were more than ample and that the public's interest would be best served by keeping the prices low. The artificially low price of gas acted to keep a lid on coal and oil prices as well, since there is much inter-fuel competition in most sectors of the economy, especially the industrial. This distortion of the market caused many customers to switch to gas when another more abundant fuel, such as coal, would have sufficed to meet their needs.

The effects of regulated low prices for gas were two-fold. First, it stimulated the rate of consumption of natural gas, and, second, it decreased the incentive to drill for new gas reserves. Drilling activity declined sharply, and new additions to reserves fell. Although some observers (Risser, 1960, p. 13; Carrico, 1963) warned that such a policy would lead to gas shortages in the 1970s, the country continued to consume gas as though supplies were unlimited. Only in 1967, when gas consumption actually exceeded new gas discoveries and caused total reserves to decline, did some people begin to take the situation seriously. Each year since then, with the exception of 1970, more gas has been consumed than has been found. The huge reserves of gas in the Prudhoe Bay area on the North Slope of Alaska, which were first discovered in 1968, were evaluated and added to the total reserves in 1970, causing a significant upsurge in reserves for that year. The following two years have shown a continuation of the downward trend in discoveries and in total reserves.

The current shortages in natural gas probably would have shown up earlier except for the fact that the United States has been able to import increasing amounts of gas. To date, these imports have been mostly by pipeline from Canada and, to a much lesser degree, from Mexico (Federal Power Comm., 1972, p. 39-41). Despite a rapid rate of growth in recent years, only in 1972 did imports actually exceed 1 trillion cubic feet (U.S. Bur. Mines, 1973c, p. 6). Although these imports are quite necessary to certain parts of the country, their total contribution is still less than 5 percent of the United States total gas needs. Because of increasing demands in Canada and a slowing in the finding rate of new Canadian discoveries, a leveling off or even a decline in natural gas imports from Canada is likely, unless gas from Arctic regions becomes available soon (Oil and Gas Jour., 1973c).

Petroleum and Petroleum Products

The United States is the world's largest producer of petroleum, currently accounting for some 20 percent of the total. In 1971 the United States produced 3.45 billion barrels, whereas the Soviet Union, the second largest producer, produced 2.78 billion barrels. The gap, however, is closing quickly (U.S. Bur. Mines, 1973b, p. 855, 969). It has been predicted that by late 1974 the Soviets will take the lead in world oil production (Oil and Gas Jour., 1973d, p. 73).

Unfortunately, despite our huge domestic production, the United States must import sizable amounts of crude petroleum and refined products. In fact, the United States has been a *net* importer since 1948. U.S. dependence* on foreign oils has grown from 8.1 percent in 1950 to 16.5 percent in 1960 to 28.3

* Net imports as a percentage of total new supply.

percent in 1972 (Am. Petroleum Inst., 1971, p. 284; 1973, p. 1). It has been projected that, under the most unfavorable assumptions, the United States might be importing as much as 66 percent of its total oil needs by 1980 (Nat. Petroleum Council, 1972, p. 17, 24).

Oil has many advantages over gas and coal. It can be moved by barge, pipeline, ocean tanker, or truck. It is a liquid at room temperature, and, therefore, unlike liquefied natural gas, requires no special containers. Oil is an essential fuel because it can be used in its various refined forms as a source of energy in more different sectors and markets than either of the other fossil fuels. Not only is it important in the utilities, household, commercial, and industrial sectors, it is the dominant fuel in the transportation sector. In essence, oil "moves" the country.

Figure 12 shows the United States production, consumption, reserves, and imports of petroleum and petroleum products from 1946 through 1972. While reserves increased at a modest rate between 1946 and 1958, there was no significant change during the next 11 years. In 1970 a significant jump in their level was accounted for by the addition of the reserves at Prudhoe Bay, Alaska. Since 1946, production has increased steadily, but not fast enough to keep pace with domestic demand. The deficit was filled by imports, which grew at a very rapid rate; imports of refined products increased even more rapidly than imports of crude petroleum.

Because domestic production has exceeded new additions to reserves (excluding Alaska) for every year since 1967, total proved reserves in the United States are beginning to decline. The average maximum sustainable productive level for all oil fields is about one-eighth of the amount of the total reserves. Therefore, when the ratio of reserves to production reaches 8 to 1, an increase in production can occur only when reserves are increased. If reserves decline and the R/P ratio approaches 8 to 1, production must level off or even decline. An indication of the seriousness of the U.S. oil production situation is the 1972 R/P ratio for oil (excluding Alaska), which fell to 8.17 to 1.

Domestic production of crude oil peaked in 1970 with an output of 3.32 billion barrels (Am. Gas Assoc. et al., 1973, p. 24). Although 1972 production was slightly more than the 1971 total, it did not equal the record set in 1970. Only eight states actually showed any gain in output over 1971, and that was more than offset by substantial declines in big producing states

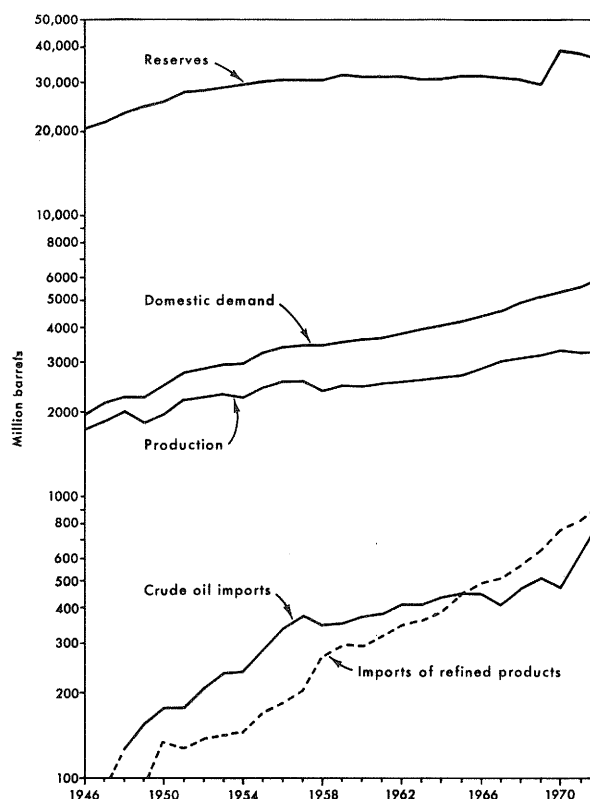


Fig. 12 - Trends in U.S. oil supply and demand, 1946-1972. (Source: American Petroleum Institute.)

such as Louisiana, New Mexico, Oklahoma, Wyoming, and California (Am. Gas Assoc. et al., 1973, p. 22-23). The estimated 90-day productive capacity for crude oil and natural gas liquids attainable on March 31, 1970, was 14,788,000 barrels per day; three years later, the productive capacity attainable on March 31, 1973, had declined by 11 percent to 13,168,000 barrels per day (Am. Gas Assoc. et al., 1970, p. 1; 1973, p. 1).

The supply/demand situation in the United States has continued to deteriorate. During the first six months of 1973, domestic crude oil production was 2.5 percent lower than in the same period in 1972. In the face of a declining supply, demand for all oil products increased by 6.0 percent. To overcome this deficit, crude oil imports were increased by 45.9 percent and imports of refined products by 16.5 percent.

The demand for residual fuel oils increased by 11.2 percent during this period. Even though production of residual increased 21.7 percent and imports rose by 6.2 percent, stocks were 7.7 percent lower in June 1973 than at the same time a year earlier. The propane situation also has deteriorated. Production increased by only 1.0 percent in the face of a 6.5 percent increase in demand for propane. To overcome this deficit, imports soared by 73.6 percent and stocks were drawn down by 17.9 percent. In anticipation of winter fuel needs, imports of distillate fuel oils during the first six months of 1973 increased by 113.3 percent over imports in the same period in 1972 (U.S. Bur. Mines, 1973e).

Why the Energy Crisis?

Although the *effects* of the current energy crisis have made themselves widely felt only recently, various experts had predicted as much as 15 or more years ago that shortages in natural gas and petroleum were likely to occur in the 1970s. Unfortunately, their predictions were not heeded when they were made, and no corrective measures were taken. The precise timing of the current shortages was accelerated by rates of growth in energy demand that were greater than projected, by the imposition of environmental regulations that caused a widespread switchover to clean fuels that already were in short supply, and by the recent Arab oil embargo that has curtailed our total oil supply by from 11 to 18 percent. However, examination of the long-term trends in reserves and the finding rates for new reserves indicate that our fuels position has been declining for a number of years.

The adequacy of reserves of a particular mineral commodity may be judged by several useful indicators or ratios. One of these is the F/P ratio, or the finding-to-production ratio, the ratio of the quantity of new additions to remaining reserves found in any given year compared with the quantity of production during the same year. As long as the F/P ratio is 1 to 1 or higher, new reserves are being found at a rate sufficient to replace those depleted by current production. If the ratio falls below 1 to 1, sufficient reserves are not being maintained to accommodate the current production rate.

Figure 13 indicates the trend in the F/P ratio for crude oil in the United States from 1946 to 1972. The ratio has been trending downward for most of the period; in fact, it dropped below 1 to 1 as early as 1957 and again in 1960, 1962, and 1963. Since 1966 the F/P ratio has been consistently below the replacement level. The figure also shows similar data for natural gas. Again the downward trend is evident, or even more pronounced. Although the F/P ratio

for natural gas never fell below 1 to 1 prior to 1968, it came very close to it in 1954 and 1960. The addition of the Alaskan North Slope reserves in 1970 reversed the trend for one year, but the ratio fell again in 1971 and 1972.

The R/P ratio also indicates the adequacy of reserves. It compares total reserves in any given year to the production in that year. As long as production is below the maximum producible level, this ratio may or may not be important. It has been argued that the reserves figure is not a significant indicator of maximum productive capacity because only enough reserves are proved up in advance of production to allow for proper planning in production, and that the cost of proving up additional reserves is uneconomic. If this argument is correct, it may well explain the rather level and narrow range in which the R/P ratio for oil lay from 1946 through 1965 (fig. 14). A significant decline in the ratio began in 1966 and, except for the rise in 1970 caused by the addition of the Alaskan North Slope reserves, the decline has continued. Even more important, however, is the fact the R/P ratio is approaching the level of maximum sustainable output, which is about 8 to 1.

The R/P ratio for natural gas has been falling steadily for almost the entire 26 years between 1946 and 1972. In the period from 1946 through 1962 when the R/P ratio was above 20 to 1, there was little reason to be concerned about a gas shortage because a 20-year supply was sufficient to justify a pipeline and to allocate supplies for long-term contracts. However, when the R/P ratio began to drop below the 20 to 1 level there was room for concern, but as late as 1966 the then chairman of the Federal Power Commission was quoted as stating that there were ample reserves of natural gas and that a declining R/P ratio was "not a cause for alarm" (Oil and Gas Jour., 1966).

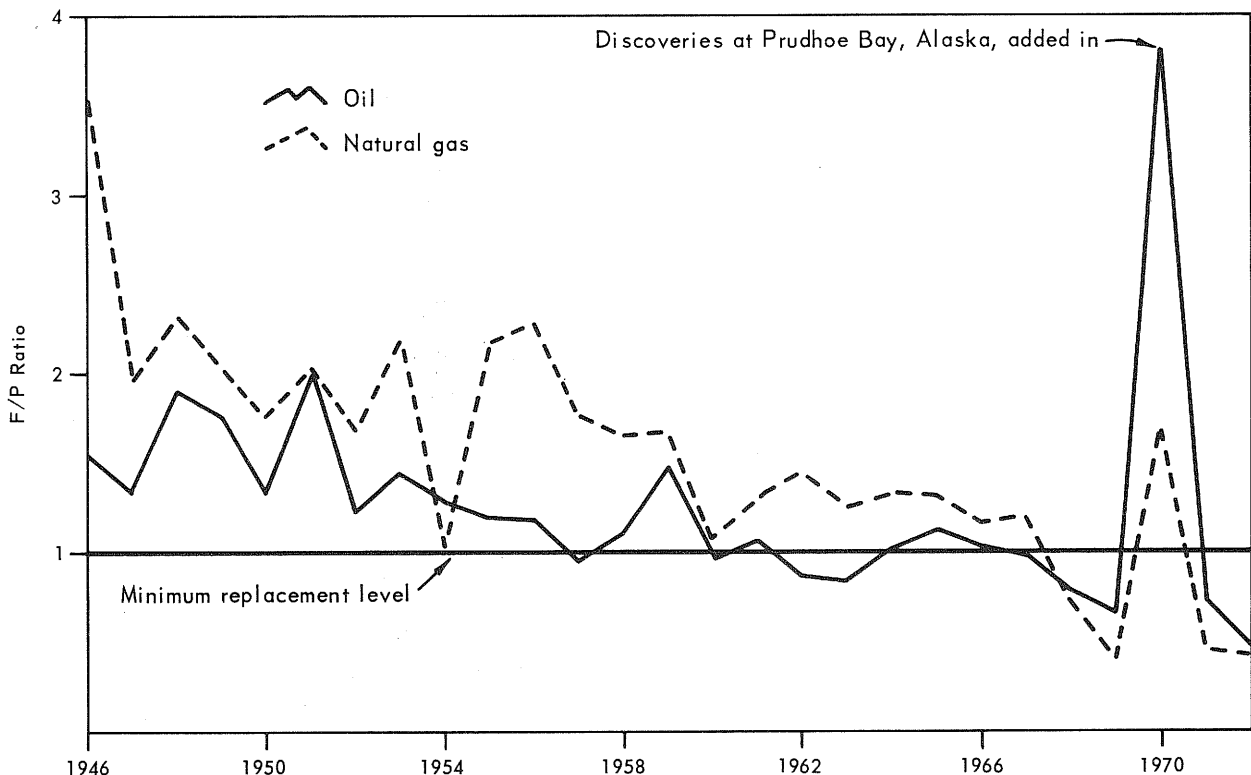


Fig. 13 - Trend in the finding-to-production ratio (F/P) for oil and natural gas, 1946-1972.

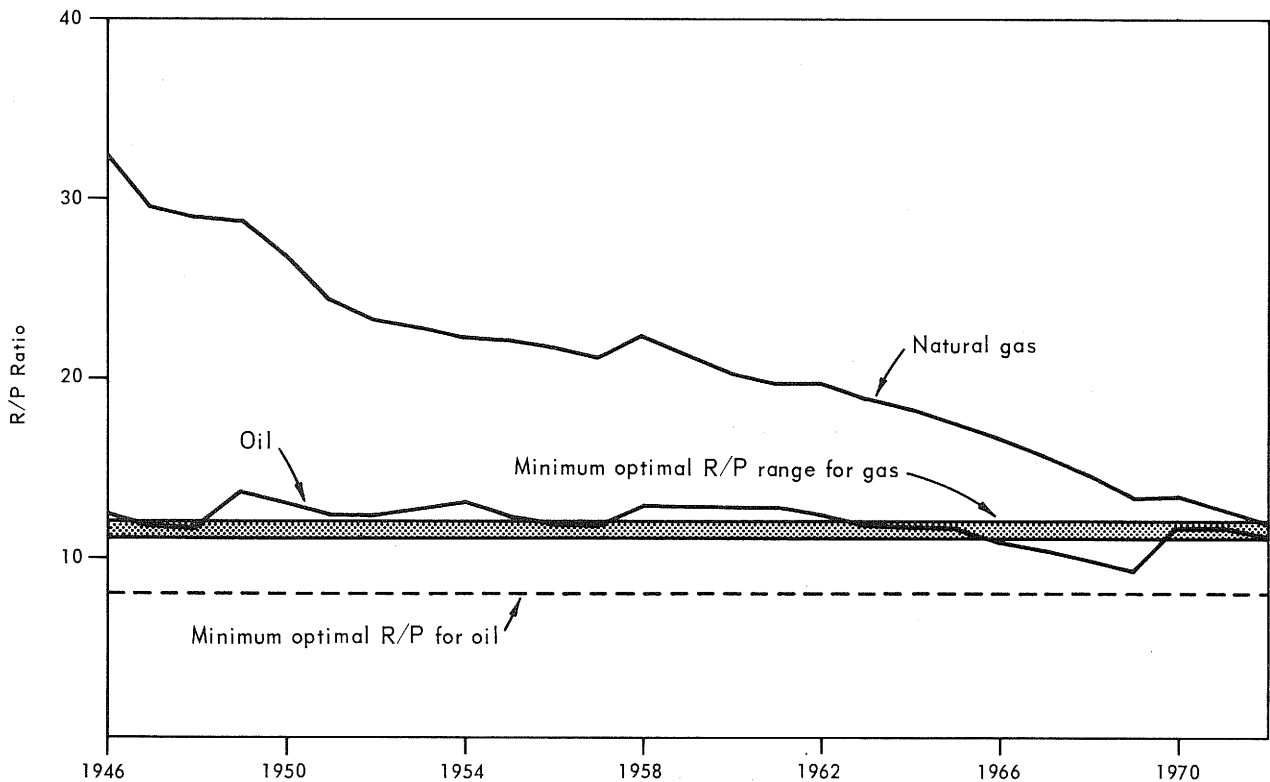


Fig. 14 - Trends in reserves-to-production ratio (R/P) for oil and natural gas, 1946-1972.

Unfortunately, he and the other optimists have been proved wrong—a gas shortage is already upon us. Last winter many industrial customers, especially in the Midwest, who were on interruptible contracts had their gas supplies curtailed during periods of peak demand (Industry Week, 1973a). As a result, plants closed in several states and workers were laid off. Fortunately, most of these closings were of short duration, but the impact was severe for those involved. Some of the utilities in the Midwest have announced that gas curtailments to industrial customers will take place during the winter of 1973-1974 and that no new large customers will be added to their systems in the immediate future (Wall Street Jour., 1973a, 1973e). The Federal Power Commission has estimated that total gas curtailments from April through October 1973 amounted to 966.3 billion cubic feet, an increase of 74 percent over 1972. For the winter of 1973-1974, 14 interstate pipeline companies have indicated that together they expect to curtail gas deliveries by 679.7 billion cubic feet, 20 percent more than last year (Oil and Gas Jour., 1973g).

SHORT-RUN OPTIONS

In light of the evidence that most fuels will likely be in short supply for at least the next few years, industry in the Midwest is faced with the problem of finding stop-gap measures.

The American Gas Association has projected natural gas sales by census regions through the year 1990. It has predicted that between 1971

and 1976 gas sales to industry in the East North Central Region (Ohio, Indiana, Illinois, Michigan, and Wisconsin) will decline 10.8 percent; in the West North Central Region (including Minnesota, Iowa, and Missouri) gas sales to industry will decline 20.2 percent. For the East South Central Region (including Kentucky), industrial gas sales are predicted to remain essentially unchanged (-0.4 percent) during the 1971-1976 period. The report (Am. Gas Assoc., 1973, p. S-12, S-13) predicts:

The 1976 industrial gas sales in this [East North Central] region will not only be 29 percent less than their potential, but will also show an actual decline in volume due to supply deficiencies. Normal growth patterns will re-emerge, however, in the next decade.

Total gas sales [in the West North Central Region] from 1971 to 1976 are expected to show a volumetric decrease of about one percent, although this is concentrated in the industrial sector. [Reduced] gas sales for electric power generation (a component of industrial sales) are primarily responsible for this decline.

If natural gas will not be available in sufficient quantities to meet new industrial demands and probably will not be available for even all old customers, what are the possibilities of using coal? The answer to this question is partly controlled by the policies of the United States Environmental Protection Agency. Unless proved flue-gas desulfurization techniques or systems can be widely installed in existing plants, industrial consumers in the Midwest who wish to continue to burn coal must either obtain a variance to burn high-sulfur coal or switch to coals that are either naturally low enough in sulfur to comply with the standards or can be cleaned by conventional preparation methods to meet such standards.

Recently, the Federal Environmental Protection Agency proposed an allowable change in state implementation plans that accepts the selective use of "supplementary control procedures" for certain fossil-fuel burning stationary sources. These procedures would involve continuous monitoring of stack gas emissions, meteorological conditions, and ambient air quality in the vicinity of the source. By using these data in computer diffusion models for predicting concentrations of pollutants, emissions can be cut back during periods when air quality is poor by a reduction in the rate of plant operations. The EPA's acceptance of supplementary control procedures was based on a recognition that adequate technology for control of sulfur oxides is not available now at many locations. However, the EPA's action is only a delay in the implementation of secondary standards in some areas, not an abandonment of these standards. Plants using these strategies are required to be working towards a permanent solution to their emissions problems. The use of tall stacks as an air pollution control strategy was rejected (Engineering and Mining Jour., 1973, p. 13).

The problems involved in using western coals have already been discussed. In light of these problems and of the delays involved in developing and implementing new coal supply systems, it is unlikely that any customer who has not already committed himself to using western coals will be able to convert his plant to burn such coal or to secure needed supplies in less than two or three years. Therefore, for many industrial consumers in the Midwest Region, switching to low-sulfur coal from the west is not a viable short-term solution to their fuel supply problems.

Because it is unlikely that natural gas will be available in sufficient quantities to meet all demands, because midwestern coals are generally unacceptable on environmental grounds, and because the short-term availability of vast quantities of low-sulfur western coals is highly questionable, it had been assumed that refined petroleum products could be counted on to fill the increasing deficits. However, as was pointed out earlier, domestic production of crude oil has declined. Not only is production inadequate to meet current demands, but it will not be able to meet the additional demands being made because of shortages in other fuels. Therefore, any increased use of petroleum products must involve increased oil imports. Even prior to the recent Arab oil embargo, the shortage of oil was growing because a number of problems were peaking at the same time (Oil and Gas Jour., 1973a, p. 27):

...booming demand, declining domestic production, a worldwide shortage of sweet (low-sulfur) crude oil, and tight supplies even of sour (high-sulfur) crude, too little U.S. refining capability, and inadequate facilities to distribute surging imports of crude and products throughout the country.

Because imported refined products are more expensive than imports of crude oil, it would have been preferable to import crude oil and then refine it here in the United States. Domestic output, however, has been limited by a shortage of refining capacity, and, consequently, imports of refined products have increased substantially in recent years. During the first six months of 1973, imports accounted for 66.0 percent of our residual fuel oil supply, 17.7 percent of jet fuel, 11.9 percent of distillate fuel oil, 8.6 percent of propane, and 1.4 percent of gasoline (U.S. Bur. Mines, 1973e).

The lack of adequate refinery capacity is partly the result of economic conditions that have prevailed in this country for the last 6 to 8 years, during which low prices for petroleum products have made the rate of return on such investments unsatisfactory (Shell Oil Co., 1973, p. 10-11). Opposition to proposed new refineries for environmental reasons also has caused delay or cancellation of several projects (Oil and Gas Jour., 1973f, p. 47).

Between January 1, 1961, and January 1, 1973, the operating capacity for all refineries in the United States increased by 39.7 percent, from 9.63 million barrels per day to 13.45 million barrels per day. However, since the demand for oil products was increasing even faster, the gap between demand and domestic refinery capacity increased from 168,000 barrels per day at the end of 1960 to 2,900,000 barrels per day at the end of 1972. In other words, the self-sufficiency of the United States declined from 98.3 percent to 82.3 percent over the 12-year period. Even if the United States wished to restrict its imports to crude oil only and refine the products here, it would lack sufficient capacity to do so (U.S. Bur. Mines, 1963, p. 3; 1973a, p. 3; Am. Petroleum Inst., 1973, p. 4).

Because of insufficient refining capacity in the United States, many domestic companies and consumers had been counting on increased imports of refined products to meet their future needs. A likely source of such imports is Western Europe, where there was thought to be a surplus of refining capacity. However, even prior to the curtailment of Arab oil shipments to Europe, some observers felt that the ability of these refineries to supply the United States with the needed volumes of products was overrated (Oil and

Gas Jour., 1973b). In light of the cutback on Arab oil shipments to Europe, this source may dry up completely. It has been estimated that as much as 300,000 barrels per day of product imports to the United States originate in Western Europe (Industry Week, 1973c). What products are available on the world market are in very tight supply, with severe competition driving prices up rapidly. In any case, increased imports of products was considered only a short-term solution. Over the longer run, it is felt that it is essential that the United States increase its domestic refinery capacity.

Since the announcement last spring of a revised oil import program, United States refiners have made firm commitments of more than \$1 billion to expand existing plants by 1.13 million barrels per day (West, 1973, p. 32). In addition, six other companies have made firm commitments to build new refineries (Oil and Gas Jour., 1973f, p. 46). It has been estimated that all of the proposed projects combined will cost between \$2 and \$3 billion and could eventually increase U.S. refinery capacity by approximately 2.5 million barrels per day (Industry Week, 1973b, p. 25). However, although these announcements are a good sign, problems still must be overcome. Many of the planned refineries may not be built because of opposition on environmental grounds from state and local authorities. The Department of the Interior predicts no significant relief in the tight supply situation will occur until 1975, when the first big refinery expansions are completed (Oil and Gas Jour., 1973f, p. 46). Even if all the planned projects are completed—and this will take years—these additions will not be sufficient to eliminate completely the refining capacity deficit. It is estimated that by 1980 the United States will need the equivalent of 58 new refineries, each with an average throughput capacity of 160,000 barrels per day; they will cost as much as \$30 billion (Industry Week, 1973b, p. 26).

To make matters worse, the sudden curtailment of Arab oil has caused many companies that had previously announced plans for new or expanded refinery facilities to re-evaluate those plans, because many of the proposed plants were expected to run on imported Arab oil. Fearing a lack of assured crude oil, some of the proposed refineries will be delayed or even canceled. Both actions will aggravate and prolong the fuels shortages (Wall Street Jour., 1973f).

A last point to be considered with regard to oil availability is the question of sulfur content. Many of the oils being imported from foreign sources are sour (high-sulfur) crude oils that must be desulfurized before they can meet current and proposed sulfur standards that generally limit the sulfur content to 1.0 percent or less. Some metropolitan areas have even more restrictive standards of 0.3 percent or less sulfur (Environmental Science & Technology, 1973, p. 495).

Although the technology for desulfurizing oil is available, it has been used on only a limited scale because the process adds considerably to the cost of the final products. In the past few years, domestic refineries have increased their output of low-sulfur fuel oils and, at present, many refineries in the United States have some capacity for removing sulfur from the more costly light and distillate oils, although they have little capacity for the production of low-sulfur residual fuel oil from sour crudes. Sufficient amounts of low-sulfur residual will not be available in time for all customers to be able to comply with the 1975 deadline set by the EPA, because it takes

2 years or longer to complete a refinery (Environmental Science and Technology, 1973). Only plants that either have been announced or are under construction will be able to produce a low-sulfur residual fuel oil by 1976.

During the first 6 months of 1973, only 50.8 percent of the residual fuel oil produced could meet a 1.0 percent sulfur standard. The supply situation for the oils even lower in sulfur content (0.5 percent or less) was even worse. Only 27.5 percent of the residual and 63.9 percent of the No. 4 fuel oil produced between January and June 1973 could meet the lower standard (U.S. Bur. Mines, 1973d, p. 4).

Because more of the distillate fuel oils can meet the low-sulfur standards, some customers have tried to switch to distillate or else to buy low-sulfur distillate oil for blending with high-sulfur residual. Unfortunately, such a move has only compounded the supply problems by taking fuel oil away from the residential and commercial heating markets at the very time when supplies of these fuels are already short (Oil and Gas Jour., 1973e). Because of the threat of further switching, the Federal Government has proposed regulations that would place a ban on further conversion from higher sulfur coals and residual oils to lower sulfur distillate fuel oils (Wall Street Jour., 1973f).

NEW ENERGY SOURCES

The main focus of this paper has been on conventional fossil fuels that are currently available. However, over the longer run the United States must increasingly turn to other sources of energy to meet its growing demands. Although much has been written about the potential for such new sources as solar energy, geothermal power, nuclear fusion, MHD (magnetohydrodynamics), and oil shales, most of those sources are still many years away from widespread commercial use, and many will have little direct impact on the energy supply of the Midwest Region. The potential magnitude of the supply of energy from various new sources and the types of problems that must be resolved before such potential can be achieved have been discussed at some length in a recent Survey publication by Risser (1973). No attempt is made in this report to cover the broader aspects of the long-range energy supply problem, but five of the new sources with special significance for the Midwest Region will be discussed briefly.

Tar Sands

Since the late 1960s, a prototype plant has been producing oil from the tar sands of the Athabasca region of Alberta, Canada, and small quantities of these "Athabasca hydrocarbons" have been exported into the Midwest (PAD II) since March of 1968 (U.S. Bur. Mines, 1968, p. 16). Although additional plants are planned that would increase the output of Canadian tar sand oil to from 275,000 to 500,000 barrels per day by 1980 (Nat. Petroleum Council, 1971, p. 180), the impact of such oil on the total energy supply of the United States is difficult to predict at this time. If all of these plants are built, their output in 1980 would be equivalent to 1.3 to 2.4 percent of the predicted consumption of 20.8 million barrels of oil per day in the United States at that time (Dupree and West, 1972, p. 31).

Although the Midwest Region would likely be a major consumer of such oil, several problems are involved. First, the growing oil shortages in Canada make it problematical how much of the tar sand oil will be available for export and whether the government will allow it to be exported. Second, the decision as to whether to go ahead with the next tar sand plant (the Syncrude project) has been delayed pending resolution of differences between the Alberta government and the oil companies regarding tax and royalty provisions (Wall Street Jour., 1973e, p. 4).

Although the United States possesses large reserves of tar sands in Utah and other states, it has previously been considered uneconomic to utilize them. However, in light of the recent substantial increases in the price of crude oil and the shortages of oil from other sources, interest in our domestic tar sand resources may increase. Although the technology for extracting oil from the Canadian tar sands is considered as perfected, it may not be directly transferable to our domestic deposits (Nat. Petroleum Council, 1972, p. 226).

Liquefied Natural Gas

A promising new source of natural gas is liquefied natural gas, or LNG. In several areas of the world, surplus gas is available because the local market is too limited to consume all of the potentially producible gas from local fields (Federal Power Comm., 1972, p. 59-83). Some of this gas is "flared" (burned off) so that the associated oil can be produced, but more often it is put back into the ground for future use.

As many of the areas where surplus gas is located are too remote from potential markets and/or are located in areas where large expanses of ocean separate them from the markets, normal pipeline transport of this gas is not feasible. However, if natural gas is cooled to -259° F at atmospheric pressure, it will become liquid. In liquid form it can be moved by special tankers insulated to keep the gas liquid. In the process of liquefaction, the volume of the gas is reduced to 1/600th of its volume as a gas at room temperature.

Although a sizable number of LNG projects are either under development or on the drawing boards, only a few are in actual operation at this time. Ironically, one of the first of the projects to be placed in operation involves LNG exports from Alaska to Japan (Gardner, 1972). This project was conceived in the mid-1960s before the current energy crisis. At that time, selling to Japan appeared to be the only way Alaskan producers in the Kenai Peninsula could market their product because no pipeline to the United States was available and Alaskan domestic distribution companies had shown no interest in this more expensive source of gas. During 1972, 47.9 billion cubic feet of LNG was shipped from Port Nikiski, Alaska, to Yokohama, Japan, at an average price of 55.75 cents per thousand cubic feet. LNG imports into the United States during that year amounted to 2.3 billion cubic feet, of which 2.03 billion cubic feet came in by tanker from Algeria at a cost of \$1.25 per thousand cubic feet. The rest of the imported gas—230 million cubic feet—was trucked in from Canada at a cost of \$2.48 per thousand cubic feet (Internatl. Gas Technology Highlights, 1973c).

Generally speaking, most of the early projects have been directed at serving coastal rather than inland markets. However, with the increasing severity of the domestic gas shortage, at least one midwestern gas company is actively involved in an LNG import project designed to bring such gas into the upper Midwest markets. Peoples Gas Company of Chicago has contracted with Standard Oil Company of Indiana to bring natural gas from Trinidad by LNG tanker to Louisiana, where it will be regasified and injected into the company's pipeline distribution system. If all goes according to schedule, the first of this gas will enter the Chicago market in 1976 at the rate of 200 million cubic feet per day. Total investment in the project will be \$1.5 to \$2.0 billion (Wall Street Jour., 1972a).

According to the Federal Power Commission, LNG imports are expected to reach 0.3 trillion cubic feet per year in 1975, or about 1.1 percent of the estimated domestic consumption of gas in that year. By 1980, LNG imports are expected to increase to 2.0 trillion cubic feet, but this will be equivalent to only 8 percent of the total consumption in 1980 (Federal Power Comm., 1972, p. 3).

Synthetic Natural Gas

Another new energy source with intermediate- to long-range importance is synthetic natural gas (SNG), which is made from crude oil, naphtha, and other petroleum-based feedstocks, most of them imported. Whether foreign naphtha will be available in sufficient quantities (750,000 barrels per day by 1980) is questionable. Only one SNG plant was actually in operation by mid-1973, but 35 other plants are either under construction or in the planning or engineering stage. If all of the plants on the drawing boards are completed, their combined capacity will be 5.5 billion cubic feet per day (Wett, 1973). This would be equivalent to more than 2.0 trillion cubic feet per year, or to about 9 percent of the natural gas consumption in the United States in 1972.

The Midwest Region will benefit directly from this program, for eight of the proposed plants are to be located there. Five of them are planned for Illinois and one each for Missouri, Michigan, and Ohio. The combined initial planned capacity of these plants is 1,216 million cubic feet per day (Wett, 1973), which would be equivalent to about 8 percent of the region's 1972 total gas consumption. The first of these plants, at Marysville, Michigan, came on stream in October, 1973 (Oil and Gas Jour., 1973h), and most of the other plants should be operating by 1976. Preliminary estimates for the cost of SNG from these plants are between \$1.00 and \$1.50 per thousand cubic feet. However, recent increases in the price of feedstocks, such as propane and naphtha, plus inflation of construction costs have caused prices to escalate sharply. For example, Algonquin SNG, Inc., is building a plant at Freetown, Massachusetts. In 1971, delivered prices were projected at \$1.80 per million Btu, but in 1973 they filed a revised schedule with the Federal Power Commission indicating that the projected prices for SNG from their Freetown plant were now \$2.78 per million Btu. The reasons for the price escalation were that the price of propane had tripled (from 10 to 30 cents per gallon) and the price of naphtha had increased 52 percent (from 10.5 to 16.0 cents per gallon). Investment costs for the plant had increased from \$39.5 million to \$60.0 million during the two-year period (Internat'l. Gas Technology Highlights, 1973e).

In light of such cost escalations and the forecast shortages in raw material feedstocks, some of the contemplated SNG plants may not be built. In fact, the completion of two proposed SNG plants in New Jersey and Oregon has been delayed because the required feedstocks for the plants have not been secured (Internatl. Gas Technology Highlights, 1973a; 1973b).

Synthetic natural gas derived from petroleum-based feedstocks should be considered only as a stop-gap, short-term source of energy, for coal gasification and liquefaction will be superior methods of obtaining energy, both from the viewpoint of cost and the wise use of resources.

Coal Gasification and Liquefaction

Coal gasification and liquefaction offer tremendous potential in the future because the coal resource base of the United States completely dwarfs our resources of oil and natural gas. The Midwest is favorably situated for the development of such an industry, as has been previously discussed by Risser (1968). The Panhandle Eastern Pipe Line Company, in conjunction with Peabody Coal Company, had planned to build a coal gasification plant in Illinois, but recently announced that the project would be temporarily shelved and a plant in eastern Wyoming substituted (Internatl. Gas Technology Highlights, 1973d). This represented a temporary setback for the Midwest, but ultimately such plants will be built here to take advantage of the region's vast coal reserves and close proximity to major markets. The first commercial coal-to-gas plants, which are planned for completion in the mid-1970s in New Mexico, will use the Lurgi process.

Despite much effort for many decades, commercial coal gasification on a large scale is still considered by many to be several years away. Director H. Guyford Stever of the National Science Foundation, in recent testimony before the House of Representatives Science & Astronautics Energy Subcommittee, noted that, while 12 coal gasification plants *could be* in operation by 1985, "*...it is important to realize that it will be in the 1990s before coal gasification can substantially supplement our natural gas supply.*" (Coal Age, 1973.)

The technology to produce synthetic liquid fuels from coal is even less advanced than the gasification technology (Natl. Petroleum Council, 1971, p. 126). As a result, it appears that coal liquefaction will not help to meet our energy needs until sometime after 1985.

Solvent-Refined Coal

Because of the expense and problems involved in using western coals and the unavailability of flue-gas desulfurization technology, much interest has arisen in finding a way to clean up high-sulfur coals. Conventional washing, froth flotation, and gravity separation methods are incapable of cleaning most high-sulfur coals sufficiently to meet some current standards. Therefore, research is being carried out to develop a chemical method of "refining" the coal to remove the bulk of the sulfur and non-combustible material occurring in the raw coal.

An 18-million-dollar pilot plant with a capacity of producing 50 tons of solvent-refined coal (SRC) per day is now under construction at Fort Lewis, Washington. The project is being financed by the Office of Coal Research (OCR), U.S. Department of the Interior. The Pittsburgh & Midway Coal Mining Company (P & M), a subsidiary of Gulf Oil Co., developed the process being used at the plant and will operate the unit for OCR. The process is reported capable of converting coals (except anthracites) of any sulfur content into a solid fuel with a heat value of 16,000 Btu per pound (nearly one-third higher than the heat value of a typical bituminous coal), a sulfur content of less than 1.0 percent, and 0.1 percent ash. The cost of solvent-refined coal, based on small-scale tests, has been estimated as being equal to the cost of the raw coal (in cents per million Btu) plus 35 cents per million Btu for processing (Oil and Gas Jour., 1972).

The long-range contribution of solvent-refined coal is hard to predict. Although the process has much potential, its ultimate success will depend on perfecting the method and on its cost relative to synthetic liquid and gaseous fuels produced from coal by other processes. SRC is not likely to have much of an impact until the 1980s at the earliest.

ENERGY CONSERVATION

The question has been raised as to what extent conservation and more efficient use of energy might allow the United States to reduce a significant part of its future demand for energy. The Office of Emergency Preparedness (1972, p. ii) issued a report in October 1972 in which the possibility of significantly reducing energy demand in the United States by 1980 was indicated. Measures needed to achieve adequate conservation include: (1) improvement of insulation in homes; (2) adoption of more efficient air conditioning systems; (3) shifting of intercity freight from truck to rail, intercity passenger traffic from airplanes to surface means, and urban passenger traffic from private automobile to mass transit; (4) consolidating shipments of urban freight; and (5) introduction of more efficient industrial processes and equipment.

The estimated savings in energy consumption shown in the report were based on the assumption that the conservation measures suggested can actually be implemented. No in-depth analysis of the feasibility of implementation, of consumer acceptance, or of impact on the economy was undertaken. However, total annual energy savings as the result of the implementation of such measures would be only 4.3 quadrillion Btu by 1975 (Office of Emergency Preparedness, 1972, p. vii-ix), which represents a reduction of 5.4 percent of the projected energy consumption (80.27 quadrillion Btu) for 1975 (Dupree and West, 1972, p. 17). The estimated annual savings on energy by 1980 would be equivalent to 7.3 million barrels per day. This amounts to 2.66 billion barrels or 14.97 quadrillion Btu per year. Energy conservation measures, *if they can be implemented*, could reduce estimated energy consumption in 1980 (96.02 quadrillion Btu) by 15.6 percent. Despite this reduction, the energy demand for 1980 would still be 12.4 percent higher than it was in 1972. Proposed energy conservation measures will help slow down the rate of growth in energy use, but they will not solve the problems of energy shortages.

CONCLUSIONS

1) The energy crisis that currently faces the United States is not a short-term phenomenon. It is likely that it will be with us for at least the next decade.

2) Although the recent emergence of environmental activism and legislation has compounded the current energy crisis, it is not the cause of the shortages.

3) The current shortages of oil and natural gas do not result from exhaustion of reserves and potential resources in the United States, but rather from the fact that we have used up the readily available reserves to the limit of their maximum efficient productivity.

4) The Federal Power Commission's regulation of wellhead prices for natural gas has distorted the normal market operations so that we have, in effect, encouraged the consumption of gas—the fuel in shortest supply—for uses for which other, more abundant fuels could suffice. The other effect of the hold-down on prices has been to discourage the drilling for new gas reserves, which, in turn, has contributed to the decline in available natural gas.

5) In the past, the industrial market in the Midwest Region has depended on coal and natural gas to supply 85 to 90 percent of its fossil fuel needs. Until the recent gas shortages, the trend was from coal to gas. Although the region is essentially self-sufficient in coal, it must import more than 90 percent of its oil and natural gas requirements.

6) Although the Midwest Region is abundantly endowed with coal resources, practically all of them have a sulfur content too high for compliance with current or proposed air-quality standards for sulfur oxides emissions. Approximately 76 percent of the reserves contain 3.0 percent or more sulfur, and only 3.8 percent of the region's coals contain 0.7 percent or less sulfur.

7) Continued use of coal by industry (and other consumers) in the Midwest Region after the mid-1975 EPA deadline will be possible only if one or more of the following schemes can be implemented:

- a) Perfection of technically feasible and economically competitive flue-gas desulfurization devices and their installation on boiler units.
- b) Conversion of boilers to enable them to burn western low-sulfur coals, provided supplies of such coals can be procured.
- c) Blending of low-sulfur coals with high-sulfur coals in such a ratio that the standard of 1.2 pounds of sulfur oxides per million Btu of heat input can be met.
- d) Conversion to a dual-fuel system in which low-sulfur oil or natural gas is burned jointly with high-sulfur coals in such a ratio that the 1.2 pound limit is met.

- e) Use of supplementary control systems that involve close monitoring of the ambient air and reduction in operating loads during periods of atmospheric inversions to maintain primary standards.

8) Over the longer run, continued use of coal is likely to depend upon the eventual perfection of the solvent refining process for cleaning up coals and/or on the conversion of coal into synthetic gas and oil. However, the widespread use of such processes will not occur until the 1980s or later.

9) Because natural gas is not likely to be available in sufficient amounts to meet all of the expected demands for it, allocation of available supplies will result in curtailments to certain users, particularly the industrial and utility consumers on interruptible contracts, although some consumers on firm contracts also will be cut off for varying lengths of time.

10) For many industrial consumers of coal in the Midwest Region, the only real options open in the immediate future are to switch to (or increase use of) refined petroleum products or to obtain a variance to continue burning high-sulfur coals. However, distillate fuel oils are expected to be in very short supply this winter, and how quickly domestic coal supplies can be increased to meet new demands is problematical. It is therefore likely that there will be plant closings this winter during periods of peak demand.

11) Although conservation of energy through utilization of more efficient processes, improved insulation, and other measures can help to stretch the available supplies, it cannot solve our energy crisis in the immediate future.

12) Mandatory fuel allocation programs instituted by the Federal Government on November 1, 1973, may be able to increase the effective supply by shifting surpluses in one area to regions where deficits exist. However, such programs cannot increase the actual amount of fuel available for use.

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