THE GAS SUPPLIES OF THE UNITED STATES--PRESENT AND FUTURE

Gordon K. Zareski, Bureau of Natural Gas

Federal Power Commission, Washington, D.C. 1/

INTRODUCTION

The growth of natural gas service in the United States between 1945 and 1970 must rank as one of the great success stories of American business and technology. During this period the number of miles of utility gas mains carrying natural gas increased from 218,000 miles to 906,925 miles, and a $17 billion high-pressure gas transmission pipeline network was extended into all of the lower 48 states. Natural gas consumption increased at an annual average rate of about 6.5 percent and moved from a position where it supplied 13 percent of the Nation's total energy consumption in 1945 to the point where it provided about 33 percent of the total energy consumed in 1970.

The Nation's gas reserves are distributed among 25,000-30,000 gas fields (shaded areas of Figure 1) which in many instances are geographically remote from the gas consuming areas. The pipeline system which connects the consuming areas with their respective areas of supply can, in a general way, be characterized by a number of national "pipeline corridors." For instance the interstate gas consumed in the New England, Great Lakes, Appalachian, and Southeastern regions (proportional to the width of the arrows in Figure 1) originates chiefly in the South Louisiana, Texas Gulf Coast, and Hugoton-Anadarko (Oklahoma Panhandle region) gas supply areas. In addition to these domestic supplies, the United States is also a net importer of gas from Canada and Mexico. Although net imports during 1970 amounted to only about 3.5 percent of national consumption, imports are an important contribution to the gas supply of some areas.

The requirements for gas are expected to increase significantly during the 1971-1990 period, not only because of the growth in total energy requirements but because of the clean nature of this fuel and its premium value from a pollution control standpoint. Unfortunately the deliverable supply of natural gas, which presents the fewest pollution problems of all the Nation's present primary energy sources, will be inadequate to meet all of the demand for it.

1/ The views expressed herein are those of the author and do not necessarily reflect the views of the Federal Power Commission or of individual Commissioners.

The American gas consumer has only recently begun to be affected by the developing imbalance between the supply of this environmentally superior fuel and the burgeoning demand for it. The emerging shortage of gas is evidenced by major pipeline companies and distributors in many parts of the country being forced to curtail service to some existing customers and to refuse requests for additional gas service from many new customers and from present large industrial customers. Present and projected trends in the supply and demand for gas in the United States indicate that the national supply deficit which has recently developed will continue throughout the 1972-1990 period.

DEMAND

Until recently gas requirements (demand) of the United States were equivalent to gas consumption, because gas supplies were abundantly available as new markets for gas were developed. In retrospect then, demand for gas was approximately equal to domestic net production plus net pipeline imports. Prospectively, however, under conditions of insufficient gas supply, consumption will be less than demand.

While numerous projections of the future demand for gas have been made, the most recent projection of future gas requirements developed by the Future Requirements Committee has been adapted in this analysis as the yardstick against which anticipated gas supply will be measured. On this basis the annual demand for gas in the lower 48 states is projected to grow from 22.6 trillion cubic feet in 1970 to 46.4 trillion cubic feet in 1990 (Figure 2). The growth of demand to this level reflects an anticipated average annual compound growth rate of about 3.7 percent during the 1970-1990 period compared to a historical average annual compound growth rate of over six percent for the 1950-1970 period.

HISTORICAL RESERVE AND PRODUCTION TRENDS

The historical domestic supply position of the United States, as reported by the American Gas Association, is illustrated in Table I and Figure 3. These data exclude Alaskan resources because they are not presently available to the markets of the lower 48 states.

Prior to 1968 the annual net additions to reserves exceeded the annual production of gas, resulting in a surplus of gas found over the amount of gas consumed. In 1968, for the first time, production exceeded reserve additions by 7.3 trillion cubic feet. This historic reversal was followed by excesses of production over reserve additions of 12.3, 10.7, and 12.5 trillion cubic feet in 1969, 1970, and 1971, respectively. Because reserve additions in the past 4 years have been considerably below the historical level and because production has been increasing, the year-end inventory of proved reserves has been reduced from its historical high of 289.3 trillion cubic feet in 1967 to a current level of 247.4 trillion cubic feet.

A distinct change in the rate of production occurred during 1971 when production increased only 0.1 trillion cubic feet. Although this change results from many factors, including the fact that the 1971-72 winter was unseasonably mild in many parts of the country, it may also indicate that the Nation's peak productive capacity is being approached. As will be discussed later, this peak has been projected to occur beginning about 1973.

One commonly used indicator of the Nation's gas supply posture is the reserve to production (R/P) ratio. The R/P ratio is a measure of the remaining years of proved reserves at the current level of production. Although the R/P ratio does not consider many of the physical limitations which govern the rate of gas withdrawal, it is useful as an indicator of gas supply. The R/P ratio has declined steadily from 26.8 in 1950 to 11.3 in 1971. Considered by itself, the historical decline in the R/P ratio was not a major source of concern because it was believed by some that, ideally, the R/P ratio would stabilize at a point sufficient to enable the quantities of gas demanded to be met without the development of excessive reserves. A decline below the ideal level, however, results in deliverability problems, i.e. reserves are insufficient to deliver the peak quantities of gas needed.

The findings (reserve additions) to production (F/P) ratio is another indicator which is sometimes useful when talking about gas supply. While reserve additions have fluctuated about an average value, production has been increasing, causing the F/P ratio to decline from about 2 in the early 1950's to 0.4 in 1971, indicating that gas reserves are now being consumed faster than they are being renewed (Figure 4).

FUTURE DOMESTIC GAS SUPPLY

Any analysis of future domestic supply necessarily involves an estimate of the level of future reserve additions. A recent analysis of natural gas supply and demand relationships by the Federal Power Commission (FPC) Staff reached several conclusions with respect to the future annual reserve additions depicted in Figure 5. First, an increase from the present level of annual reserve additions to the average national finding level of the past ten years (17 trillion cubic feet annually) is consistent with factors such as estimates of the undiscovered potential gas remaining and recent regulatory actions which have increased the wellhead price of gas in several important supply areas. Second, it is unlikely that annual reserve additions will increase to a sustained level higher than the average of the past 10 years.

Finally, it is improbable that findings will increase immediately to the 17 trillion cubic feet level from the 1970 level of 11.1 trillion cubic feet. Accordingly, for the purpose of projection, it is assumed that annual reserve additions will increase by approximately one trillion cubic feet per year from the 1970 level of about 11 trillion until additions reach 17 trillion cubic feet per year in 1976. Reserve additions are subsequently projected at 17 trillion cubic feet per year during the period 1977 through 1990.

Cumulative reserve additions under this anticipated schedule would amount to 325 trillion cubic feet from 1971 through 1990. This rate of reserve additions is compatible with current independent estimates of potential gas supply by the Potential Gas Committee (PGC) and the United States Geological Survey (USGS). Under this schedule of annual reserve additions, cumulative additions through 1990 would represent the development of about 38 percent and 21 percent, respectively, of gas supply in the lower 48 states as estimated by PGC and USGS.

Average reserve additions for the five year period 1971 through 1975 would be 14 trillion cubic feet per year which was also the average experienced during the period from 1966 through 1970. Reserve additions for 1971 were projected by the Federal Power Commission Staff to be about 12 trillion cubic feet (Tcf). In 1971, reported additions amounted to only 9.4 Tcf. Some reserves resulting from drilling on acreage leased in the December, 1970 Federal lease sale in offshore South Louisiana were not included, however, because data was insufficient to properly estimate the amount of proved reserves.

Estimates by the FPC Staff have been made of the future annual production levels which could be supported by these projected additions to reserves. The period from 1971 through 1975 was focused on by employing the projected national additions to reserves in an area-by-area analysis of the major producing areas of the country. Each area was examined by evaluating past drilling trends, reserve finding rates and production history as well as the potential of the area for sustained contributions to national supply. Two things were established through this analysis: (1) our national reserve additions schedule through 1975 was reconciled with individual supply area considerations and (2) we were able to approximate the national production rate which could be anticipated by summing the area-by-area estimates of production capability.

The dynamics of the relationship between gas supply, demand, and production can result in changing inter-area relationships with the passage of time. For this reason production projections based on an area-by-area approach do not have much validity beyond five years. Beyond that time span, estimates of the production available from a given reserve base are probably best made on a national basis.

A commonly used method of approximating the productive capacity of a body of reserves is to assume that a minimum reserve to production ratio (usually 10) is required to provide for adequate delivery rates. This rule of thumb approach does not consider the sometimes rather wide variations experienced with actual gas reservoirs. In an attempt to make an improved approximation of future long-term gas deliverability, the FPC Staff developed a method to estimate the national production capability for each year by the computerized application of a "national availability curve." This curve was synthesized from FPC Form 15 deliverability data from more than 900 individual sources of supply which comprised more than 88 percent of the interstate and 62 percent of the national reserves in 1968. This method is superior to an R/P limit approach because it is derived from deliverability data which considers actual reservoir production characteristics.

The production projection for 1971 through 1990 (Figure 6) was derived from presently proved reserves plus anticipated reserve additions as scheduled by the methods described above and was computed using the "national availability curve." Annual gas production has increased exponentially in the past. In the 1971-1990 time interval, however, it is projected to peak at about 24.8 trillion cubic feet, around 1973-1974, and thereafter decline and stabilize at a somewhat lower level in the 1980's. Because demand is projected to grow while domestic supply is projected to stabilize within the time frame considered, a gas supply shortfall will develop. This supply deficit is projected to increase annually and reach 28.6 trillion cubic feet by 1990 (Table II).

Future supply and demand will not develop exactly as depicted in the above projections because precision is not possible in such a projection. Both demand and domestic production are susceptible to considerable deviation from the levels projected. In terms of sensitivity to error, it is obvious that the projection of domestic production is very susceptible because of its dependence upon the level of future reserve additions. Even if much more optimistic levels of reserve additions (and hence productive capacity) are assumed, however, increasing demand cannot be satisfied. Figure 7 illustrates a comparison of demand and three different levels of productive capacity should annual reserve additions exceed 17 trillion cubic feet per year. Reserve additions of 20, 25, and 30 trillion cubic feet are programed for every year beginning with 1971. Even under the best of these conditions, a substantial supply gap develops in the mid-1970's and worsens over the time span considered.

SUPPLEMENTAL GAS SUPPLIES

When considered against the backdrop of a projected indigenous supply deficiency, the importance of the future role to be played by supplemental sources of gas is obvious. Pipeline imports of gas from Canada and Mexico constitute the only substantive source of supplemental gas presently available. However, significant supplemental supplies of gas are expected to become available from several other sources in the future as development of the associated technologies and/or required systems proceeds. These major new supplemental sources are liquefied natural gas imports (LNG), gas from coal, and gas from Alaska (Table III). A positive contribution to gas supply will also be made by reformer gas derived from liquid hydrocarbons (SNG). However, the quantification of meaningful long range projections with respect to this source is not practicable at this time.

Pipeline Imports

During 1970 net imports of natural gas to the United States from Canada and Mexico amounted to 794.5 billion cubic feet. Of this amount, net imports from Mexico were only 26.7 billion cubic feet. There appears to be little reason to expect any substantial increase in imports from Mexico chiefly because of Mexico's relatively small undiscovered gas potential. There are prospects for increased overland imports of gas from Canada, however, which depend in large measure upon the timely development of gas reserves in excess of those required to satisfy Canada's future internal requirements.

In April 1969 the Canadian Petroleum Association estimated the ultimate potential raw recoverable natural gas reserves of Canada to be 720.9 trillion cubic feet (at 14.73 psia and 60°F.). If the total raw recoverable gas discovered through 1970 is subtracted from this value, a remaining undiscovered potential of 634.8 trillion cubic feet of raw gas is derived. Much of this undiscovered potential is attributed to Canada's frontier areas comprised of Northern Canada, the Arctic Islands, the MacKenzie Delta, Hudson Bay, and the continental shelf areas off the Atlantic, Pacific, and Arctic coasts. An important factor relative to Canada's natural gas potential is the interrelationship between the possible development of the potential in the MacKenzie Delta and Arctic Islands areas and the effect that this would have in unlocking the proven and potential gas resources of Alaska. The successful development of Canada's MacKenzie Delta and Arctic Islands resources would greatly enhance current proposals to move gas from Alaska and Northern Canada to Canadian and United States markets.

Several significant gas discoveries have already been made in the frontier areas. Because of these discoveries, a future level of annual reserve additions greater than historical rates can reasonably be used to estimate the future gas surpluses which the Canadians may be able to make available for export. Annual reserve additions in Canada's traditional supply areas averaged 4 trillion cubic feet from 1966 to 1970. On the basis of the potential of the frontier areas, however, future annual average additions may be estimated to be 6.5 trillion cubic feet. Use of this finding level in conjunction with Canada's projected requirements and scheduled exports under existing licenses would result in an increase in the annually exportable volumes of 0.8 trillion cubic feet in 1970 to 1.9 trillion cubic feet by 1990 (Table III).

Liquefied Natural Gas

Many regions of the world have extensive volumes of developed natural gas reserves but have limited internal markets. These resources in conjunction with advancing technologies in the liquefaction, handling, and transportation of liquefied natural gas (LNG) have kindled an intense interest in the delivery of liquefied natural gas volumes to the energy hungry centers of the world.

At present the Federal Power Commission has authorized only one long-term marine import of LNG into the United States. Several other proposals for the long-term import of base load LNG have been filed with the Federal Power Commission, however, and a number of other prospective projects have been widely discussed in the trade press. These filed and prospective LNG projects are an indication of the future availability of long-term LNG imports to the contiguous United States. While the estimated operational dates for these projects may be based on reasonable assumptions or on the most current expectations, other more difficult factors to evaluate such as the length of time required for the necessary governmental authorizations and the construction time necessary to build the extensive facilities required make it unlikely that actual LNG imports will precisely follow current schedules and expectations. Current analyses of these projects indicate that the import of significant LNG volumes into the United States (0.3 trillion cubic feet) can first be expected in 1975 and that these imports will increase to about 2.0 trillion cubic feet annually by 1980 (Table III). In the longer term future, the degree of precision in any forecast is even less clear, but numerous companies have indicated that certain additional projects are under "active consideration" or "investigation". On this basis the growth rates expected in the 1975-1980 period should continue into the decade of the 80's, thus yielding a projected LNG availability of about 4 trillion cubic feet annually by 1990.

Gas From Coal

Progress toward the development of improved processes to produce high - B.t.u. synthetic pipeline quality gas from coal can currently be seen on several fronts. Two large-scale coal gasification pilot plants are currently in operation or under construction and plans to build two others have been firmed up. The pilot plant in operation is located near Chicago, Illinois, and employs the HYGAS process developed by the Institute of Gas Technology. A plant using the Consolidation Coal Company CO_2 Acceptor process is nearing completion at Rapid City, South Dakota. The Department of the Interior has awarded a contract to Bituminous Coal Research to build and operate a pilot plant based on their BI-GAS process near Homer City, Pennsylvania, and construction on a fourth pilot plant, intended to study the Bureau of Mines' SYNTHANE process, is scheduled to begin in September of 1972 in suburban Pittsburgh, Pennsylvania. The research and development work associated with these new coal gasification processes is not expected to be completed prior to the late 1970's.

In addition, two other major efforts have been announced to develop coal gasification facilities in northwestern New Mexico. These proposed plants would be based on an extension of the Lurgi technology which has been used in Europe for many years. The first is a project proposed by El Paso Natural Gas Company, and the second is a proposal by a consortium composed of Pacific Lighting Service Company, Texas Eastern Transmission Corporation, and Utah International Inc. Each of these projects calls for the construction of one or more gasification plants capable of producing about 250 million cubic feet per day each and would utilize some of the extensive coal reserves of the area.

The first few commercial coal gasification plants will probably be based on Lurgi technology, and the first of perhaps several Lurgi type facilities could be producing synthetic gas in commercial quantities by 1976. By 1980 the newer gasification processes will likely have been fully demonstrated which will permit the significant expansion and development of a coal gasification industry in the period beyond 1980. Several factors will bear heavily upon the rate of growth which can be attained by this new industry. Among these are the availability of substantial tonnages of coal for conversion, the tremendous capital expenditures which will be required for gasification plants and the supporting mining facilities, and the problems associated with locating the mine-plant complexes in areas able to provide the necessary uncommitted coal reserves as well as the required process water.

With these factors in mind the availability of pipeline quality gas from coal may be projected to rise from about 0.1

trillion cubic feet in 1976 to 0.3 trillion cubic feet annually by 1980 with these volumes most likely entirely attributable to Lurgi type plants. Gas available from added facilities based on the newer process technologies currently under development is projected to bring the total annual volumes of gas available from coal gasification to about 1.4 and 3.3 trillion cubic feet, respectively, in years 1985 and 1990.

Gas From Alaska

The year-end 1971 proved reserves of natural gas in Alaska were 31.4 trillion cubic feet. Of this amount about 26 trillion cubic feet are attributable to the Prudhoe Bay area of the North Slope. It is widely known, however, that because the North Slope gas reserves are chiefly associated-dissolved volumes related to the North Slope oil reserves, this gas can become available to market only as provision for the production of the oil is provided. Any projection of the availability of North Slope gas to the markets of the lower 48 states is therefore heavily dependent on the availability and timing of a transport capability for both the oil and the gas.

A great deal of planning, research, engineering and other preliminary work with respect to a Trans-Alaska oil pipeline has already been completed. However, considerable delays in the initiation of construction of the proposed pipeline have been encountered chiefly as a result of the environmental implications of the project. For the purpose of this projection, further delays are assumed to be minimal and oil production from the North Slope is assumed to begin in 1976.

Three major proposals have been advanced which would provide large diameter pipeline transportation for North Slope gas as well as that gas which may become available in Canada's Northwest frontier areas. The Gas Arctic Systems group has proposed a 1550 mile system which would connect the Prudhoe Bay area with an extension of Alberta Gas Trunk Line's existing system in Alberta, Canada. This system could make gas available to U.S. Westcoast and Midwest markets through pipeline interconnections with existing pipeline systems. Sponsors of the Mountain Pacific Project have proposed the construction of a system passing from the North Slope area through the Fort Liard region of the Northwest Territories and then southward through British Columbia to the international border where it would connect with a newly proposed U.S. carrier and serve Pacific coast markets as far south as Los Angeles. A third proposal, advanced by the Northwest Project Study Group, would provide a 2,500 mile line extending from Prudhoe Bay to the Canadian-U.S. international boundary near Emerson, Manitoba. Whichever line is ultimately built will likely be capable of moving approximately three billion cubic feet of gas daily when fully powered.

The projection of the availability of Alaskan gas (Table III) is based on the assumption that a gas pipeline system traversing Canada will be completed for initial service in late 1976 or in 1977. Although the timing of current plans to provide for the pipeline movement of North Slope oil and gas is subject to considerable conjecture, a projection of 0.7 trillion cubic feet of Alaskan gas in 1980 is reasonable. Alaskan natural gas production and transmission capability should expand to 1.3 and 2.3 trillion cubic feet annually by 1985 and 1990, respectively. These projections exclude those Canadian volumes which may be transported in the same pipeline system; all Canadian gas has been included with the projection of Canadian imports.

CONCLUSIONS

Our projection of the United States' gas supply-demand balance through 1990 is summarized in Table IV and Figure 8. The availability of gas from all sources is expected to fall increasingly behind demand. An annual unsatisfied demand for gas of about 9 trillion cubic feet by 1980 will increase to about 17 trillion cubic feet by 1990. Domestic production of natural gas is projected to peak in the mid-1970's and fall slowly thereafter, placing an increasingly heavy future reliance on imports and other supplemental gas supplies. While this outlook may appear to be pessimistic, it is not predicated on a pattern of failure. The future prospects for domestic reserve additions, pipeline and LNG imports, Alaskan gas, and synthetic gas from coal have been carefully analyzed and a reasonably successful program of development and implementation for each has been assumed. The purpose of these projections has been to approximate the likely national supply-demand balance over the period considered and to establish some idea of the probable supply-demand posture which the Nation can expect. If these projections portray the future course of events with any degree of accuracy, it is obvious that solutions to the Nation's gas supply problem or a significant modification of the anticipated supply-demand balance will not be simple or swift.

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Table I

UNITED STATES NATURAL GAS SUPPLY EXCLUDING ALASKA
1950-1971
(Volumes in Tcf)

Year	Net Production (1)	Reserve Additions (2)	Year-End Reserves (3)	R/P Ratio (3)/(1) (4)	F/P Ratio (2)/(1) (5)
1950	6.9	12.0	184.6	26.8	1.7
1951	7.9	16.0	192.8	24.4	2.0
1952	8.6	14.3	198.6	23.1	1.7
1953	9.2	20.3	210.3	22.9	2.2
1954	9.4	9.6	210.6	22.4	1.0
1955	10.1	21.9	222.5	22.0	2.2
1956	10.9	24.7	236.5	21.7	2.3
1957	11.4	20.0	245.2	21.5	1.8
1958	11.4	18.9	252.8	22.2	1.7
1959	12.4	20.6	261.2	21.1	1.7
1960	13.0	13.8	262.2	20.2	1.1
1961	13.4	16.4	265.4	19.8	1.2
1962	13.6	18.8	270.6	19.9	1.4
1963	14.5	18.1	274.5	18.9	1.2
1964	15.3	20.1	279.4	18.3	1.3
1965	16.3	21.2	284.5	17.5	1.3
1966	17.5	19.2	286.4	16.4	1.1
1967	18.4	21.1	289.3	15.7	1.1
1968	19.3	12.0	282.1	14.6	0.6
1969	20.6	8.3	269.9	13.1	0.4
1970	21.8	11.1	259.6	11.9	0.5
1971	21.9	9.4	247.4	11.3	0.4

Source: American Gas Association

Table II

UNITED STATES DOMESTIC SUPPLY AND DEMAND
1972-1990
(Volumes in Tcf)

Year	Demand	Production	Domestic Supply Deficit
1972	26.1	23.8	2.3
1973	27.7	24.7	3.0
1974	28.8	24.8	4.0
1975	29.8	24.7	5.1
1980	34.5	20.4	14.1
1985	39.8	18.5	21.3
1990	46.4	17.8	28.6

Table III

SUPPLEMENTAL SUPPLIES OF NATURAL GAS
Projected 1971-1990
(Volumes in Tcf)

Year	Pipeline Imports	LNG Imports	Gas From Coal	Alaskan Gas	Annual Total
1970	0.8	*	-	-	0.8
1971	0.9	*	-	-	0.9
1972	1.0	*	-	-	1.0
1973	1.1	*	-	-	1.1
1974	1.1	*	-	-	1.1
1975	1.2	0.3	-	-	1.5
1980	1.6	2.0	0.3	0.7	4.6
1985	1.9	3.0	1.4	1.3	7.6
1990	1.9	4.0	3.3	2.3	11.5
Total	31.1	38.0	17.3	20.6	107.0

*Small Volumes

Table IV
UNITED STATES GAS SUPPLY-DEMAND BALANCE
Actual 1966-1970; Projected 1971-1990
(All Volumes in Trillions of Cubic Feet @ 14.73 Psia and 60° Fahrenheit)

Year	Annual Demand 1/	Net Pipeline Imports	LNG Imports	Gas From Coal	Gas From Alaska	Gas From Liquid Hydrocarbons	Domestic Production	Annual Consumption	Un-Satisfied Demand	Reserve Additions	Year-end Reserves	R/P Ratio
1966	17.9	0.4	-	-	-	-	17.5	17.9	0.0	19.2	286.4	16.4
1967	18.8	0.5	-	-	-	-	18.4	18.8	0.0	21.1	289.3	15.8
1968	19.9	0.6	*	-	-	-	19.3	19.9	0.0	12.0	282.1	14.6
1969	21.3	0.7	*	-	-	-	20.6	21.3	0.0	8.3	269.9	13.1
1970	22.6	0.8	*	-	-	-	21.8	22.6	0.0	11.1	259.6	11.9
1971	24.6	0.9	*	-	-	-	22.8	23.7	0.9	12.0	248.8	10.9
1972	26.1	1.0	*	-	-	**	23.8	24.8	1.3	13.0	238.0	10.0
1973	27.7	1.1	*	-	-	**	24.7	25.8	1.9	14.0	227.3	9.2
1974	28.8	1.1	*	-	-	**	24.8	25.9	2.9	15.0	217.4	8.8
1975	29.8	1.2	0.3	-	-	**	24.7	26.2	3.6	16.0	208.7	8.4
1980	34.5	1.6	2.0	0.3	0.7	**	20.4	25.0	9.5	17.0	186.1	9.1
1985	39.8	1.9	3.0	1.4	1.3	**	18.5	26.1	13.7	17.0	175.4	9.5
1990	46.4	1.9	4.0	3.3	2.3	**	17.8	29.3	17.1	17.0	170.4	9.6
1971-1990 Totals	707.6	31.1	38.0	17.3	20.6	**	414.2	521.2	186.4	325.0	-	-

* Very small volumes
** Insufficient data for quantitative projection: unsatisfied demand will be reduced by the amount of SNG actually produced.
1/ Contiguous 48 states.

1970 INTERSTATE NATURAL GAS MOVEMENTS

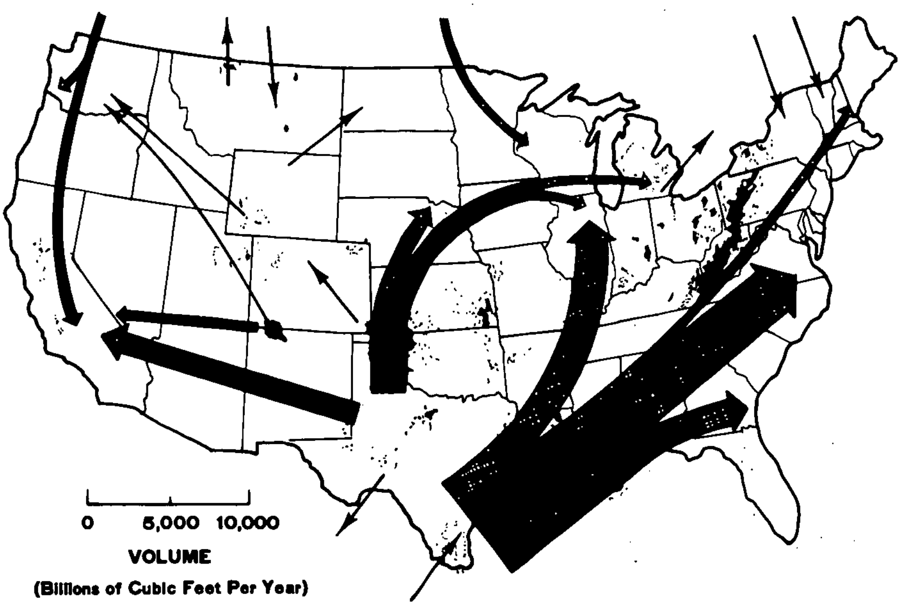


Figure 1

DEMAND FOR NATURAL GAS

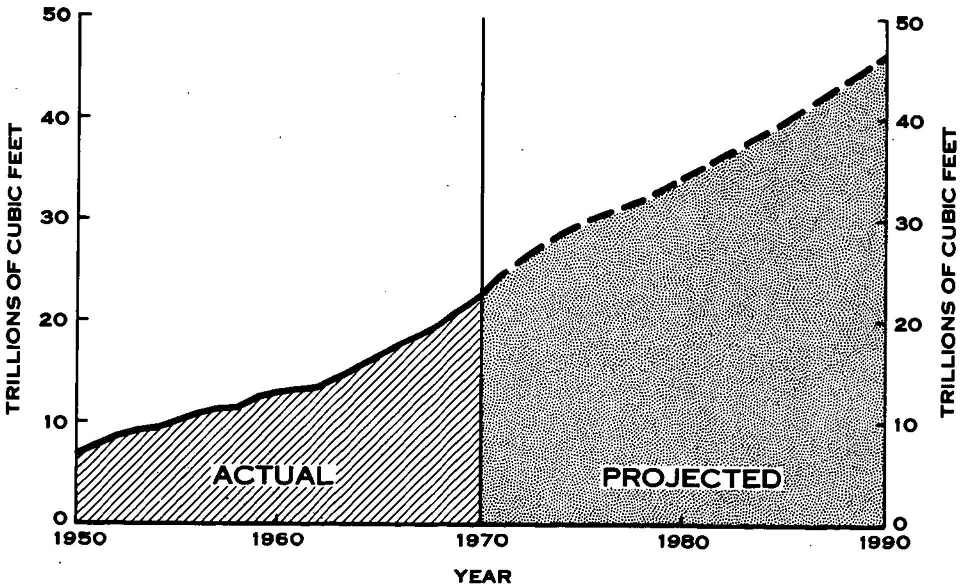
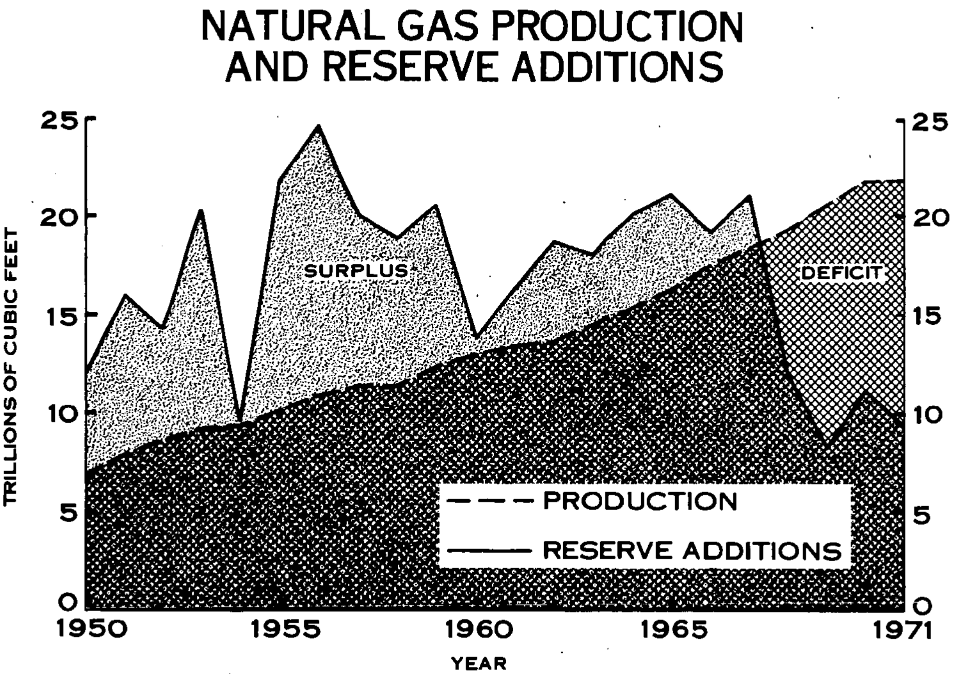


Figure 2



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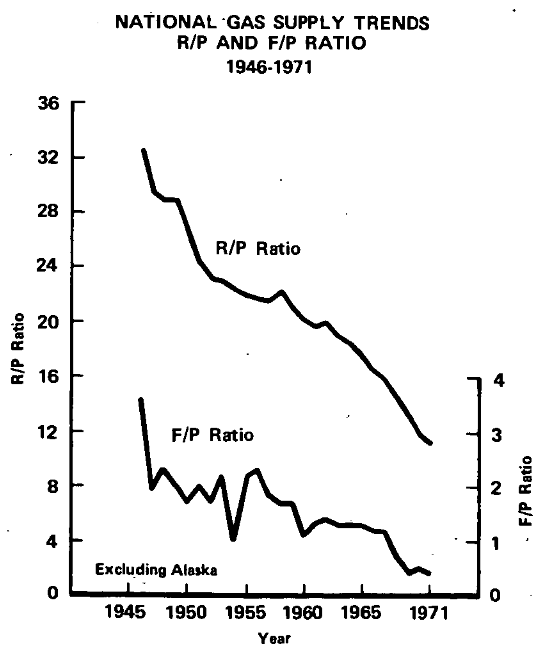


Figure 4

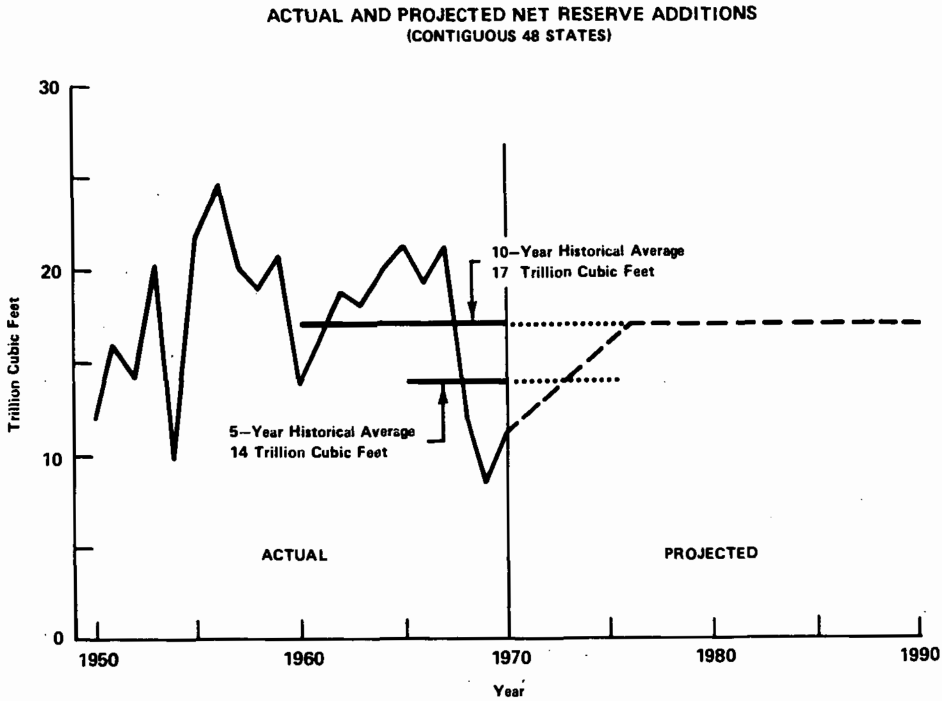


Figure 5

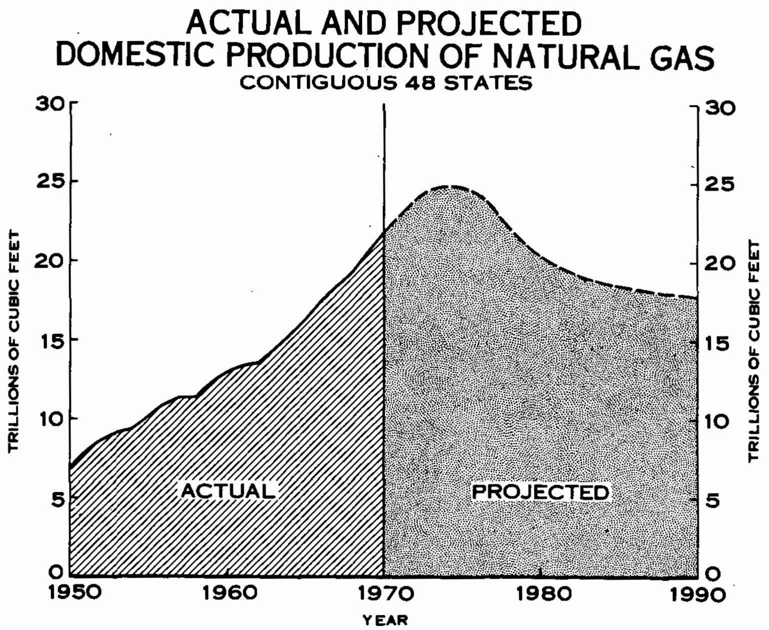


Figure 6

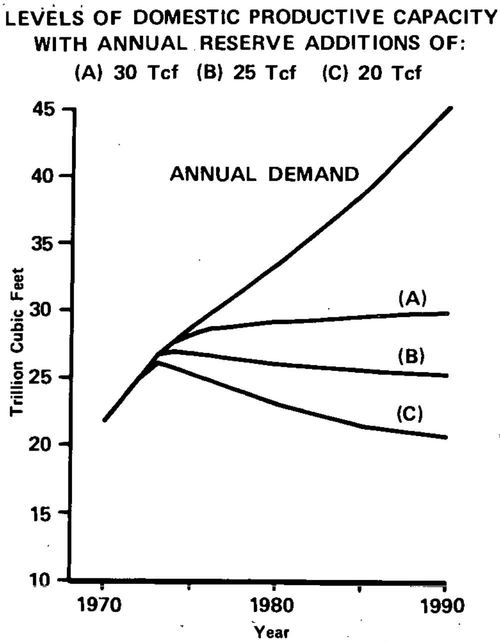


Figure 7

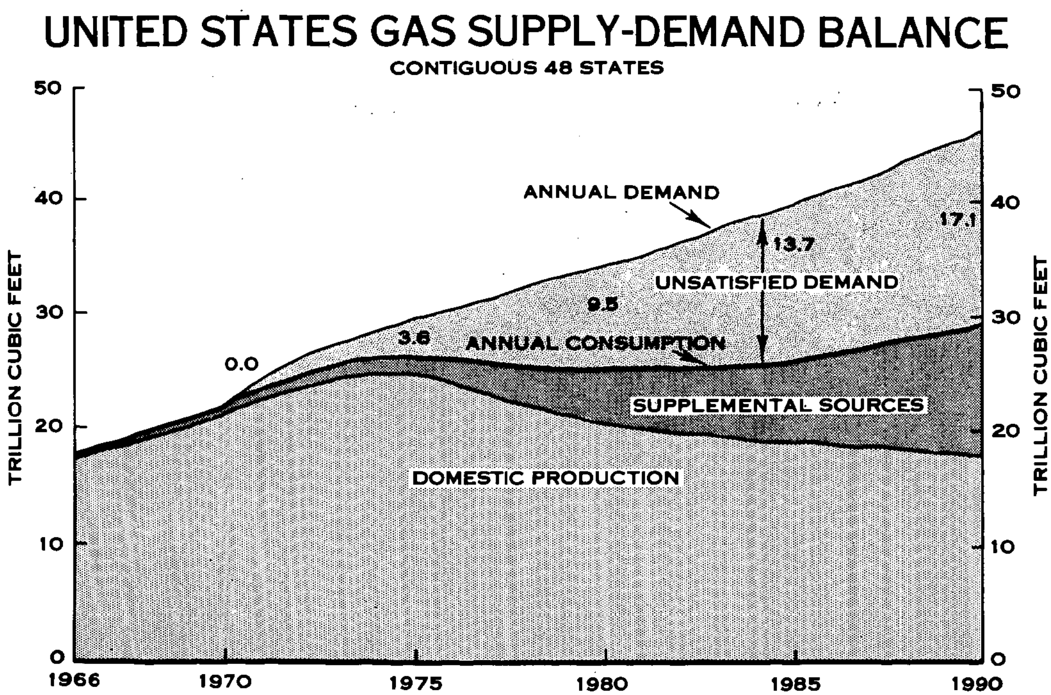


Figure 8

Low Sulphur Coal Supplies for Environmental Purposes

Thomas W. Hunter

Division of Fossil Fuels, Bureau of Mines,
United States Department of the Interior
Washington, D. C.

As the agenda of this symposium emphasizes national concerns with regard to the adequacy of supplies of all forms of fuel, consistent with environmental requirements, it is essential that coal be placed in perspective vis-a-vis other energy sources, and with regard to the many problems associated with its availability both as a solid fuel and in converted form.

The vital role that coal must play if the Nation's energy requirements are to be met, and if a sound balance is to be achieved between indigenous and foreign sources of energy supply, is underscored by the serious need for supplemental supplies to meet the insatiable demands being made on natural gas, the decline in proved indigenous oil reserves, and increasing dependence on imported oil, with its consequent implications on national security. Equally significant is that economic, technologic, and societal problems also are delaying the availability of large-scale nuclear power availabilities.

Although environmental concerns cover a broad spectrum of considerations, anxieties with respect to the adequacy of supplies of low-sulphur coals, and of other coals for which utilization can be made viable for environmental purposes through chemical processing and other new technologies, center principally around the enormously increasing needs of electric utilities for their basic energy supplies. Closely related are the relative availabilities of the other energy sources and the extent to which low-sulfur coals are held, and used, for coke production for steelmaking both at home and abroad.

There is no question regarding the enormity of our coal resources, particularly as compared to the relatively limited resources of our other indigenous energy fuels, nor even with respect to our large reserves, per se, of low-sulphur coals. There are many problems involved in the availability of the latter, however, including their extent and location; strong deterrents to, or lack or incentives for, the development of substantially increased capacity for their production; the extent of their need in relation to potential availabilities of other energy supplies, including imports; the development of technologies to condition our high-sulphur coals to meet environmental standards; and increasingly severe sulphur content limitations which correspondingly narrow even the low-sulfur coal resource base.

Although in the interplay of economic forces coal's percentage contribution to electric power generation has declined, from 1955 to 1970 tonnages consumed increased from 141 million to 320 million tons. Notwithstanding optimism for power generation from other sources, it has been estimated that there will be a need for between 800 million and 1 billion tons of coal for electric power generation by the end of the century if the Nation's total demand is to be satisfied.

Will we be able to provide low-sulphur coal in this magnitude, or its equivalent through process technology, for power generation alone by the year 2000?. And what will the availabilities be in the near-term and intermediate periods?

Environmental requirements, rules, and regulations are now! The magnitude and complexities involved are compounded by the relative suddenness with which they have been promulgated, and by their progressively severe limitations. Rather abruptly, and with little time for adjustment, we have been brought to the realization that the large reserves of our great energy resources--upon which our national strengths and social attainments were built and our expectations for the future predicated--no longer are as abundantly usable as in the past. Because of evolving social concepts our energy resource base is being sharply reduced. The name of the game today is quality, not quantity.

As patterns of control already have been set, it is essential that we have more detailed and accurate information on the extent, nature, and location of our low-sulphur coal reserves, and some indication of their relative costs to consumers. Incentives must be provided for the development of substantially increased productive capacity, and for providing the transportation facilities that will be required in the movement of these coals to markets. Also, new technologies of combustion will be required to meet differences in quality characteristics.

Whatever the reserves, the availability of mining capacity will be the major determinant of the availability of low-sulphur coal--and at the present time there are many strong deterrents to capital investments in increased capacity, especially in the East. Principal among these are uncertainties regarding the growth and timing of nuclear power generation and of utility commitments thereto, regardless of relative costs; increased oil imports; increasingly severe air pollution regulations; and some expectations that stack gas emission processes to permit the use of high-sulphur coals will obviate the need for heavy investments in new capacity for low-sulphur coal production. As a result, in recent years the great preponderance of new deep mine commercial capacity has been developed only under long term contracts. Since large underground mines are developed for a life span of 20 to 30 years, contractual assurances of continuing markets will be necessary to encourage investment of the many millions of dollars that will be required for the development of large-scale increases in capacity. Essentially, this means long term contracts with electric utilities.

Another important factor in the availability of coal is an adequate supply of transportation facilities, particularly of railroad hopper cars. As there is little or no storage at the mines, except for unit train shipments, mines generally cannot operate without an adequate supply of coal cars, which determine the number of days of active mine operation. Because of the close affinity of coal and rail transportation, the deterrents to expanded coal productive capacity also affect the development of new transportation facilities. Of considerable importance in the future will be an increase in the number of unit trains, which help to reduce transportation costs and which have contributed significantly to the shipment of low-sulphur coals from the West into Midwestern markets; and the potentials for more coal slurry pipelines and "mine-mouth" generating plants. An impressive change in energy transportation in recent years has been the increasing transmission of coal-produced power from generating plants located in or near the coalfields. Only a few thousand miles of extra-high voltage (EHV) transmission lines 10 years ago were increased to nearly 26,000 miles of lines by the end of 1970, and current construction plans call for an increase to approximately 60,000 miles within this decade.

Among the major problems of low-sulphur coal supply is the uneven distribution of reserves in relation to demand. Although major markets are in the East and Midwest, the largest reserves are in the West. Based on preliminary studies by the Bureau of Mines, it is estimated that there are 251 billion tons of low-sulphur coal reserves at less than 1,000 feet in depth, of which an estimated 198 billion tons are in the West and 53 billion tons East of the Mississippi River. Of these totals, 30 billion tons are considered to be low-sulphur strippable reserves in the West at less than 100 feet deep and 2 billion tons in the East. Preponderantly, the low-sulfur reserves are at depths which would require underground mining (168 billion tons in the West and 32 billion tons in the East). Approximately 50 percent of these quantities is recoverable in mining. Supplemental surveys and analyses are being made by the Bureau of low-sulphur coal reserves and production, separately for both the Appalachian region and the rest of the country.

The low sulphur coals of the East are located primarily in the Southern Appalachian region (mostly in West Virginia, Virginia, and eastern Kentucky, with smaller amounts in Pennsylvania, Alabama, and Tennessee). There is very little low-sulphur coal in the Midwest, which is a major area of electric power generation and other coal consumption. Even with washing, the high-sulfur coals indigenous to the Midwest generally are above the sulphur limits of air pollution regulations in most States. Under current technology only the pyritic sulphur can be removed from the coal by conventional methods. Accordingly, to conform to regulations governing coal consumption, the huge markets of the Midwest will have to rely on the Southern Appalachian and Western areas for low-sulphur coal supplies, or on indigenous or other higher-sulphur coals through the use of stack emission processes or other technological developments, including coal conversions to gaseous or liquid fuels.

In the East, most of the low sulphur coal produced customarily has been used for the production of coke for steelmaking, both at home and abroad. Primarily this is because of its high cost as compared to coals heretofore used for power generation. Much of the latter has been lower cost strip-mined coal, whereas in the low-sulphur coal areas production is preponderantly from deep mines which have higher costs and which are at longer distances from consuming markets. Also, because of quality characteristics other than sulphur content, such as differences in ash fusion, many of the coals are not usable in the combustion facilities of some utilities. Accordingly, for power generation in the East under environmental regulations there will be limited supplies of low sulphur coal for some time unless and until there is a substantial increase in mining capacity, supported by contracts with utilities.

Because of the large low-sulphur coal reserves in the West, Western coals have significant potentials for becoming major suppliers to Midwestern and other easterly markets, as well as in their own areas. As an example, owing to the use of unit trains, coal now moves from Montana into Chicago and other Midwestern areas, shipments that were unthinkable only a few years ago. Although these coals are of lesser Btu content than the low-sulphur coals of the East, they are largely strip-mined coals and are appreciably less costly to produce. In addition to unit trains there also are potentials for movement by pipeline, and for the transmission of coal-produced energy by EHV. Coal slurry pipelines have proved their practicability, the best current example being the 275-mile line from the Black Mesa coalfield in Arizona to the Mohave Power Project in Nevada. Also, there are future potentials for the transmission of synthetic coal gas into markets far distant from the coal and synthetic gas producing areas.

Just as air pollution regulations are resulting in significant shifts in consumer sources of coal supply, there also will be drastic changes in the pattern of coal production as demand shifts steadily from high-sulphur to low-sulphur coal areas--until such time as the use of high-sulphur coal becomes permissible through the use of stack emission processes or other technologies, or unless it is found that environmental standards need not be as stringent in some areas as initially considered. The interim economic and social effects on communities in high-sulphur coal areas can be drastic. Some States already require extreme reductions in the level of sulphur content over relatively short periods of time, and although other States presumably have the prerogative of determining their own requirements, they will be under the influence of rather strong Federal guidelines. The EPA recently stated that about half of the new State standards limit the sulphur content of coal to less than 0.8 percent, even though they say at the same time that not enough low-sulphur coal supply is projected to meet these requirements.

The factor of security of supply in both civilian and defense emergencies seems to be a relatively minor consideration, both in some consumer planning and environmental considerations. As costs may be a determining factor for consumers in this respect, comprehensive studies should be made of the relative costs, at points of consumption, of the respective clean energy sources.

Sample transportation studies being made by the Bureau of Mines indicate that there may be some significant price differences in favor of coal as compared to other energy sources, even in the shipment of Western coals farther eastward than Illinois.

Fundamentally, our national concerns for the environment are fully justifiable. While they should not be unnecessarily stringent, regulations should be as strong as is shown to be necessary by factual appraisal. The overall objective must be to preserve, or even improve, the environment while at the same time attaining other social goals without severe disruption to the production, distribution, and utilization of our energy resources. This requires both judgment in the determination and application of controls, and full speed ahead in the development of new technologies to bring about a favorable balance.

In summary, although it is estimated that we have large reserves of low-sulphur coals nationwide, their availability for environmental purposes is fraught with many problems. Among the most significant of these are that their location and markets are largely in contraposition; there are strongly adverse economic influences and consumer preferences, particularly in the East, that militate against the development of heavily increased productive capacity; and the extension of controls increases demand while progressively severe restrictions sharply narrow the range of availabilities as they trend toward sulphur levels that are practicably unattainable. Accordingly, it is anticipated that the supply of low-sulphur coals for environmental purposes will continue to be tight for some time to come.

The Supply of Oil for Future U.S. Needs and the Subsequent Effects on the Environment

Gene P. Morrell, David R. Oliver, and J. Lisle Reed, Office of Oil and Gas, Department of the Interior, Washington, D. C. 20240.

Throughout most of this century, the United States has been self-sufficient in petroleum supply; however, since 1968 our rate of consumption of oil has been greater than our daily oil production capability. During the present decade, the gap between domestic petroleum demand and domestic production will increase. The gap is a result of several factors: First of all, a seriously insufficient exploration for, and development of, natural gas and crude oil; secondly, the disqualification, for environmental reasons, of much of our high sulfur coal from its normal industrial and utility markets; and finally, a lag in the construction and operation of nuclear electric power plants.

As shown in this first chart, domestic production of crude oil and natural gas liquids appears to be levelling off in this country at slightly over 11 million B/D. The levelling off may even be considered a slightly optimistic projection. Unless present finding and development rates are accelerated, production will soon begin to decline.

With U.S. petroleum demand constantly growing and domestic supply remaining relatively stable, it is proper to assume that this country will look increasingly to other countries for oil. An important question is, how much foreign oil will be needed and what area of the world will the oil come from? In the projection shown here, 6.5 million B/D will be needed in 1975, and about 10 million B/D in 1980.

There are four major exporting regions in the world: South America (Venezuela); Africa (Libya, Algeria, and Nigeria); Indonesia; and the Persian Gulf countries (Middle East). South American and Persian Gulf oil tend to be high sulfur oil, whereas African and Indonesian oils tend to be low in sulfur. Environmental constraints in this country as well as other countries will probably require most fuel oil to be of low sulfur content. This will probably mean low sulfur crude oil will be sold at a premium price, compared to high sulfur oil, reflecting a cost savings on desulfurization equipment.

It would be difficult to predict at this time exactly where all of our imported oil will come from. But as far as the environment is concerned, it should make little difference because most high sulfur crude oil used in the United States will be desulfurized. If European and Japanese environmental constraints lag behind U.S. criteria, domestic firms, anxious to save the cost of desulfurization, will outbid foreign firms for low sulfur crude. Of course this would accelerate environmental concerns in foreign developed areas since these countries would be left using increasing quantities of high sulfur oil. Therefore, it seems logical that other developed nations will adopt environmental regulations similar to those that are forthcoming in the United States, and low sulfur crude oil will be distributed throughout the world by other considerations, such as transportation and product yield slates.

There is one other aspect that should be noted at this point. The United States is in a unique and slightly advantageous position compared to other large oil-consuming countries. Much of our domestic crude oil production in East Texas and Louisiana is low in sulfur. This will afford our domestic refineries some additional flexibility in optimizing the use of low sulfur oil, high sulfur oil, and desulfurization facilities.

In the second figure crude oil producing areas of the world are depicted and the areas are drawn in proportion to their known reserves. The crude oil production in all regions except the Persian Gulf is committed for consumption, due either to proximity to a consuming area or qualify of the oil. The crude oil production in these areas is insufficient to meet world consumption needs; because of this, most of our additional imports, as well as the rest of the importing countries' crude oil, will come from the Persian Gulf.

Before leaving the subject of crude oil supply and demand, I am obligated to point out some problems concerned with projecting the quantity of oil that will be imported. Referring to the first figure that was discussed, an oil supply/demand balance was presented. The imports that are necessary for the country can be calculated by the difference in estimated oil demand and domestic oil supply. This sounds simple enough, but other factors affect and complicate the issue.

Figure 3 displays the total energy supply/demand balance for the United States for the present century. As can be seen, oil is a large part of the total energy picture. More importantly, it is also the alternate or "swing" source of energy. If there are shortfalls in the development and utilization of nuclear, gas, or coal, oil will be required to fill the gap.

Projections concerning the timing and quantity of coal, gas and nuclear development vary greatly. For instance, in figure 4, projections by Interior's Bureau of Mines, the Federal Power Commission and the National Petroleum Council, are given for domestic natural gas production. These gas projections appear on the surface to be quite different, but they are consistent with the bases and assumptions used by each group. The point here is that there are many things that can happen which will affect the development of our various sources of energy; several assumptions can be made; and a lot of personal judgment is involved in anticipating fuels usage. This results in a very clouded picture of the exact quantity of oil imports that will be needed for the future. Therefore, it is necessary that I caution against naive use of the oil import projection used in this presentation.

The next topic I wish to comment upon is the form in which the oil will be imported, that is crude oil or refined oil products. At the present time foreign residual fuel oil (a refined product) is, for all practical purposes, freely imported into District I (states on the Eastern Seaboard). However, the domestic refiner is not allowed freely imported foreign crude oil from which to manufacture residual fuel oil for District I. The domestic refiner has to use higher cost domestic crude oil or foreign crude oil imported pursuant to an oil import quota to manufacture residual fuel oil; this has caused domestically produced residual fuel oil to be at a higher cost and to be noncompetitive. In figure 5 the imports of foreign residual fuel oil over the past decade are shown in comparison with imports of foreign crude oil. As can be seen in the figure, imports of residual fuel oil which were once about 50% of crude oil imports have now exceeded crude oil imports.

Residual fuel oil is a natural and significant product of crude oil. A yield of 50% residual fuel oil can be derived from typical or average crudes and a yield of 25% remains after mild or moderate petroleum refining. The average residual fuel oil yield in U.S. refineries is 5 to 6%. The lack of residual fuel oil production in the United States is a result of high conversion or severe refinery processing in a complex refinery configuration. The utilization of high severity processing in the domestic petroleum industry, which has resulted in the destruction and conversion of resid, was originally attributed to the fact that the resid had to compete with low priced coal and natural gas as burner fuel. However, from the present time forward, due to the inadequate development of natural gas and disqualification of certain coal uses, the lack of domestic residual fuel oil production must be attributed to the import situation.

The import situation is subject to change, and one possible change would be to allow domestic refiners imports of foreign crude oil in proportion to the uncontrolled (freely imported) products that are manufactured in domestic facilities. This would have the beneficial effect of allowing refining facilities that may otherwise be built in foreign countries to be built domestically, and it would reduce the magnitude of high severity operations that are typical in the U.S. today. An important question at this point is what would be the effect on the environment from such an action?

As I see it, there would be two significant results of such an action and they would have a nil or possibly beneficial effect on the environment. First of all, there would be more crude oil imported and less products (resid); however, the total level of oil imported is unchanged. Oil that is imported and processed is handled and transferred a little more than oil that is imported and distributed directly to consumers, but this aspect probably has a nil effect on the environment. The second result is that there would probably be more crude oil refined in this country than would otherwise occur. This additional processing may possibly have a slight beneficial effect on the environment because it would reduce the need for extreme high severity processing.

The last point is most significant and can best be illustrated by observing the last three figures of this presentation. Figure 6 is a very simple schematic of a foreign refinery configuration. The process equipment is simple: a crude fractionation tower to separate the crude components, and a reformer to upgrade the naphtha cut into gasoline. A catalytic cracker is shown, but it is only partially colored in order to illustrate that it is not really typical for foreign refineries although there are some in existence. The desulfurizer depicts new equipment that will be going into many refineries.

The next figure illustrates a simple schematic for a U.S. refinery configuration. The contrast of the U.S. refinery to the foreign refinery is apparent; there is a massive amount of equipment (hydrocracker, coker, alkylation unit and cat cracker) that is dedicated to converting the residual fuel oil portion of the crude oil to light products. If, however, the increasing demand for residual fuel oil is considered, and the domestically produced resid is made competitive with foreign resid by a change in the oil import program, a greater yield of resid will be derived.

Figure 8 illustrates the change in refinery configuration which would result from increased resid production. There would be a larger crude oil feed rate, thus, a larger crude fractionating tower. However, many of the light products that were made in the previous configuration by severe cracking would be derived from distillation of crude oil. Furthermore, much of the resid produced by distillation would not be converted, but instead sold as a product. The net result is that more crude oil would be processed, but there would be much less processing of product streams. The type of processing that is reduced is the type that directionally has the most adverse effect on the environment. The high conversion operations generally operate at high temperatures which require significant quantities of fuel and cooling water. Also the processes produce unsaturate hydrocarbons (naphthalenes) and other organic compounds (phenols) that are resistant to biodegradability.

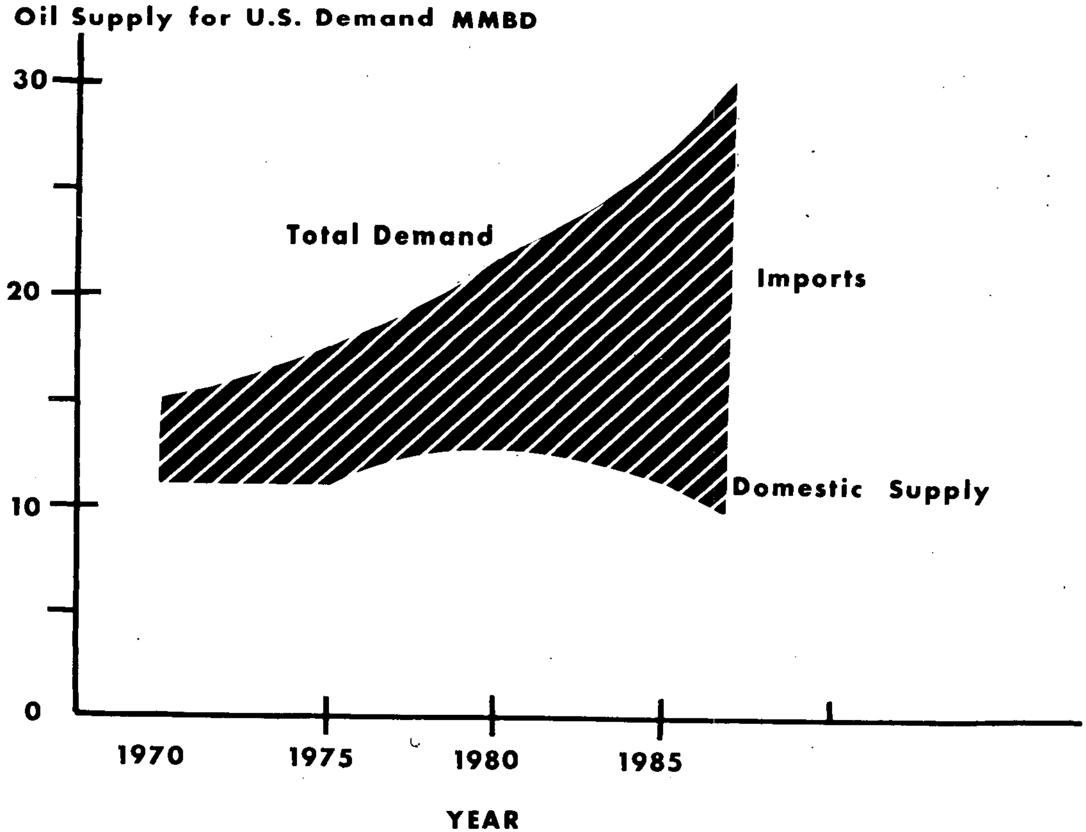
The ultimate refinery configuration would approach that of the foreign refinery. Existing refineries would probably find it advantageous to expand the crude fractionation sections and redistribute product streams to conversion units. The expected result would be a decreased percent conversion for the total crude oil feedstock.

To sum up, we see imports of foreign oil increasing rapidly in this decade. Much of the oil will probably be high sulfur crude oil from the Persian Gulf. We visualize modifications of the oil import program which will enable the refinery equipment, that will process the oil, to be located domestically. This would be beneficial to national security, trade balance, and the domestic economy. The ultimate effect such modifications in the oil import program would have on domestic refinery configurations would probably be slightly beneficial to the environment.

Earlier I referred to the interrelationships of oil, gas, coal and nuclear energy. All these energy sources and the "exotics," which are being developed, will be needed in the future. Yet, Government, as it is presently structured, does not encourage development of a unified energy policy. For example, about 61 Federal agencies are involved in some aspect of oil and gas decisions, and this fragmentation of responsibility can only result in inefficiency.

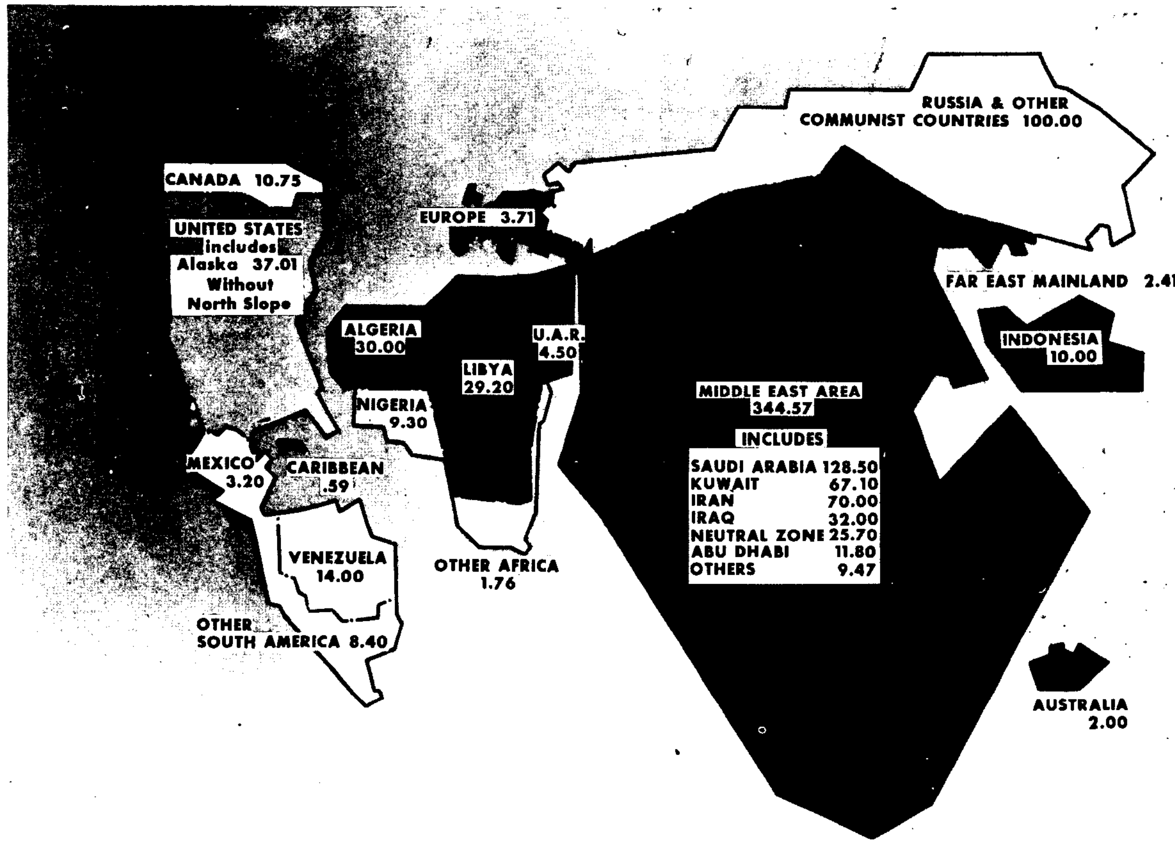
As a first step in overcoming this problem, President Nixon proposed to centralize major energy resource responsibilities in a new Department of Natural Resources. Passage of this legislation is essential if we are to integrate energy conservation and development efforts, and alleviate what more and more people are coming to realize is a serious energy supply problem.

OIL SUPPLY FOR U.S. DEMAND



WHERE THE OIL IS—

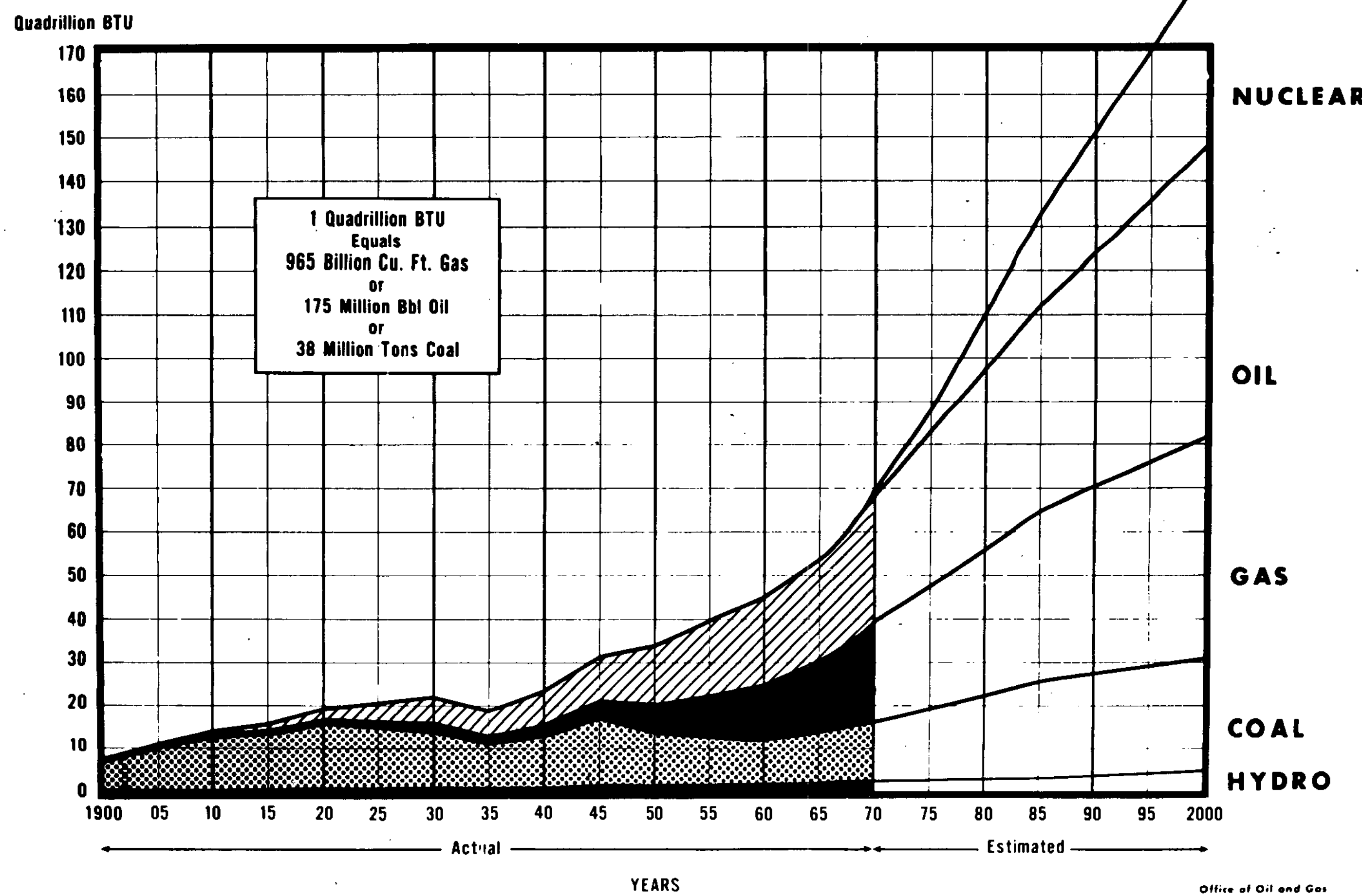
WORLD TOTAL 611.40 BILLION BBLS.
AS OF JANUARY 1, 1971



If geography reflected the reserves of oil in the ground, the map of the world would look like this.

Office of Oil and Gas
Department of the Interior
March 1971

U.S. ENERGY CONSUMPTION IN THE 20th CENTURY



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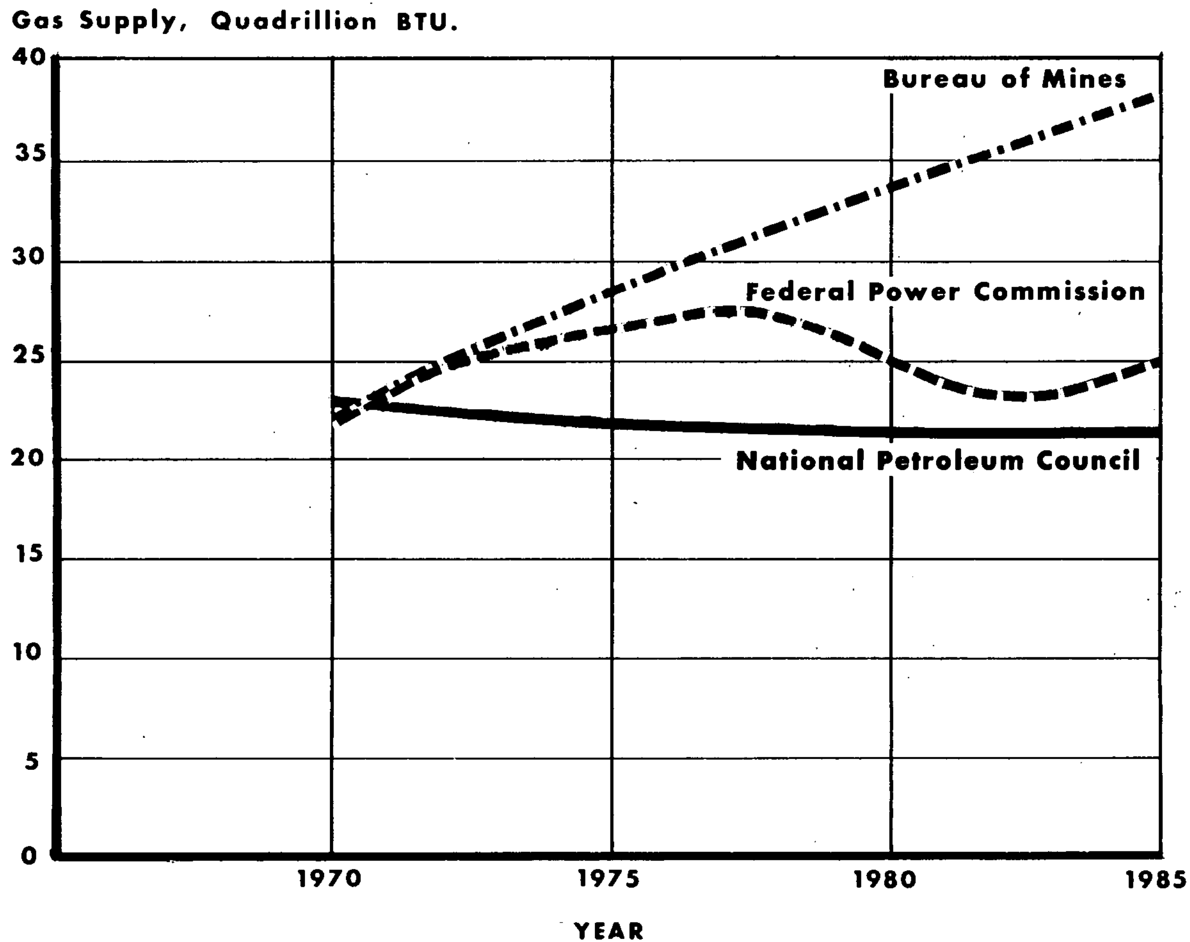
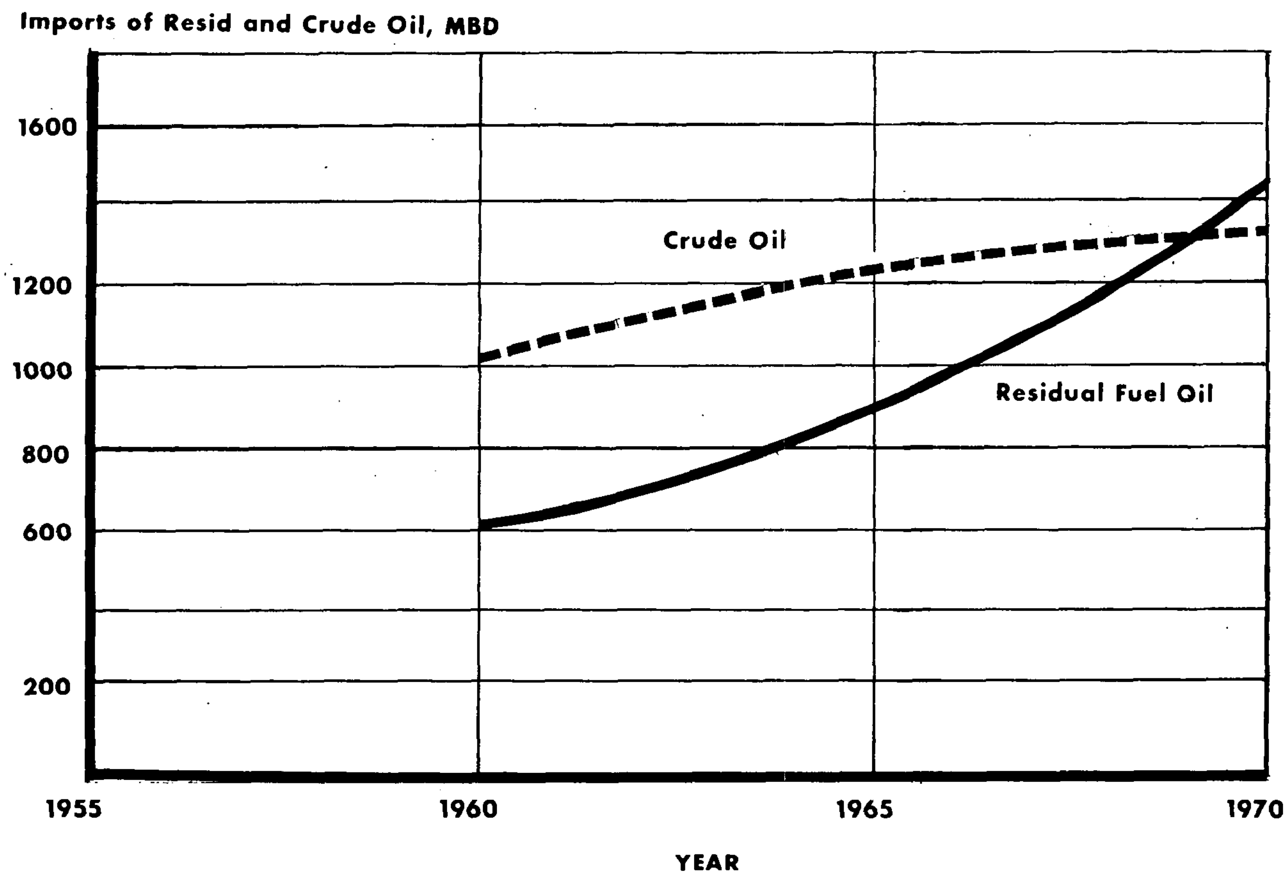
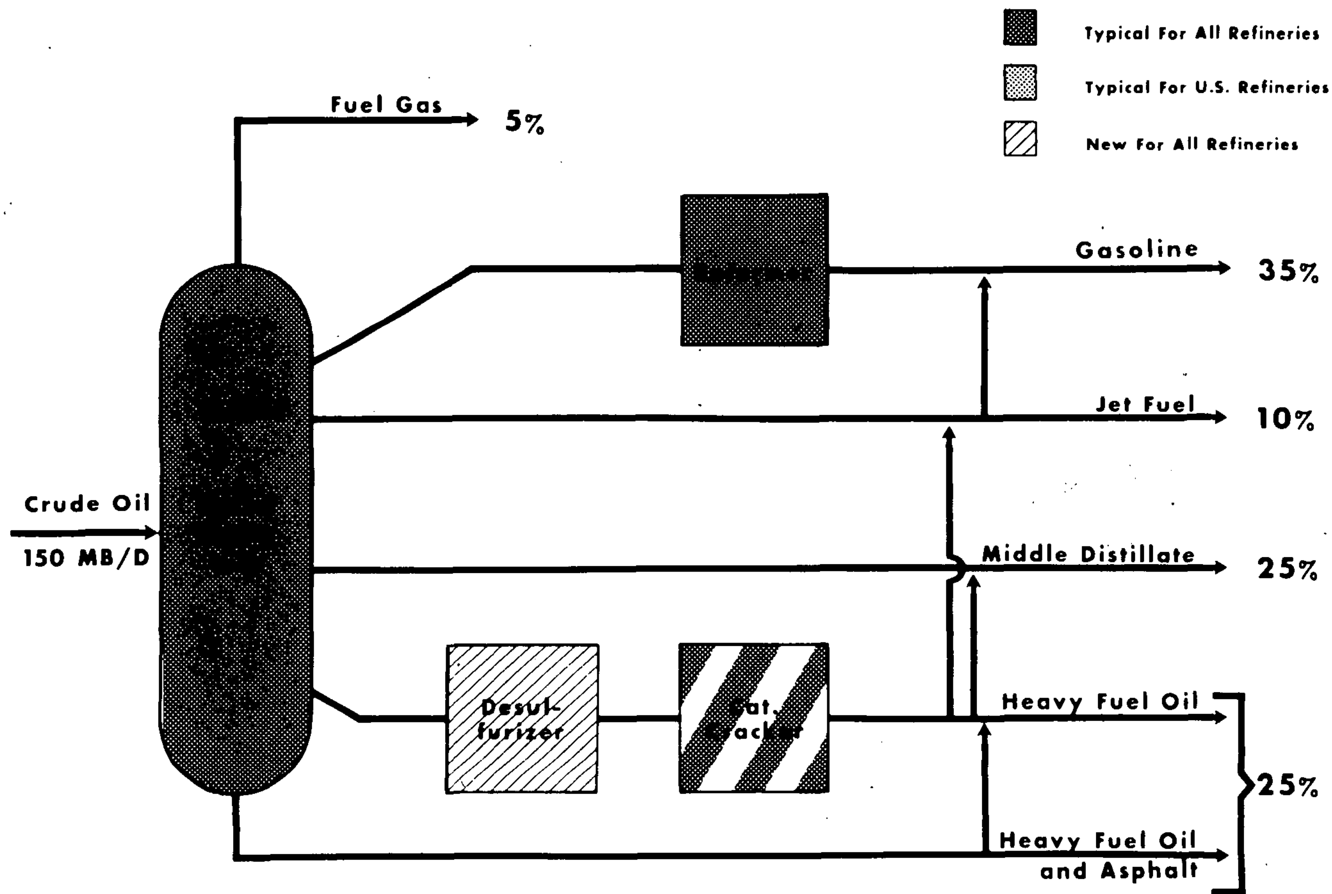
PROJECTED GAS SUPPLY



CRUDE OIL IMPORTS COMPARED TO RESIDUAL FUEL OIL IMPORTS



FOREIGN REFINERY



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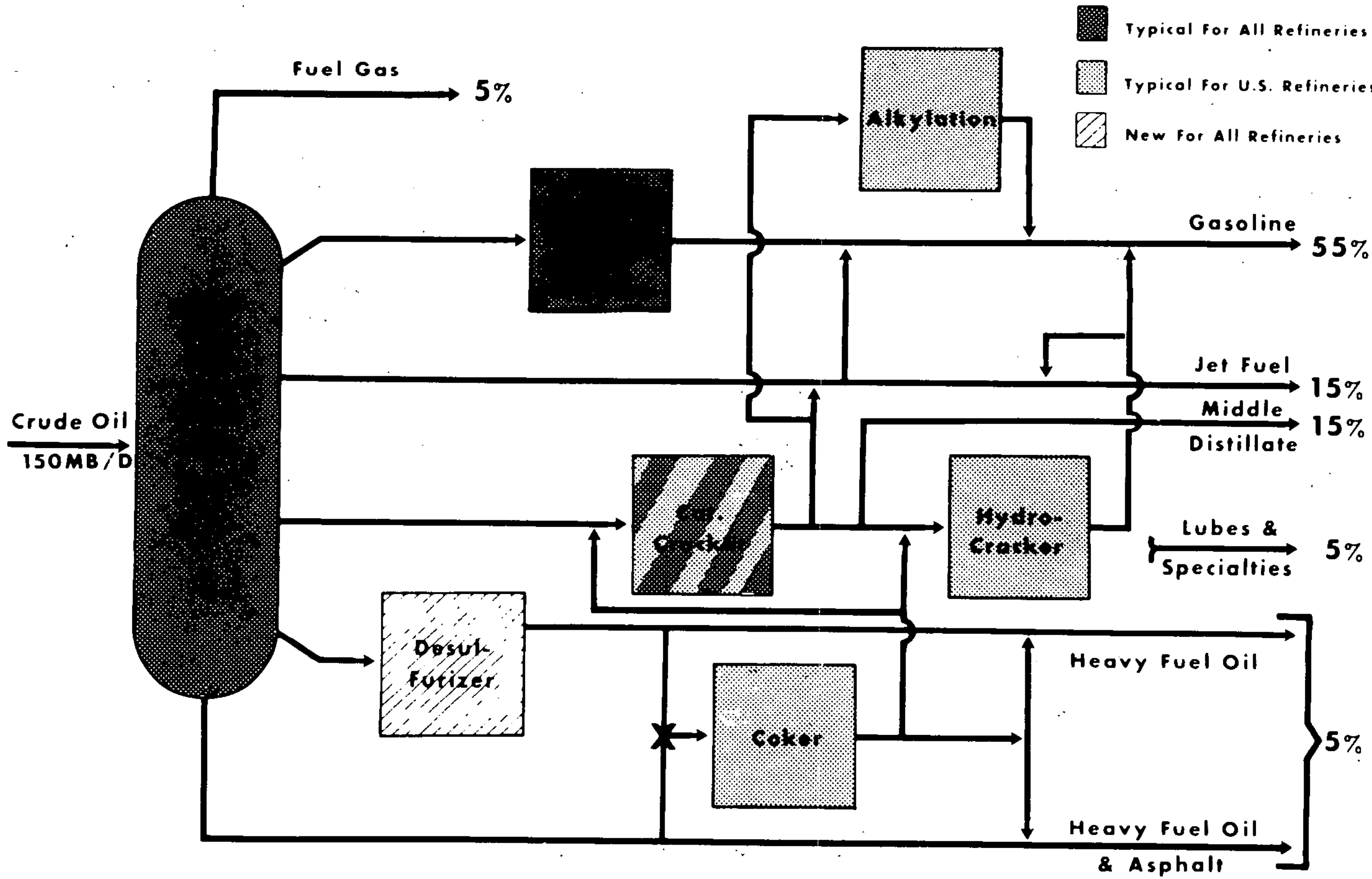
U. S. REFINERY



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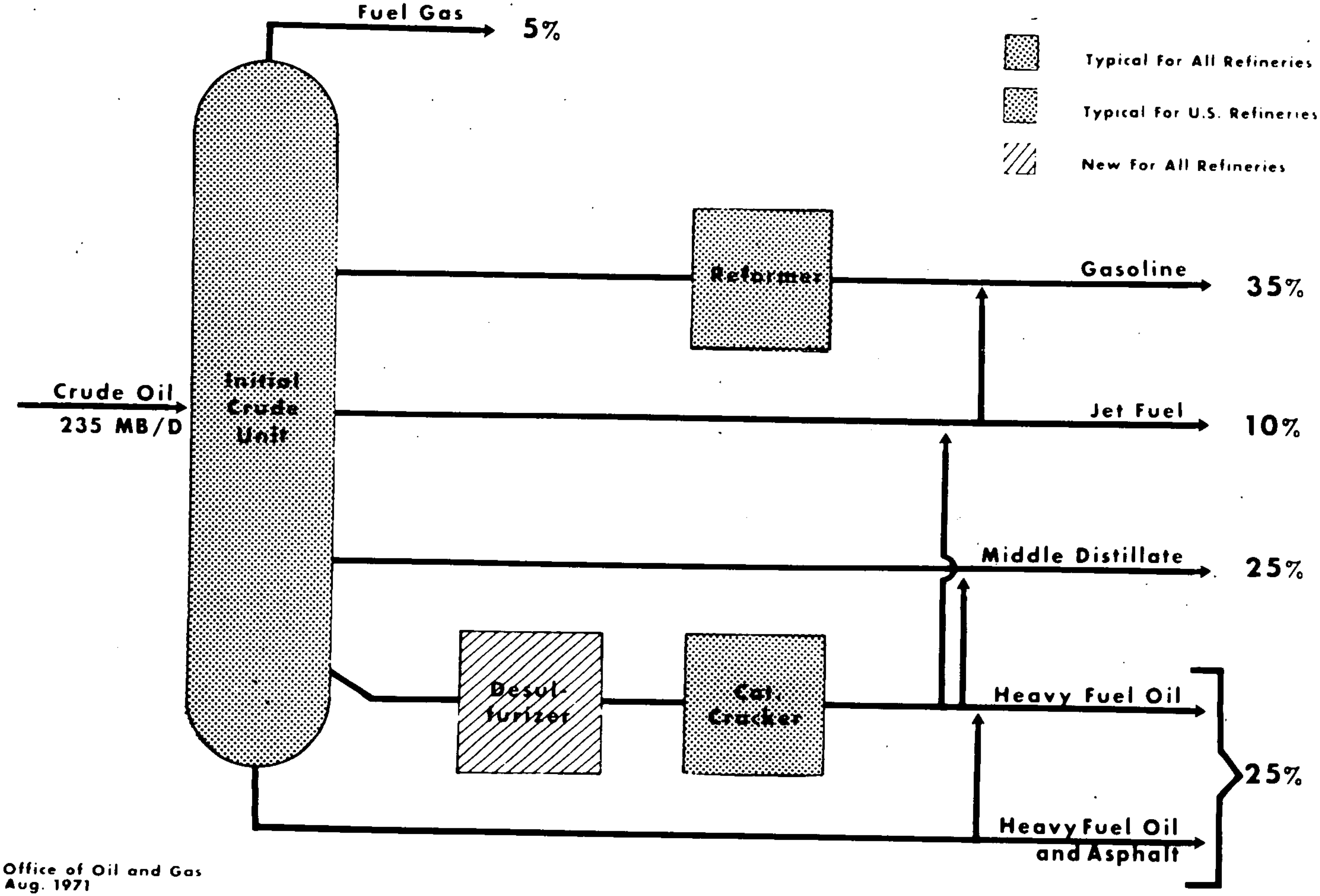
BALANCED REFINERY



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THE DEMAND FOR SULFUR CONTROL METHODS IN ELECTRIC POWER GENERATION

Robert M. Jimeson

Office of the Advisor on Environmental Quality
Federal Power Commission, Washington, D.C. 20426

INTRODUCTION

This paper examines the features of air quality legislation that have an impact on the demand for sulfur oxide control measures for the power industry; the limitations on sulfur imposed by emission regulations, and the electric power supply situation. Finally, estimates of probable demand are derived for various quality fuels and for sulfur oxide control equipment in the electric power industry in the next several years.

AIR QUALITY REGULATIONS

The Clean Air Act of 1967 called for the designation of air quality control regions by the Federal Government with the consent of the state and with local approval. Furthermore, the Federal Government had to issue for each pollutant, air quality criteria from which standards could be established. It had to issue companion reports on control technology for the reduction of emissions from various sources. Then, state governments were to establish air quality standards for their designated regions and adopt plans for implementation of control programs that would achieve constituted standards.

Under the provisions of the 1967 Act, areas were being designated as control regions in a sequence according to their severity of pollution, proceeding from the worst to the least polluted. This approach appeared to have a built-in mechanism for accelerated and achievable control activity while simultaneously permitting the primary energy supply and control equipment industries to adjust in an orderly and timely manner to a gradual, but intensified, demand for high quality fuels and emission control equipment. However, to some, the procedures appeared too tedious and slow. Consequently, the Clean Air Act as

Note: The views expressed herein are those of the author and do not necessarily represent the views of the Federal Power Commission.

amended in 1970 was designed to shorten the procedures and hasten the day in which all areas of the Nation would be brought under control, regardless of the current quality of its air. The provisions of this recent legislation accentuate the demand for control equipment and all forms of "clean" energy.

The Clean Air Act as amended in 1970 required that all areas of the Nation be designated very quickly as air quality control regions. Every part of the United States has now become part of an intrastate or interstate air quality control region. There are 237 control regions in the lower forty-eight states. All sources of pollution anywhere in the nation are now subject to regulation; thus, the demand for various control measures is immediately intensified nationwide. The location of the regions and the magnitude of their current pollution problem is shown in Figures 1 and 2.

The legislation also required the Environmental Protection Agency (EPA) to establish national primary ambient air quality standards to protect health and secondary standards to protect the public welfare. Ambient standards were greatly needed as a guide to the degree of emission controls required in various regions. National standards for particulates, sulfur oxides, nitrogen oxides, carbon monoxide and hydrocarbons, and photochemical oxidants were issued in April 1971. The states could set standards within their own boundaries more stringent than those of the Federal Government. However, by July 1975, the states had to achieve air quality equal to or better than the national standards.

The principal pollutants of concern to fossil fuel-fired electric power plants are sulfur oxides, particulates, and nitrogen oxides. The national ambient air quality standards for these three pollutants are shown in Table I.

NATIONAL AMBIENT AIR QUALITY STANDARDS

POLLUTANT	AVERAGING TIME	PRIMARY STD.		SECONDARY STD.	
		µg/m3	p.p.m.	µg/m3	p.p.m.
SULFUR OXIDES	Annual	80	0.03	60	0.02
	24 Hour*	365	0.14	260	0.1
	3 Hour*	-	-	1300	0.5
PARTICULATE	Annual	75	-	60	-
	24 Hour*	260	-	150	-
NITROGEN OXIDES	Annual	100	0.05	100	0.05
	24 Hour*	250	0.13	250	0.13

*Not to be exceeded more than once per year.

Table I

By January 30, 1972, each state was required to adopt and to submit to EPA a plan providing for the implementation, maintenance, and enforcement of a program which would enable it to meet the national primary ambient air quality standards within its regions by the middle of 1975. EPA must approve or reject these plans or portions of them by May 30, 1972.

Due to the shortness of time, the states had a tendency to determine the degree of reduction in emissions needed to meet the national or their own more stringent ambient air quality standards for their worst polluted region and then to apply the same degree of reduction to all other regions in the state. Lack of individual regional analysis which tailor regulations to each region's specific needs intensifies the demand for clean fuels and control equipment due to an aggregation of excessive requirements. Non-critical regions are thus put in competition with the critically polluted regions for the limited "clean" fuels and control devices.

EPA also had to establish national emission standards for certain categories of new sources. Table II shows the Federally mandated emission standards for new and modified fossil-fired steam generators. They apply to units with a capacity of 250 million Btu per hour (i.e., about 25 megawatts) or larger for which major construction or modification contracts were signed after August 17, 1971.

STANDARDS OF PERFORMANCE FOR
NEW FOSSIL-FIRED STEAM GENERATORS
(construction commenced after August 17, 1971)

	STANDARDS Lbs. per Million Btu		
FUEL TYPE	PARTICULATE	SULFUR OXIDES	NITROGEN OXIDES
SOLID	0.10	1.2	0.70
LIQUID	0.10	0.80	0.30
GASEOUS	-	-	0.20

Table II

Having examined the air pollution regulations influencing the demand for various quality fuels and for control devices, consider next the Nation's need for electric generation as a factor in the magnitude of the demand for controls.

OUTLOOK FOR ELECTRIC POWER GENERATION

Many of the projections used in this section were taken from the Federal Power Commission's 1970 National Power Survey. More than one hundred experts representing all segments of the electric power industry and branches of government contributed to its contents.

As illustrated in Figure 3 the electric power industry of the United States in 1970 generated nearly eighty-two percent of the electricity in fossil-fueled plants. Almost all of the remainder, except for 1.4 percent produced by nuclear plants, was generated by hydro-power. Nuclear generation is expected to make significant inroads into the generation picture of the next two decades and, consequently, the relative position of fossil-fueled generation will decrease from about 82 percent in 1970 to about 44 percent in 1990.

Figure 4 shows that the electric power industry generated 1.541 billion megawatt-hours in 1970. In the process it consumed approximately one-quarter of all the primary energy used during that year by all segments of the American economy. During the next two decades total electric power generation by electric utilities is expected to about double every ten years. Total generation is estimated to reach 3.11 billion megawatt-hours in 1980 and close to 6 billion megawatt-hours in 1990. In the same period, fossil-fueled generation will increase to about 1.9 billion megawatt-hours in 1980 and about 2.6 billion megawatt-hours in 1990. While fossil-fueled steam plants will supply a decreasing portion of the total as shown in Figure 3 the fossil-fueled units will supply twice as much electric energy in 1990 as in 1970. This is further reflected in projected fossil-fueled capacity additions from 1970 to 1990 shown in Table III.

The fossil-fueled energy was generated at plants having 3298 boiler-generator units with a total steam-electric generating capacity of 259 thousand megawatts. The capacity will increase to 558 thousand megawatts by 1990. Average size of the units will increase from 80 to 370 megawatts and the number of units will decrease to 1520 in 1990.

During the same period, 1970 to 1990, total generating capacity, including nuclear and hydroelectric plants, is expected to nearly quadruple from 340 thousand megawatts to 1260 thousand megawatts--an increment of 920 thousand megawatts.

Some of the 920 thousand megawatts of generating capacity will be required by the "clean" primary energy and control process industries sewage treatment plants, incinerators, and others to accomplish the environmental goals in the fields of air and water pollution control and solid waste management. Electricity is very necessary for the achievement of this Nation's environmental goals, and serious thought must be given to the trade-off of the environmental benefit of the use of electricity relative to the environmental impacts of its generation.

In the shorter range projection to the year 1975, when the state air pollution control programs are to be implemented, Table III shows that there will be about 2900 fossil-fueled units with a total estimated capacity of 320 thousand megawatts. The average size of the fossil-fueled units in operation during that year will be about 110 megawatts.

U.S. FOSSIL-FUELED STEAM-ELECTRIC CAPACITY

YEAR	CAPACITY MW (Thous.)	NO. OF UNITS	AUG. SIZE MW (Thous.)
1970	259	3,298	80
1975	320	2,900	110
1980	380	2,389	160
1990	558	1,520	370

Table III

The Federal Power Commission, with the cooperation of the Environmental Protection Agency, collects on FPC Form 67 air and water quality control data for each fossil fuel-fired electric generating plant of 25 megawatts and greater. Under this program the FPC collected information for the year 1969 from 655 fossil-fueled plants with 2995 boiler-generator units having a total capacity of 244 thousand megawatts, as compared with the 3298 units with a total capacity of 259 thousand megawatts reported in Table III for the year 1970.

Form 67 data shows that of the 2995 units surveyed for the year 1969, 1150 units were primarily coal-fired, 945 units were primarily oil-fired, and about 900 units were primarily gas-fired. Assuming that the 303 small units not covered by the Form 67 program divide in the same proportions, then the distribution of the number of units in operation in 1970 by type of fuel fire is shown in line 1 of Table IV.

PROJECTED MIX OF
FOSSIL-FUELED GENERATING UNITS

	TYPE OF FUEL		
	COAL	OIL	GAS
NUMBER OF UNITS 1970	1265	1045	990
ADDITIONS	+66	+26	+24
Subtotal	1331	1071	1014
RETIREMENTS	-281	-141	-80
Subtotal	1050	930	934
CONVERSIONS	-90	+120	-30
NUMBER OF UNITS 1975	960	1050	904

Table IV

From information reported on April 1, 1971, by the nine Regional Electric Reliability Councils in response to the Commission's Statement of Policy on Adequacy and Reliability of Electric Service, Order No. 383-2, the author estimates that about 116 additional units with 70 thousand megawatts of capacity might be in operation by the end of the year 1975. As shown in the second line of the Table, 66 are expected to be coal-fired, 26 oil-fired, and 24 gas-fired.

There were 1004 fossil-fueled units with a total capacity of about 18 thousand megawatts which were installed in 1940 or earlier, but were still in operation in 1970. Some of these units date back to the first two decades of this century. These units were an estimated 56 percent coal-fired, 28 percent oil-fired, and 16 percent gas-fired. Assuming that one half of each of the types of older units will be retired by 1975, then 281 coal-fired, 141 oil-fired and 80 gas-fired units will be retired. In addition 90 coal-fired and 30 gas-fired units are expected to be converted to oil-fired.

Consequently, by 1975 there will be 960 coal-fired and 1050 oil-fired for a total of 2010 units which will require some form of sulfur emission control either through the use of stack devices for the removal of sulfur dioxide from power plant flue gases or through the use of low-sulfur fuels.

FOSSIL FUEL DEMAND FOR ELECTRIC POWER GENERATION

The National Power Survey projections of electric power generation, when translated into primary energy demand based on energy conversion efficiencies now demonstrated and anticipated during the next several years, indicate a continuing growth in fuel consumption in the form of coal, oil, and gas. Projected requirements of these fuels for electric power generation in terms of coal equivalent quantities is shown in Figure 5.

The most remarkable element of this projection is the very rapid decline in the rate of growth of natural gas usage for electric power generation. This projection is supported by a variety of gas curtailment cases currently before the Commission. It means, of course, that gas, the only "clean" fossil fuel, cannot be counted on to make a significant contribution to the reduction of undesirable emissions from electric power plants. The use in 1969 of the various fossil fuels for electric power generation expressed in their customary units of measure was 310 million tons of coal, 251 million bbls. of oil, and 3486 billion cubic feet of gas.

CURRENT QUALITY OF FUELS

Figure 6 prepared from information collected in FPC Form 67 shows the quantities of coal at the various sulfur levels consumed by electric utilities in 1969. The 303 million tons of coal burned by electric utilities reporting in 1969 ranged in sulfur content from 0.4 percent to as much as 6 percent by weight. The bulk of the coal, however, was in the two to four percent sulfur range; the weighted average was 2.58 percent. The distribution curve is bimodal, with one peak at below one percent sulfur. This, most likely, reflects an early response by several utilities to local air pollution control regulations requiring the use of fuels with less than one percent sulfur.

The quality of coal burned by electric utilities in 1969 was compared plant-by-plant and state-by-state with regulations in state implementation programs. About 44 million tons of coal consumed by electric utilities in 1969 in 255 units could meet the standards; whereas, 259 million tons with an average sulfur content of 2.81 percent was burned in 1010 units that could not meet standards and would require control measures.

Likewise, Figure 7 shows the quantities of oil at various sulfur levels consumed by electric utilities. Similarly, the sulfur content of the oil used in 1969 ranged from a fraction of a percent to nearly 3 percent, with a major portion of the oil in the 1.4 to 2.6 percent sulfur range. The weighted average was 1.66 percent. In the case of the oil distribution curve, three peaks were observed. One peak at 0.3 percent. Another at slightly below the one percent sulfur level, and the largest peak at an average sulfur content of 1.9 percent. Both peaks under 1 percent sulfur undoubtedly reflect response to local sulfur emission control regulations.

The quality of the oil burned by electric utilities in 1969, compared plant-by-plant and state-by-state, with the preliminary state implementation programs showing that 59 million bbls. of oil burned in about 310 units could meet the standards and that 199 million bbls. of oil burned in 735 units would require some type of control measures to meet the proposed sulfur limitations.

Table V shows fuel requirements projected in the National Power Survey. In 1975 when state plans are to be fully implemented, except where a two-year extension is asked, 425 million tons of coal will be required and 565 million bbls. of oil will be needed.

FOSSIL-FUEL REQUIREMENTS
FOR ELECTRIC POWER GENERATIONS

YEAR	COAL (Million Tons)	OIL (Million Bbls)	GAS (Billion Cu. Ft.)
1969	310	251	3486
1970	322	332	3894
1975	425	565	4110
1980	500	640	3800

Table V

Consider company plans for supplies of low sulfur fuels to get an order of magnitude of added supplies of low sulfur fuels that would be required in 1975 if control devices were not in operation at the electric generating units.

The National Coal Policy Conference estimated about a year ago that there would be 300 million tons of new mine capacity by 1975 of which 75 million tons would be in low sulfur coal. Assume 2/3 or 50 million tons could be dedicated to the electric utilities. This quantity added to the 45 million tons of low sulfur coal which already meets the standards yields 94 million tons of naturally occuring low sulfur coal that could be available in 1975. Subtracting 94 million tons from the 425 million tons to total requirement leaves 331 million tons of high sulfur coal which will be burned in utilities with devices. Or in the absences of devices, this quantity of coal must be processed to low sulfur standards.

On the oil side, the Bureau of Mines in August 1970 in its study on Oil Availability by Sulfur Levels estimated the additional U.S. and Caribbean residual desulfurization capability would be around 300 million bbls. This added to the 59 million bbls. of low sulfur oil which already meets the standards yields a total of 359 million bbls. of low sulfur oil in 1975. Deducting this quantity from the total utility requirement of 565 million bbls. leaves about 206 million bbls. that will be burned in utilities with control devices, or in the absence of devices, 206 million bbls. must also be processed to low sulfur.

SUMMARY

The Clean Air Amendments of 1970 and the accompanying regulation have intensified the demand for "clean" fuels and control devices on a nationwide bases. These control measures must be in operation by 1975 or in some instances 1977.

In general there will be a demand for 425 million tons of low sulfur coal and 565 million bbls. of low sulfur oil. The majority of this will require some type of processing. Clean fuels are a preferred pollution control for electric generation because they are fail-safe and compatible with load changing characteristics of power plant operations. About 94 million tons of naturally occuring low sulfur coal and 359 million bbls. of low sulfur oil can be foreseen as a possible supply that meets air quality regulations. About 331 tons of coal and 206 bbls of oil will be burned in anywhere from 1300 to 1400 units each requiring control devices in operation in 1975. To the extent that control equipment manufacturers have a deficiency in these numbers of units operating in 1975, an equivalent demand will appear for processing portions of each of the high sulfur quantities of coal and oil.

The challenge is great, the time is short. Achievement of the ambient air quality objectives by the electric power industry in that short a period of time will require the utmost effort on the part of suppliers of low-sulfur fuels and manufacturers of sulfur emission control equipment, dedication on the part of the electric power industry, a great deal of investment capital, and the cooperative spirit of environmental groups and the public.

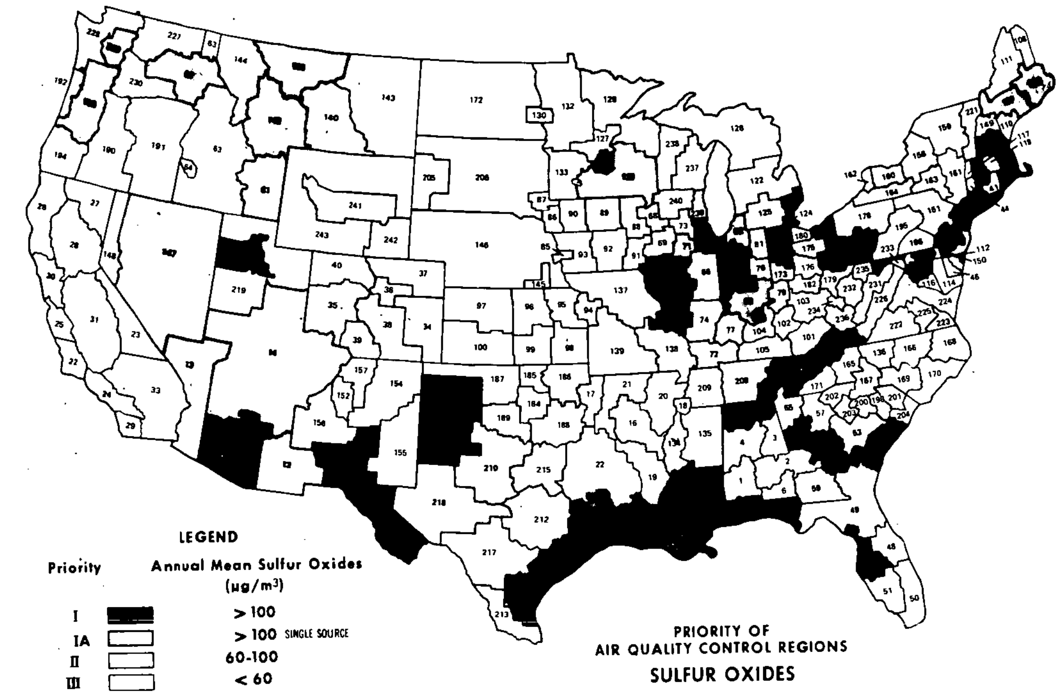

Figure 1

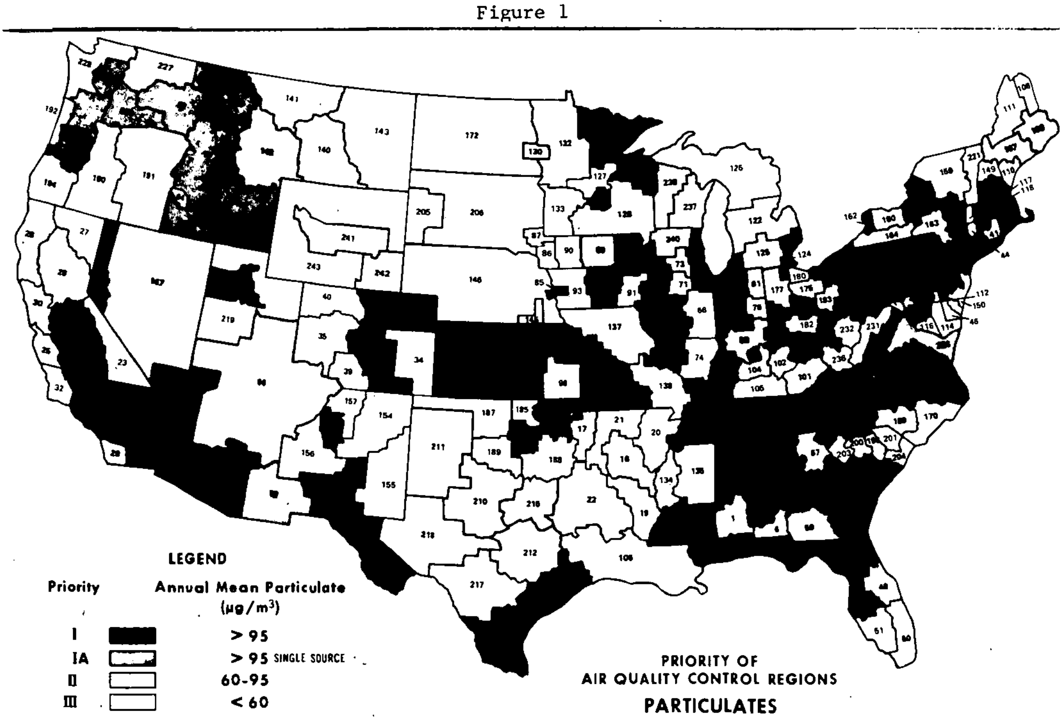

Figure 2

PROJECTED GENERATION MIX

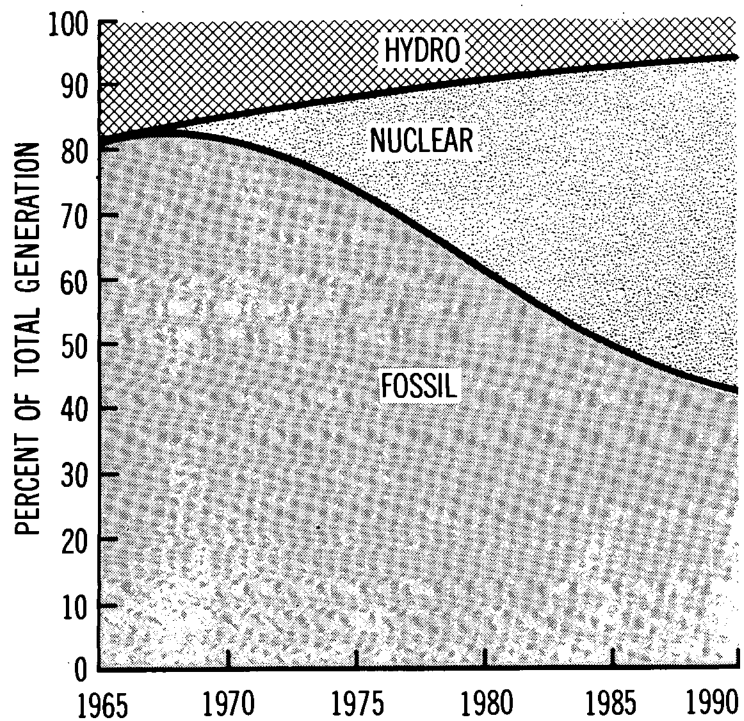

Figure 3

ESTIMATED ANNUAL ELECTRIC UTILITY GENERATION BY PRIMARY ENERGY SOURCES

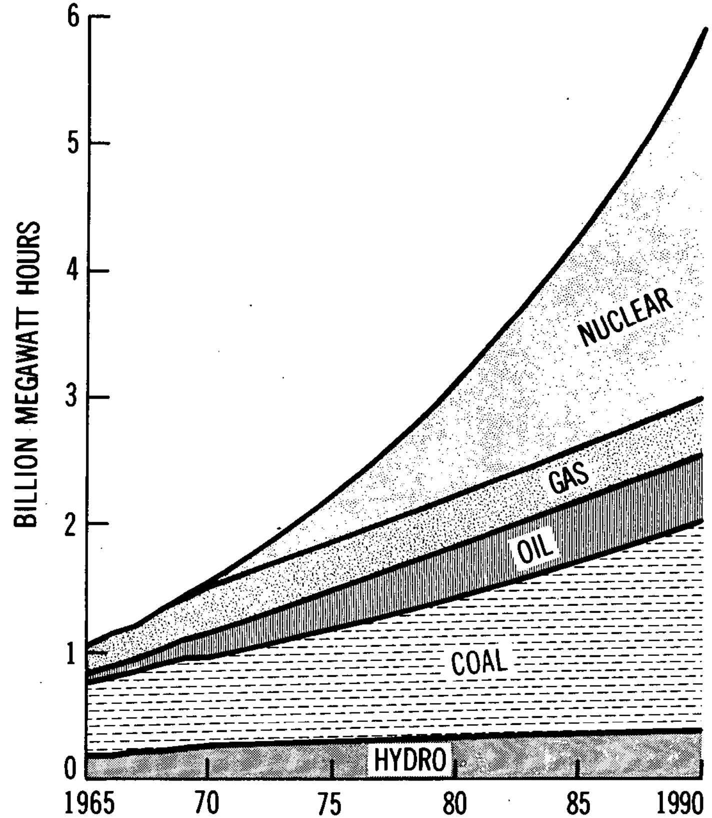

Figure 4

ESTIMATED ANNUAL FOSSIL FUEL REQUIREMENTS FOR ELECTRIC UTILITY GENERATION

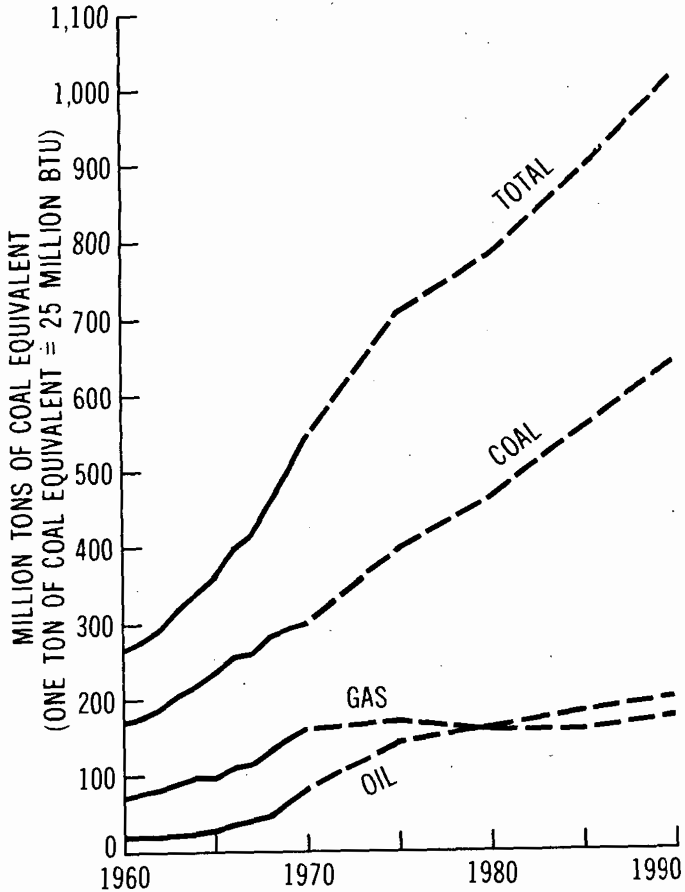

Figure 5

DISTRIBUTION OF SULFUR CONTENT OF COAL BURNED BY ELECTRIC UTILITIES (1969)

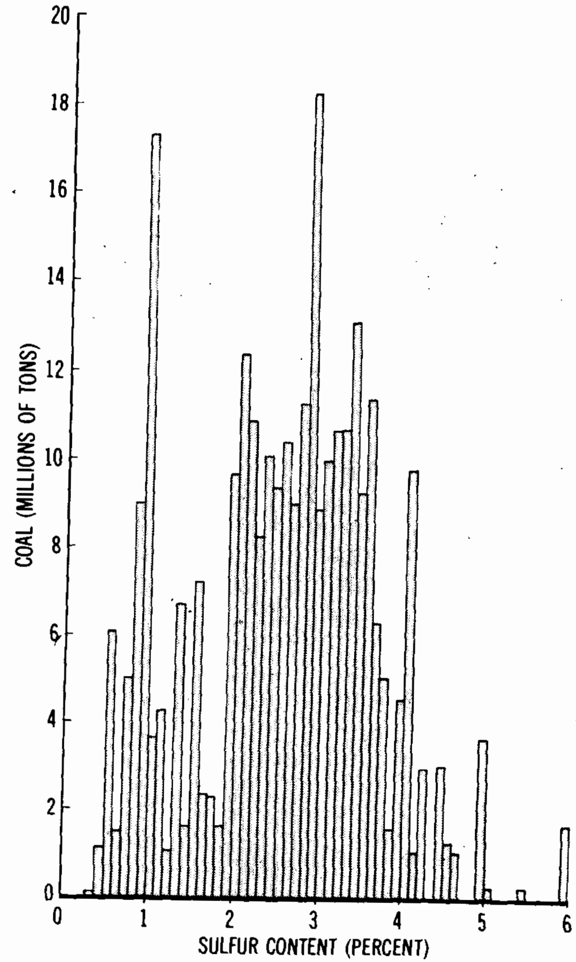

Figure 6

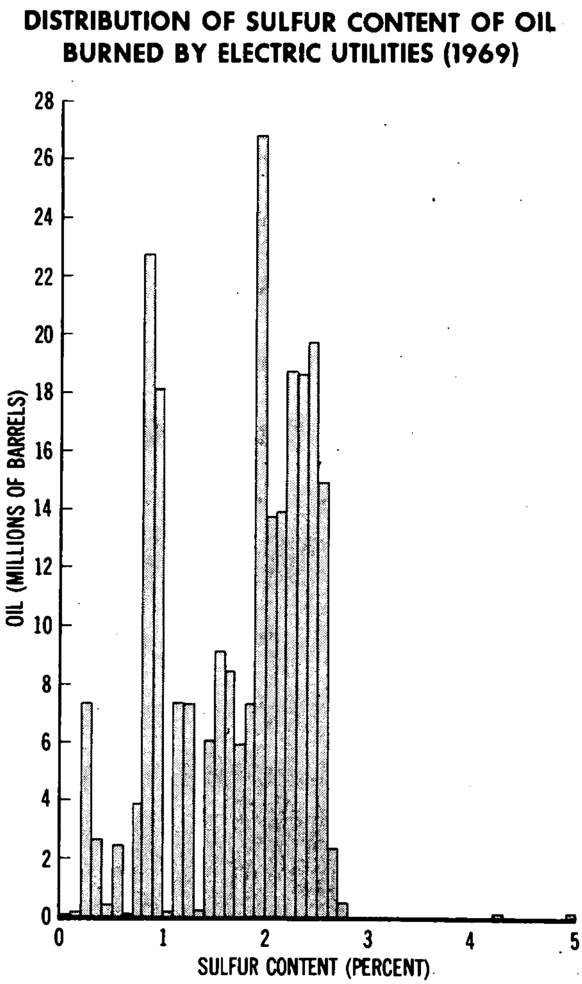
DISTRIBUTION OF SULFUR CONTENT OF OIL
BURNED BY ELECTRIC UTILITIES (1969)
OIL (MILLIONS OF BARRELS)
28
26
24
22
20
18
16
14
12
10
8
6
4
2
0
0
1
2
3
4
5
SULFUR CONTENT (PERCENT)

Figure 7

The Effect of Desulfurization Methods on Ambient Air Quality by Kurt E. Yeager, Environmental Protection Agency, Washington, D.C. 20460

The environmental constraints on the use of coal and oil will be described with emphasis on sulfur oxide and particulate emissions and their relation to ambient air quality. These relationships will be developed for three major fossil fuel fired emitter categories; i.e. utility power plants, industrial combustion, and commercial/ residential combustion.

Based on the relationships between emissions and ambient air quality, various strategies for the achievement of ambient air quality standards will be developed. These control strategies will consider the following alternatives for achieving the required levels of emission control, both individually and in combination : (1) effluent treatment, (2) fuel treatment, and (3) fuel switching. The analyses will consider the degree of air quality improvement, in terms of population achieving the ambient air quality standards, relative to the cost and time necessary to implement the control strategy.