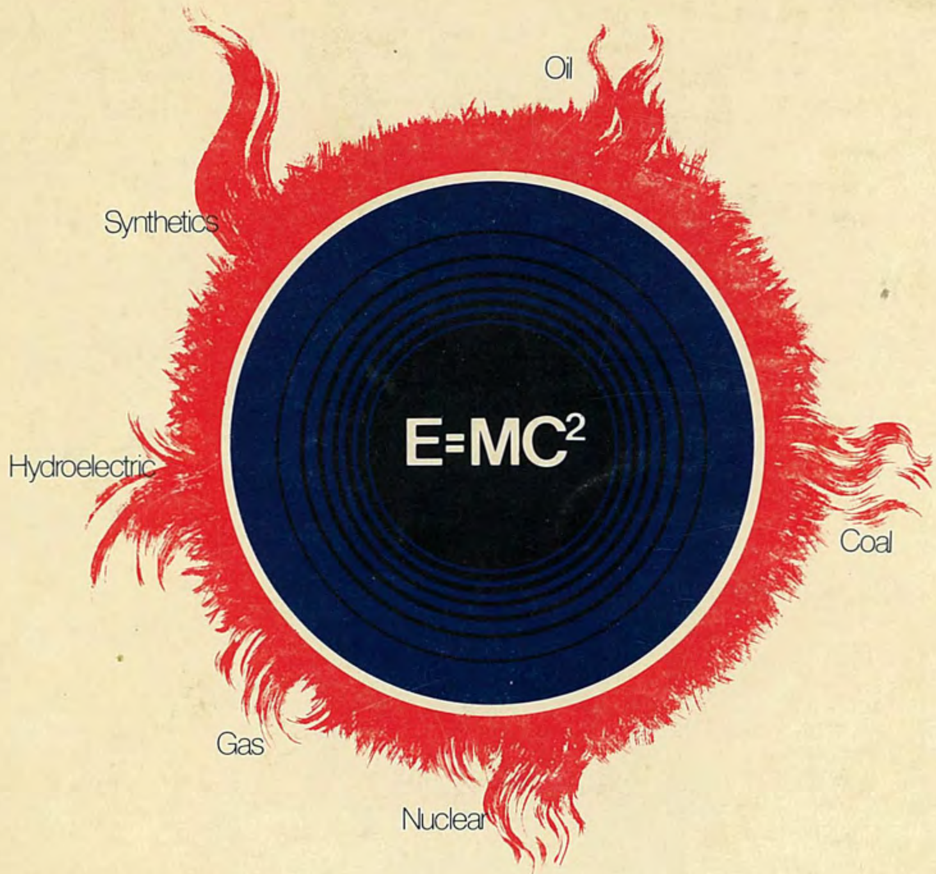
U.S. Energy Outlook

An initial appraisal 1971-1985



Volume One
July 1971

An Interim Report
of the
National Petroleum Council

NATIONAL PETROLEUM COUNCIL
E.D.Brockett, Chairman/H.A.True,Jr., Vice Chairman/Vincent M.Brown, Executive Director

July 15, 1971

My dear Mr. Secretary:

I am pleased to transmit herewith the preliminary report of the National Petroleum Council, entitled *U.S. Energy Outlook--An Initial Appraisal (1971-1985)*.

This report projects supply-demand relationships under certain assumed conditions which involve minimal changes from present policies, practices and economic climate. In particular, it has been assumed that current trends of government policy and regulation would continue without major change and that the present economic climate for the energy industries would be maintained throughout the 1971-1985 period.

The assumptions as to trends in government policy were developed prior to the issuance on June 4, 1971, of the President's Energy Message. Therefore, while some of the proposals described in this Message are touched upon, treatment of certain others will be included in the final report requested of the National Petroleum Council on the outlook for energy through the year 2000.

The contents of this report do not represent a probable forecast of the future, but strictly a set of projections suitable as bench marks against which the effects of possible changes in policies and economic conditions can be considered. They provide a means of defining the problem and clarifying the areas in which corrective actions may be needed.

The major implications of the findings from the initial appraisal are as follows:

1. Continuation of present government policies and economic conditions would lead to significantly increased U.S. dependence on foreign energy resources, mostly in the form of oil from Eastern Hemisphere countries, and to an acute shortage of gas.

2. Potential energy resources of the United States would support higher growth rates for domestic supplies given adequate economic incentives and careful coordination of effort between government and industry.

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3. Capital requirements to meet U.S. energy needs through 1985 are extremely large and will be difficult to obtain unless the general economic climate in the energy resource industries is improved.

As suggested by the above, some changes in the economic climate and government policies will be essential. It is heartening that the Government is already moving to alleviate some of the constraints on energy supplies that are apparent from this Initial Appraisal. The President's Message proposes increased federal research on energy problems and making available the energy resources on federal lands. Initial steps for implementation of these proposals were indicated by you on June 15, 1971.

In the concluding stages of the Council's studies on the U. S. energy outlook through the year 2000, emphasis will be placed on identifying the changes in industry and/or government policies and programs which would increase indigenous energy supplies, making appropriate allowances for environmental and other cost considerations. The results of this analysis will be presented in the Council's final report, scheduled for completion in July 1972.

Respectfully submitted,

E. D. Brockett

E. D. Brockett, Chairman

Honorable Rogers C. B. Morton
Secretary of the Interior
Washington, D. C.

U.S. ENERGY OUTLOOK:

AN INITIAL APPRAISAL 1971-1985

VOLUME ONE

July 15, 1971

AN INTERIM REPORT
PREPARED BY THE
NATIONAL PETROLEUM COUNCIL'S
COMMITTEE ON U.S. ENERGY OUTLOOK

CHAIRMAN - JOHN G. MCLEAN

NATIONAL PETROLEUM COUNCIL

E. D. Brockett, *Chairman*
H. A. True, Jr., *Vice-Chairman*
Vincent M. Brown, *Executive Director*

Petroleum Advisory Council
to the
U.S. DEPARTMENT OF THE INTERIOR

Rogers C. B. Morton, *Secretary*
Hollis M. Dole, *Asst. Secretary-Mineral Resources*
Gene P. Morrell, *Deputy Asst. Secretary-Mineral Resources*
and to the
OFFICE OF OIL AND GAS

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PREFACE

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On January 20, 1970, the National Petroleum Council, an officially established industry advisory board to the Secretary of the Interior, was asked to undertake a comprehensive study of the nation's energy outlook. This request came from the Assistant Secretary--Mineral Resources, Department of the Interior, who wrote to the Council as follows:

> "A number of events affecting basic policies of government and the social and physical environment of this Nation have occurred or appear imminent which will set the stage for a new era in the petroleum industry in the United States. These events will have a decided impact on the Nation's resource capability and the structure of the industry.
>
> "Because of the important and pervasive nature of the changes which may be engendered by these events, there is need for an appraisal of their impact on the future availability of petroleum supplies to the United States . . . ."

The Assistant Secretary asked the Council to project the energy outlook in the Western Hemisphere into the future as near to the end of the century as feasible, with particular reference to the evaluation of future trends and their implications for the United States (see Exhibit 1). The Council was also specifically asked to indicate ranges of possible outcomes, where appropriate, and to emphasize where federal policies and programs could effectively and appropriately contribute to the attainment of an optimum long-term national energy posture.

Responsive to this request, the National Petroleum Council in the summer of 1970 established a Committee on U.S. Energy Outlook to carry out the study. Thanks to the generous support of many cooperative organizations and people, this Committee is comprised of over 200 representatives of the oil, gas, coal, nuclear and other energy-related fields, as well as a number of financial experts (see Exhibit 2). This broad makeup permitted an assessment to be made of the total energy outlook. In addition, the Committee felt it desirable to compare the fuel demand estimates made by its several task groups with the results of some comprehensive energy studies made by individual companies or other organizations. Battelle Northwest was retained to make a composite of such relevant studies.

This volume contains the Committee's initial appraisal of the U.S. energy outlook. As noted in the covering letter, this appraisal projects supply-demand relationships for the period 1971-1985 under certain assumed conditions which involve minimal changes in the economic climate of the energy industries and in the government policies and regulations pertaining thereto. Consequently, the contents of this interim report do not represent a probable forecast of the energy outlook, but rather only a frame of reference from which the need for changes in policies and conditions could be inferred and the probable effect of such changes analyzed.

The final report on this topic by the National Petroleum Council, which is scheduled for completion in July 1972, will (1) assess the potential impact on the U.S. energy outlook of various changes in economic conditions, technology and governmental policies for the balance of the century and (2) identify probable trends in energy demand-supply relationships between 1985 and the end of the century.

That important changes are likely to occur is already suggested by the issuance on June 4, 1971, of the President's Energy Message to Congress. This statement, which appeared after the interim report had been drafted, will be given full consideration in the final report.

SUMMARY

SUMMARY

This report summarizes the National Petroleum Council's "Initial Appraisal" of the U.S. energy outlook through 1985. Supply-demand relationships are projected assuming that current government policies and regulations[1] and the present economic climate for the energy industries would continue without major changes throughout the 1971-1985 period.[2]

ASSUMPTIONS OF INITIAL APPRAISAL

In line with maintenance of a basic "status quo", it was assumed that:

1. Recent physical levels of oil exploration and development drilling activity and exploration success trends would continue into the future.

2. The level of capital investment in gas exploration and development drilling activity would remain relatively constant and the past trends in the results of such activity would provide the basis for future expectations.

3. After domestic oil production capacity is reached, remaining requirements would be satisfied by imports. It was also assumed that political, economic and logistical considerations would not restrict the availability of foreign oil.

4. All presently feasible sources of gas supply, domestic and foreign, would be utilized. It was also assumed that political, economic and logistical considerations would not restrict the availability of foreign gas.

5. Nuclear power would be utilized to the maximum extent consistent with a feasible development program.

6. Coal production would rise to the degree necessitated by demand and technological advances would permit coal producers and consumers to meet environmental requirements.

These assumptions are generally optimistic. In view of past trends, the assumed levels of oil and gas exploratory activity, in particular, are not likely to be realized without substantial improvements in economic conditions and government policies. Similarly, the availability of foreign oil to meet shortfalls in domestic supplies cannot be assured. Significant limitations could arise for political or logistical reasons.

This initial appraisal, therefore, is not a forecast of what will probably happen in the future, and it should not be so interpreted. It is solely a set of projections, reflecting an optimistic view of what might happen without major changes in present government policies and economic parameters. These projections will be used as reference points by the Committee in its subsequent task of identifying and evaluating the changes in government policies and economic conditions which might contribute to an improved national energy posture.

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[1] Particularly in respect to oil import controls, natural gas price regulation, leasing of federal lands, environmental controls, tax rates and research funding.

[2] This analysis relates to government policies prior to the President's June 4, 1971, Energy Message to Congress.

FINDINGS OF THE INITIAL APPRAISAL

In the initial appraisal, an assessment was made of total U.S. energy consumption by market sectors.[1] The Subcommittees for Oil, Gas and Other Energy Resources made independent assessments of the individual fuels involved. They applied their respective judgments in deciding what factors would affect demand for the particular fuel examined and took into account the probable supply of other fuels. From these projections, the Coordinating Subcommittee developed an energy supply-demand balance. The principal findings of the initial appraisal, made under the assumed conditions summarized above, were as follows:

1. *Energy Consumption*--U.S. energy consumption would grow at an average rate of 4.2 percent per year during the 1971-1985 period. The respective growth rates by market sectors would be as follows: electric utilities, 6.7 percent; nonenergy uses, 5.4 percent; transportation, 3.7 percent; residential and commercial, 2.5 percent; and industrial, 2.2 percent.

2. *Domestic Energy Supplies in Relation to Consumption*--In 1970 domestic energy supplies satisfied 88 percent of U.S. energy consumption. Under the assumptions of the initial appraisal, domestic supplies would grow at an average rate of 2.6 percent per year during the 1971-1985 period. Since domestic supplies would increase at a slower rate than domestic demand, the nation would become increasingly dependent on imported supplies. By 1985, domestic supplies would take care of about 70 percent of U.S. consumption.

3. *Petroleum Liquids*--Domestic supplies, consisting of crude oil, condensate and natural gas liquids, totaled 11.3 million barrels a day (B/D) in 1970, which was 31 percent of total energy consumption. Despite the addition of an estimated 2.0 million B/D from the Alaskan North Slope and another 2.7 million B/D from new discoveries to be made after 1970, total U.S. production in 1985 was estimated at only 11.1 million B/D. Therefore, in order to meet growing demands for petroleum liquids, imports would have to increase more than fourfold by 1985, reaching a rate of 14.8 million B/D in that year. Assuming the availability of foreign supply, oil imports would then account for 57 percent of total petroleum supplies and would represent 25 percent of total energy consumption. Most of the imports would have to originate in the Eastern Hemisphere because of the limited potential for increased imports from Western Hemisphere sources.

4. *Gas*--In the absence of supply limitations, potential gas demand would approximately double between 1970 and 1985, reaching a level of about 38.9 trillion cubic feet (TCF) per annum. Under current regulatory policies and federal leasing policies, however, the supplies of domestic natural gas (excluding North Slope) could be expected to fall from 21.82 TCF in 1970 to 13.00 TCF in 1985. By this time, another 1.50 TCF would be contributed by the Alaskan North Slope and 0.91 TCF from synthetic gas manufactured from coal and naphtha; meanwhile, imports from Canada could provide 1.15 TCF and imports of LNG and LPG could furnish an additional 4.93 TCF.[2] Taking all of these

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[1] For an assessment of requirements by geographic area as well, see Chapter One, Volume II.

[2] Supplies from all the sources mentioned could be made available only at prices substantially above those postulated for production of domestic natural gas under the assumptions of this initial appraisal.

sources into account, 1985 supplies would total only 21.49 TCF, or 1.25 TCF less than 1970 supplies of 22.74 TCF. Dependency on imports would rise from 4 percent of gas supplies in 1970 to more than 28 percent in 1985, assuming the availability of foreign supply. The shortfall in energy supply between potential gas demand and available gas supplies would have to be made up from increased supplies of other fuels.

5. *Coal*--Supply of domestic coal, including exports, would increase from 590 million tons in 1970 to 1,071 million tons in 1985. Coal reserves were judged ample and could support a faster growth rate in production. Potential constraints, however, were seen as being the availability of manpower and transportation facilities, health and safety regulations, and the need to develop a commercially proven technology for control of sulfur dioxide emissions.

6. *Nuclear*--Nuclear power supply would increase from 23 billion kilowatt hours (KWH) in 1970 to 2,067 billion KWH in 1985. This is consistent with estimates of the Atomic Energy Commission. Achievement of this level would depend primarily on resolving delays from siting, environmental and construction problems. No shortage of domestic fuels was foreseen, assuming prices for U_3O_8 up to \$10 per pound. By 1985, nuclear energy would be supplying 48 percent of total electric power requirements.

7. *Other Fuels*--The remaining fuels--hydropower, geothermal power and synthetic crude from shale--would together contribute only 3 percent of energy requirements in 1985. Ceilings on the output of the first two would be imposed by physical limitations. Ceilings on the output of synthetic crude would be limited by government policy on leasing land, economics and technology; consequently only about 100,000 B/D would be obtainable from oil shale.

8. *Capital Requirements*--In order to achieve the initial appraisal energy balance, capital outlays for resource development, manufacturing facilities and primary distribution in the United States would have to total approximately \$375 billion over the 1971-1985 period.[1] Not included in this estimate were other major sums for petroleum marketing, gas and electricity distribution, and the development of overseas natural resources needed to satisfy U.S. import requirements.

IMPLICATIONS OF THE INITIAL APPRAISAL

In the long run, all indigenous energy supplies that can be developed will be needed. Potential U.S. energy resources could physically support higher growth rates from domestic supplies than shown in this initial appraisal, particularly for coal, nuclear fuels, petroleum liquids and natural gas. U.S. coal reserves are ample to meet foreseeable needs. The quantity of original oil and gas in place, as estimated in the NPC report[2] on future U.S.

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[1] Excludes capital outlays for Alaskan North Slope exploration, development and production. Includes capital outlays of \$200 billion for electric power plants and transmission lines.

[2] As indicated in the NPC report *Future Petroleum Provinces of the United States* (July 1970), *if* discovered and produced, future production of crude oil would be 346 billion barrels (4.0 times past production) and future production of natural gas would be 1,195 trillion cubic feet (3.6 times past production). The discovery and commercial development of these potential resources will, however, take many decades and require major improvements in economic incentives.

petroleum provinces, exceeds the total of cumulative oil and gas production to date and the domestic demand for oil and gas projected in this appraisal. Also, the combined total of currently proven and potentially discoverable oil and gas as estimated in that report is above projected needs during the study period interval. It is extremely important to note, however, that these resources are not likely to be developed to their full potentials under the "status quo" assumption regarding government policies and economic conditions. For example, using the discovery rate projected in the initial appraisal, it would take almost a century to find the estimated discoverable oil projected in the referenced study.

Since the mid-1950's, the growth rate for domestic petroleum production has slackened, while that for imports of petroleum has increased. As a result, incentives and prospective profitability for exploration and development of hydrocarbon resources in the United States have decreased.[1] In the last few years, there has been a higher rate of growth in the market for domestic oil, but the "real" price of crude oil still remains below the level of the decade earlier.

Based on historical precedent, the assumption of U.S. oil and gas prices continuing at recent levels indicates that supplies of domestic oil and natural gas will decline in the future. However, an improved economic climate would encourage (1) increased exploration for new reserves of oil and gas and (2) increased recovery of oil from known reserves.

The extent to which indigenous supplies could be increased by these and other changes was not considered in this initial appraisal, but will be assessed in the final report scheduled for completion in July 1972.

At this time, it is appropriate only to note certain areas of concern that are implicit in the continuation of existing conditions. These items can be conveniently placed in four groups:

1. *Government Policies*--Continuation of present government policies, particularly in respect to leasing of federal lands, environmental controls, health and safety, tax rates, research funding, natural gas price regulation, and import policies, clearly will result in a sharp rise in national dependence on imported energy sources, particularly petroleum liquids. This will require careful assessment, in respect to both national security aspects and the impact on the U.S. balance of payments. Furthermore, the United States cannot expect indefinitely to be able to increase imports of foreign oil. Towards the end of the century, foreign oil supplies may prove insufficient to meet all potential demands.

   Continuation of present government policies will also result in available gas supplies being equal to only about one-half of market requirements in 1985. In view of the indicated availability of substantial undiscovered domestic reserves, a critical review of natural gas regulations and other parameters impinging on the incentives for expanded exploratory efforts is clearly in order and urgently needed.

2. *Physical Facilities*--The satisfaction of the nearly doubled energy requirements of 1985 will require enormous additions of new facilities, which will not easily be forthcoming under existing political, social and economic conditions. *In petroleum*, the importation of an incremental 10-11 million B/D of overseas crude oil and products above the 1970 level would require more than 350 tankers, each of 250,000 deadweight tonnage (DWT). No U.S. ports are presently equipped to receive

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[1] For further discussion of effect of economic factors in 20 years after World War II, see the report of the National Petroleum Council, *Factors Affecting U.S. Exploration, Development and Production*, dated January 31, 1967.

such tankers, so new terminals would have to be developed in coastal areas. Similarly, the increase in refined products requirements would necessitate net additions of about 10 million B/D to domestic refining capacity over the 15-year period. This would involve construction at about 2.5 times the rate of the past decade. *In gas*, the importation of 4 TCF of LNG annually by 1985 would require the building of 120 tankers each having a maximum capacity equivalent of approximately 790,000 barrels. In addition, such operations would require the building of liquefaction plants at the loading terminals and the building of unloading terminals, regasification plants and storage and transportation facilities at points of delivery. *In coal*, the doubling of mine output would involve the development of Western coal reserves with associated transportation to markets as well as expanded development of underground mines in the East and Midwest. *In nuclear power*, the pace of construction of new plants would have to rise very sharply from recent levels, reaching a capability of bringing thirty 1,000-megawatt plants on line each year from 1980 through 1985.

3. *Financial Requirements*--Annual new investment required to finance development of natural resources and construction of new facilities would greatly exceed the levels of recent years. Funds provided from operations of energy industries at present price levels would fall far short of meeting these capital requirements. Environmental regulations affecting the supply, transportation and consumption of all fuels would further increase investment costs. All these things indicate increasing energy costs.

4. *Technology*--The doubling of energy consumption over the next 15 years implies a sharp step-up in all kinds of measures needed to protect the environment, both at the points of energy production and use. The urgent need for energy also provides varied research challenges, including problems such as new coal mining methods, new exploratory techniques, new methods of increasing the recovery of oil and gas, new energy transportation methods, advanced nuclear technology, and the development of commercial processes for flue-gas desulfurization and for manufacture of synthetic liquid and gaseous fuels from oil shale and coal.

Finally, it should be noted that long lead times are involved in the orderly development of energy resources. Therefore, it is essential that the many considerations bearing on the selection of an optimum national energy posture be brought into sharp focus at the earliest possible date. In its final report on the U.S. energy outlook, the National Petroleum Council will seek to provide as much pertinent material as possible, including analyses of alternatives open to both government and industry.

ADDITIONAL STUDIES

The NPC Committee on U.S. Energy Outlook has already started to develop additional analyses of changes in industry and/or government programs and policies and changes in economic conditions which would lead to the following effects:

1. Increase indigenous energy supplies
2. Enhance the environment
3. Maintain the security of the nation's energy supplies
4. Increase efficiency in the production and use of fuels, particularly through technological research and development

In the process of this additional work, special attention will be given to costs, including the range of cost increases involved in various steps to improve the energy supply situation, and the resultant impact of such increases on demand. The Committee recognizes that price levels will have a significant impact on both the supply of and demand for various energy resources; an effort will be made to evaluate the elasticity of demand and supply for each major type of energy.

Chapter One

ENERGY OUTLOOK UNDER INITIAL APPRAISAL ASSUMPTIONS

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Projecting the energy outlook in this initial appraisal required estimates of total energy consumption and total energy supply, and these estimates had to be balanced. In order that consumption by many different market sectors and supply by many different energy sources could be aggregated, a common denominator was required. For this purpose, estimates were expressed in terms of British Thermal Units (BTU's). (For a fuller definition, see box insert on p. 10.)

Besides these estimates in BTU's and other physical units of measure, a projection of the energy outlook involved certain gross assessment of at least the most predictable capital requirements for reaching the needed energy supply. Like energy consumption and supply, investment will be covered in this chapter only briefly. More details will appear in the separate chapters on individual fuels.

U.S. ENERGY CONSUMPTION

Total U.S. energy consumption will probably grow at an average annual rate of 4.2 percent during the 15 years 1971-1985, thus almost doubling its starting 1970 volume by the end of the period. Measured in trillions of BTU's, energy consumption should increase as follows:

Year	Volume	Percent Increase Over 1970
1970	67,827	--
1975	83,481	23.1
1980	102,581	51.2
1985	124,942	84.2

Source: Energy Demand Task Group

This outlook is predicated on important assumptions regarding environmental restraints, basic economic trends, prices, fuel availability, capital requirements and technological developments which will be reexamined in subsequent variant analyses.[1]

As developed more fully in the demand projections in Chapter Two, the overall average yearly growth rate conceals a wide range of variation in the growth rates of the five major market sectors that account for total energy consumption. These are (1) residential and commercial, (2) industrial, (3) transportation, (4) electrical utilities,[2] and (5) nonenergy uses for fuel.

[1] For further discussion see Chapter One, Volume II.

[2] Though commonly thought of as energy *suppliers*, electric utilities are actually also energy *users*, consuming coal, gas, oil, nuclear fission products, etc. Thus utilities *convert* one form of energy to another. In technical parlance, electrical utilities are users of *primary* energy sources, and suppliers of *secondary* energy. In every stage of their operation--production, transmission and distribution--some BTU's are lost.

Throughout the body of this text, utilities are treated as energy consumers. Thus, to avoid duplication, the consumption of electricity by other consuming sectors (such as industrial and residential) has been omitted from statistics in their total energy consumption.

For a picture of energy consumption patterns by consuming sector with electricity consumption included in the figures for the other sectors, the reader is referred to Chapter One, Volume II.

WHAT IS A BTU?

A BTU is the amount of heat required to raise the temperature of one pound of water one degree Fahrenheit. The BTU is a very small unit of measurement, and when one adds up large quantities of energy, one must count in large multiples of the BTU. Thus, the energy balance tables in this report are expressed in trillions of BTU's.

The BTU equivalents of common fuels are as follows:

Fuel	Common Measure	BTU's
Crude Oil	Barrel (Bbl.)	5,800,000
Natural Gas	Cubic Foot (CF)	1,032
Coal	Ton	24,000,000 to 28,000,000
Electricity	Kilowatt Hour (KWH)	3,412

Two trillion BTU's per year are approximately equal to 1,000 barrels per day of crude oil.

ENERGY SUPPLIES

To satisfy demand of the magnitude expected will not be easy under the initial appraisal assumptions as to economic climate and government policies. The pattern of fuel sources used will shift markedly in response to such factors as supply limitations, interfuel competition and U.S. import policies. Oil and coal will continue to supply roughly 43 percent and 19 percent, respectively, of energy consumption; however, imports are projected to grow from 22 to 57 percent of oil supply.

Potential gas demand, without consideration of supply limitations or changes in the energy pricing structure, would almost double, reaching 38.9 TCF by 1985. During the same period, however, the available supply of gas (including imports of LNG and LPG, plus synthetic pipeline gas) would decline from 22.7 TCF in 1970 to 21.5 TCF in 1985. It is thus obvious that consumption of gas is inhibited by a lack of foreseeable supply, assuming the continuation of current regulatory policies and economic conditions. It is equally apparent that any shortfall in total energy supplies resulting from a lack of gas must be made up from increased supplies of other fuels. The total gas supply projected for the years through 1985 holds almost even over the period, but dependence on imports rises from 4 percent in 1970 to over 28 percent of total gas supply in 1985. Moreover, gas is projected to decline from 33 to 18 percent of total energy consumption.

Nuclear energy is projected to grow from less than 1 percent to more than 17 percent of total energy. Remaining energy needs will be met from geothermal and hydropower sources.

To develop these projections, the Oil, Gas and Other Energy Resources Subcommittees made independent assessments of the individual fuels (see Chapters Three through Nine). Each group made its own judgment of the factors that would affect demand for the particular fuel examined, including the supply of other fuels. The independent assessments of supply and demand of the several fuels made by the respective Task Groups did not total exactly to the overall energy forecast developed by the Energy Demand Task Group (see Exhibit 3 for the Energy Trial Balance). The Coordinating Subcommittee accordingly adjusted the separate Task Force projections of supplies to conform with the total energy requirements as forecast by the Energy Demand Task

Group. The necessary adjustments were small, ranging from 1.4 percent of total demand in 1975 to 2.4 percent in 1980 and 2.1 percent in 1985.

To achieve the needed gains in supplies, slight increases were assumed to be available from the two sources that could most probably be increased, namely, oil imports and domestic coal. In the absence of any clear-cut indication as to which of these two sources should be counted on for what, the Committee made a purely arbitrary allocation, getting one-third of the requirements from oil imports and two-thirds from domestic coal, as follows:

TABLE I

RECONCILIATION OF TASK FORCE PREDICTIONS, FUEL DEMAND AND SUPPLY

Fuel Demand and Supply Requirements	1975	1980	1985
Projected by the Energy Demand Task Group (Trillion BTU's)	83,481	102,581	124,942
Projected by the Separate Fuel Task Groups (Trillion BTU's)	82,347	100,116	122,299
Difference (Trillion BTU's)	1,134	2,465	2,643
Residual Fuel Oil			
Equivalent of Difference (Thousand B/D)	490	1,070	1,150
Coal			
Equivalent of Difference (Million Tons)	45	100	105
Fuel Oil Share (at One-Third of the Difference, Thousand B/D)	165	360	400
Coal Share (at Two-Thirds of the Difference, Million Tons)	30	65	70
Residual Fuel Share as a Percent of Total Residual Fuel Demand	5%	9%	9%
Coal Share as a Percent of Total Domestic Coal Demand	4%	8%	8%

Source: Coordinating Subcommittee.

In subsequent tabulations, it will be routinely noted whether supply figures are adjusted (to conform with Energy Demand Task Group Estimates) or unadjusted (Individual Fuel Task Group figures).

From the above projections, the Coordinating Subcommittee developed the supply-demand balance which is shown in Table II. The supply data are repeated in Table III in the physical units appropriate for the respective fuels and depicted graphically in Figure 1.

CAPITAL REQUIREMENTS

The capital requirements to meet U.S. energy needs through 1985 are extremely large. Taken to the wholesale operations level (i.e., exclusive of petroleum marketing, gas distribution, electricity distribution, etc.), these capital requirements (in constant 1970 dollars) for the 15-year period 1971-1985 are estimated as follows:

	Billion Dollars
Oil and Gas Production*	$ 92
Oil Refining*	20
Oil Transportation (Marine and Domestic Pipelines)	18
Gas Transportation	21
Coal Production	9
Coal Transporation	6
Nuclear Production and Processing	5
Oil from Shale	0.5
Syngas Plants	2.5
Subtotal	$174
Electric Power Plants and Transmission Lines	200
TOTAL	$374

* Excludes foreign facilities.

This sum represents about 14 percent of the projected nonresidential fixed investment of the United States for the period 1971-1985.

TABLE II

ENERGY BALANCE--INITIAL APPRAISAL
(In Trillions of BTU's)

	1970	1975	1980	1985
U.S. Domestic Energy Consumption*	67,827	83,481	102,581	124,942
Projected Domestic Supply:†				
Oil - Conventional‡	21,048§	22,789	24,323	23,405
Synthetic	--	--	--	197
Subtotal	21,048	22,789	24,323	23,602
Gas - Conventional‡	22,388§	20,430	18,030	14,960
Synthetic	--	380	570	940
Subtotal	22,388	20,810	18,600	15,900
Coal‖	13,062	16,310	19,928	23,150
Hydropower	2,677	2,840	3,033	3,118
Nuclear	240	3,340	9,490	21,500
Geothermal	7	120	343	514
TOTAL DOMESTIC SUPPLY	59,422	66,209	75,717	87,784
(Percent of U.S. Consumption)	87.6	79.3	73.8	70.3
Imports Required to Balance:				
Oil	7,455	15,662	22,984	30,878
(Percent of Oil Supply)	22.0	40.7	48.6	56.6
Gas	950	1,610	3,880	6,280
(Percent of Gas Supply)	4.1	7.2	17.3	28.3
TOTAL IMPORTS	8,405	17,272	26,864	37,158
(Percent of Energy Supply)	12.4	20.7	26.2	29.7

* As projected by the Energy Demand Task Group.
† As projected by the various Fuel Task Groups; oil and coal adjusted to meet demands as predicted by the Energy Demand Task Group (see Table I).
‡ Includes Alaska North Slope starting in 1975 for oil and 1977 for gas.
§ Excludes additions to oil (2,086) and gas (132) stocks.
‖ Excludes BTU's consumed in conversion of coal to syngas.

Source: Coordinating Subcommittee and indicated Task Groups.

TABLE III

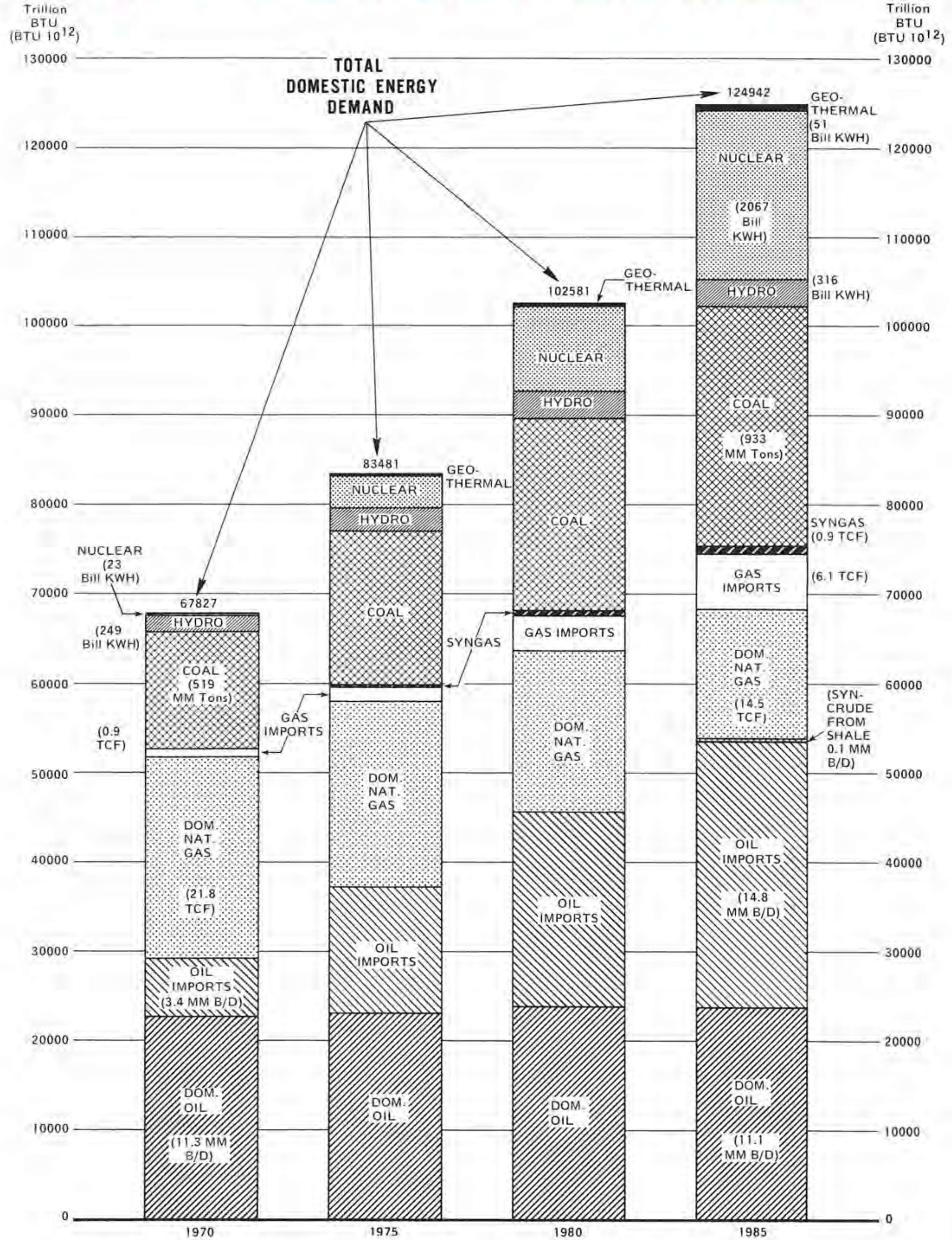
ENERGY SUPPLY--INITIAL APPRAISAL
(In Conventional Physical Units)

	1970	1975	1980	1985
Projected Domestic Energy Supply				
Oil - In Million B/D				
Conventional	11.3	11.1	11.8	11.1
Synthetic	-	-	-	0.1
TOTAL	11.3	11.1	11.8	11.2
Gas - In Trillion CF				
Conventional	21.82	19.80	17.47	14.50
Synthetic	-	0.37	0.55	0.91
TOTAL	21.82	20.17	18.02	15.41
Coal - In Millions of Short Tons				
For Domestic Use*	519	651	799	933
For Export	71	92	111	138
TOTAL	590	743	910	1,071
Other - In Billions of KWH				
Hydro	249	271	296	316
Nuclear	23	326	926	2,067
Geothermal	0.7	12	34	51
TOTAL	272.7	609	1,256	2,434
Imports Required to Balance:				
Oil - In Million B/D†	3.4	7.3	10.7	14.8
Gas - In Trillion CF	0.92	1.55	3.75	6.08

	1970	1975	1980	1985
* Includes adjustment of million tons	-	30.0	65.0	70.0
† Includes adjustment of million B/D	-	0.2	0.4	0.4

Source: See Table II.

Figure 1. U.S. ENERGY BALANCE – INITIAL APPRAISAL



Source: See Tables II and III.

Chapter Two

ENERGY CONSUMPTION PROJECTIONS

ENERGY CONSUMPTION PROJECTIONS

As indicated in the previous chapter, energy consumption in the United States is expected to grow at an average annual rate of 4.2 percent a year over the next 15 years, which is just a little slower than the pace maintained in the 1960's. Demand being so critical a figure in this report, the remainder of this chapter is directed to indicating how demand estimates were determined.

METHODOLOGY

The projection of total energy requirements has resulted from analysis and synthesis of the component parts, rather than by assuming a fixed relationship between energy and Gross National Product (GNP), or some other economic index. While the energy/GNP relationship is frequently useful, past experience in the United States indicates that the ratio has changed from time to time (as shown in Figure 2), and that it is not likely, by itself, to provide a firm basis for projections. However, assumptions as to the outlook for GNP and many other economic and technological factors have been used as a framework for developing the component market projections (see Chapter One, Volume II).

To achieve this "building up" of demand estimates, it is, of course, essential to think in terms of the main consuming sectors and subsectors of which total demand is composed. As noted in the previous chapter, five such major sectors have been identified. The market share of each sector and some of the major subcomponents of each are discussed in the following paragraphs.

1. *Residential/Commercial* markets for direct usage of fossil fuels account for about 19 percent of total energy consumption in the U.S. (1970 data). About two-thirds of this total is used for *residential* heating, cooling, cooking and water heating. The remainder is consumed for similar purposes in apartments, houses, stores, hospitals, schools, hotels, restaurants and other *commercial* establishments.

2. The *Industrial* market for fossil fuels comprises 26 percent of total energy demand. This market, of course, is primarily manufacturing and mining operations.

3. *Transportation* consumption of fossil fuels representing 24 percent of total energy demand, includes such major markets as motor fuels, aviation fuels, railroad fuels and ships' bunkers.

4. *Electric Utilities* consume almost 25 percent of the nation's "primary energy" meaning fossil fuels, nuclear energy, geothermal energy and water power.[1] Output is sold mainly to the residential/commercial and the industrial markets, where it competes with fossil fuels.

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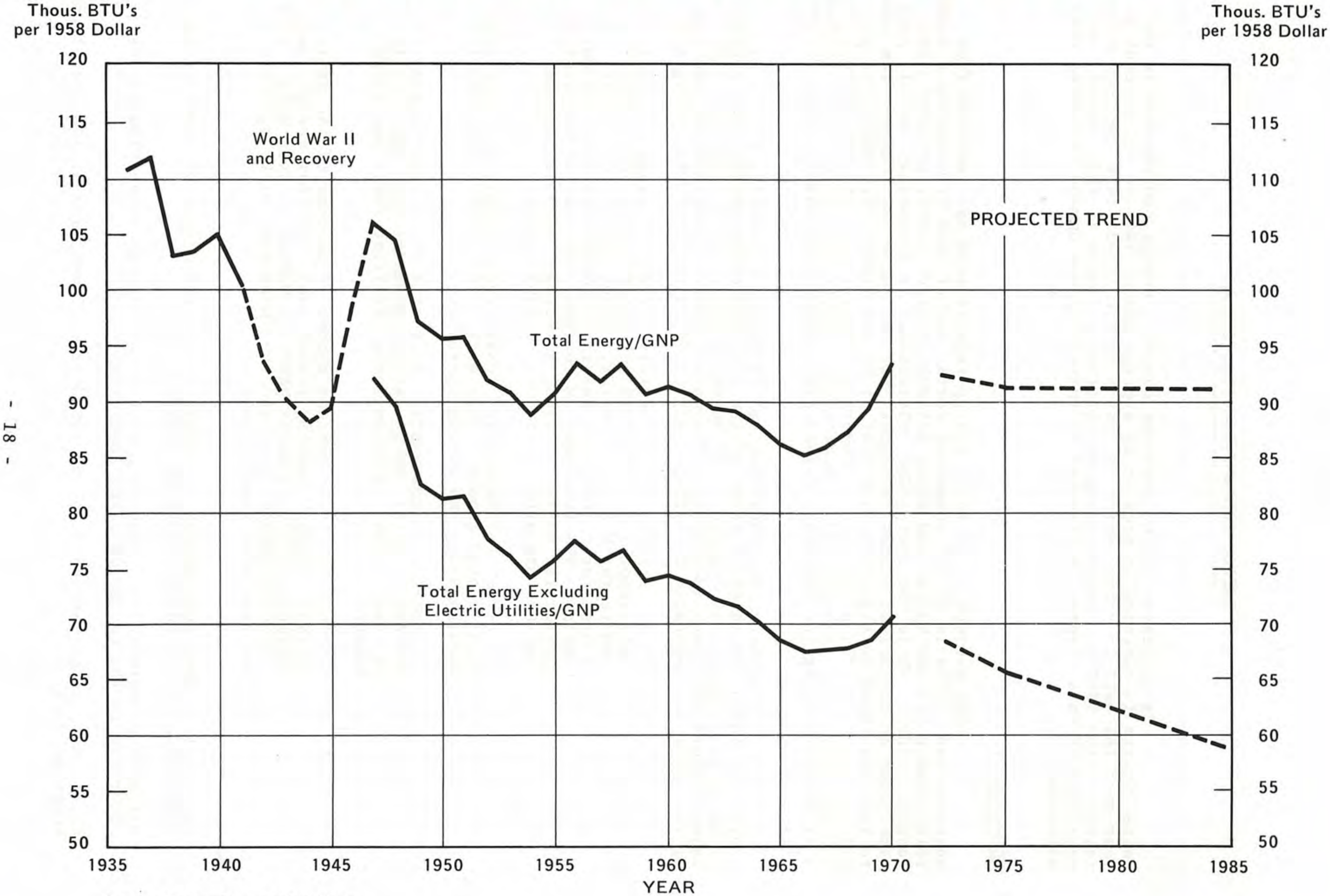
[1] Such utility fuel consumption is termed *input*; the *output* of electricity is regarded as a "secondary" form of energy.

Differences between *input* and *output* represent energy conversion losses occurring in the course of power generation.

Electricity is not included in the residential/commercial or industrial consumption data.

Figure 2. RATIO OF U.S. ENERGY CONSUMPTION TO REAL GNP



Source: Energy Demand Task Group

5. *Nonenergy and Miscellaneous* uses account for 6 percent of the total primary energy consumption. Nonenergy uses include lubricants, asphalts, petrochemicals and other raw materials. The miscellaneous category includes both energy and nonenergy "unaccounted for" items.

In order to identify possible special problem areas, energy demand estimates were developed by consuming sectors for all five Petroleum Administration for Defense (PAD) Districts and for selected Census Districts. These geographical details appear in Chapter One, Volume II.

GROWTH RATES

Projections developed for the individual markets described above are summarized in Table IV. Although the contributors to this study differed substantially with respect to the outlook for demand in several of these *component sectors*, variations in different estimates of *total energy demand* were relatively small. All the long-term growth forecasts by individual participants showed total energy consumption increasing at rates of 4.1 percent to 4.2 percent per year, except for one estimate at 4.3 percent and another at 3.8 percent.

In terms of future growth prospects, the top ranking sector is electrical utilities. The total input of energy to electric utilities from fossil fuels, nuclear, geothermal and water power is predicted to increase at an average annual rate of 6.7 percent per year. This is less than the 7.2 percent rate experienced during the past decade. This sector, which represents about 25 percent of total energy currently, will be the fastest growing sector, will become the largest sector before 1975, and will account for over 35 percent of total energy in 1985.

Taking into account the expected improvements in generating efficiency, the *output* of electric power is projected to grow at a rate of 7.2 percent per year. In developing this outlook, it was assumed that the electric utilities would be reasonably successful in overcoming serious obstacles such as: difficulties in obtaining rights-of-way for transmission line corridors and new sites for generating plants arising from environmental restraints, shortages of fuels of the type that will meet anti-pollution standards, and problems in generating required capital inputs. Capital requirements for the electric utility industry (generation and transmission) will be huge--amounting to over $200 billion (in 1970 dollars) for the entire 15-year period. This is about three times the industry's total current (undepreciated) investment and more than three times the total capital expenditures of the past 15 years.

The second ranking sector in terms of growth prospects is the nonenergy and miscellaneous group, with an estimated 15-year average annual growth of 5.4 percent. The trend is turning upward primarily because of just one factor--expanding demand for petrochemical feedstocks.

In spite of a decline in the rates at which consumption is increasing, the third ranking sector remains transportation. At least in the years through 1985, little reason exists for expecting significant changes in the basic technological, economic and demographic factors behind the consumption of transportation fuels. Perhaps the most important development in the direction of increased fuel usage is the application of anti-pollution devices to motor vehicles. But a trend toward smaller cars is operating in the other direction. No major shift from internal combustion engines to electrical or other power is foreseen during the 1971-1985 period. After examining all the important variables, the Task Group concluded that this sector would show declining, though still high, future growth at yearly average rates of 4.1 percent, 3.7 percent, and 3.4 percent for the periods 1970-1975, 1975-1980, and 1980-1985 respectively.

Ranking fourth, the residential and commercial sector is expected to grow at an average annual rate of 2.5 percent, compared with 3.3 percent for the past decade. This fall-off reflects mainly an assumption that population growth will be only 1.1 percent per year. Also reflected is a trend toward smaller families and, probably, toward smaller dwelling units. On the other hand, substantial growth will continue in the labor force, the numbers of households, and personal income.

The consumption of energy by the industrial sector is projected to grow at a rate of 2.2 percent, which is less than the very high rate of the 1960's, but well above the average rate for the entire post-World War II period.

SECTOR CONSUMPTION SHARES

Having calculated sector growth rates, the Task Group considered sector shares of total primary energy consumption. These estimates are shown in the following tabulation. Consistent with the growth rate picture, the sector that is expected to increase its share the most is electrical utilities. Other sectors, except for nonenergy and miscellaneous, are expected to show a relative decline:

SECTOR PERCENTAGE SHARES OF TOTAL U.S. PRIMARY ENERGY CONSUMPTION

	Percentage of U.S. Total				
Sector	1960	1970	1975	1980	1985
Residential/Commercial	21.1%	19.2%	17.6%	16.2%	15.0%
Industrial	29.3	26.2	24.0	21.8	19.7
Transportation	24.3	24.0	23.9	23.3	22.6
Electric Utilities	18.8	24.6	28.2	32.2	35.5
Nonenergy & Miscellaneous	6.5	6.0	6.3	6.5	7.2
TOTAL	100.0%	100.0%	100.0%	100.0%	100.0%

Source: Energy Demand Task Group.

TABLE IV

TOTAL U. S. PRIMARY ENERGY CONSUMPTION BY CONSUMING SECTORS*

Consuming Sector	Volumes (In Trillions of BTU's)					Average Annual Growth Rates				
	1960†	1970†	1975	1980	1985	1960-70†	1970-75	1975-80	1980-85	15-Year Forecast
Residential/ Commercial	9,426	12,994	14,733	16,669	18,768	3.3%	2.6%	2.5%	2.4%	2.5%
Industrial	13,056	17,798	20,039	22,341	24,667	3.1	2.4	2.2	2.0	2.2
Transportation	10,817	16,282	19,905	23,870	28,214	4.2	4.1	3.7	3.4	3.7
Electric Utilities	8,387	16,695	23,525	32,996	44,363	7.2	7.1	7.0	6.1	6.7
Nonenergy & Miscellaneous	2,916	4,058	5,279	6,705	8,930	3.4	5.4	4.9	5.9	5.4
GRAND TOTAL	44,602	67,827	83,481	102,581	124,942	4.3%	4.2%	4.2%	4.0%	4.2%

* Includes fossil fuel consumption in each sector. The nuclear and water power outputs are converted to fossil fuel input equivalents at average central station heat rates and are included in the electric utility sector.

† Source: Prepared by the Energy Demand Task Group. The historical volumes are from the U.S. Bureau of Mines, except for the 1970 electric utility estimate which is based on Federal Power Commission data covering 12 months, 1970. The BTU conversion factors also are from the Bureau of Mines except for modifications in the bituminous coal factors as follows: Electric utility coal is calculated at 24 million BTU's per ton and all other bituminous at 26.2 million BTU's per ton.

Chapter Three

PETROLEUM

PETROLEUM

Although petroleum will continue to supply about the same percentage of total U.S. energy demand in 1985 as in 1970, the proportion of domestic vs. foreign supply will change radically under the assumptions used in this initial appraisal. Insofar as the supplies of conventional petroleum energy are concerned (i.e., crude oil and gas condensates and liquids), the domestic contribution will not quite hold its own when measured in barrels per day, and will drop as a percentage of the total oil supply from 78 to 43 percent. Rising imports will allow petroleum to retain approximately the present share of U.S. energy consumption.

The following chapter provides a brief discussion of demand and its component parts and a more detailed discussion of supply. Emphasis is placed on explaining the declining domestic contribution, identifying the kinds of sources from which this contribution will come, describing the conditions underlying the assumption that imports will be available to make up the needed energy balance, and calculating some of the new facilities required to meet the projection and some of the associated investments.

U.S. PETROLEUM DEMAND 1971-1985

Total "normal" domestic demand for liquid petroleum products was projected in the initial appraisal by the Oil Demand Task Group to grow at a rate of 3.8 percent a year, increasing from 14.7 million B/D in 1970 to almost 26 million B/D in 1985. As indicated in Chapter One, it will take only a small shortfall in other fuels to drive petroleum needs above the 26 million B/D level.[1] In spite of this large growth in physical requirements, demand for petroleum will remain almost constant as a percentage of total energy needs. At 26 million B/D at the end of the study period, demand for petroleum will be some 43 percent of total energy demand, or almost exactly the same percentage as it was at the start.

This total demand for liquid petroleum breaks down into demand for five main product classes, of which motor gasoline at 39 percent of the total is the largest, although scheduled to fall to 35 percent by 1985. Both the growth of demand and its distribution among product classes is illustrated in Figure 3. Of the product classes listed, only two call for discussion: motor gasoline and residual fuel. Relative demand for these two classes differs significantly as between the United States and other Free World countries. Thus, for 1970, as a percentage of total petroleum demand, motor gasoline is 39 percent for the United States, 14 percent for the rest of the Free World; residual fuel is 15-16 percent for the United States, 40 percent for the rest of the Free World. These differences in demand distribution among products, plus the fact that the United States imports over 70 percent of the residual fuel it uses, are reflected in differences in the type of refining capacity between the two areas, that of the United States being much more complex and expensive.

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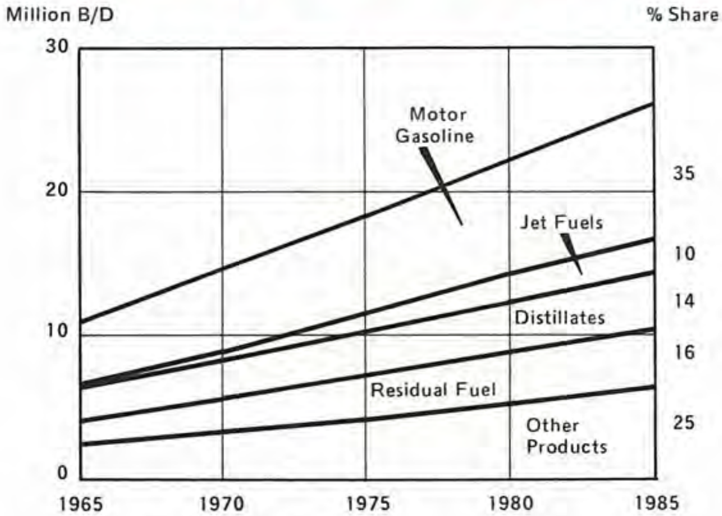
[1] As pointed out in Chapter One, page 11, the Coordinating Subcommittee raised the oil import estimates of the Oil Supply Task Group by 165,000 B/D in 1975, 360,000 B/D in 1980, and 400,000 B/D in 1985 in order to make up for shortfalls in other fuels. The increase would probably be mostly heavy fuel oil to offset the availability of natural gas.

Figure 3.
U.S. DEMAND FOR PETROLEUM PRODUCTS



Source: Oil Demand Task Group

Although still relatively small in comparison with motor gasoline, U.S. demand for residual fuel oil has been greatly accelerated in recent years by diminishing natural gas supplies, more stringent air conservation requirements, and some productivity and transportation limitations on coal supplies. As a result, demand, which grew at an average annual rate of 1.9 percent during 1959-1968, jumped to an average annual rate of 10 percent during 1969-1970. Future conditions may be such that the demand for residual fuel oil could grow even faster than the projected rate of 4.5 percent a year. Instead of reaching 4.3 million B/D in 1985, it could possibly reach 5.0 million or even more, depending on the limitations affecting the supplies of other fuels and on the impact of environmental controls.

For petroleum products, both consumption patterns and product specifications will be significantly affected by pure-air or emission-control regulations; two noteworthy examples are possible requirements to cut the lead in gasoline and the sulfur in fuel and heating oils. Increasing stringent requirements in the environmental area can be expected to raise the total fuel consumption, refining investments and fuel costs.

U.S. PETROLEUM SUPPLY 1971-1985

Petroleum supplies are classed as "conventional" and "synthetic," the first coming either from crude oil (by far the largest source) or from gas plant liquid production and condensates. Synthetics are still a negligible fraction of the total, and consideration of them is contained in Chapter Eight.

Total U.S. demand for petroleum products is satisfied by processing foreign as well as domestic raw materials in U.S. refineries. The kind and amount of supplies derived from each of these several sources depends upon the interaction of government policies, economic conditions and the availability of natural resources.

In this connection, it should be noted that physical availability of natural resources in the ground as yet poses no constraints on the use of domestic as opposed to foreign oil. The estimated quantity of original domestic oil in place, as reflected in a recent report by the National Petroleum Council,[1] greatly exceeds the total of cumulative oil production to date and the domestic demand for oil as projected in this initial appraisal. However,

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[1] *Future Petroleum Provinces of the United States*, a report of the National Petroleum Council (July 1970).

using the discovery rate projected in the initial appraisal, it would take almost a century to find the estimated discoverable oil projected in the referenced study.

In projecting supplies for the initial appraisal, a large number of assumptions had to be made. While these are detailed in Chapter Three, Volume II, the more important ones are also noted here. Future U.S. crude oil *capacity* was projected by analyzing past trends in activities, costs and results. Except for the Alaskan North Slope, estimated production rates were projected as a function of developed reserves, with a reserve/production ratio of approximately 8-10/1 being maintained. In the case of the North Slope, it was assumed that reserves would be adequate to operate the Trans-Alaska pipeline at its projected capacity of 2 million B/D during the 1980-1985 period. Reserve data from the American Petroleum Institute and cost data from the Joint Association Survey were used extensively.

Under the general "status quo" approach of the entire study, it was assumed that the *"real" price* of oil (in 1970 dollars) would be maintained through 1985, that the *level of exploration and development drilling activity* (measured by total footage drilled) actually experienced in each portion of the country during 1967-1969 would continue unchanged, and that the exploratory success trends of the past decade can continue into the period ahead. *U.S. fiscal policies* (e.g., depletion and other tax provisions) were also assumed to remain unchanged, as were policies on government lands. A North Slope pipeline, with an ultimate oil capacity of 2 million B/D, was assumed to be in operation in 1975 and operating at capacity by 1980. It is worth mentioning here that a large part of the estimated future discoverable oil underlies federal lands, particularly in offshore areas. Therefore, future *federal* offshore *leasing policies* will play a vital role in determining actual future discovery rates.

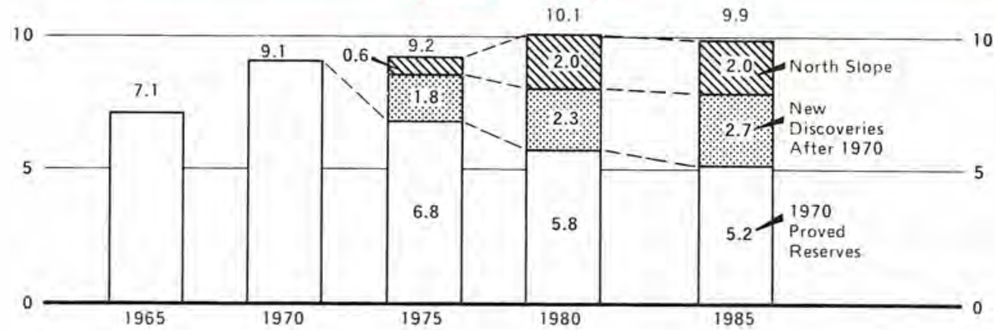
U.S. import policies were assumed to be modified in the future to the extent needed to permit the importation of sufficient foreign supplies to balance demand, while still retaining a control system which would permit constant real prices (in 1970 dollars) for oil in the United States. An assessment of Free World *foreign demand and supply* indicated that sufficient *foreign reserves* were available to assume that worldwide demand could be satisfied through 1985. Towards the end of the century, however, foreign oil supply may prove insufficient to meet all potential demands.

Domestic production of conventional crude oil, excluding the Alaskan North Slope, was projected to increase slightly in the next one to three years, but to decline thereafter. By 1975, crude oil production (excluding the North Slope) would be 8.55 million B/D compared to 9.1 million B/D in 1970. By 1985 the corresponding figure would be 7.9 million B/D. Thus, were it not for the North Slope, domestic crude oil production would be lower in 1985 than in 1970 by 1.2 million B/D, a substantial percentage of the starting figure. With condensates and gas liquids also lower, the domestic trend would have turned down steeply.

In this total picture, there is reason to believe that the assumptions on which the estimate was based, and thus the estimate itself, are optimistic rather than pessimistic. The past decade has seen an actual decline in "real" crude oil prices, a decline in drilling activity, a tendency toward smaller and more expensive offshore lease sales, and increases in income taxes. The assumptions on these items used in this study are more favorable than these recent trends would indicate. It follows, therefore, that unless the assumed improvements actually occur, the available domestic petroleum supplies could prove to be less than projected herein.

So far as crude oil sources are concerned, Figure 4 gives a detailed picture of how the domestic supply divides among major sources over the period since 1965. The future sources shown include 1970 proved reserves; reserves discovered after 1970; and the North Slope, whose 1985 production of 2 million B/D would more than compensate for the decline in U.S. crude output from other sources. Not shown separately on the Figure but contributing to the indicated future supply will be programs to increase recovery from reserves by both secondary and tertiary means.

Figure 4. SOURCES OF U.S. CRUDE OIL PRODUCTION (Million B/D)



Source: Oil Supply Task Group.

Domestic crude oil production will be supplemented by domestic condensate and natural gas liquids. The volume of these materials is dependent on nonassociated gas production rates, oil production rates which determine associated gas production volumes, and the amount of liquids content extracted from produced gas. The last factor, in turn, depends on the processing intensity with which the liquids are removed from the gas. The total volume of such liquids is approximately 2.1 million B/D currently, but is expected to decline to 1.2 million B/D in 1985 (see page 37).

Imports are assumed to provide the remainder of U.S. oil supplies for purposes of this initial appraisal. The source of these imports is determined by the following physical and regulatory constraints and assumptions:

- In 1975 and after, overland imports, available practically entirely from Canada, will be related to Canadian supply less local Canadian requirements.
- Current U.S. policy on residual fuel oil imports will be sustained in PAD District 1.
- Other overseas imports will be permitted to grow as needed to meet total U.S. supply requirements.

Based on the foregoing assumptions and production assessments, a U.S. petroleum supply balance is shown in Figure 5, and a second, slightly different balance is depicted in Table V. The small difference between the two sets of figures derives, as previously discussed, from adding an increment to oil imports to make up for shortfalls possible in other fuels.

As to the source of imports of crude, those from Canada are projected to more than double by 1985, reaching 1.9 million B/D. This growth is predicated on successful exploration efforts in the Canadian Arctic and Canadian Atlantic offshore and on the development of Canadian tar sands as discussed in Chapter Eight.[1] The balance of U.S. needs is met from overseas imports which could grow from about 2.5 million B/D in 1970 to approximately 12.9 million B/D in 1985. The division of overseas imports between crude and products will be determined by future government policy.

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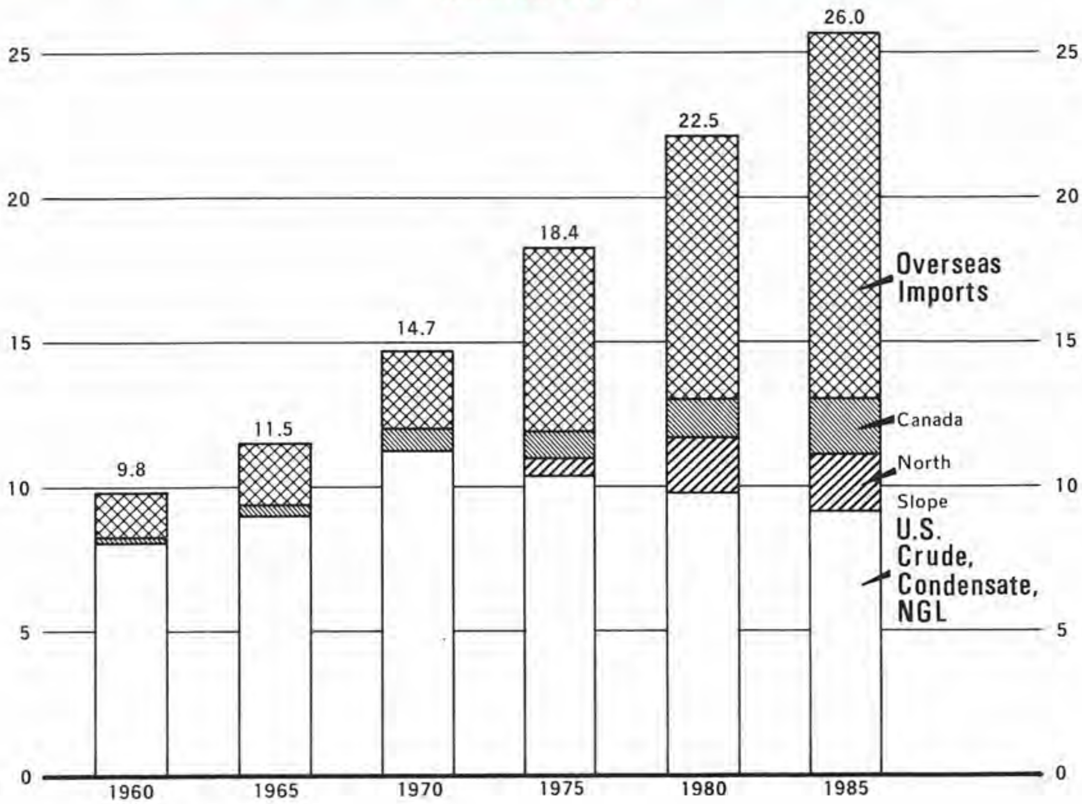
[1] No distinction is made in respect to imports from Canada between conventional crude oil and synthetics, thus differing from other statistics used in this report and resulting in some understatement of the expected contribution of synthetic oil.

Figure 5. U.S. PETROLEUM REQUIRED SUPPLY (Million B/D)



Source: Oil Supply Task Group.

FOREIGN CRUDE AVAILABILITY

The relationship between Free World oil reserves as of December 31, 1970, and estimated Free World oil demand through 1985 indicates that total crude oil requirements *for this period* can be more than covered by proved and expected additional Free World crude oil reserves. Estimated 1970 Free World oil reserves were reported by the *Oil and Gas Journal*, in its December 12, 1970, issue, as 511 billion barrels. While the Oil Subcommittee questions some of the estimates for the individual countries, the Subcommittee believes this total volume is a reasonable estimate of proved and probable worldwide reserves.

Free World gross additions to reserves totaled about 450 billion barrels in the past 15 years. If it is assumed that a similar volume will be added in the next 15 years, total Free World oil available in the years ahead (including proved reserves remaining in 1985) would approach 1,000 billion barrels. By comparison, estimated Free World petroleum demand over the next 15 years is projected to be about 350 billion. This comparison suggests that total Free World oil supplies will probably be adequate to meet needs in the forecast period. However, we must put this projection of the adequacy of oil supplies in perspective. The 1970 Free World demand of 37 million B/D required that Free World oil reserves be produced at a reserves to annual production ratio of about 38. The projected Free World demand in 1985 is 92 million B/D. Thus, 1985 demand will require that the reserves that might be available at that time be produced at a reserves to production ratio of about 17, or a relative rate more than twice the current level. Stated differently, if future reserve additions are maintained at the historic level of 30 billion barrels per year, by about 1982, the Free World demand will exceed the reserve addition rate, resulting in a net decrease in reserves each year thereafter. In addition, there could be significant political and/or economic problems in bringing this oil to the marketplace. Later studies will examine this problem in greater detail.

The patterns of worldwide petroleum logistics and the relationships of indicated supply sources to specific demand centers are extremely complex. No assessment has been made of the volumes of overseas imports into the United States by country of origin. The specific sources of overseas imports will be determined by the interaction of a number of factors, including (1) the supply, demand and qualities of oil, (2) consuming and producing country policies, and (3) the logistical supply patterns of individual companies.

The Oil Subcommittee projected Latin American productive capacity to grow only 1.7 percent annually to 1985, while Latin American local demand for petroleum was projected to grow at a rate of 4.7 percent annually to 1980. Hence, practically all of the growth in overseas imports must come from the Eastern Hemisphere. Any significant growth in imports from the Latin American countries can only occur, in effect, by displacing oil produced there with Eastern Hemisphere oil for local consumption. In 1985, total Latin American productive capacity is projected at 6.8 million B/D; local consumption should exceed 5 million B/D. U.S. overseas import needs as projected in this initial appraisal could be 12-13 million B/D at that time.

U.S. PETROLEUM DEMAND-SUPPLY BALANCE

Figure 5 gives a graphic indication of domestic petroleum supply and where it would be expected to come from under the initial appraisal assumptions. Table V presents basically the same picture, except that its figures have been adjusted upward to reflect the possibility that shortfalls in other fuels may drive up the need for petroleum imports. The difference is a small one, however: only 0.4 million B/D by 1985.

TABLE V

U.S. PETROLEUM SUPPLY-DEMAND BALANCE

	Million B/D					
	1960	1965	1970	1975	1980	1985
Domestic Demand	9.8	11.5	14.7	18.5	22.7	26.4*
Processing Gain, Exports, Stock Change, Etc. (Net)	--	--	--	(0.1)	(0.2)	(0.4)
REQUIRED SUPPLY	9.8	11.5	14.7	18.4	22.5	26.0*
U.S. Production of Petroleum Liquids (Ex. North Slope)	8.0	9.0	11.3	10.5	9.8	9.1
North Slope Crude and Condensate	--	--	--	0.6	2.0	2.0
Syncrude from Oil Shale	--	--	--	--	--	0.1
Imports	1.8	2.5	3.4	7.3	10.7	14.8*
Imports as Percent of Domestic Demand	18%	22%	23%	39%	47%	57%

* Adjusted from figures on Figure 5.

Source: Oil Subcommittee and Coordinating Subcommittee.

Based on the stated levels of total demand and domestic production, total imports into the United States would have to increase by 3.9 million B/D, or over 100 percent between 1970 and 1975. The level of imports would increase substantially thereafter, reaching 14.8 million B/D by 1985. Since overland movements from Canada are restricted in the short term by limitations on Canadian crude producibility and crude pipeline capacity, the bulk of supplementary supplies would have to be in the form of imports from overseas sources.

FACILITIES REQUIREMENTS

Total overseas imports during the decade of the 1960's rose at a rate of about 100,000 B/D a year. After allowing for continuing increases in Canadian overland imports and the delivery of 2 million B/D of Alaskan North Slope oil to the lower 48 states, overseas imports for the period 1971-1985 would need to increase over 650,000 B/D per year, or six and one-half times the rate of the 1960's.

The optimal size of tankers in the international petroleum trade during the 1971-1985 period may range in the order of 300-400 thousand deadweight tons (DWT) in long-haul service, and 70-120 thousand DWT in coastal and short-haul service. The larger vessels would have a draft of 72 feet. There are no ports in the United States presently capable of handling vessels of this size. Large-scale, deep-water terminals to service East, Gulf and West Coast import requirements would be necessary.

Except for residual fuel oil and uncontrolled products such as bonded aircraft and vessel bunker fuels, it is assumed that most of the required imports would be crude oil, requiring processing in domestic refineries. It has been calculated that total crude runs in the United States would exceed 20 million B/D by 1985 compared with 10.9 million B/D in 1970. At a 95 percent operating ratio, this output would require the construction of 10 million B/D of refinery capacity in the United States during the next 15 years. For contrast, from January 1, 1961, to January 1, 1971, net additions to refinery throughput capacity in the United States amounted to 2.6 million B/D.

In addition to this capacity for "clean" products, refinery capacity would have to be added somewhere in the Free World to meet the added U.S. requirements for residual fuel oil of 2-3 million B/D by 1985. This would represent about 5 million B/D of additional refining capacity, depending on characteristics of crude, fuel oil yield, and fuel oil quality. Current government policy and refining economics would effectively export most of this capacity to overseas locations.

CAPITAL REQUIREMENTS

Construction of 10 million B/D of refinery crude throughput capacity in the United States during the next 15 years would require capital expenditures estimated at $18 billion (1970 dollars). The replacement of obsolescent refinery capacity would add approximately another $2 billion to this sum for a combined requirement of $20 billion. Adding the 5 million B/D refinery capacity needed to supply heavy fuel oil could, if built by U.S. companies, call for another $5-8 billion, at least half of which could be considered dedicated to meeting U.S. needs. In sum, the 15-year refinery investment would be $25-28 billion.

A fleet of 367 (250,000 DWT) foreign-flag tankers was estimated as needed to accommodate incremental waterborne imports (both long and short haul) over the next 15 years. Thus, at $37 million per vessel (current price quoted for 1975 delivery), the capital need for foreign-flag tankers would amount to $13.5 billion. The estimated initial investment in the Trans-Alaskan pipeline from Prudhoe Bay to Valdez was expected to be in the order of $3 billion. Alternatively, a Trans-Canadian pipeline from Prudhoe Bay to Chicago might require an investment of $4 billion or more. The required capital for three large-scale, deep-water terminal facilities, one each for the East Coast, Gulf Coast and West Coast, would be in the order of $1 billion.

Added together, the indicated capital required to meet U.S. needs for oil refining and transportation facilities is set at $40-43 billion. No method exists whereby one can determine just how much of this would be U.S. capital; it is safe to assume, however, that at least that portion physically located within the United States would probably be met with U.S. funds. This would be a minimum of $24 billion. No assessment has been made of the capital call that might be placed on U.S. companies for foreign investment in producing operations or in logistical facilities to meet growing foreign petroleum demand.

Under the "status quo" assumptions as to economic climate and level of activity assumed for this initial appraisal, capital requirements for oil and gas exploration, development and production are projected to increase as shown in Table VI.

TABLE VI

CAPITAL REQUIREMENTS
FOR OIL AND GAS EXPLORATION, DEVELOPMENT & PRODUCTION
(In Millions of Dollars)

	1970	1975	1980	1985	Cumulative 1971-1985
Oil Activity	$2,800	3,910	4,620	5,360	$64,705
Gas Activity	2,000	1,836	1,856	1,882	27,735
TOTAL	$4,800	5,746	6,476	7,242	$92,440
Percent of Net Wellhead Value Reinvested					
Oil Activity	28%	40%	49%	60%	
Gas Activity	67	64	73	82	
COMBINED	37%	45%	54%	65%	

In contrast to these projected requirements, the actual percentage of net wellhead value reinvested has declined continuously for both oil and gas since the early 1950's, reflecting a growing lack of incentive to invest in the domestic producing industry and a need to deploy additional funds in other phases of the business.

No estimate can be made of capital requirements for Alaskan North Slope exploration and development, other than the estimated pipeline investment cost mentioned earlier, since this area as yet has no history of capital expenditures. It is safe to say, however, that developing this area to a point where it is capable of producing 2.0 million B/D by 1980-1985 will add considerably to capital requirements.

Summed up for the 15 years through 1985, the investment to meet U.S. needs in oil and gas production, oil refining and oil transportation could aggregate close to $140 billion.

Chapter Four

GAS

GAS

Gas markets, in recent years, have been characterized by rapidly increasing demand and lagging additions to supply. Supply limitations are now beginning to restrict demand growth. These divergent trends are due in large measure to the Federal Power Commission's regulation of prices of wellhead gas destined for interstate movement. This regulation has held gas prices to below parity with other fuels and not only reduced the incentive of producers to explore for and develop new supplies but also stimulated demand. Unlike oil, which by drawing on imports could meet projected demand, gas cannot meet its potential demand under initial appraisal assumptions.

This chapter will consider (1) the supply of gas that would be forthcoming under initial appraisal assumptions, (2) potential demand for gas and the degree to which demand would be restricted by limited supply, (3) capital requirements for transporting gas (capital requirements to explore for and develop gas reserves are included in the Petroleum chapter) and (4) gas plant liquids and condensate production arising from the processing of natural gas.

GAS SUPPLY

Under initial appraisal assumptions, total U.S. gas supply would actually decline slightly over the 1970-1985 period. As shown in Table VII, total gas supply would fall from 22.7 trillion cubic feet (TCF) in 1970 to 21.5 TCF in 1985. A steep drop in wellhead gas production from the "lower 48" states would not quite be offset by (1) production of synthetic gas and (2) imports of pipeline gas from Canada, liquefied natural gas (LNG), liquefied petroleum gas (LPG) and Alaskan North Slope gas.

TABLE VII

GAS SUPPLY FOR U.S.

	1970		1975		1980		1985	
	TCF	Quad.BTU	TCF	Quad.BTU	TCF	Quad.BTU	TCF	Quad.BTU
U.S. (Except North Slope)	21.82	22.52	19.80	20.43	16.30	16.82	13.00	13.41
North Slope	-	-	-	-	1.17	1.21	1.50	1.55
Synthetic P/L Gas	-	-	0.37	0.38	0.55	0.57	0.91	0.94
TOTAL DOMESTIC SUPPLY	21.82	22.52	20.17	20.81	18.02	18.60	15.41	15.90
Imports:								
Canada	0.83	0.86	1.15	1.19	1.15	1.19	1.15	1.19
Mexico	0.05	0.05	0.05	0.05	-	-	-	-
LNG	*	*	0.18	0.19	2.10	2.17	4.00	4.13
LPG	0.04	0.04	0.17	0.18	0.50	0.52	0.93	0.96
TOTAL IMPORTS	0.92	0.95	1.55	1.61	3.75	3.88	6.08	6.28
TOTAL GAS SUPPLY	22.74	23.47	21.72	22.42	21.77	22.48	21.49	22.18

* Negligible.

Source: Gas Supply Task Group.

WELLHEAD PRODUCTION IN THE U.S.

As Table VII shows, gas production from the "lower 48" states would in the initial appraisal diminish from 21.82 TCF in 1970 to 13.00 TCF in 1985, an average annual rate of decline of 3.4 percent. North Slope gas production would commence in the late 1970's and would provide 1.50 TCF in 1985. Projections of U.S. wellhead gas production were developed by first estimating reserves in place and reserve additions that would be forthcoming under initial appraisal assumptions through 1985, and then applying appropriate reserves/production ratios to the reserve estimates. In the case of North Slope gas, it was necessary to consider logistic constraints to delivery as well.

Reserves. Estimates of reserve additions between 1971 and 1985 were based on estimates made earlier by the Potential Gas Committee[1] of original gas in place and potential U.S. gas reserves. The estimates made by the Potential Gas Committee are consistent with those made by the NPC in its report on future U.S. petroleum provinces.[2] Economic considerations inherent in initial appraisal assumptions proved to be the controlling factors in the estimated reserve additions, rather than any shortage of gas in the ground. The estimates of original gas in place exceed cumulative historical demand for gas plus forecast potential demand through 1985, and currently proven and potential gas reserves are greater than cumulative potential demand between 1971 and 1985.

In the initial appraisal, reserve additions between 1971 and 1985 in the "lower 48" states would total 141 TCF. This is shown in Table VIII, which lists estimated additions to reserves of nonassociated and associated and dissolved gas as estimated by the Oil Supply and Gas Supply Task Groups. Reserve additions for the Alaskan North Slope would total an additional 19 TCF and consist almost entirely of associated and dissolved gas.

TABLE VIII

NATURAL GAS RESERVE ADDITIONS IN LOWER 48 STATES (1971-1985)

	Nonassociated		Associated and Dissolved		TOTAL	
	(TCF)	(Quad. BTU's)	(TCF)	(Quad. BTU's)	(TCF)	(Quad. BTU's)
1971-1975	43.52	44.91	6.48	6.69	50	51.60
1976-1980	46.34	47.82	5.66	5.84	52	53.66
1981-1985	33.86	34.95	5.14	5.30	39	40.25
Total	123.72	127.68	17.28	17.83	141	145.51

Source: Nonassociated estimated from the Gas Supply Task Group, Gas Subcommittee. Associated and dissolved estimate from the Oil Supply Task Group, Oil Subcommittee.

1 Report by Potential Gas Committee, *Potential Supply of Natural Gas in the United States (As of December 31, 1968)*, Mineral Resources Institute, Colorado School of Mines Foundation, Inc. (Golden, Colorado, October 1969).

2 Report by the National Petroleum Council *Future Petroleum Provinces of the United States*, (July 1970).

Nonassociated Gas Reserves. Several factors have limited discoveries of nonassociated gas in the recent past. Prices of gas destined for interstate movement have been held to artificially low levels by federal regulation, while the cost of the average gas well has increased substantially (62 percent between 1961 and 1969). In addition, the price of gas sold in the intrastate market, in a price-unregulated atmosphere, has increased. Reserves discovered per foot drilled and per dollar of expenditure have declined in recent years (see Chapter Seven, Volume II). There has been a continuing decline in the number of gas well completions in the U.S. (31 percent between 1961 and 1969).

Key projections and assumptions used in deriving initial appraisal estimates of nonassociated gas reserve additions between 1971 and 1985 were the following:

- Regulated wellhead price assumptions for 1971 were those recommended by the staff of the Federal Power Commission in the proceeding No. R-389-A: 26¢ per Mcf for new gas in South Louisiana including production taxes and 22.33¢ per Mcf for new gas elsewhere excluding state production taxes. These base prices were escalated at the rate of 1¢ per Mcf every five years. These assumed wellhead prices would provide little or no additional economic incentives if measured in constant dollars, because of rapidly increasing real costs for new gas during the 1971-1985 period. In projecting volumes of pipeline imports, LNG and synthetic pipeline quality gas, price was not considered a governing factor.

- Nonassociated reserve additions per foot of gas well drilled were assumed to improve by the Gas Supply Task Group. This would reverse the historical trend, and after 1976 additions would remain above the trend extrapolated from 1950-1970 data.

It is significant that in 1985, it would be necessary to reinvest 82 percent of the net proceeds from gas production in order to fund the drilling required for this projection of nonassociated reserve additions. The attainment of this is unrealistic and this level would represent a sharp increase from 67 percent in 1970, due to the substantially higher cost of deeper drilling and of drilling offshore and in Alaska, coupled with only a moderate increase in wellhead prices.

Associated and Dissolved Gas Reserves. The associated and dissolved reserve additions projected by the Oil Supply Task Group, shown in Table VIII, are considerably lower than would be expected if based purely on historical data relationships. During the 1971-1985 period, associated and dissolved gas are projected to account for approximately one-eighth of annual reserve additions, less than the proportion of about one-quarter realized during the 1950-1970 period. This reduction is explained by the fact that a much larger proportion of future oil production will result from secondary and tertiary recovery methods which yield no significant volumes of associated and dissolved gas.

Forecast of Wellhead Gas Production. Production levels of natural gas were estimated by assuming a reserves/production ratio (R/P) of 10 in each of the NPC regions; for those regions where the R/P ratio is currently above 10, production was increased at a 6 percent annual rate over the prior year until an R/P ratio of 10 was attained. Based on industry experience, an R/P of 10 was the minimum that could be tolerated without significant and recurrent curtailments in service.

Alaskan North Slope reserves consist of associated and dissolved natural gas, and utilization of these reserves cannot commence until a market outlet is established for the completed oil wells that are responsible for these new gas additions. Considering the uncertainty as to the status of approval of the proposed Alaskan pipeline facility, natural gas production will probably not begin until 1976-1977 at the earliest. Even if there were no logistical constraints, Alaskan gas alone would not offset the difference in the Gas Subcommittee's initial appraisal projections between gas requirements and gas supply.

SYNTHETIC PIPELINE GAS AND IMPORTS

Synthetic pipeline gas production of 0.37 TCF per year is projected for 1975, and shown in Table VII. This gas would be produced by naphtha-reforming facilities; further increases from this source would be limited by availability of naphtha as a feedstock. Coal gasification projects would account for the projected increase in synthetic gas production to 0.91 TCF in 1985. These projects, like other synthetic fuels, would have high capital costs (totalling $2.5 billion by 1985) and would be justified by the need to minimize the curtailments in gas service that might otherwise result under initial appraisal assumptions.

As shown in Table VII, annual pipeline imports from Canada are expected to increase less than 50 percent above the 1970 level, based on current projections of availability. Imports from Mexico are minimal and are expected to be negligible following 1975.

Sizeable imports of liquefied natural gas (LNG) and liquefied petroleum gas (LPG) are projected by 1985 (see Table VII). LNG imports would increase from less than 1 percent of U.S. gas supply in 1975 to almost 20 percent by 1985. Proven foreign reserves exist to support projected imports, and it appears that there are adequate shipyard facilities to build the LNG tanker capacity to transport the volumes projected.

World supply of LPG is expected to expand because of development of the North Sea area of Europe, permitting U.S. importation of the equivalent of 0.96 TCF of LPG in 1985. LNG and LPG imports from some sources may pose problems of import dependency similar to those associated with oil imports from overseas.

POTENTIAL DEMAND AND SUPPLY-DEMAND BALANCE

If there were no restrictions on supply, demand for gas would grow very rapidly. Because of its relatively pollution-free characteristics and low price in many areas, natural gas is an attractive fuel in all major market sectors. The underlying attractiveness of gas is shown in a projection[1] by a principal gas industry forecasting group, the Future Requirements Agency. Its report concluded that, *assuming no gas supply limitations or changes in the energy pricing structure*, demand for gas would grow at an average annual rate of 3.2 percent between 1970 and 1985. This estimate of gas requirements (shown in Table IX and Figure 6) took into account field use, shrinkage and other operational losses. Since gas demand has grown continuously since 1945 and at an average annual rate of almost 7 percent during the past several years, the projection shown in Table IX and depicted by market sectors in Figure 6 is considered a very conservative estimate of future market potential under the assumptions of unrestricted supply and constant real prices.

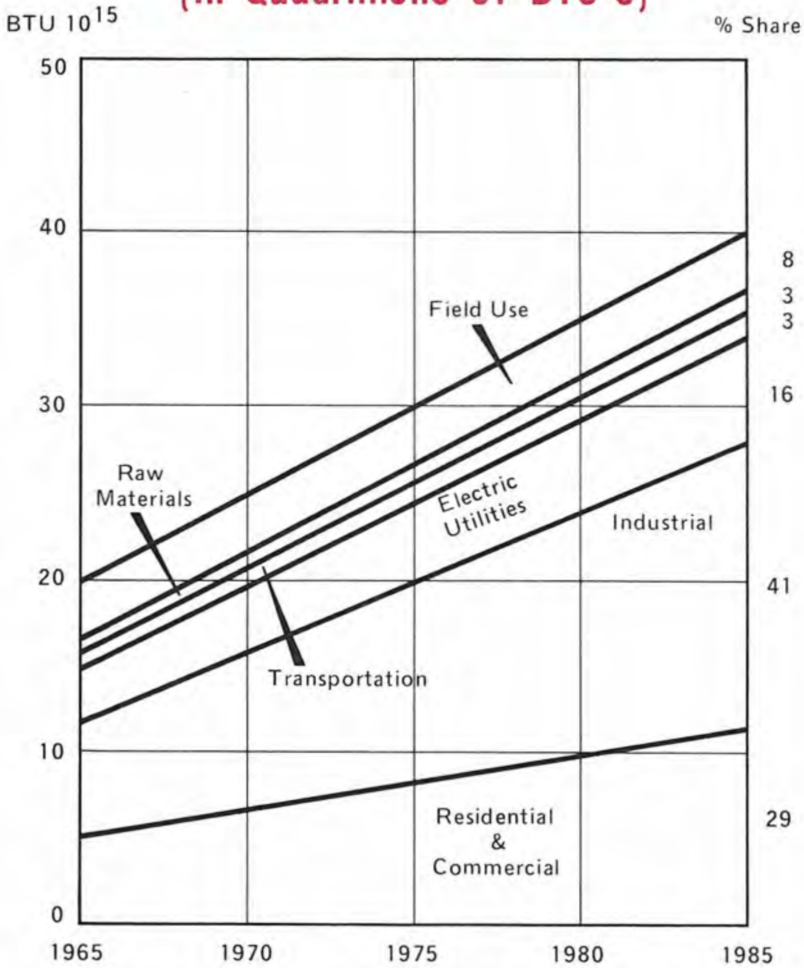
TABLE IX

THE GAS SUPPLY SHORTFALL
(In Trillions of BTU's)

	1975	1980	1985
Demand	30,268	34,700	40,119
Supply	22,420	22,480	22,180
Indicated Shortfall	7,848	12,220	17,939

[1] Future Requirements Agency, Denver Research Institute, University of Denver, *Future Natural Gas Requirements of the United States* Volume No. 3 (Denver, September 1969 and December 1970).

Figure 6. U.S. DEMAND FOR GAS (In Quadrillions of BTU's)



Source: Volume No. 3 Future Requirements Agency, Denver Research Institute; University of Denver; Denver, Colorado; September 1969. Supplemented December 1970.

These figures merely quantify a widely shared opinion that potential demand could not be totally satisfied because supply capability would be lacking under current regulatory policies and economic conditions. Under these circumstances, actual demand for gas would be curtailed by limited supply. The contribution of gas to the total energy "mix" would thus be limited to the available supply shown above and discussed in the Gas Supply section. In subsequent studies the Gas Demand Task Group will review the conditions under which additional supplies of gas might become available and assess the probable impact of such factors on market demand.

CAPITAL REQUIREMENTS FOR TRANSPORTATION OF GAS

Total capital requirements during the 15-year study period for the movement of gas are estimated at $21.0 billion, in 1970 dollars. These requirements are summarized in Table X.

TABLE X

REQUIRED CAPITAL EXPENDITURES FOR GAS TRANSPORTATION
(In Millions of 1970 Dollars)

	GAS PIPELINES			LNG	LPG		
PERIOD	From Lower 48 Sources	From Alaska and Canada	Revaporized LNG and Syngas	Plants Ships Terminals Storage	Ships Barges and Pipelines	Railroad Cars Trucks	TOTAL
1971-1975	879.5	874.0	302.0	675.0	151.3	142.8	3,024.6
1976-1980	678.2	3,714.0	1,065.0	5,115.0	149.1	119.9	10,840.9
1981-1985	502.2	246.0	1,087.0	4,948.0	176.7	137.7	7,097.6
TOTAL	2,059.9	4,834.0	2,454.0	10,738.0	477.1	400.4	20,963.1
PERCENT OF TOTAL	9.8	23.1	11.7	51.2	2.3	1.9	

Source: Gas Transportation Task Group.

Approximately 49 percent of the capital required would be used to provide for transport capacity from Alaska, Canada and overseas LPG sources, to replace pipeline capacity in the "lower 48" states, and to transport synthetic gas from coal. The remaining 51 percent would be needed to build LNG plants, ships, terminals and storage facilities. The location of new sources of supply would require the construction of new facilities, while continuing production from existing sources would require replacement of old facilities. Therefore, substantial investment would be required to transport gas even though annual volumes of gas production are projected to decline. Furthermore, unit costs for new and replacement facilities are expected to increase above historical levels because of environmental restrictions, higher financing costs, the more removed location of sources of supply to be transported and stricter government regulation.

NATURAL GAS LIQUIDS

Gas plant liquids and condensate are obtained by processing natural gas and, therefore, direct correlation exists between their production and the volumes of oil and gas produced and gas processed. Table XI shows actual production for 1970 and projections for the years 1975, 1980 and 1985.

TABLE XI

GAS PLANT LIQUID PRODUCTION

	1970	1975	1980	1985
Millions of Barrels	613	558	475	342
Millions of B/D	1.7	1.5	1.3	1.0

CONDENSATE PRODUCTION

	1970	1975	1980	1985
Millions of Barrels	134	140	121	89
Millions of B/D	0.4	0.4	0.3	0.2

Chapter Five

COAL

COAL

Coal will make a steady percentage contribution to filling U.S. energy needs as these expand over the 15-year study period. Coal is projected to be able to fill all its rising domestic demand and even to generate some output for export. As brought out in this chapter, the rising demand for coal will not be constrained by domestic reserves. This projection is dissimilar from that described for the years to 1985 in the initial appraisal of the domestic oil industry. The key difference between the two industries relates primarily to the dissimilarity in the physical occurrence of reserves and widely disparate characteristics of petroleum and coal.

Coal, like most extractive industries, is a rising-cost industry. Furthermore, getting coal from the mines to the market will call for heavy expenditures by the transportation industry, especially by the financially hard-pressed railroads. Utilizing coal in a way consistent with clean-air demands is also going to involve some costs and problems, but these fall not only on the coal industry itself but on its chief customer, electricity, as well.

The following comments apply to the outlook for coal in its established markets; synthetic gas from coal is dealt with in Chapter Eight.

DEMAND

The Coal Task Group projects the total "normal" domestic demand for coal to grow at 3.5 percent a year, as shown in Table XII.

TABLE XII

PROJECTED U.S. DEMAND FOR COAL

	1970	1975	1980	1985
		(In Trillions of BTU's)		
Coking Coal	2,688	3,136	3,360	3,528
Industrial	2,366	2,262	2,184	2,080
Residential and Commercial	280	196	140	84
Electric Utility	7,728	9,960	12,600	15,696
Projected Normal Domestic Demand	13,062	15,554	18,284	21,388
Assumed Replacement for Shortfall in Other Fuel Supplies	---	756	1,644	1,762
TOTAL DEMAND (Excluding Exports)	13,062	16,310	19,928	23,150
		(In Millions of Tons)		
Total U.S. Demand for Coal (Excluding Exports)	519	632	799	933
Plus Exports:				
Coking Coal	56	76	94	120
Electric Utility Coal	15	16	17	18
Total Exports	71	92	111	138
TOTAL DEMAND (Including Exports)	590	724	910	1,071

Source: Coal Task Group and Coordinating Subcommittee.

Coking coal for domestic usage will grow only 2 percent a year. Coking coal for export has a potential 7 percent growth rate. This difference reflects the more rapid growth of steel production in the rest of the Free World compared with the United States. The key item in future coal demand is steam coal for electric power generation, although steam coal demand for the industrial market will remain substantial. This demand will be affected by the ability of other fuels (notably gas, oil and nuclear) to supply these market sectors. In this regard, the forecast of demand by electric utilities is very sensitive to the nuclear plant load factors that are assumed. The demand figures for coal shown in Table XII for electric power generation are based on a 70 percent operating factor for all nuclear plants in 1975 and 74 percent[1] in 1980 and 1985. The long lead time involved in meeting these coal demands is of the utmost importance, as it is for all fuels, fossil and nuclear alike.

COAL RESERVES

The coal reserves of the United States are ample and would support a faster growth rate should coal be called upon to furnish a greater share of U.S. energy demand for electric power generation, synthetic gas, or fuels.

Coal reserves are commonly reported as "Measured," "Indicated," and "Inferred." "Measured" and "Indicated" reserves are computed from specific measurements (drill holes) and from projections of visible data on the basis of geologic evidence. "Inferred" reserves are based on less abundant and reliable data and are *not included* in this report. The Bureau of Mines has reviewed the latest information on "Measured" and "Indicated" reserves and has concluded that as of January 1, 1970, U.S. coal reserves in beds over 28 inches thick and at depths of up to 1,000 feet are as follows:

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

Some 30 billion tons of subbituminous coal and lignite are located in strippable reserves in PAD District 4. These deserve special mention since they represent a large, fairly low-priced, and accessible source of energy, uniquely useful for synthetic gas or liquid processes. Furthermore, most of these coals, as well as the balance of western coal reserves, are relatively low in sulfur content (0.5 to 1.0 percent).

COAL MINING

Coal is mined in the United States in both deep and surface mines. The contribution of surface mining is large and rising:

	1960	1965	1969
Deep-Mined Coal	68.6%	65.0%	61.9%
Surface-Mined Coal	31.4	35.0	38.1
Total	100.0%	100.0%	100.0%

---

[1] A higher operating factor for 1981-1985 (80 percent) was used to develop the projection of nuclear energy supply shown in Chapter One. However, the total demand for energy consumption in all sectors is still greater than the sum of the supply projections by the various fuel Task Groups (see Exhibit 3). This fact, plus the flexibility in uses of hydrocarbon fuels, negates the effect of utilizing different operating factors.

In spite of the importance of surface mining, the future ability of the coal industry to supply its overall share of U.S. energy demand will depend on its ability to produce coal from deep mines. In this connection, the manpower problem will be controlling. Productivity in coal mining has improved steadily during the period 1960-1969, but the enactment of the new Coal Mine Health and Safety Act of 1969 has had a profound impact on productivity. Current statistics still do not reflect the final results. Reductions in productivity at individual mines of from 15 to 30 percent have been reported.

Underground mines in the United States employed 106,000 men in 1970 to produce 360 million tons. This figure should reach 430 million tons by 1980. If no extended loss in productivity is assumed for the average of this period, a net addition of 20,000 men would be called for. The turnover in the industry is rather high, however, so the total need for recruiting and training will be a multiple of this figure.

Even more crucial is the shortage of professionally trained people. In 1969 the total number of mining engineers in the coal industry was 3,300. Annual replacements and modest additions amounting in total to 5 percent of the work force would require 165 engineers each year. Yet the total number of *all* mining engineers expected to graduate in the near future is only about 135 per year. Steps to increase both this area of engineering education and the recruitment of all types of manpower for mining are a key requirement of the industry.

In addition, development of improved mining technology must be substantially accelerated to offset the severe impact of the Coal Mine Health and Safety Act of 1969 on existing production capacity. This development will have an even greater impact on the energy supply during the 1985-2000 period, when it may be necessary to reach further into the available coal reserves and to mine thinner seams under deeper cover.

On balance, the cost of deep coal will rise significantly, since new mining capacity must be added at much higher unit investment than the cost of existing mines. This increase results from the rapid rise in construction costs and from the more stringent operating rules resulting from the Coal Mine Health and Safety Act of 1969.

Coal mine characteristics vary much too widely to permit precise cost analyses; but, in view of the foregoing factors, a cost range of *25¢ to 45¢* per million BTU's at the mine for deep-mined coal should prevail during the next 15 years. A cost range of *15¢ to 25¢* per million BTU's for strip-mined coal can be assumed, since costs for this type of coal are expected to increase less than deep-mined coal.

The total capital demand for the industry to develop needed additional capacity and to replace exhausted mines (the latter at an annual rate of 3 percent) will be about $9.25 billion over the next 15 years. Investment at this level will require an assured long-range outlet for coal in its established markets. This is an important consideration in view of the long lead time required to open new mining capacity. As a practical matter, very little spare producing capacity exists in the coal industry at present.

TRANSPORTATION

Railroads -- Coal relies primarily on other industries for transport to the market, as shown by the following figures:

	Total U.S. Coal Production	Tons Originated by Class I Railroads	Tons Waterborne Internal (Lake and Coastwise)
		(In Millions of Tons)	
1965	520	353	144 (approximate)
1969	590	376	156 (1968)

The introduction of the unit train has helped to increase efficiency of car utilization. But the need for further improvement in utilization of hopper cars is emphasized by the ever-present car shortage. This is a serious problem because the majority of mines are not equipped to store coal; thus limitations on the availability of hopper cars often force production shutbacks, including shutdown of mines. Additions to the fleet of hoppers are urgently needed.

The railroad industry states that over \$36 billion of new expenditures for all plant and equipment is necessary during the next decade. Of this total, between \$5 and \$6 billion will be required for coal cars and associated motive power. Thus, it is apparent that the ability of the nation's railroad system to serve the major portion of the transportation requirements of an expanding coal industry will require considerable investment.

Water Transportation -- Water transport of coal will become increasingly important if coal is to supply its share of U.S. energy needs. The low freight rate for barge movement (average 3 mills per ton mile) will let coal supply markets which would otherwise remain beyond economic reach.

The key concern regarding water transport is adequate capacity and maintenance of locks on the river system. Particular emphasis must be placed on the locks near the confluence of the Mississippi and Ohio Rivers, where the locks have already reached their maximum capacity. Construction of adequate new facilities has been initiated but will take five years to complete. In the meantime, growth of coal movements through this key section of the nation's inland waterways will be constricted.

COAL UTILIZATION

The use of coal in steelmaking and other industrial applications will continue to be largely along current lines. A continued reduction will occur in the amount of coke needed for each ton of steel owing to improvements in technology.

The major uncertainty in the use of coal in its present markets relates to the generation of electricity--more specifically, to air pollution problems. An exhaustive study made of this subject in 1970 by an *ad hoc* panel of the National Academy of Sciences and the National Academy of Engineering states, *inter alia*, that "commercially proven technology for control of sulfur oxides from combustion processes does not exist," and that "unless the necessary technology becomes available, the country may have to choose between clean air and electricity."

A concerted effort is currently under way to solve the problem. Maximum attention is being given to the scrubbing of stack gases with various forms of lime, limestone and dolomite. A series of large but still experimental scrubbers will be under test by the end of 1971, and an initial solution may be available in the next one to two years. Presumably, other, more economic systems will follow.

At the present time (1971), one can expect the cost of sulfur dioxide (SO_2) removal, within a range of 80 to 90 percent, to fall between 8¢ and 16¢ per million BTU's for large, base-load stations, but costs of 20¢ will easily be exceeded in older, peaking plants.

All schemes for removal of sulfur oxides imply increased costs except one, which is, however, based on a modified power cycle and is thus limited to new plants. In this instance, coal is gasified under pressure; the resulting gas is cleaned and fed to a combined gas-turbine/steam-turbine system. A 170-megawatt plant of this type is under construction abroad and will be watched with interest by the U.S. power industry. The real promise inherent in the combined cycle lies in its potential for increasing gas-turbine inlet temperature and thus improving plant efficiency in the future. The system deserves vigorous development and, given such support, could begin to make an appearance toward the end of the 1970-1985 period.

Chapter Six

HYDROELECTRIC ENERGY

HYDROELECTRIC ENERGY

As of January 1, 1971, about 16 percent (249 billion KWH) of the energy requirements for electric power generation was supplied by hydropower. However, conventional hydroelectric energy had been so extensively developed in the United States that few desirable unused sites remain. The Committee therefore reached the following conclusion. Although growth of conventional hydroelectric generation was expected to continue in the period 1971 to 1985, that growth was projected to average only about 1.6 percent annually and to include small sites, generally of less than 200 megawatt capacity. Thus, it was estimated that only about 7 percent (316 billion KWH) of total electric power would be supplied by hydroelectric generation in 1985. Pumped storage hydropower capacity was expected to increase rapidly during the period, principally in conjunction with nuclear power plants. However, such hydropower does not represent primary energy.

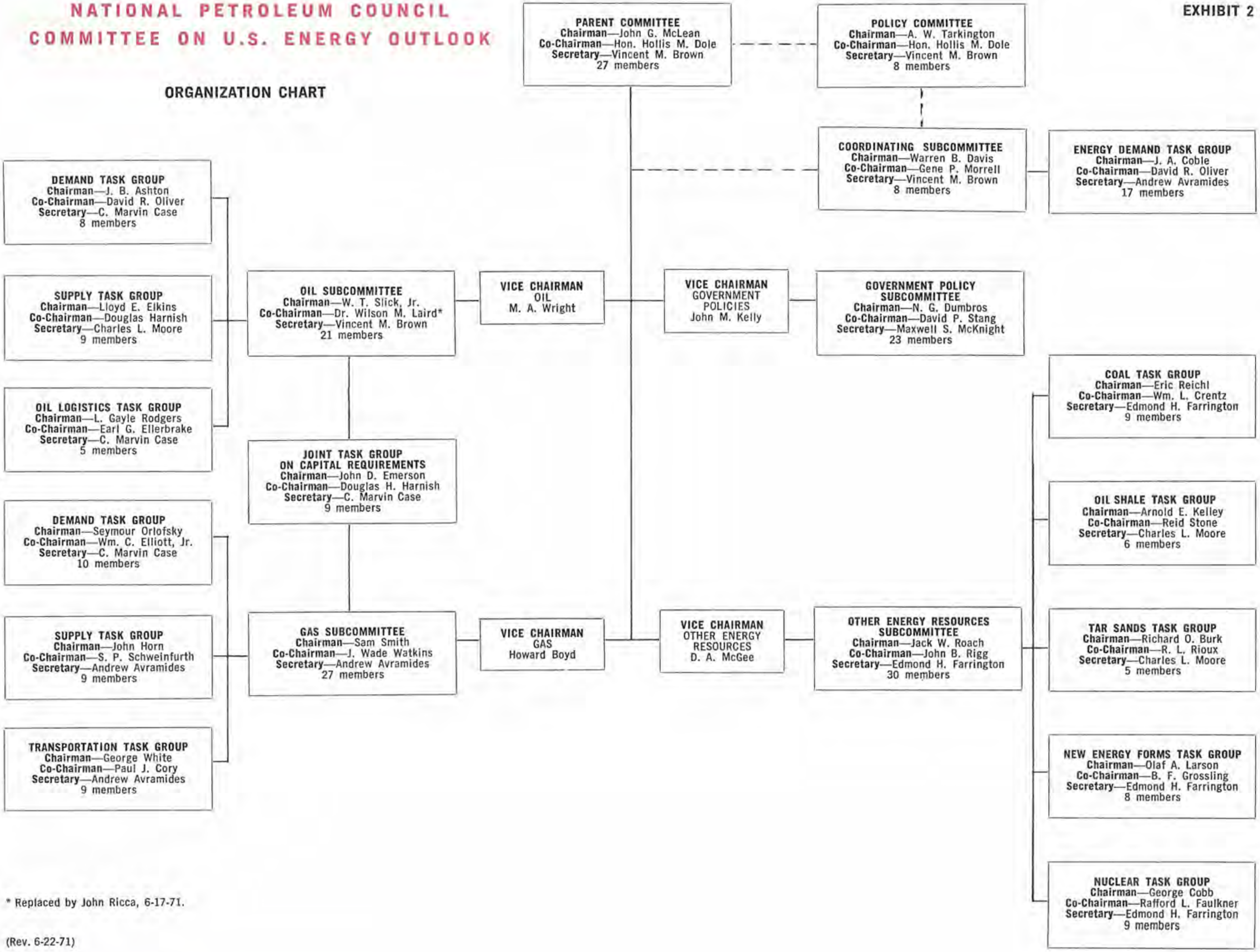
Approximately 84 percent of the expansion of conventional hydroelectric power was expected to occur in the western areas of the United States. Thus, the available hydroelectric energy would have negligible impact on requirements for coal, oil, gas and nuclear power east of the Mississippi.

In recent years, the trend has increasingly been to design hydroelectric plants for peak-load operation. The Federal Power Commission has concluded that this is a more economical utilization of this energy source. Many future hydroelectric plants will be designed for peak-load operation, and will operate at an average annual capacity rate of 20 to 25 percent, compared to the present average rate of 55 percent. Also, the FPC projects that certain existing plants will be modified and changed to peak-load operations.

EXHIBIT 2

NATIONAL PETROLEUM COUNCIL
COMMITTEE ON U.S. ENERGY OUTLOOK

ORGANIZATION CHART



* Replaced by John Ricca, 6-17-71.

(Rev. 6-22-71)

NATIONAL PETROLEUM COUNCIL'S

COMMITTEE ON U.S. ENERGY OUTLOOK

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DEVELOPMENT OF INITIAL APPRAISAL ENERGY BALANCE

In addition to the assessment of total energy requirements by the Energy Demand Task Group, the Oil, Gas and Other Energy Resources Subcommittees made independent assessments of the individual fuels involved (see Chapters Three through Nine). Each group made its own judgment of the factors which would affect demand for the particular fuel examined, including the supply of other fuels. The projections as to the *strictly domestic* supplies available in the period 1971-1985, given the assumptions for the initial appraisal, are shown in Table XVII.

TABLE XVII

PROJECTED U.S. DOMESTIC ENERGY SUPPLY--INITIAL APPRAISAL*
Unit: Trillion BTU's (BTU 10^{12})

	1970	% of Demand†	1975	% of Demand†	1980	% of Demand†	1985	% of Demand†
Oil Subcommittee	21,048‡	31.1	22,789	27.3	24,323	23.7	23,405	18.7
Gas Subcommittee	22,388‡	33.0	20,430	24.5	18,030	17.6	14,960	12.0
Other Energy Resources Subcommittee:								
Coal§	13,062	19.3	15,554	18.6	18,284	17.8	21,388	17.1
Hydropower	2,677	3.9	2,840	3.4	3,033	3.0	3,118	2.5
Nuclear	240	0.3	3,340	4.0	9,490	9.3	21,500	17.2
Geothermal	7	--	120	0.1	343	0.3	514	0.4
Synthetic Oil	--	--	--	--	--	--	197	0.2
Synthetic Gas	--	--	380	0.5	570	0.5	940	0.7
TOTAL DOMESTIC SUPPLY	59,422	87.6	65,453	78.4	74,073	72.2	86,022	68.8

* As projected by individual fuel subcommittees.

† As a percentage of total energy requirements

‡ Excluding additions to oil (2,086) and gas (132) stocks.

§ Does not include BTU's consumed in conversion of coal to syngas.

A further comparison of the projected consumption of energy in the United States through 1985 with the added projections of imported supply of energy (under continuation of current conditions without major change) is presented in Table XVIII.

TABLE XVIII

ENERGY TRIAL BALANCE--INITIAL APPRAISAL
Unit: Trillion BTU's (BTU 10^{12})

		1970	1975	1980	1985
A.	Total Domestic Energy Consumption	67,827	83,481	102,581	124,942
B.	Total Projected Domestic Supply	59,422	65,453	74,073	86,022
C.	Demand in Excess of Domestic Supply	8,405	18,028	28,508	38,920
D.	Indicated Import Levels Derived by Task Groups Under Initial Appraisal Assumptions				
	Oil	7,455	15,284	22,163	29,997
	Gas	950	1,610	3,880	6,280
	Total Imports	8,425	16,894	26,043	36,277
E.	Indicated Remaining Difference of Demand Exceeding Supply	--	1,134	2,465	2,643
F.	Remaining Difference as Percent of Energy Demand	--	1.4%	2.4%	2.1%

The "indicated differences" between the total energy consumption projected by the Energy Demand Task Group and the sum of the several fuel task groups' individual supply projections range from 1.4 percent to 2.4 percent of domestic energy consumption. These differences represent energy requirements that must be met by coal or oil, the only two fuels found to have any significant flexibility in total supply. Considering the many parameters of fuel demand and utilization would lead to the conclusion that this demand shifting will probably take place within the Utility and the Industrial market sectors. Most of the oil requirement would probably be met in the form of residual fuel.

The indicated differences and their fuel equivalents are:

	1975	1980	1985
DIFFERENCE--Trillion BTU's	1,134	2,465	2,643
COAL EQUIVALENT--Million Tons	45	100	105
RESIDUAL FUEL OIL EQUIVALENT--Thousand B/D	490	1,070	1,150

In the absence of any clear-cut indications of a more accurate distribution, the Committee arbitrarily allocated these requirements one-third to oil and two-thirds to coal. The resulting volumes and their relationship to base requirements are:

	1975	1980	1985
OIL---Thousand B/D	165	360	400
---Percent of Residual Fuel Demand	5%	9%	9%
COAL--Million Tons	30	65	70
--Percent of Total Domestic Coal Demand	4%	8%	8%

Given the projected U.S. energy demand shown above, and having applied the adjustments to energy supply as discussed in the immediate preceding section, the Committee developed the Initial Appraisal Energy Supply-Demand Balance shown as Table II in the body of the report.

Chapter Seven

NUCLEAR POWER

NUCLEAR POWER

Of various new industries capable of contributing to rising power needs, nuclear energy is by far the largest and has the greatest near-term potential. As pointed out in this chapter, raw material reserves impose no constraint on expected output in the 15 years through 1985 and could even support a larger than predicted growth rate. In predicting what growth was likely to be, the Nuclear Task Group saw no reason to depart from the predictions of the Atomic Energy Commission, although all assumptions were examined carefully, including environmental assumptions. The chapter concludes with a look at investment, and notes that the industry is so new that its cost outlook is to some extent still unpredictable.

URANIUM RESERVES

Within the United States, low-cost[1] uranium reserves appear adequate to meet the total projected demand for nuclear energy, all of which comes from electrical utilities, over the 15-year forecast period. As presently estimated, cumulative U.S. uranium requirements are about 450,000 tons (Table XIII).[2] The reasonably assured reserves in the U.S. totalled 390,000 tons of U_3O_8 at the end of 1970 (Table XIV). Additional resources of 680,000 tons of U_3O_8 are presently estimated to be available in the U.S. Past U.S. experience has shown that both exploration for and development of uranium deposits have increased sharply during periods when incentives were attractive, more than adequately meeting market requirements.

The potential for discovery in this emerging industry is such that utilities could draw on nuclear resources for an even larger share of their primary energy. Long-range purchase arrangements providing adequate incentive and sufficient lead time are necessary.

DEMAND FOR REACTORS AND FUEL

The detailed assumptions behind the predictions of the Nuclear Task Group appear in Chapter Ten, Volume II. Only a few of these require mention here, including the assumptions pertaining to technology as it affects uranium demand. It is assumed that (1) recycling of plutonium will start in 1974 and will be continued in the United States through 1985; (2) the high-temperature gas-cooled reactor will not materially affect uranium demand through 1985, but will have an impact thereafter; and (3) fast-breeder reactors will not significantly influence the quantity of uranium required before 1985.

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[1] "Low cost" refers to uranium reserves that can be developed, mined and milled at product costs up to $10.00 per pound.

[2] The requirements of 450,000 tons are only for consumption during the period. The establishment of an 8-year forward ore reserve in 1985 (at 1985 consumption rates) would require that exploration and development be accomplished for an additional 480,000 tons. The capital investment requirements stated in this chapter for uranium exploration and production are based on such an 8-year forward reserve being developed.

Other key assumptions pertain to health and safety and environmental considerations. It is assumed that, even though lower radon limits have been announced, this regulation will not be administered in such a way as to materially reduce the ability of underground uranium mines to maintain and expand their production. This is an important and possible tenuous assumption since it is estimated that 46 percent of the presently proven domestic uranium ore reserves will be produced from underground mines. Health and safety and environmental considerations are expected to increase the near-term cost of nuclear power, e.g., through limitations on siting and thermal discharges, but increased costs are not expected to materially retard the long-term growth of nuclear power or alter its competitive position. Also, while it is assumed that the disposal cost of radioactive wastes will be small in comparison to the overall cost of the power generated, a waste disposal system that embodies adequate health and safety considerations will have to be developed.

The foregoing assumptions are compatible with those used in a recent AEC forecast[1] of nuclear power growth. The AEC forecast was, therefore, used in this study which results in a forecast of installed nuclear power generating capacity of 150,000 and 300,000 megawatts of electricity (MWe) in 1980 and 1985, respectively. The AEC forecast is basically an extrapolation of 1960-1975 data on nuclear and conventional plants installed, under construction, and definitely planned by utilities. Plants having a capacity under 100 MWe and those used specifically for peaking purposes were excluded. A similar method has been used for making the projections shown on Table XIII for nuclear power growth in other Free World countries.

In these estimates, nuclear power growth is projected on the basis of indicated installed capacity available for electric power generation during the 1971-1985 period.

INVESTMENT

As for capital investment over the period 1970-1985, it is estimated that approximately \$5 billion will be required in the United States both for uranium exploration and to provide the facilities necessary for the domestic mining, milling, refining and converting, enriching, fabricating, and reprocessing of uranium for use as a fuel in nuclear power plants (see Chapter Ten, Volume II). This amount represents an investment of approximately \$17/KWH for the additional 292,500 MWe of nuclear generating capacity. For that portion of the fuel cycle which includes only exploration, development, mining and milling, the capital investment required to meet the initial appraisal expectations is estimated to be approximately \$2.1 billion, or about \$7/KWH.

In assessing the significance of these capital requirements, two factors should be considered: (1) the uniqueness of the nuclear fuel cycle and the newness of the technology involved in comparison with fuel forms for fossil-fueled plants, and consequently the relatively greater opportunities for improving the nuclear fuel cycle; and (2) the somewhat larger investment in nuclear generating plant facilities than in comparable fossil-fueled plants.

[1] U. S. Atomic Energy Commission, *Forecast of Growth of Nuclear Power,* Wash -1139 (Washington, January 1971).

TABLE XIII

UNITED STATES AND NON-COMMUNIST FOREIGN REQUIREMENTS FOR NUCLEAR POWER REACTORS

Calendar Year	Installed MWe†	Tons U_3O_8‡		Annual Separative Work MT SWU‡
		Annual	Cumulative	
United States*				
1971	11,000	6,900	6,900	3,200
1975	59,000	18,400	66,200	10,500
1980	150,000	34,200	206,000	20,500
1985	300,000	59,300	450,000	37,400
Non-Communist Foreign§				
1971	12,400	7,400	7,400	1,900
1975	37,000	16,300	56,600	6,000
1980	127,000	34,500	191,000	14,800
1985	270,000	60,400	440,000	33,300
Total Non-Communist World§				
1971	23,400	14,300	14,300	5,100
1975	96,000	34,700	122,800	16,500
1980	277,000	68,700	397,000	35,300
1985	570,000	120,000	890,000	70,700

* Uranium and separative work requirements based on plutonium recycle commencing in 1974.

† Installed generating capacity of nuclear power plants measured in megawatts of electricity (MWe). The energy supply (measured in trillion BTU's) to fuel U.S. nuclear power plants would be: 240 in 1970; 3,340 in 1975; 9,490 in 1980; 21,500 in 1985.

‡ Uranium and separative work requirements assume "tails" of 0.2 percent at gaseous diffusion plants (GDP). The AEC has recently suggested that industry use a projected level of 0.25 percent as a tentative figure for planning purposes, starting in 1973. A level of 0.25 percent would increase U.S. uranium requirements on the order of 10 percent.

§ Uranium and separative work requirements include requirements for natural uranium reactors without plutonium recycle, foreign light water reactors commencing plutonium recycle during 1974, and the British advanced gas-cooled reactors (AGR's) without plutonium recycle.
AEC has assumed separative work requirements in the U.S. during 1985 for foreign LWR's to be 18,400 MT SWU. (Metric tons, separative work units.)

Source: U.S. Atomic Energy Commission, *Op. Cit.*

TABLE XIV

WORLD RESOURCES OF URANIUM IN 1970
(U_3O_8 in Thousands of Tons)

Price to $10 per Pound	Reasonably Assured*	Estimated Additional†	Total Resource
Canada	232	230	462
South Africa	200	15	215
France, Niger, Gabon, C.A.R.‡	95	81	176
Other§	63	49	112
United States‖	390	680	1,070
$10 Subtotal	980	1,055	2,035
South West Africa & Australia¶	100	200	300
$10 Subtotal	1,080	1,255	2,335
Price $10-$15 per Pound**			
Canada	130	170	300
South Africa	65	35	100
France, Niger, Gabon, C.A.R.‡	22	35	57
Other	43	70	113
United States	190	360	550
$10-$15 Subtotal	450	670	1,120
Less-than-$15 Total	1,530	1,925	3,455

* Reasonably assured occurs in known ore deposits, based on specific sample data and measurements of deposits.

† Estimated additional surmised to occur in unexplored extensions of known deposits or undiscovered deposits in known uranium districts.

‡ Central African Republic.

§ Argentina, Australia, Brazil, Italy, Japan, Mexico, Portugal, Spain.

‖ According to U.S. AEC estimates of January 1, 1971, some 90,000 tons of U_3O_8 may occur as a by-product of phosphate and copper production through year 2000; 25,000 might be available by 1985.

¶ The Committee decided it would be desirable to recognize recent reported discoveries in South West Africa and Australia. In the absence of specific data, the Committee arbitrarily added 100,000 reasonably assured and 200,000 estimated additional for these discoveries.

** Excludes reasonably assured of 350,000 tons and estimated additional of 50,000 tons for Sweden considered to be essentially unavailable because of production limitation and stated Swedish policy of meeting only a "certain part" of Swedish requirements.

Source: U.S. data from U.S. Atomic Energy Commission, Press Release No. 0-67 (April 30,1971); foreign data other than Australia and South West Africa from a joint report by the European Nuclear Energy Agency and the International Atomic Energy Agency, *Uranium Resources, Production and Demand* (Paris, September 1970); data for Australia and South West Africa estimated by Nuclear Task Group.

Chapter Eight

SYNTHETIC FUELS

SYNTHETIC FUELS

Synthetic fuels comprise both oil and gas, the former available from oil shales and tar sands, the latter from oil and coal. The contribution of synthetics to the U.S. energy supply in 1985 under existing government policies and economic conditions likely will be small, accounting for perhaps one percent of total energy supplies. Nevertheless, synthetics do have a substantial potential which, given the size and trend of energy needs, is worth careful consideration.

This chapter describes the resources and reserves of oil shale and tar sands, with particular emphasis on determining which of these offer the best near-term potential and why. Also discussed are the technical and economic problems of producing syncrude and syngas.

The technology of producing liquids from coal is not as far advanced as that for synthetic gas manufacture, thus no significant contribution to energy supply from this source is expected before 1985 under the assumptions of the initial appraisal.

SYNCRUDE FROM OIL SHALE

Oil shale deposits are found in numerous areas of the United States. The only deposit of adequate size and availability to have potential commercial value at the present time, however, is the Green River Formation of Eocene Age. This formation underlays 16,000 square miles of several basin areas in Colorado, Utah and Wyoming. For the initial appraisal study, the basic assumptions behind the estimates of resources and reserves are as follows:

1. Only the Green River Formation shales will be commercially attractive.
2. Reserves will be recoverable mainly by underground mining and thus will average only 60 percent of in-place resources.
3. Early interest will center on zones at least 30 feet thick and yielding at least 30 gallons of oil per ton. For purposes of the initial appraisal, only Class I reserves were considered, these being capable of yielding an average of 35 gallons per ton.

Within the Green River Formation, resources capable of meeting these quality specifications are mostly concentrated within two basins, Piceance and Uinta, and are all classified within the two highest of the four classes of shale resources.[1] Piceance contains Class I resources estimated at 34 billion barrels, Class II estimated at 83 billion; Uinta contains 12 billion Class II.

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[1] For purposes of analysis, oil shale resources (in-place) were divided into four classes which, in order of their numerical designation, reflect the degree of commercial attractiveness. Class I and II resources are designated as those where deposits are at least 30 feet thick and yields average 30 gallons per ton. Class I is the highest quality resource and is measured by an average yield of 35 gallons per ton of shale. A description of the four classes is contained in the Summary Report of the Oil Shale Task Group (Chapter Eleven, Volume II).

Since underground mining is required, provision must be made for pillars, barriers between mines and unforeseen contingencies. Recovery of the resources in place is thus cut down to 60 percent. For further details on reserves recoverable from resources (see Chapter Eleven, Volume II).

Economic prospects of recoverability depend not only on geological and mining considerations, but also on land ownership. The following table indicates how ownership is divided for the Piceance/Uinta resources of interest:

Ownership	Recoverable Reserves in Billions of Barrels* Class I Only	Class I + Class II
Private Lands	6	17
Federal Lands--Clear Title	7	37
Federal Lands--Clouded Title	5	20
Federal Lands--Naval Reserve	2	3
TOTAL	20	77

* At 60 percent recovery factor.

Of the estimated 20 billion barrels of Class I recoverable reserves that were of special interest for purposes of this initial appraisal, only that fraction situated on private lands is presently available for development. Moreover, of these private lands, a substantial portion needs land exchanges with adjacent federal holdings to improve workable development. Development of the major portion of the nation's oil shale reserve awaits the issuance of a federal leasing policy. In any case, however, questions relating to process operability and project economics must be answered to the satisfaction of those who will make the investment decisions. Furthermore, considering the number of companies holding sufficient reserves, the capital requirement placed upon them, and the availability of logistics support, there is a limit to the rate at which even the presently available reserves can be developed.

Once reserves large enough to work commercially have been assembled, decisions must be reached as to the method of mining the deposit and removing the kerogen (shale oil). Four mining methods are available, and it was only after considering annual costs for each of these four methods in relation to each of three classes of shale that the Oil Shale Task Group decided to base its initial appraisal on Class I deposits worked by adit mining. For the next operation, removing the kerogen from the shale, a retorting method utilizing hot recycled solids was selected as representative of a commercial operation.

Regardless of the retorting method used, removing kerogen from shale leaves a large shale residue, substantially expanded from the "in-place" shale volume, which must be disposed of. For example, production of just 100,000 B/D of syncrude requires the *daily* disposal of shale residue sufficient to cover 40 acres of ground to a depth of about one foot. With respect to above-ground disposal, attention and study are being given to such items as development of a mechanically stable dump, prevention of major water flow or seepage through the solids, prevention of excessive blowing of dust and development of a cover of permanent vegetation.

Shale oil from retorting (called crude shale oil) is dissimilar in several respects from conventional crude and its unusual characteristics call for further processing to make it useable in a petroleum refinery. Upgrading is necessary because shale oil contains a comparatively high concentration of nitrogen compounds, which deactivate the catalysts used in many petroleum refining processes. The oil also has high pour-point and high viscosity, which need to be reduced to facilitate handling in pipelines.

As for the economics of a shale operation, this study shows a syncrude value at the upgrading plant in Colorado generally within the range of \$4 to \$5 per barrel--depending on the assumptions used regarding return on investment, the development schedule for production and other key parameters.

Considering all reserve, technological and economic factors, the *potential* syncrude production from shale could be somewhat higher than the actual total syncrude production shown in the initial appraisal.

Year	Potential Syncrude Thousand B/CD	Production from Shale Trillion BTU's a Year
1978 through mid-year 1981	100*	197*
Mid-year 1981 through 1983	200	394
1984-1985	400	788

* Amount estimated to be produced in 1985 under the initial assumptions.

In summary, some development of oil shale by private companies will probably occur on Class I reserves. Production of syncrude from Class I reserves could conceivably reach about 400,000 B/D by 1985, assuming sufficient economic incentive and availability of federal leases. However, in the initial appraisal, which is based on the assumption that no federal leases will be available, only a token volume of syncrude from oil shale will be developed from private lands and only one such 100,000 B/D plant is expected to be operating by 1985. Capital investment in facilities rated to produce 100,000 barrels per calendar day (B/CD) of syncrude from oil shale will be of the order of $500 million.

SYNCRUDE FROM TAR SANDS

"Tar sands," "oil sands" and "bituminous sands" are terms used to describe hydrocarbon-bearing deposits which are distinguished from more conventional oil and gas reservoirs by the high viscosity of the hydrocarbon. Such deposits are not recoverable in their natural state through completion of an ordinary well, as in ordinary oil production methods. They must either be mined, or, alternatively in some cases, the formations can be "stimulated" *in situ*, so that the bitumen will flow underground to wells from which it can be pumped to the surface. Once extracted, the bitumen output from either method has to be further upgraded to produce synthetic crude oil suitable for shipment. In addition, surface mining ventures would involve the disposal of earth wastes.

Many tar-sand deposits are known, but only a few are likely to become of major commercial importance to the United States in the next 15 to 30 years. Chief among these few is the Athabasca deposit in northern Alberta, Canada. Athabasca bitumen is a napthene-base, black, solid material, which contains relatively large amounts of sulfur, nitrogen and metals. These properties make the material undesirable as a feed to conventional oil refineries, and impossible to ship via pipeline to important refining centers. Accordingly, some "upgrading" of the bitumen must be effected in the field to convert it into commercial syncrude. In an upgrading process of hydrogen-enrichment, the sulfur and nitrogen contents are reduced to tolerable levels by hydrogenation. The metals exit with the carbon residue, so that the finished synthetic crude is of quite acceptable quality. Indeed, in some major respects, it is a superior feedstock for refining.

Estimates of the extent of the Alberta tar sands reserves are shown on page 52. (These are lower than the estimates given by the Report of the Alberta Oil and Gas Conservation Board, but still show very large reserves.)

ATHABASCA TAR-SAND DEPOSIT RESERVES

Overburden (Feet)	Tar In-Place Subject to Recovery (Billion Bbls.)	Estimated Percent Recovery	Potential Synthetic Crude* (Billion Bbls.)
0-100	45	72	27
100-250	54	60	27
Over 250	300	48	120
TOTAL	399		174

* At 1.2 bbl. bitumen/bbl. synthetic crude.

Besides Athabasca, another potential major source of heavy hydrocarbons is the Cold Lake area in Canada, along the Alberta-Saskatchewan border. Conventional production techniques have not been successful in the Cold Lake area. A number of experimental projects using thermal (fire or steam-flood) means of stimulation have been carried out, but neither these nor any others so far tried out are now operable. As with tar sands proper, the existence of a major hydrocarbon deposit at Cold Lake is beyond doubt, but its availability at a competitive price to the U.S. energy market is very uncertain.

While extensive literature exists as to the occurrences of tar-sand deposits in the United States, little of it is sufficiently detailed to provide the type of data needed for comprehensive reserve analysis. The most recent estimates[1] of the occurrence of giant tar-sand deposits in the United States are as follows:

ESTIMATED GIANT U.S. TAR-SAND DEPOSITS

	Extent (Sq. Mi.)	Thickness (Feet)	Overburden Thickness (Feet)	Saturation (Percent/Wt)	Resources In-Place (Billion Bbls.)
Tar Sand Triangle, Utah	200-230	few-300+	0-2000+	-	10.0-18.1
P. R. Spring, Utah	215-250	3- 75	0- 250	9	3.7- 4.0
Sunnyside, Utah	20- 25	10-550	0- 600	9	2.0- 3.0
Circle Cliffs, Utah	28	few-310	0-1800	-	1.0- 1.3
Asphalt Ridge, Utah	20- 25	5-135	0- 500	11	1.0- 1.2
TOTAL					17.7-27.6

Some commercial development of the Utah deposits may occur before 1985. It is doubtful, however, that they will significantly affect domestic energy supply by this date. There is higher likelihood that the Utah deposits could be developed in the 1985-2000 interval.

As previously noted, tar-sand oil is now more expensive than conventional crude oil, but as and if conventional crude becomes scarcer in North America and less reliable and/or more costly from overseas sources, a point may be reached where the exploitation of Canadian tar sands will become competitive. For the next 10 years, however, it appears that economic and technological factors, and possibly construction industry saturation, will limit tar-sand oil output to those projects currently under way or announced, plus some projects in the "talking" stages. After 1980, if the economics permit, expansion

[1] Phizackerley and Scott (1967) and Utah Geological and Mineralogical Survey (1970).

at a yearly average rate of perhaps 100,000 B/D per year might be supported, leading to about one million B/D capability in 1985. A range of values is shown in the table below in order to indicate the degree of uncertainty inherent in these estimates at present.

POTENTIAL PRODUCTION OF SYNTHETIC CRUDE FROM TAR SANDS

Year	Total (Thousand B/D)	Likely Range
1971	45	- -
1975	65	50- 75
1980	375	275- 500
1985	1,000	500-1,250

It is estimated that facilities to produce synthetic crude from Athabasca tar sands via either the *in situ* or mining/extraction routes will cost on the order of $4,000 per daily barrel (1970 dollars) for a nominal 100,000 B/CD installation. Not included in this amount are pipelines or other transportation facilities, access roads and other public works, community facilities and housing for personnel, and the cost of the extensive process development and engineering studies necessary for "first ventures" but not for subsequent similar installations.

Operating costs are more difficult to generalize. Ranges in capital-related costs can be estimated, but some operating costs are directly related to the type of process employed, such as mining or *in situ* extraction. In addition, Canadian government policies with respect to such items as pollution abatement, taxes and royalties affect the costs of operations in Canada and, consequently, the capability for growth.

The above-mentioned projections of the output of syncrude from tar sands assume that total costs, including return on investment, from synthetic crude will, within the forecast period, be in a range which is competitive with crude oil at the upgrading plant.

SYNGAS FROM COAL

Proven technology is currently available to convert coal to pipeline gas. The process is one developed over 30 years ago by Lurgi G.m.b.H of Germany and has been in commercial use ever since. Most western and midwestern coals can be used, and strip mining generally produces coal of the proper size. Coal-based gas will, however, be of somewhat reduced heat content: it will contain from 900 to 925 BTU/CF, compared to 1,025 to 1,050 BTU/CF for natural gas.

The economics of the Lurgi process have been appraised and an order-of-magnitude cost of gas developed. The results are summarized in the following table:

TABLE XV

ECONOMICS OF SYNGAS FROM COAL*
(Assuming a Plant with a Capacity of 270 Million CF/D Producing Syngas with 900 BTU's/CF)

Investment (Millions of Dollars)	$209
Cost per Million BTU's of Syngas (Cents)	
Coal 15¢/million BTU's†	22.2¢
Operating	20.0¢
Capital Charge (18% on Initial Investment)	46.7¢
TOTAL (at the plant)	90.0¢

* Lurgi process.
† Western strip.

Specific coal prices and quality and location will result in varying costs from 90¢ to $1.10 per million BTU's for gas from western strip coal to $1.05 to $1.25 for gas from eastern shaft-mined coal.

A series of new processes currently in the pilot-plant stage offer potential savings in plant investment. The result could be a reduction in gas price from 8¢ to 12¢ per million BTU's in syngas. These processes still require completion of the various pilot-plant programs and demonstration of the new technology in at least a single full-size reactor train. These developments may be ready for commercial application in the middle of the 1970-1985 period.

The potential growth of pipeline gas from coal, as shown on Table XVI, indicates the maximum amount of capacity that could be added, assuming no regard to economic considerations and assuming the immediate start of a full program. In contrast, the synthetic gas supply figures used by the Gas Subcommittee reflect only potential capacity that may become available under present economic parameters.

TABLE XVI

POTENTIAL GROWTH OF PIPELINE GAS FROM COAL
(Assuming Existing Technology and an Immediate, Accelerated Rate of Buildup)

	Capacity in Trillions of CF/Yr.		Investment in Millions of Dollars			
Yearend	Total In Year	Total Cumulative	Plant	(Strip) Mines	Total In Year	Total Cumulative
1975	.08	.08	$210	$ 40	$250	$ 250
1976	.16	.24	420	80	500	750
1977	.16	.40	420	80	500	1,250
1978	.25	.65	600	120	720	1,970
1979 thru 1985	.33 (ea. yr.)	3.00	800 (ea. yr.)	160 (ea. yr.)	960 (ea. yr.)	8,690
TOTAL	--	3.00*	--	†	--	$8,690

* 3 Trillion CF/year (approximately 36 units, 250 million CF/D each).

† Total mining capacity (strip) in 1985: 225 to 250 million tons/year (8-9 billion Ton Reserves).

Chapter Nine

NEW ENERGY FORMS

NEW ENERGY FORMS

Rising energy needs and the problem of meeting them from fossil fuels and nuclear power lend interest and significance to any new forms or sources of energy that might be developed. This is true no matter how small their current or immediate contribution.

Several potential new energy forms have been examined for the initial appraisal. These include geothermal energy, energy from agriculture, solar energy, tidal energy and such energy conversion devices or systems as fuel cells, thermionic devices, total energy systems and magnetohydrodynamics (MHD). Several of these may become increasingly important beyond 1985, depending generally on progress made in technical development before that time. Prior to 1985, however, the amounts of primary energy they are likely to provide and the impact they are likely to have on the use of fossil and nuclear fuels are expected to be relatively small in the overall domestic energy picture. Chapter Thirteen, Volume II reviews the possibilities in detail.

In the western portion of the United States, the development of geothermal energy appears promising for the 1971-1985 period. A capacity of 82 megawatts (MW) has been available since 1970. Projections of the planned development of the Geysers Field in California and of presently subcommercial fields in California and Nevada lead to an estimate that the following installed capacities may be achieved in PAD District 5:

Year	Megawatts	Equivalent Energy Output (Trillion BTU's)
1975	1,500	120
1980	4,500	343
1985	7,000	514

If desalinization proves feasible in the Salton Sea area, power development may proceed even faster than indicated for 1980-1985. Furthermore, if heat exchangers are developed so that lower-temperature hot-water systems can be produced economically, additional prospects will be attractive for exploration. In this event, installed capacity could be as high as 19,000 MW by 1985. This would, however, represent only 2 percent of total U.S. electric generating capacity at that time.

EXHIBITS

EXHIBIT 1

United States Department of the Interior

OFFICE OF THE SECRETARY
WASHINGTON, D.C. 20240

C O P Y

January 20, 1970

Dear Mr. Abernathy:

A number of events affecting basic policies of government and the social and physical environment of this Nation have occurred or appear imminent which will set the stage for a new era in the petroleum industry in the United States. These events will have a decided impact on the Nation's resource capability and the structure of the industry.

Because of the important and pervasive nature of the changes which may be engendered by these events, there is need for an appraisal of their impact on the future availability of petroleum supplies to the United States. The long-range planning and investments to sustain the petroleum industry requires that the appraisal be projected into the future as near to the end of the century as feasible.

Therefore, the Council is requested to undertake a study of the petroleum (oil and gas) outlook in the Western Hemisphere projected into the future as near to the end of the century as feasible. This appraisal should include, but not necessarily be limited to, evaluation of future trends in oil and natural gas consumption patterns, reserves, production, logistics, capital requirements and sources, and national policies, and their implications for the United States. This should draw upon National Petroleum Council studies such as those relating to geological provinces, manpower, technology, ocean mineral resources and pollution, as well as other studies that will become available from Government agencies and industry. The Council's final report should indicate ranges of probable outcomes where appropriate and should emphasize areas where Federal oil and gas policies and programs can effectively and appropriately contribute to the attainment of an optimum long-term national energy posture.

Sincerely yours,

Hollis M. Dole

Hollis M. Dole
Assistant Secretary of the Interior

Mr. Jack H. Abernathy
Chairman
National Petroleum Council
1625 K Street, N.W.
Washington, D. C. 20006