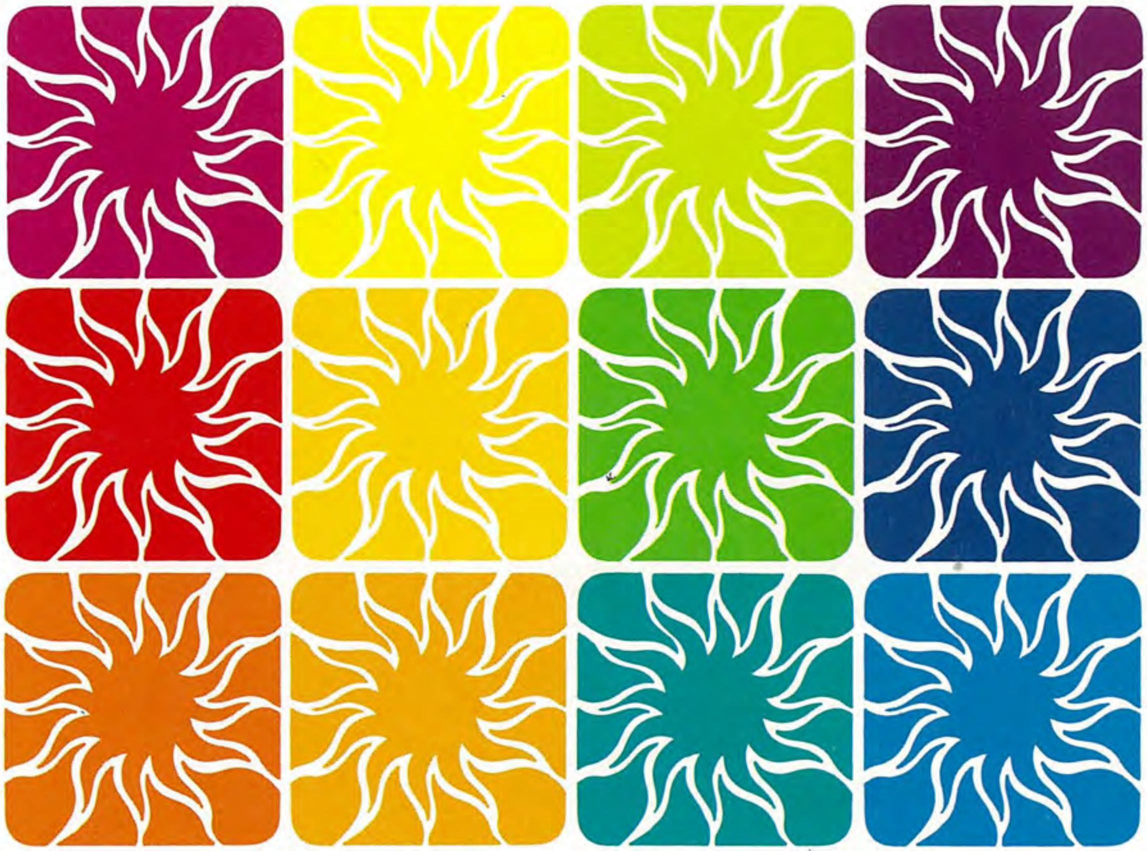

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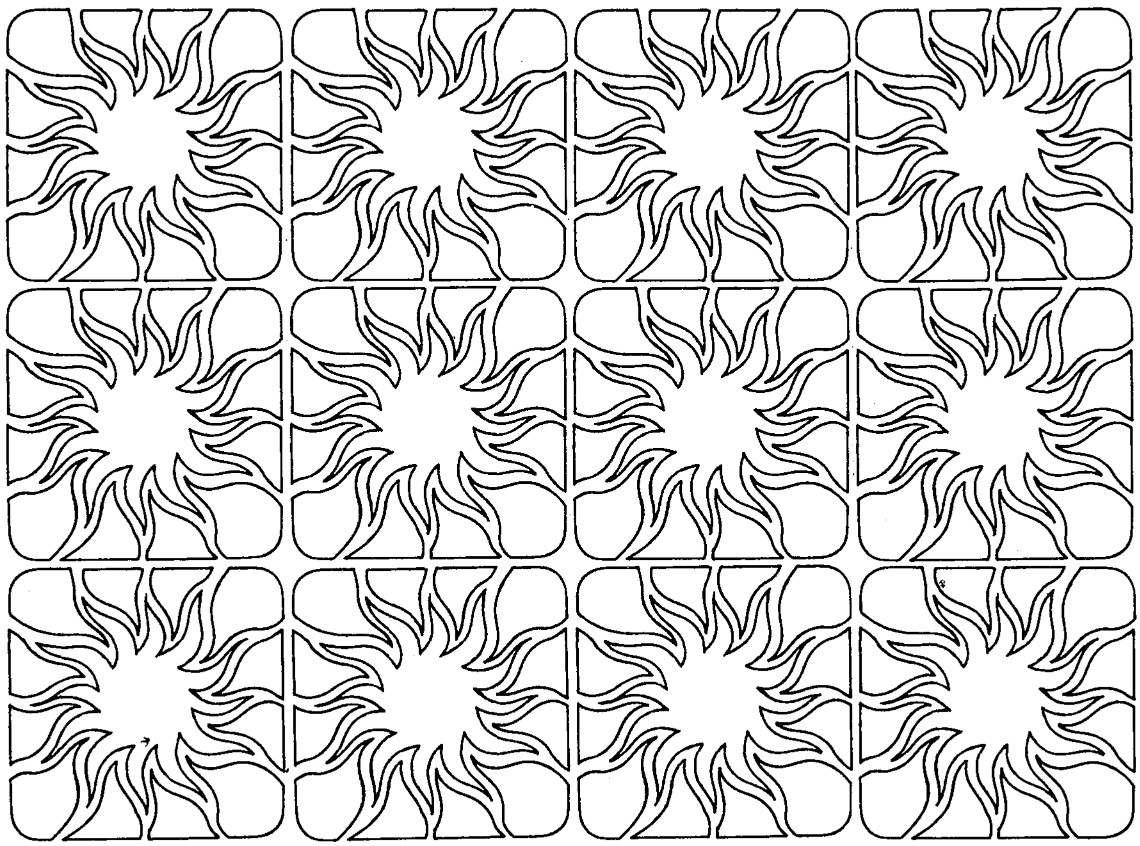

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A Report of the National Petroleum Council's Committee on U.S. Energy Outlook

John G. McLean
Chairman of Committee

Warren B. Davis
Chairman of Coordinating Subcommittee

December 1972

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Preface

On January 20, 1970, the National Petroleum Council, an officially established industry advisory board to the Secretary of the Interior, was asked to undertake a comprehensive study of the Nation's energy outlook. This request came from the Assistant Secretary—Mineral Resources, Department of the Interior, who 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 of 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. 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 (see Request Letters, Appendix 1).

In response to this request, the NPC Committee on U.S. Energy Outlook was established under the chairmanship of John G. McLean with the assistance of M. A. Wright, Vice Chairman—Oil; Howard Boyd, Vice Chairman—Gas; D. A. McGee, Vice Chairman—Other Energy Resources; and John M. Kelly, Vice Chairman—Government Policies. The Coordinating Subcommittee was chaired by Warren B. Davis. The generous support of many cooperative organizations and people made possible a committee structure of over 200 representatives of oil, gas, coal, nuclear and other energy-related fields, as well as a number of financial experts. (For a listing of members of the Committee and its sub-groups, see Appendix 3.) This provided a uniquely broad base for the assessments made in this study.

In July 1971, the National Petroleum Council issued an interim report entitled, *U.S. Energy Outlook: An Initial Appraisal 1971-1985.* This earlier report, along with associated task group reports, provided the groundwork for subsequent investigation of the U.S. energy situation.

The results of the investigation since July 1971 are presented in the summary report, *U.S. Energy Outlook.* The more detailed findings of the Committee on U.S. Energy Outlook, which are the basis for this summary report, are contained in this, the full report of the Committee. Additionally, individual fuel task groups will publish reports that will include methodology, data, illustrations and computer program descriptions.

This final stage of the study has been considerably more complex than the Initial Appraisal. A central feature of the approach for this final report involved the identification of the various economic and government policies which affect the energy situation. Changes in these policies were then postulated and, through a series of parametric studies, the effects of the changes on our energy position were estimated.

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

This study differs from customary National Petroleum Council assignments in that it encompasses, for the first time, all forms of energy. Many members of the Council have knowledge or operations relating to all the energy forms. Not all members, however, have had the requisite expertise to deal with all aspects of the report. Additional expertise was obtained from the other energy industries.

The National Petroleum Council endorses the findings and conclusions of the report "U.S. Energy Outlook—A Summary Report of the National Petroleum Council," which has been issued as a separate document. This report contains the detailed findings of the Committee on U.S. Energy Outlook.

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Introduction

The National Petroleum Council's interim study presented in the two-volume report, *U.S. Energy Outlook: An Initial Appraisal 1971-1985,* was made under the assumption that 1970 government policies and regulations, and economic climate for the energy industries would continue without major change in the 1971-1985 period. The Initial Appraisal was not designed to be a forecast of what would occur in the future; rather, it was a set of projections based on optimistic assessments of what could occur without major changes in the political and economic climate.

The detailed analyses contained in this final report have confirmed the fact that the Initial Appraisal projections may have been more optimistic than were justified. The findings of the Initial Appraisal, however, serve to demonstrate that significant changes in economic climate and government policies are essential if the present trend in the U.S. indigenous energy supply is to be substantially improved.

In this present study, U.S. energy demand, supply, logistics and financial requirements are examined in detail for the period 1971-1985. Using the Initial Appraisal as a reference point, total domestic energy demand, as well as demand in each energy consuming sector, was examined to estimate the potential variation in the Nation's future energy requirements.

These comparisons were made by analyzing the potential effects of changes that might occur in the rate of population growth, the rate of economic growth, the cost of energy, and the energy required for environmental improvement. In addition to developing a range of energy requirements, an examination was made of the impact on the Nation, its economy and our way of life that could result from restrictions on energy consumption.

Each of the individual fuel supply task groups conducted supply-economic studies. These studies considered the relationships between potentially available supplies and the future economic climate as affected by government policy. The approach was to construct four principal cases to cover the range of reasonable supply projections. These cases were then analyzed to determine the average primary fuel unit revenues required to support various levels of exploration and development, given an assumed range of investment returns. Costs and "prices" were calculated in 1970 constant dollars to eliminate all future inflationary effects.*

In defining the four cases, a number of necessary assumptions were made regarding physical, economic and government policy factors. The sensitivity of these assumptions and the effect of adoption of various government policy options were then evaluated through "parametric studies," which examined the independent effect of such variables as federal land leasing policies, environmental considerations, and variations in the taxation system on fuel supply volumes or costs.

As a starting point, this procedure required the development of *assumed* ranges of activity levels and, where relevant, success ratios. These were translated into production volumes, costs and "prices" needed to provide reasonable returns on investment. The methodology was not designed to develop activity levels or resulting supplies based on assumed prices or to quantify the incentives needed to realize the assumed levels of activity. These incentives, which are not measurable within calculated prices, include such important motivational factors to an investor as the anticipated future economic and political climate.

Where appropriate, external limitations were examined. These included such items as the amount

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* As used in this study, "price" does not mean a specific selling price as between producer and purchaser and does not represent a future market value. The term "price" is used to refer generally to economic levels which would, on the basis of the cases analyzed, support given levels of activity for the particular fuel. For a discussion of "constant" and "current" dollars, see Glossary.

of water available in the western states to meet the needs of new synthetic oil and gas industries and the ability of the Nation's electric utilities to use the fuels that could be made available to them.

With these projections of domestic demands and supplies, it was possible to estimate the total energy imports required to meet the Nation's needs under each case. An effort was also made to determine the foreign availability of oil and gas and the practical limits of their importation. After considering limitations on foreign gas availability, the level of gas imports was projected; the remainder of needed energy imports was assumed to be supplied by oil.

To arrive at foreign oil availability, foreign energy requirements were first determined. Total world oil demand was projected, and an examination was made of the adequacy of world oil supply. Special consideration was given to Western Hemisphere supply and demand in view of the relative proximity and security of supply of these sources.

Based on domestic supply, demand and import requirements, the transportation and other logistical facilities needed to transport and process energy fuels were determined. Parametric studies on significant variables were also performed.

The capital requirements for the 15-year period needed to generate projected energy supplies and to support the necessary processing and transportation facilities were calculated. Additionally, consideration was given to the impact of the projected energy imports on the U.S. balance of trade.

The supply/demand situation from 1985 to the end of the century was also analyzed, although many more uncertainties are involved.

Recommendations for a national energy policy were drafted in response to the Secretary of the Interior's request for information on areas where federal policies and programs could contribute to attainment of an optimum long-term energy posture.

Chapter One
Summary and Conclusions

Domestic Energy Supply Outlook

For many decades, the United States has enjoyed abundant low-cost supplies of domestic energy. These fuel resources have contributed significantly to the country's economic growth, national security and quality of life.

In more recent years, because of various political, economic and environmental developments, domestic fuel supply has not grown as fast as domestic energy demand. During the next 3 to 5 years, a further deterioration of the domestic energy supply position is anticipated, and as a result fuel imports will have to be increased sharply. The Nation's dependence on imports of oil and gas increased to **12** percent of total energy requirements in 1970 and is likely to be 20 to 25 percent by 1975. The long lead times required to provide new domestic supplies make this development virtually certain.

Options for Balancing Energy Supply and Demand

The Nation must face *now* the fundamental issue of how to balance energy supply and demand most advantageously in the term beyond 1975. The major options involve (a) increased emphasis on development of domestic supplies, (b) much greater reliance on imports from foreign sources and (c) restraints on demand growth.

To some degree, all of these courses of action could contribute to solving the Nation's energy problem. The advantages, disadvantages and feasibility of each option are evaluated in this report. It is concluded that increasing the availability of domestic energy supplies is the best option available for improving the U.S. energy supply and demand balance. This approach requires increased development of domestic supplies, many of which may cost substantially more than in the past. The increased development will depend on margins between costs and prices being sufficient to attract the necessary additional investment. Accelerated development of domestic energy supplies would benefit all segments of society: employment would increase, individual incomes would rise, profit opportunities would improve, government revenues would grow, and the Nation would be more secure.

Relying on Imports to Meet Demand

The alternative of relying to a greater extent on imports would not well serve the Nation's security needs nor its economic health because of uncertainties regarding availability, dependability and price. Greater reliance on imports would also result in major balance of trade problems that could adversely affect the value of the dollar. The option of reducing energy demand growth would provide only limited help for the reasons enumerated below.

Reducing Demand Growth

Decreases in demand resulting from efficiency improvements were considered as were possible reductions from variations in the other principal factors influencing energy consumption: economic activity, population, cost of energy and environmental controls. It was judged unlikely that growth in consumption would depart significantly from the average 4.2-percent per year rate during the 1971-1985 period, as was projected in the Initial Appraisal. This is the intermediate demand growth rate used in this study. A range of 3.4-percent to 4.4-percent annual growth embraces the probable changes which could be effected. The lowest growth rate would reduce 1985 demand by 10 percent (or the equivalent of 6 million barrels per day [MMB/D] of oil) from the intermediate projection and 13.5 percent from the high projection.

Restrictions on energy demand growth could prove expensive and undesirable. Among other things, they would alter life-styles and adversely affect employment, economic growth and consumer choice. Despite possibilities for extreme changes or revisions in existing social, political and economic institutions, substantial changes in life-style between now and 1985 are precluded by existing mores and habits, and by the enormous difficulties of changing the existing energy consumption system. More efficient use of energy is desirable, and some improvement is possible and likely as energy becomes more costly. However, there are some inherent limitations in how much energy demand growth can be reduced during the next 15 years through efficiency improvements. These include the difficulties and high costs associated with altering existing equipment and the long lead times necessary before more efficient equipment can be developed and put into use.

Increasing Domestic Energy Supplies

The U.S. Energy Outlook analyses indicate that actions taken soon could increase domestic supplies in the longer term, thus reducing additional dependence on imports. No major source of U.S. fuel supply is limited by the availability of resources to sustain higher production. In this study, *resources* refer to the amount of the fuel in the ground, including that which has not yet been discovered; *reserves* are those resources that have been delineated and are capable of being developed for production; and *supplies* are the quantities that could be produced per day or per year. Despite some differences in these concepts among fuels, it is still possible to make relevant comparisons regarding the resource base and supply capabilities of individual fuels.

Oil and Gas: Oil and gas resources are sufficient to support a substantial increase in production. According to authoritative estimates,* U.S. oil and gas resources, much of which remain to be discovered, are sufficient to provide twice the 93 billion barrels of oil and three times the 393 trillion cubic feet (TCF) of gas produced through 1970. However, a substantial part of the undiscovered portions of these oil and gas deposits is believed to be located in less accessible areas and, thus, will be generally more costly than prior discoveries.

Coal: Coal is abundant. The U.S. Geological Survey estimates the Nation's coal resources at 3.2 trillion tons. Of this total about 150 billion tons of recoverable coal are presently known to be located in formations of comparable thickness and depth to those being mined by present technology. Maximum projected production in the next 15 years would use less than 10 percent of the 150 billion tons. This modest utilization of total coal reserves includes the output of coal for making synthetic fuels.

Uranium: Domestic uranium resources minable at reasonable costs are adequate to support the production of uranium needed to meet cumulative requirements through 1985. The Atomic Energy Commission (AEC) currently estimates there are 700,000 tons of uranium resources minable at a cost up to \$8/lb. of U_3O_8 and 1.6 million tons at a cost up to \$15/lb. of U_3O_8.

The dollar costs estimated by the AEC do not necessarily represent the market price which would stimulate exploration and development of these resources. However, they are useful to provide a basis for judgment as to the existence of proved and potential reserves in known deposits and uranium districts. In addition, the prospects for locating other ore bodies in partially explored and unexplored areas are good.

Oil Shale: Oil shale deposits in the western United States are estimated to contain 1.8 trillion barrels of crude shale oil. Of this amount, 129 billion barrels are in zones that contain over 30 gallons of oil per ton of shale in seams exceeding 30 feet in thickness. Within these richer zones, attention in this study was focused on tracts containing 54 billion barrels, which are considered to be the most economically recoverable. However, less than 6 billion barrels of recoverable reserves are needed to support the maximum production that could be developed by 1985 when considering limitations imposed by construction time and environmental and leasing constraints.

In addition to an ample resource base, development of fuel supplies requires the opportunity to explore prospective areas, the availability of technical competence and exploratory success. These

* NPC, *Future Petroleum Provinces of the United States* (July 1970); *Potential Supply of Natural Gas in the United States (as of December 31, 1970)*, a Potential Gas Committee report sponsored by Potential Gas Agency, Mineral Resources Institute, Colorado School of Mines Foundation, Inc. (Golden, Colorado, October 1971).

prerequisites must be accompanied by adequate profitability after taxes to provide incentives for investment. These physical and economic factors were investigated under different sets of assumptions. Because there is considerable uncertainty regarding future conditions, no one case could be selected as most probable. Rather, the analysis focused on four cases, spanning what was judged to cover a probable range of future outcomes. Any one of the cases described in this report could occur under various conditions.

The high end of the calculated supply range (Case I) would be difficult to attain because it requires a vigorous effort fostered by early resolution of controversies about environmental issues, ready availability of government land for energy resource development, adequate economic incentives, and a higher degree of success in locating currently undiscovered resources than has been the case in the past decade. The low end of the range of supply availability (Case IV) represents a likely outcome if disputes over environmental issues continue to constrain the growth in output of all fuels, if government policies prove to be inhibiting, and if oil and gas exploratory success does not improve over recent results. Two intermediate appraisals (Cases II and III) were also developed, with the higher supply Case II assuming improvement in finding rates for oil and gas, and a quicker solution to problems in fabricating and installing nuclear power plants.

Two further points of perspective relating to the cases in this study should be noted:

- In each of the four principal supply cases discussed, variations in key factors affect the production volumes and costs of various fuels. For oil and gas, as an example, accelerated application of improved recovery techniques, offshore leasing policies and tax provisions are of considerable importance. For convenience and clarity of presentation, attention has been focused on the effect of such variations on only the two intermediate cases.
- Certain policies and administrative judgments (for example, early resolution of environmental issues) would improve the prospects of attaining a high rate of growth for all fuel supplies. However, other factors could lead to different outcomes for different fuels. For instance, a high degree of exploratory success for oil and gas might lessen, to some degree, the priority on development of synthetic fuels.

Table 1 indicates that, by 1985, fuel availability under the most favorable conditions of Case I will be in the range of 50 to 100 percent greater than that under the Case IV assumptions.

The potential for increased domestic energy availability by 1985 depicted in Table 1 could be realized only with appropriate policies and economic conditions which are discussed in more detail later in this chapter.

TABLE 1

AVAILABILITY OF PRINCIPAL DOMESTIC FUEL SUPPLIES IN 1970 AND 1985

		1985			
		High Supply	Intermediate Supply		Continuation of Current Trends
	1970	Case I	Case II	Case III	Case IV
Petroleum Liquids (MMB/D)	11.2	15.5	13.9	11.8	10.4
Natural Gas (TCF/yr)	21.8	30.6	26.5	20.4	15.0
Coal (million tons/yr)*	590	1,570	1,134	1,134	1,004
Uranium (thousand tons/yr)	12.9	108.5	89.2	70.7	60.4

* Includes 47 to 339 million tons of coal production for synthetic fuels in 1985.

The Nation's Energy Picture in 1985

Energy Mix

The utilization of potential fuel supplies in meeting energy requirements by 1985 is dependent on the specific fuel needs of various consuming sectors and on the outcome of interfuel competition within certain of these sectors.

An industry advisory committee comprised of competitors is constrained from assessing interfuel competition in specific markets. Consequently, the following steps were taken in making supply/demand balances: (1) A task group composed of representatives of the electric utility industry (a regulated industry that is not constrained from considering interfuel competition because it is a customer for, not a supplier of, primary fuels) used Federal Power Commission (FPC) data to establish estimates of oil and gas consumption in the critical electric power sector. (2) After utilizing these sources and all available hydroelectric and geothermal power, coal and nuclear power were used to balance needs in this sector. No separation as to the individual supply contributions of coal and nuclear was made for the energy balances. (3) The amount of coal required to meet demand outside the electric power sector was added to energy supplies. (4) All available conventional and synthetic domestic oil and gas and projected gas imports were added to the supply. (5) Remaining energy requirements were then assumed to be satisfied by oil imports.

This procedure was used to compute the supply and consumption patterns depicted by Figure 1. Some coal and nuclear potential was unused in most cases. This result is consistent with the present use patterns of the various fuels. Coal and nuclear fuels, which are utilized principally in the electric utility sector, do not have the same degree of interchangeability in various uses as do oil and

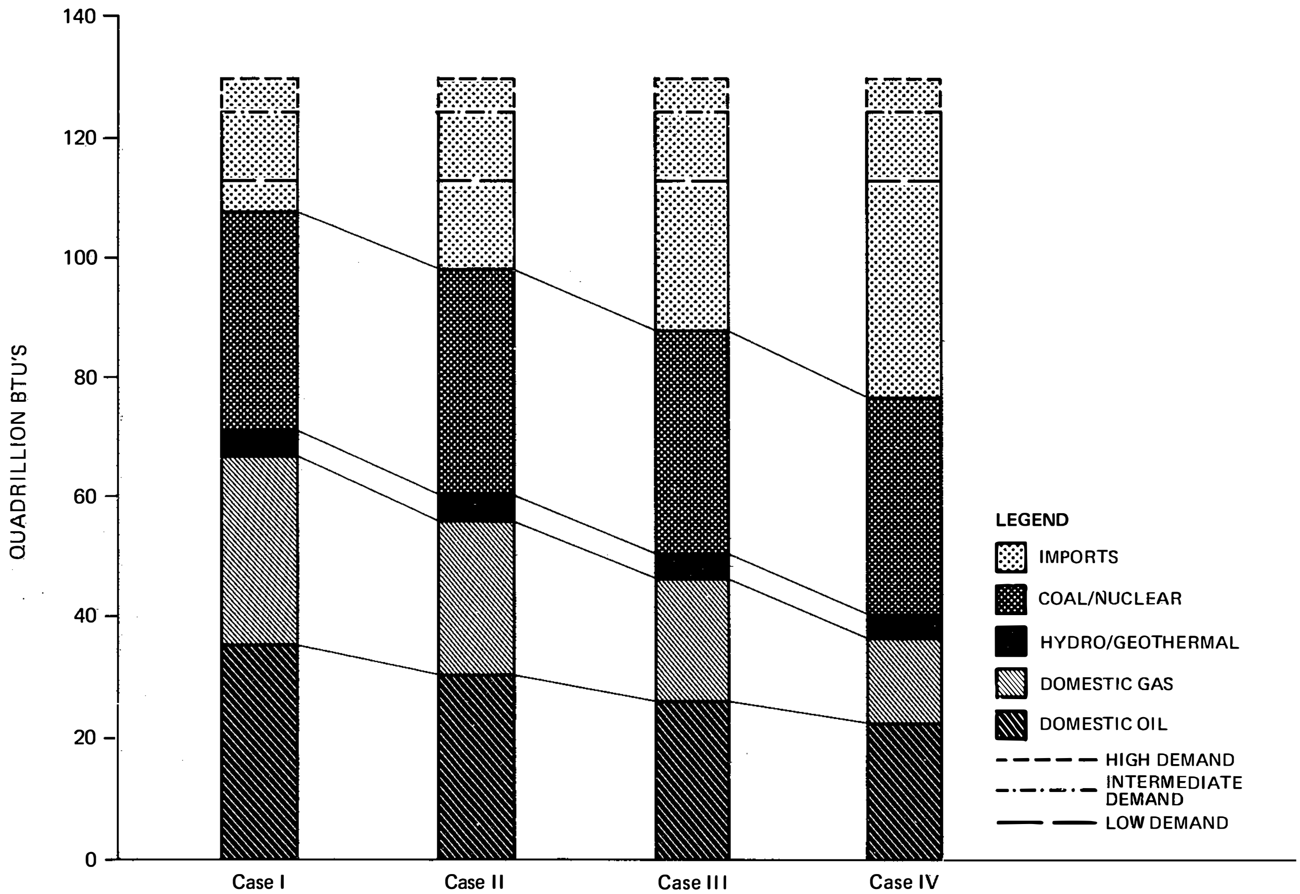


Figure 1. U.S. Energy Supply and Consumption in 1985.

gas. Thus, if the electric utility sector does not require all the potential or available supplies of coal and nuclear fuels, the excess supplies of these two fuels will remain undeveloped or unused.

Supply/demand balances were developed only with respect to the total energy situation. Supply/demand balances for individual fuels were not attempted because the availabilities of certain individual fuels have corollary effects on the demands for others.

The following conclusions, based on the intermediate energy demand and the four supply cases, can be drawn from the balances computed for 1985:

- Domestic supplies of energy, which now provide 88 percent of U.S. requirements, would provide only 62 percent if current trends continue, or 89 percent under the most optimistic supply case.
- Oil imports ranging from 3.6 to 19.2 MMB/D would be required compared to a present level of 3.4 MMB/D. By 1975, under all cases, oil imports will increase to 18 to 25 percent of energy requirements, which would amount to 42 to 51 percent of total oil supply. By 1985, oil imports will represent 6 to 33 percent of total energy supplies and 18 to 65 percent of total oil supply.
- Imports of natural gas (liquefied natural gas [LNG] and pipeline gas) may reach 5.9 to 6.6 TCF/year by 1985. This would represent about 5 percent of U.S. energy needs and from 15 to 29 percent of total gas supply. If it were not for projected limitations on gas imports imposed by Canadian gas availability and the ability to build required facilities such as LNG tankers for overseas imports, these import volumes would be even larger.
- Domestic oil and gas could provide as much as 56 percent of total energy requirements in 1985. However, if present trends continue, these fuels would contribute only 30 percent of the Nation's energy needs. By comparison, domestic oil and gas met 64 percent of total energy requirements in 1970.
- Coal and nuclear fuels could provide about 30 percent of U.S. energy requirements in 1985 in the four supply cases investigated, up from 20 percent in 1970. If a greater proportion of the Nation's energy needs could be met by electricity rather than by direct use of primary fuels, the combined potential supply of coal and nuclear fuels would be sufficient to meet up to 45 percent of 1985 U.S. energy requirements.
- Despite improved availability considered possible over current trends, natural gas supplies will be tight in relation to potential demand. Synthetic gas from coal and petroleum liquids, and natural gas from nuclear-explosive stimulation of low productivity gas reservoirs may provide from 1.8 to 5.1 TCF/year by 1985 to supplement domestic conventional natural gas supplies. Cost of these supplementary supplies will probably be greater than comparable costs required to bring forth an increase in conventional domestic gas supplies.
- The U.S. shale oil industry will come into being and could provide up to 750 thousand barrels per day (MB/D) of synthetic crude to supplement conventional liquid petroleum supplies.

Fuel "Prices"*

For each fuel, the four principal supply cases estimated the average unit revenues or "prices" required to support assumed ranges of activity levels, given an assumed range of investment returns. These analyses indicate that real energy "prices" of domestic fuels at the wellhead or mine must rise significantly by 1985. Since the "prices" cited for the fuels do not consider differences in quality, distribution costs or use characteristics, the "prices" calculated in this study cannot be meaningfully compared with each other. The projected range of percentage increases in average "prices" required to 1985 (in terms of 1970 dollars) over 1970 for individual fuels is indicated below:

- Oil at the wellhead: up 60 to 125 percent
- Gas at the wellhead: up 80 to 250 percent
- Coal at the mine: up about 30 percent
- U_3O_8: up about 30 percent.

* As used in this study, "price" does not mean a specific selling price as between producer and purchaser and does not represent a future market value. The term "price" is used to refer generally to economic levels which would, on the basis of the cases analyzed, support given levels of activity for the particular fuel. For a discussion of "constant" and "current" dollars, see Glossary.

The above ranges would imply an average annual increase in fuel "prices" of 2 to 9 percent, though the rate of increase would not necessarily be uniform throughout the period to 1985 and would not be the same for each fuel. These are increases in real costs over and above inflation. The "prices" for U_3O_8 are based on the cost of new production.

In the years ahead, foreign energy prices are also expected to rise if recent experience is repeated. As an example, after a long period of price stability, crude oil prices in the Middle East and North Africa have risen 50 to 65 percent since the second half of 1970, and additional annual increases are already scheduled through 1975. There is no assurance that foreign energy will cost less in the future than domestic supplies.

Energy Import Implications

In the four principal cases, 1975 oil imports are expected to be more than double the 3.4 MMB/D imported in 1970. As noted earlier, 1985 oil imports are projected to range from 3.6 MMB/D to 19.2 MMB/D. Besides the possible large increases in volumes of imports, a shift in the source of imports through 1985 is indicated. The United States will become increasingly dependent on Eastern Hemisphere crude supplies. Projected Western Hemisphere petroleum supply/demand balances were developed. These indicate that not only would the export availability of potential oil and gas supplies from the Western Hemisphere outside the United States be limited, but that the Western Hemisphere itself would become more dependent on Eastern Hemisphere supplies. (A longer term exception to the limited oil availability in the Western Hemisphere is that of the Canadian tar sand resources. Maximum production from this source is projected at about 1.25 MMB/D by 1985 and almost 7 MMB/D by the end of the century.) In certain of the cases developed in this study, as much as three-fourths of U.S. oil imports in 1985 would have to come from the Eastern Hemisphere, compared with 16 percent in 1970. To obtain these imported supplies, the United States will be competing with sharply expanded requirements in Western Europe and Japan.

Net imports of natural gas in 1970, primarily from Canada, were slightly less than 0.8 TCF and represented less than 4 percent of U.S. gas consumption. While transportation and logistical obstacles may constrain their growth, natural gas imports from Canada and waterborne imports of LNG, liquefied petroleum gas (LPG) or feedstocks for substitute natural gas (SNG) plants may increase more than sevenfold between 1970 and 1985. Most of these imports will be at prices higher than those now contemplated for domestic conventional production, and a large portion of these imports will come from the Eastern Hemisphere.

Three implications arise from the expected increase in imports of oil and gas.

National Security

As imports rise, the country will become increasingly dependent on the political and economic policies of a relatively small number of countries. This in turn can have important consequences on the military, political and economic security of the United States. Over the long term, the expansion of U.S. domestic energy supplies, including synthetic fuels, would provide basic safeguards against the problems and uncertainties of over-dependence on energy imports. Consideration should be given to (1) the need for additional storage to cushion the impact of possible near-term interruptions of foreign supplies and (2) desirability of utility plants being constructed to burn more than one type of fossil fuel.

Balance of Trade

Balance of trade pressures must be ameliorated. The cost of imported energy fuels, less the small sales revenue from fuel exports, results in a sizable net dollar drain. This dollar drain resulting from trade in energy fuels ($2.1 billion in 1970) will range from $9 billion to $13 billion in 1975 and from $7 billion to $32 billion annually by 1985. The threefold to fifteen-fold increase in foreign exchange requirements in 1985 above the current level will not be easily offset. Such increases will necessitate (a) adequate control of inflation by the Government and (b) close attention by U.S. industry to providing up-to-date capital equipment and improving operating efficiency. Such measures—plus export promotion programs and efforts to reduce barriers to exports of U.S. goods—will be necessary to ameliorate the foreign exchange drain of greater oil and gas imports.

Logistics

Arrangements must be made to accommodate growing oil and gas imports. The use of very large crude carriers (VLCC's) of 250,000 to 400,000 deadweight tons (DWT) is desirable for economic and environmental reasons.

At the present time, however, there are no U.S. ports capable of handling ships of those sizes. Accordingly, deepwater terminals must be built on the Gulf Coast, East Coast and Pacific Coast if the benefits of VLCC's are to be gained. Additionally, large diameter pipelines and increases in waterborne commerce into the interior will be needed.

Similar considerations are involved in the importation of natural gas, LPG, LNG and syngas feedstocks. New gas pipelines from the Canadian Arctic will be needed. LNG imports will also require substantial capital investment, both foreign and domestic, for such facilities as liquefaction plants, LNG tankers, regasification facilities and storage.

Improving the U.S. Energy Outlook

Federal government policies can accelerate or reverse adverse trends in the U.S. energy supply situation and will be a crucial determinant of the long-run energy position of the United States. Favorable policies will be required to achieve both the intermediate or high supply conditions projected in this report. If, however, government policies remain essentially the same as at present, domestic fuel production may not even be as high as the lowest supply condition described in Case IV.

The long lead times required for orderly development of energy resources make it essential that national energy objectives and sound enabling policies be established promptly. This will provide guidance to investors about the climate for expanded programs to develop domestic energy supplies. Investors will be seeking some assurance that future changes will not jeopardize the capital investments risked in efforts to provide energy to meet increasing demand.

To find, develop and process the primary energy supplies projected in Cases I-IV of this study, capital requirements will range from more than $200 billion to over $300 billion for the 1971-1985 period. In addition, electric generation and transmission facilities will exceed $200 billion. Thus, total capital requirements will be in the range of $450 billion to $550 billion.

The energy industries must earn sufficient returns on investments to provide needed capital from retained earnings and to attract additional equity and debt capital from outside sources. Higher prices for energy will be required to attract the large sums of capital needed to expand supplies above current levels. Unforeseen major technological advances might reduce costs and investment requirements, but cannot be relied upon in the time period 1971-1985. Favorable tax provisions can limit upward price pressures as they have in the past. On the other hand, any changes imposing higher taxes on energy will require even higher prices to secure the same levels of energy supplies.

The Department of the Interior requested that this report emphasize areas where federal policies and programs can effectively and appropriately contribute to the attainment of an optimum long-term national energy posture. In response to that request, the following recommendations are set forth.

Coordinate Energy Policies

Coordination and consistency are necessary in energy policies to achieve national energy goals. Unfortunately, the more than 60 federal organizations that have specific responsibilities for various fuels, together with all the interested state and local agencies, deal with the several fuels on individual bases. Their actions are often impromptu, duplicative and divergent, if not actually conflicting. For example, standards promulgated by the Environmental Protection Agency (EPA) promote increased utilization of natural gas because of its clean burning characteristics, while Federal Power Commission policies are inhibiting an increase in natural gas supplies. Coordination of federal energy policies in the Executive Branch is necessary to provide consistent guidance on energy related matters.

Establish Realistic Environmental Standards

Realistic environmental standards are essential if energy demands are to be met and the environment improved at reasonable costs. Protection of the environment will require higher energy use to achieve cleaner air and water.

Standards for a better environment must recognize the time required to effect the desired results. They must be compatible with such other important national goals as full employment, reduction of poverty, further improvement in average living standards, and assurance of energy supplies at all times for health, comfort and national security.

Reasonable demands of society with respect to the environment can be satisfied. However, programs to assure environmental quality during the production and consumption of energy fuels will involve large sums of capital. So, in reordering its priorities, the Nation must recognize the inescapable impact of added environmental costs on supplies and prices. In providing for the Nation's future energy needs, prompt action is needed to eliminate the serious delays that have been caused by environmental issues. The Government should direct immediate attention to—

- Minimizing delays in oil and gas exploration and development, laying of pipelines, and construction of deepwater terminals and new refineries
- Establishing effective siting and licensing procedures for nuclear power plant construction and operations which will eliminate undue delays while assuring safety
- Accelerating development of commercially viable stack gas desulfurization technology and other means of utilizing high-sulfur fuels
- Establishing guidelines for land restoration to ensure minimum environmental impairment in surface mining operations.

The impact of environmental considerations on the Nation's domestic energy supplies can be significant and can affect all energy fuels. Delays of authorizations for the Alaskan pipeline system are depriving the Nation of at least 2 MMB/D of crude oil and about 3 TCF/year of natural gas. Nuclear reactor plant siting and licensing delays could cost the electric utility industry an additional $5 billion to $6 billion for each year's delay during the early 1970's in nuclear plant schedules, lead to increased utilization of less efficient equipment, and reduce installed nuclear plant capacity by up to 135,000 megawatts (MWe) in 1985. Until the technology for economic stack gas cleanup is developed, or some other means of using high-sulfur coal is commercially economical, such as using syngas from coal in a combined cycle, over 40 percent of estimated coal resources east of the Mississippi River (those resources having a sulfur content of over 3 percent) will be unusable as a boiler fuel under most air quality standards. Banning of surface mining would reduce Case I 1985 coal supply potential by approximately one-half and would essentially eliminate western coal production for making synthetic liquids and gas. Environmental regulations have already restricted the fuel options available to electric utilities so that, in many parts of the United States, they have no choice but to use imported low-sulfur fuels.

Establish Realistic Health and Safety Standards

Health and safety standards and regulations for mining should be based on reliable evidence that such regulations will, in fact, achieve desirable goals. This is particularly important in such areas as radiation control, sound abatement and dust control. The economic impact of unnecessarily restrictive regulations can curtail production of needed energy resources.

It is important to continue enforcement of the Federal Coal Mine Health and Safety Act of 1969 equitably throughout the industry and to review the results of its application in order to improve it. The features which prove to be helpful to health and safety should be retained and strengthened. Any features which reduce productivity but have little bearing on health and safety should be eliminated. The impact on coal productivity of the Mine Health and Safety Act was quite significant, with individual mines reporting 15- to 30-percent reductions in output.

Encourage Greater Development of Resources on Public Lands

At least 50 percent of the Nation's remaining oil and gas potential, approximately 40 percent of the coal, 50 percent of the uranium, 80 percent of the oil shale and some 60 percent of geothermal energy sources are located on federal lands. Proper economic incentives are essential for their effective development. However, proper incentives are of no avail unless accompanied by leasing policies and programs that open the public domain to mineral exploration and development in an orderly and timely fashion. Access to such areas is being seriously delayed or completely denied at the present time.

Government should accelerate the leasing of lands for exploration and development of energy resources by private enterprise in a manner consonant with environmental goals. Such a leasing system should provide sufficient total acreage at more frequent intervals so industry can fully deploy its skills to develop needed energy supplies. In addition, once energy resources are discovered in frontier areas the industries should be allowed to bring them to market after having provided adequate environmental safeguards.

The impact of government leasing policies on energy supplies can be quite significant. This study indicates that the largest potential for developing new domestic reserves of oil and gas in the 1971-1985 period is located in the offshore areas of the United States (Gulf Coast and California), and in frontier areas (Alaska and offshore Atlantic). To support the petroleum supplies potentially available from the offshore areas under the Case II conditions, lease sales totaling 21 million acres would be required for the 15-year period. This compares with the 7 million acres made available since 1954 on the Outer Continental Shelf (OCS). If leasing were to be restricted so that no new leases were offered in the offshore areas by the Federal Government, it could cost the country about 2 MMB/D of domestic crude oil and nearly 6 TCF/year of gas in 1985.

Federal leasing policies should recognize that coal conversion to synthetic gas and liquids will require dedication of very large blocks of coal lands in order to justify the large cost of technological development and the construction of economical processing plants. Unitization of public land coal leases should be permitted to facilitate this effort.

All lands having uranium or thorium potential should remain available for exploration and development until exploration information allows assessment of mineral values. Any new time limits placed on federal claims or leases held for uranium should take into account the long lead times associated with uranium exploration and development as well as future market requirements.

Federal leasing policy is also important in the development of oil shale land. The Mineral Leasing Act of 1920 now limits a company to one lease of a maximum of 5,120 acres. This size lease does not permit a single operator sufficient reserves either to establish a sizable, and therefore economical, operation (50 to 100 MB/D) or to take advantage of improved second generation plants by having access to reserves adequate for long-term operation. A policy that (a) makes government reserves available in adequate quantities, (b) permits individual companies to have initial holdings of at least 10,000 acres, and (c) permits additional acreage to be obtained as commercial operation proceeds would provide a spur for oil shale bidding and development.

Projection of as much as 9,000 MWe of installed electric power generation capacity in 1985 utilizing geothermal energy is reasonable only if large areas of land are available for prospecting. The success ratio in drilling during the next 5 years will have a vital bearing on future development.

Assure Water Availability for Energy Production

The maximum development of synthetic fuels production (Case I) requires both an immediate government program to provide the necessary aqueduct systems in the western United States and timely resolution of disputes over water rights or water allocations.

Continue Tax Incentives

Fiscal policies should be designed to encourage the finding and development of all energy supplies. Recent developments have had a contrary effect. For example, the 1969 Tax Reform Act alone placed an additional tax burden on the domestic petrolum industry of some $500 million per annum. Fiscal policies should encourage the creation of capital requisite for increasing energy supplies and reducing costs to the consumer. Unless more effective tax provisions are devised for all energy resources, existing measures should be retained and improved.

Long-established tax provisions for the extractive industries have historically promoted the development of energy supplies. These tax features deal with percentage depletion applicable to coal, uranium, oil, gas, oil shale and geothermal steam, and those permitting current deductions of intangible costs for oil and gas. Adverse changes in such tax provisions would prove expensive for the Nation because they would reduce supplies and lead to higher costs and prices. For instance, complete removal of the statutory depletion allowance would necessitate an immediate "price" increase on the order of $0.50 per barrel for all oil and $0.03 per thousand cubic feet (MCF) for gas; by 1985 it would necessiate increases of $0.90 to $1.00 per barrel and $0.05 to $0.07 per MCF in order to maintain a return on investment sufficient to generate and attract the capital needed to provide the supply projected. These "price" increases are over and above the increased "prices" indicated for the particular fuel cases in 1985 due to higher investment and operating costs.

Maintain Oil Import Quotas

In the interest of national security the Government has adjudged that a healthy and viable petroleum industry must be maintained. To assist in meeting this objective the United States, by a 1959 Presidential Proclamation, placed a limit on petroleum import levels.

The continuation of oil import quotas is essential primarily for three reasons:

- A secure domestic energy base is a vital element of national security; over-dependence on foreign sources can make the United States vulnerable to interruption of petroleum supply from military action or from shutdown for political reasons. Without the deterrent effect of a strong domestic oil industry, producing countries could more easily threaten economic sanctions and boycotts to significantly influence U.S. international policies. Moreover, major supply interruptions of energy imports could severely hamper the functioning of the U.S. economy.
- Elimination of oil import quotas would have an adverse effect on the U.S. economy. As noted earlier, the balance of trade problem would increase greatly if imports of foreign oil were unrestrained. Direct government revenues from lease sales, royalty payments and income taxes from domestic producers—as well as indirect revenues from employee taxes and taxes from companies supplying goods and services to the domestic oil industry—would be reduced. Employment, both within the petroleum industry and in the industries supplying goods and services to the petroleum industry would be reduced.
- Oil import quotas are needed to encourage development of all indigenous energy resources. For example, since oil exploration and gas exploration are generally joint activities using the same people, techniques and equipment, the availability of these two fuels is inextricably interrelated. Without oil import quotas, the availability of domestic gas, as well as the availability of domestic oil, would decline further. This would require the importation of large quantities of foreign gas at landed costs considerably greater than the costs for domestic gas production. Also, foreign liquids would have to be imported and gasified at substantially higher costs than domestic natural gas supplies. Development of synthetic fuels from domestic resources could be retarded by the lack of economic incentives to develop such energy sources caused by the threat of unrestricted imports at a price that would not yield an adequate return for producers of synthetic fuels.

Clearly, attaining a high level of national self-sufficiency in the energy sector at a manageable cost should be a prime national policy of any industrial country. The present import quotas provide protection against the dramatic adverse effects of unrestrained imports of foreign oil at a national cost that is considerably less than other alternatives, such as maintenance of standby production and storage capacity.

Although increased imports of oil and gas will be needed in the years immediately ahead, import control policies should be implemented in a manner that will encourage increased domestic supply availability over the long term. Although concurring with the general purpose of oil import quotas, the National Petroleum Council does not feel its responsibilities in this report extend to a detailed analysis of specific regulatory or allocation features of the present Mandatory Oil Import Program.

Investigate the Feasibility and Desirability of Greater Use of Electricity Generated from Domestic Coal and Uranium Resources

Most cases studied did not utilize all of the potential coal and uranium fuel supplies because these supplies were not needed to fuel the projected electric utility generating capacity. Policies that would help overcome barriers to more rapid development of electric generating plants and encourage wider use of electrical equipment would permit the Nation to use more of its coal and uranium resources. This would reduce projected energy imports thereby mitigating the adverse effect of such imports on national security and the balance of trade.

Maintain Uranium Import Controls

Policies for imports, enrichment operations and government stockpile disposal should continue to encourage the growth of the domestic uranium mining industry. Present import policy requires that uranium enriched in U.S. government facilities for use in domestic reactors must be of U.S. origin as necessary to ensure the existence of a viable domestic uranium mining industry. A continuation of a policy to restrict the importation of uranium is necessary if a healthy domestic industry is to survive the period of transition from supplying primarily a government market to supplying a mature commercial market.

Future demand for nuclear fuel is projected to reach levels several times greater than historical quantities. In the long term, it will become not only the major fuel for electric power generation but also a major source of energy in the United States. Uranium resources in the United States are believed to be adequate to supply the necessary nuclear fuel. However, because of long lead times involved, large investments will have to be made in exploration, mining, milling and enrichment. Investments in domestic exploration and production of uranium concentrates are unlikely to be forthcoming unless government import policy encourages suppliers to make the long-range plans and commitments necessary to minimize U.S. dependence upon foreign sources of uranium.

The program proposed by the AEC in March 1972 for operation of government enrichment facilities and disposal of the government-owned stockpile is reasonable in conjunction with present import policy if adequate economic incentives can be developed to lead domestic suppliers to promptly initiate and maintain sharply increased domestic uranium supply capability. However, when a condition of oversupply leads to erosion of investment in domestic supply capability, the program for disposal of the government stockpile should cease and the existing stockpile be reserved for emergency use.

Allow Field Prices of Natural Gas to Reach Their Competitive Level

Despite the superior characteristics of natural gas, domestic prices of this fuel are held by the FPC to a fraction of the price of substitute fuels. This results in a paradoxical situation in view of present and prospective major supply shortages. At the same time that the Government engages in this supply-limiting action, serious consideration is given by Government and industry to the importation of natural gas at substantially higher prices, thus illustrating the contradictions in current regulatory policies.

As a result of these artificially low prices, reserve additions (excluding North Slope) in the last 3 years have averaged about 9.5 TCF/year while consumption has exceeded 21 TCF annually. The FPC's recently proposed optional pricing mechanism and current emergency pricing provisions are apparent admissions that the area rate prices now in existence fail to provide the needed incentives for additional exploration and production of natural gas. However, these recent changes in FPC regulations are inadequate measures; optional pricing is contingent on so many restrictions and qualifications that this proposal is of questionable value. Natural gas prices and the prices of gas manufactured from petroleum liquids or coal and liquefied gas imported from abroad should be freed to reach market clearing levels, thereby (a) encouraging exploration for new reserves, (b) stimulating development of new sources of supply and (c) discouraging the consumption of gas in low priority uses. Permitting market forces to work is certainly a better solution than to continue the counterproductive regulation of gas prices and thereby the arbitrary allocation of supplies.

Rely Primarily on Private Enterprise

The Federal Government should establish an economic and political climate which is conducive to energy development by private enterprise. An earlier section indicated the necessity and benefits of restraining imports of energy. Within the broad limits set by government import controls, private competitive enterprise will continue to be the best and lowest cost method of meeting energy needs. Competitive markets are a particularly effective mechanism for determining price levels necessary to balance demand and supply. The complex operation of market forces will best serve consumers and the national interest in (a) providing energy in the amounts needed and in the forms preferred for environmental reasons, (b) promoting efficient use of energy, and (c) allocating resources among energy activities. The results of this study clearly indicate that there is a substantial capability on the part of U.S. industry to provide additional energy from domestic resources, given the opportunity and incentives to do so. To approach the full potential of U.S. energy resources indicated in this study will require the ingenuity and effort of thousands of firms, ranging from small to large, and of millions of people.

Expand Research

This study indicates that additional research is required in such fields as: (a) exploration methods and equipment, (b) the production of synthetic fuels, (c) more efficient production and use of energy, (d) coal mining technology, (e) greater recovery of oil and gas reserves and (f) development of new energy forms. The extent to which such research is undertaken will, however, depend on establishment of an economic and regulatory climate that will permit attractive returns to those fuel suppliers conducting such research.

Benefits from technological advances could be sizable. Chapter Fifteen deals more extensively with the potential for technology to aid in improving the Nation's energy position in the latter years of this century.

Historically, research expenditures by the oil and gas industry have primarily been privately funded, as is the case with most American industries. On the other hand, other fuel suppliers, particularly coal and nuclear, have relied largely on governmental funding. The National Petroleum Council endorses continued reliance on private industry as the principal source of funds for oil and gas research and takes no position on the optimal way to fund research in other fuel areas.

Supplies of clean, secure energy fuels will become increasingly tight over the next 3 to 5 years. This condition will become more severe in the longer term if present trends and policies continue. The potential for significantly reducing U.S. energy demand through 1985 without restricting economic growth and consumer choice is limited. The most obvious and necessary corrective action is to encourage the development of domestic supplies of all forms of energy.

Such an approach will enhance national security, ensure freedom of consumer choice, help mitigate the growing trade deficit caused by importing more of the Nation's energy requirements, and promote economic growth. Most Americans would benefit from such a program: more jobs would be created, individual incomes would rise, industrial profits would improve, and government revenues from lease sales, royalties and taxes would increase. However, the potential for improving the U.S. energy situation in the 1980's can only be realized if the economic climate is favorable and sound national policies are adopted and implemented soon.

Chapter Two
Energy Supply and Demand Balances

In this chapter projections of future U.S. energy requirements and supplies are made. The various levels (or cases) of each are discussed and then compared to determine the Nation's future needs for energy imports.

Energy Demand Findings

The Initial Appraisal indicated that U.S. energy consumption would grow at an average rate of 4.2 percent per year during the period 1971-1985 and that the United States probably would face increasingly tighter energy supply and higher energy costs during the period. The present study has adopted the 4.2-percent growth rate as a base case and has analyzed the potential variations in future energy demand under different sets of assumptions from those used in the Initial Appraisal. The following variables were deemed to be the most significant long-range determinants of energy demand: (a) economic activity (the gross national product [GNP]), (b) cost of energy (including cost-induced efficiency improvement), (c) population, and (d) environmental controls.

These four parameters, in combination, seem to explain most of the past changes in energy demand, as indicated by special background studies. The sensitivities of energy demand relative to each of these parameters were estimated for each market sector, and the parameters were varied systematically around the Initial Appraisal estimates. In this manner, a series of energy demand cases were developed for different sets of assumptions. Since the number of possible variations is extremely large, two projections were selected (for each variable) that would bracket most of the likely energy demand cases. They are called the "high" and "low" energy demand cases, and the Initial Appraisal projection of energy consumption, which falls between these two cases, is termed the "intermediate" case.

The combination of individual parametric variations into totals—for the United States for each market sector—must be done on a judgmental basis rather than by simple quantitative formulas because the factors are not entirely independent. For example, it is believed that conditions leading to very stringent environmental standards, which are characteristic of the high demand case, probably would be associated with low economic growth and

TABLE 2

PROJECTIONS OF U.S. TOTAL ENERGY DEMAND UNDER THREE DIFFERENT SETS OF ASSUMPTIONS

	Growth Rate (Average Annual % Gain)			Volume (Quadrillion BTU's)	
Case	1970-1981	1981-1985	1971-1985	1980	1985
High	4.5	4.3	4.4	105.3	130.0
Intermediate (Initial Appraisal)	4.2	4.0	4.2	102.6	124.9
Low	3.5	3.3	3.4	95.7	112.5

high energy costs, which are characteristics of the low case. Furthermore, it is unlikely that all factors would reach their "lows" and their "highs" simultaneously. Table 2 presents a likely summary for the United States, which takes such relationships into account.

A probability analysis indicated that approximately 85 percent of the possible variations would fall within the high/low ranges shown in Table 2. Breakdowns of these ranges, by major consuming sector, appear in Table 3. While these are considered to be the probable ranges of demands based on the variables deemed to be the most significant long-range determinants of energy demand, it should be emphasized that there are many other possibilities.

This study assumes that the Nation will continue to rely on private enterprise and free consumer choice; it does not account for other potential factors that would come into play if energy consumption were reduced by supply limitations or by political decisions. In such cases, growth rates

TABLE 3

VARIANT PROJECTIONS OF U.S. ENERGY DEMAND*
BY MAJOR CONSUMING SECTOR

	Demand Volume—Quadrillion BTU's						
	1970	1980			1985		
	Actual	Low†	Intermediate	High†	Low†	Intermediate	High†
Residential/Commercial	15.8	21.1	22.4	23.4	23.9	26.6	28.5
Industrial	20.0	24.7	26.8	27.2	27.1	30.9	31.9
Transportation	16.3	23.0	23.9	24.4	26.7	28.3	29.0
Electricity Conversion	11.6	20.7	22.8	23.5	26.7	30.2	31.4
Non-Energy	4.1	6.2	6.7	6.8	8.1	8.9	9.2
Total	**67.8**	**95.7**	**102.6**	**105.3**	**112.5**	**124.9**	**130.0**

	Growth Rates—Average Annual Percent Change						
	1960-1970	1970-1980			1980-1985		
	Historical	Low†	Intermediate	High†	Low†	Intermediate	High†
Residential/Commercial	4.0	3.0	3.6	4.0	2.5	3.5	4.0
Industrial	3.4	2.1	2.9	3.1	1.9	2.9	3.2
Transportation	4.2	3.5	3.9	4.1	3.0	3.4	3.5
Electricity Conversion	7.2	5.9	6.9	7.3	5.2	5.8	6.0
Non-Energy	3.4	4.3	5.1	5.3	5.5	5.9	6.2
Total	**4.3**	**3.5**	**4.2**	**4.5**	**3.3**	**4.0**	**4.3**

* Electricity is allocated to each consuming sector and is converted at 3,412 BTU's per KWH and included in the total energy demand for the appropriate sector; the energy used by utilities for generation is shown in the Electricity Conversion category. The following figures show a reconciliation of electricity demands in these sectors with the total electric utility energy inputs, for the intermediate case only:

Demand Volumes—Quadrillion BTU's	1970	1980	1985
Residential/Commercial	2.8	5.7	7.8
Industrial	2.3	4.4	6.3
Transportation	—	0.1	0.1
Electricity Conversion	11.6	22.8	30.2
Total Utility Inputs	**16.7**	**33.0**	**44.4**

† Based on the variables deemed to be the most significant long-range determinants of energy demand.

for energy and economic activity would be much lower and achievement of important social goals such as full employment, higher standards of living and improvements in the environment would be seriously impeded.

A substantial portion of the reduction in energy consumption shown in the low case is estimated to result from improvements in efficiency of energy use initiated by consumers in response to higher costs, improved technology, and changed government standards (e.g., insulation in housing). Additional forced reductions in energy consumption would tend to lower economic growth and/or create losses in consumer satisfaction, which are subjective in nature and not readily expressed in quantitative terms. A few simple examples from the several consuming sectors which illustrate these distinctions are shown in Table 4.

within each of these broad categories. To attempt to treat each variation in combination with all possible variations of all other parameters would result in constructing thousands of theoretical cases. It was therefore necessary to select a limited number of combinations for in-depth analysis. (The component parameters were varied in numerous parametric studies. Their impacts are discussed throughout this report.)

Accordingly, for each primary fuel, four principal supply cases (designated I through IV) were developed, and the effects of variations in each of a series of parameters on one or more of these basic cases were evaluated. The general philosophy behind these four cases is as follows:

- Case I estimates the possible outcome from a maximum effort to develop domestic fuel sources. Case I assumes oil and gas drilling increases at a rate of 5.5 percent per year, and a high projection of oil and gas discovered per foot drilled. The nuclear power projections are based on the assumption that all new base-load generating plants ordered between now and 1985 will be nuclear. Production of coal for domestic consumption is increased at a rate of 5 percent per year. Synthetic fuels are developed and produced at the maximum rate physically possible without any restrictions due to environmental problems, economics, etc.
- Case IV, the lowest supply case, assumes that

TABLE 4

METHODS OF REDUCING ENERGY CONSUMPTION

Result	More Efficient Use	Arbitrary Reduction in Use
Lower home fuel consumption	Better home insulation	Lower room temperature
Lower automotive fuel consumption	Increased engine fuel economy	Reduced automobile trips
Lower factory use of fuel	Installation of better machinery	Reduced factory output
Lower electric fuel requirement	Improved power plant heat rate: same light, same air conditioning	Reduced electricity consumption: less light, less air conditioning

Energy Supply Analysis

The studies that followed the Initial Appraisal have been directed primarily toward quantitative evaluation of government policies and industry actions that might increase indigenous energy supplies. There are many parameters affecting energy supplies that can be varied when making studies of this character, such as prices, exploratory activity and results, mineral leasing provisions, mineral tax laws, etc. The number of parameters that could be varied is multiplied by the fact that there are several possibilities to be considered

TABLE 5

POTENTIAL DOMESTIC ENERGY SUPPLY AVAILABILITY
(Data in Conventional Units)

Year		Units	Initial Appraisal	Case I	Case II	Case III	Case IV
1975	Oil—Domestic Liquid Production	MMB/D	11.08	10.24	10.19	9.75	9.62
	—Shale Syncrude	MMB/D	0	0	0	0	0
	—Coal Syncrude	MMB/D	0	0	0	0	0
	Subtotal—Oil	MMB/D	11.08	10.24	10.19	9.75	9.62
	Gas—Domestic Production	TCF/yr	19.8	23.7	23.6	22.0	21.8
	—Nuclear Stimulation	TCF/yr	0	0	0	0	0
	—Syngas (Coal)	TCF/yr	0	0	0	0	0
	Subtotal—Gas	TCF/yr	19.8	23.7	23.6	22.0	21.8
	Hydroelectric	Billion KWH/yr	271	271	271	271	271
	Geothermal (Capacity)	MWe	1,500	1,500	1,500	1,500	1,500
	Coal	MMT/yr	621	665	621	621	603
	Nuclear (Capacity)	MWe	59,000	64,000	64,000	64,000	28,000
	Nuclear (U_3O_8)	MT/yr	18.4	19.1	19.1	19.1	11.5
1980	Oil—Domestic Liquid Production	MMB/D	11.80	13.58	12.94	11.61	8.90
	—Shale Syncrude	MMB/D	0	.15	.10	.10	0
	—Coal Syncrude	MMB/D	0	.08	0	0	0
	Subtotal—Oil	MMB/D	11.80	13.81	13.04	11.71	8.90
	Gas—Domestic Production	TCF/yr	17.5	25.9	24.3	20.4	17.3
	—Nuclear Stimulation	TCF/yr	0	.2	.1	.1	0
	—Syngas (Coal)	TCF/yr	.2	.6	.4	.4	.2
	Subtotal—Gas	TCF/yr	17.7*	26.7	24.8	20.9	17.51
	Hydroelectric	Billion KWH/yr	296	296	296	296	296
	Geothermal (Capacity)	MWe	4,500	10,250	5,250	4,500	2,500
	Coal	MMT/yr	734	851	734	734	705
	Nuclear (Capacity)	MWe	150,000	188,000	188,000	150,000	107,000
	Nuclear (U_3O_8)	MT/yr	34.2	50.9	45.6	36.5	29.1
1985	Oil—Domestic Liquid Production	MMB/D	11.08	15.46	13.89	11.83	10.38
	—Shale Syncrude	MMB/D	.10	.75	.40	.40	.10
	—Coal Syncrude	MMB/D	0	.68	.08	.08	0
	Subtotal—Oil	MMB/D	11.18	16.89	14.37	12.31	10.48
	Gas—Domestic Production	TCF/yr	14.5	30.6	26.5	20.4	15.0
	—Nuclear Stimulation	TCF/yr	0	1.3	.8	.8	0
	—Syngas (Coal)	TCF/yr	.5	2.5	1.3	1.3	.5
	Subtotal—Gas	TCF/yr	15.0*	34.4	28.6	22.5	15.5
	Hydroelectric	Billion KWH/yr	316	316	316	316	316
	Geothermal (Capacity)	MWe	7,000	19,000	9,000	7,000	3,500
	Coal	MMT/yr	863	1,093	863	863	819
	Nuclear (Capacity)	MWe	300,000	450,000	375,000	300,000	240,000
	Nuclear (U_3O_8)	MT/yr	59.3	108.5	89.2	70.7	60.4

* Does not include 0.4 TCF SNG from naphtha reported in Initial Appraisal as domestic supply.

TABLE 6

POTENTIAL DOMESTIC ENERGY SUPPLY AVAILABILITY
(All Data x 10^{12} BTU's/Year)

Year		Initial Appraisal	Case I	Case II	Case III	Case IV
1975	Oil—Domestic Liquid Production	22,789	20,735	20,630	19,754	19,502
	—Shale Syncrude	0	0	0	0	0
	—Coal Syncrude	0	0	0	0	0
	Subtotal—Oil	22,789	20,735	20,630	19,754	19,502
	Gas—Domestic Production	20,430	24,513	24,300	22,766	22,421
	—Nuclear Stimulation	0	0	0	0	0
	—Syngas (Coal)	0	0	0	0	0
	Subtotal—Gas	20,430*	24,513	24,300	22,766	22,421
	Hydroelectric	2,840	2,990	2,990	2,990	2,990
	Geothermal	120	120	120	120	120
	Coal	16,310	16,650	15,554	15,554	15,100
	Nuclear	3,340	4,000	4,000	4,000	1,661
	Total Potential Supplies	**65,829**	**69,008**	**67,594**	**65,184**	**61,794**
1980	Oil—Domestic Liquid Production	24,323	27,758	26,456	23,789	18,112
	—Shale Syncrude	0	296	197	197	0
	—Coal Syncrude	0	175	0	0	0
	Subtotal—Oil	24,323	28,229	26,653	23,986	18,112
	Gas—Domestic Production	18,030	26,746	25,043	21,041	17,906
	—Nuclear Stimulation	0	206	103	103	0
	—Syngas (Coal)	190	512	329	329	165
	Subtotal—Gas	18,220*	27,464	25,475	21,473	18,071
	Hydroelectric	3,033	3,240	3,240	3,240	3,240
	Geothermal	343	782	401	343	191
	Coal	19,928	21,200	18,284	18,284	17,550
	Nuclear	9,490	11,349	11,349	9,787	6,788
	Total Potential Supplies	**75,337**	**92,264**	**85,402**	**77,113**	**63,952**
1985	Oil—Domestic Liquid Production	23,405	31,689	28,477	24,346	21,426
	—Shale Syncrude	197	1,478	788	788	197
	—Coal Syncrude	0	1,489	175	175	0
	Subtotal—Oil	23,602	34,656	29,440	25,309	21,623
	Gas—Domestic Production	14,960	31,604	27,324	21,049	15,474
	—Nuclear Stimulation	0	1,341	825	825	0
	—Syngas (Coal)	560	2,269	1,208	1,208	494
	Subtotal—Gas	15,520*	35,214	29,357	23,082	15,968
	Hydroelectric	3,118	3,320	3,320	3,320	3,320
	Geothermal	514	1,395	661	514	257
	Coal	23,150	27,100	21,388	21,388	20,300
	Nuclear	21,500	29,810	25,249	20,220	16,126
	Total Potential Supplies	**87,404**	**131,495**	**109,415**	**93,833**	**77,594**

*Does not include 380 trillion BTU's SNG from naphtha reported in Initial Appraisal as domestic supply.

recent trends in U.S. oil and gas drilling activity and the success from such efforts will continue; the siting and licensing problems with nuclear plants will continue; the incentives to develop new coal mines will not improve; and environmental constraints will continue to retard development of resources. This case results in a continued deterioration of the Nation's energy supply posture and is generally less optimistic than the Initial Appraisal.

- Case II assumes a less optimistic future supply picture than Case I. Oil and gas drilling activity grows at a lower rate—3.5 percent per year—than in Case I but with the same finding rates per foot drilled. For nuclear, Case II assumes problems in manufacture and installation lead times will be solved quickly. Coal production is increased at a rate of about 3.5 percent per year. Synthetic fuels are developed and produced at a moderate buildup rate.
- Case III assumes that there will be improvement over Case IV but not to the level of Case II in the development of indigenous energy supplies. Oil and gas *drilling* grows at the same average annual rate of 3.5 percent per year experienced in Case II, but the trends of oil and gas *finding* per foot drilled are lowered to those of Case IV which reflect recent actual experience. The development of nuclear power proceeds at about the rate in the AEC's most favorable forecast. There is no significant difference between Cases II and III for coal and synthetics.

TABLE 7

FUEL MIX FOR U. S. ELECTRIC UTILITIES

	BTU x 10^{12}			
	1970	1975	1980	1985
Oil	2,050	3,460	4,050	4,530
Gas	3,900	3,900	3,900	3,900
Coal	7,800	8,905	14,306	13,900
Nuclear *	240	4,270	7,500	18,713
Hydro	2,677	2,990	3,240	3,320
Total	**16,667***	**23,525**	**32,996**	**44,363**

* Includes relatively minor volumes of geothermal (500 x 10^{12} BTU in 1985).

Potential Domestic Supply Availability

The total potential domestic energy supply availability was determined by combining the projections of the various fuel supply task groups under the conditions described for each of the four supply cases. The results of this compilation for the years 1975, 1980 and 1985 are given in Tables 5 and 6. Table 5 provides fuel availability in units of measurements that are conventionally used for each fuel. These data are restated in Table 6 as BTU equivalents. The BTU data are used in this report whenever it is necessary to compare fuels.

Appraisal of Limited Fuel Interchangeability

If all fuels were completely interchangeable, energy balances could be struck by adding all domestic fuel supplies and comparing the total with energy demands. The difference between domestic supply and projected consumption would be either available to be exported, or required to be imported. But all fuels are not completely interchangeable in all uses. An automobile can be converted to run on natural gas, a residential coal furnace can be changed to burn oil or gas, but an automobile or a gas or oil furnace cannot burn coal without extensive modification. Here lies the major problem of substitutability: the amount of time and capital required to convert a system—any energy system—to an alternate primary energy source. Logistical problems such as building new pipelines or railroad spurs to receive the new form of energy are also involved.

In projecting an energy balance of the various fuels, certain plausible simplifying assumptions were necessary. While oil is not completely interchangeable with other fuels in existing equipment, it could supply all the growth in any sector. Also it is uniquely required for most of the transportation sector. Gas is almost completely interchangeable. Hydropower and geothermal are used only in the electric power generation sector, but supplies of these two energy sources are small. Coal is utilized in significant quantities only in the industrial and electrical sector, and nuclear is confined to electricity generation.

The electric utility sector is the only consumer of all forms of primary energy; thus, it is the pivotal sector in developing an overall energy balance. However, projecting the utilization in the market of the several fuels requires not only an appraisal of fuel substitutability but also an assessment of interfuel competition. Such an analysis cannot properly be made by an industry advisory committee comprised of competitors. Accordingly, the Coordinating Subcommittee developed an alternative procedure as described below.

Fuel for Electricity

Electricity has a unique role in the U.S. energy outlook for three principal reasons:

- The electric utility industry is both a supplier of energy to consumers and, at the same time, is itself a major consumer of fuels.
- By 1975, this rapidly growing energy sector is expected to be the largest user of primary fuels of any energy sector in the Nation.
- The electricity sector plays a key role in preparing balances between energy demand and domestic supply of fuels.

The Electricity Task Group, consisting of electric utility representatives, was appointed to prepare evaluations of the electric utility sector's future demand for primary energy under various conditions. The group selected as their "base case" (or Condition 1) the fuel mix projections in the FPC National Power Survey and applied these to the NPC estimate of total electric power demand. This resulted in the utility fuel requirements shown in Table 7.

Between the end of 1972 and December 1985, the electric utility industry is projected to install some 560,000 megawatts (MW) of new generating facilities, approximately 85 percent (475,000 MW) in the form of nuclear or fossil-fuel steam power plants. As of April 1972, nearly 191,000 MW of this total were committed, including 101,000 MW of nuclear installations. The balance of the steam plants (284,000 MW) will utilize either fossil or nuclear fuels depending on several factors. Among these are environmental constraints, variations in rates of increase of electricity demand, lead times and government policy decisions affecting fuel supplies. Present lead times are on the order of 5 years for fossil-fueled stations and 8 years for nuclear plants although increased legal and regulatory delays may further extend these lead times.

Natural gas supplies are not being discovered as rapidly as needed. If this condition persists, electric utilities in most areas of the United States will experience curtailments of service to existing gas-burning units. Therefore, exclusively gas-fueled electric generating plants can be planned only when increased supply capability can be demonstrated.

Environmental regulations in some areas of the country have virtually eliminated most types of coal as a fuel for new plants. Current technology on stack gas desulfurization systems, coal gasification, electrostatic precipitators and combustion control is not at a stage of development to permit compliance with the sulfur, nitrogen oxides and particulate restrictions currently in effect or proposed for many areas. Consequently, many electric utilities have only nuclear and oil as fuel alternatives. The nuclear alternative requires the greatest lead time from selection to actual power generation. Thus, in many parts of the United States during the next few years oil may be the only fuel which will permit electric utilities to meet customer requirements in an environmentally acceptable manner. However, coal is still an alternative in some areas.

TABLE 8

1985 ELECTRIC UTILITY FUEL CONSUMPTION

Condition No.*	Ratio to Year 1970 Oil	Gas	Coal	Nuclear	Percent of Total Oil	Gas	Coal	Nuclear
1	2.2	1.0	1.8	78.0	10	9	32	42
2	3.2	0.5	1.8	78.0	15	4	32	42
3	3.0	0.5	1.6	85.2	14	4	29	46
4	7.8	0	1.0	71.7	36	0	18	39
5	1.0	0.5	1.0	122.0	5	4	18	66
6	4.9	0.5	2.8	31.2	23	4	49	17

* Conditions 1 through 4 are adjudged more likely than Conditions 5 and 6 by the Electricity Task Group.

The Electricity Task Group concluded that the fuel mix shown above is the most feasible from the point of view of electric utilities. It represents the mix which would probably evolve if the utility industry were not subjected to severe constraints on its decisions.

The Electricity Task Group also postulated five other feasible, although less probable, fuel mixes. These "conditions," and the base case (Condition 1), are shown in Table 8. Each of these six fuel conditions affected the mix, including the volume of imports, but not the amount of total fuel required by utilities. Condition 2 is essentially the same as Condition 1, except for the conversion of

TABLE 9

COMPARISON OF QUANTITIES OF ENERGY FROM COAL AND NUCLEAR

Supply Case	Energy from Coal & Nuclear	Trillion (10^{12}) BTU's 1975	1980	1985
I	Used in Energy Balance	18,649	26,708	36,910
	Maximum Available	20,650	32,549	56,910
II	Used in Energy Balance	18,649	27,089	37,644
	Maximum Available	19,554	29,633	46,637
III	Used in Energy Balance	18,649	27,147	37,791
	Maximum Available	19,554	28,071	41,608
IV	Used in Energy Balance	16,761	24,338	36,426
	Maximum Available	16,761	24,338	36,426

half of all natural gas-fired steam generating capacity to oil. Under Condition 3 greater reliance is placed on nuclear plants and half of all natural gas capacity would be converted to oil. Condition 4 assumes that the uses of coal and nuclear are limited and that natural gas is completely withdrawn for power generation purposes; this condition would require a substantial increase in oil consumption for electricity generation. Condition 5 restricts the 1985 consumption of coal and oil to their 1970 level and reduces the consumption of natural gas by 50 percent; nuclear energy would be responsible for virtually all net growth in utility requirements. Condition 6 assumes a nuclear "moratorium" after 1980 and a reduction of natural gas consumption; coal and, to a lesser extent, oil would absorb the resulting fuel deficit. The effects of these conditions are summarized in Table 8.

Energy Balances

Using the Electricity Task Group projections of utility fuel consumption shown in Table 8 and the previous general observations on equipment convertibility and fuel substitutability, simplified total energy supply/demand balances were constructed by the Committee. The assumptions underlying these balances are as follows:

- All available domestic supplies of conventional oil and gas and synthetics will be utilized.
- All available geothermal and hydroelectric capability will be utilized.
- All available gas imports will be utilized.
- Consumption of coal by sectors other than electric utilities will be as projected by the Coal Task Group in the Initial Appraisal.
- All utility primary fuel requirements not met by oil, gas, hydro or geothermal will be satisfied by coal and/or nuclear. It is emphasized that for the purpose of these balances, no attempt has been made to identify the exact contribution of coal and nuclear, only their total combined participation. (In the balances, when this combined supply was less than requirements the difference was assumed to be met with imported oil. In the majority of the balances, however, the combined potential was greater than requirements.)
- The difference between total energy demand and the sum of the foregoing fuel availabilities will be satisfied by oil imports.

This simplified approach yields total energy supply/demand balances, which are useful in assessing (a) energy imports as a percent of U.S. consumption and (b) the volume of oil imports required to meet U.S. energy demands. It does not provide fuel supply patterns for individual market sectors or geographic regions. It does not define the exact role of coal and nuclear in the electric utility sector. Neither of these deficiencies detracts from the usefulness of the resulting assessment of energy import requirements.

Tables 16 to 19 at the end of this chapter summarize the U.S. energy supply and demand balances for supply Cases I to IV, using Condition 1 (or base case) for electric utility fuels and the intermediate energy demand case.

Appendix 4 contains a description of the methods used to derive these balances and the full detail of all balances summarized in this section.

Pursuant to the previously stated assumptions underlying these energy balances, namely that no attempt was made to identify the individual respective contributions of coal and nuclear energy in the electric utility field, Table 9 compares the quantities of energy from coal and nuclear that were used in the energy balances with the maximum quantities of energy that could be obtained from these two energy forms.

Energy Imports

The percentages of energy that would need to be imported, as derived in the energy balances in Tables 16-19 (Electricity Condition 1 and intermediate energy demand) are summarized in Table 10. Total energy imports as a percent of U.S. requirements are shown in Figure 2.

Energy imports in 1970 were about 12 percent of the U.S. energy supply. In all cases, energy imports increase sharply between 1970 and 1975. Imports as a percent of energy consumption decline from 1975 to 1985 in Case I, stay about constant in Case II, and increase in Cases III and IV. In Case IV they reach 38 percent of the energy consumption in 1980 and 1985.

Gas imports consist of pipeline natural gas from Canada, liquefied natural gas (imported in special tankers), and liquefied petroleum gas (also imported in tankers). They are projected at their maximum feasible level in all cases. Gas imports are expected to grow from about 1 quadrillion BTU's

TABLE 10

PERCENTAGES OF ENERGY IMPORTS NEEOEO TO FILL SUPPLY

Supply Case	Oil Imports as a Percent of Total Oil Supply* 1970	1975	1980	1985	Gas Imports as a Percent of Total Gas Supply 1970	1975	1980	1985	All Imports as a Percent of Total U.S. Energy Supply 1970	1975	1980	1985
I	26	42	30	18	4	5	12	15	12	20	16	11
II	26	43	37	38	4	5	14	18	12	20	19	20
III	26	48	48	53	4	5	16	22	12	23	26	28
IV	26	51	66	65	4	5	18	29	12	26	38	38

* A portion of the energy supply consists of gas reformed from petroleum liquids. To the extent that domestic liquids are reformed into gas, a corresponding increase in imported liquids would be required. Accordingly, for the purpose of the following energy balances, the energy in liquids reformed into gas and the input energy in gas reformed from liquids were both considered imported.

in 1970 to about 7.5 quadrillion BTU's by 1985, and in Case I, they are about half of the 1985 total imports. Under one concept, they are more than half, because part of the oil imports is made up of light oil feedstocks for the manufacture of synthetic gas.

TABLE 11

OIL IMPORTS*
(MMB/D)

Supply Case	1970	1975	1980	1985
I	3.4	7.2	5.8	3.6
II	3.4	7.4	7.5	8.7
III	3.4	8.5	10.6	13.5
IV	3.4	9.7	16.4	19.2

* Electricity Condition 1 and intermediate energy demand.

As discussed earlier, the nature of the U.S. energy supply and consumption patterns is such that imported oil is the energy form that provides the final increment of supply. The volumes of oil imports corresponding to the percents in Figure 2 are shown in Table 11 and in Figure 3. The volumes cited are crude oil equivalents of the calculated BTU deficit. Some fraction of the actual import volumes will be refined petroleum products, but no effort has been made to quantify the breakdown between crude and refined products. As discussed later, the actual mix of imported crude and products will be determined to a major degree by government import policy.

Even in Case I, oil imports more than double between 1970 and 1975, and in Case IV, nearly triple. Required oil imports in 1985 range from 19.2 MMB/D in Case IV to 3.6 MMB/D in Case I.

Sensitivity Analysis of Supply and Demand Balances

The effects on the supply and demand balances were investigated for (a) variations in the electric utility fuel mix, (b) different combinations of supply cases for individual fuels, (c) variations in demand requirements, and (d) increased use of electrical energy.

Electric Utility Mix

Three of the assumptions in preparing the supply and demand balances were that (a) all domestic supplies of oil and gas would be used, (b) all available gas imports would be utilized, and (c) oil imports would be the balancing element. Thus, any increase or decrease in oil and gas used by

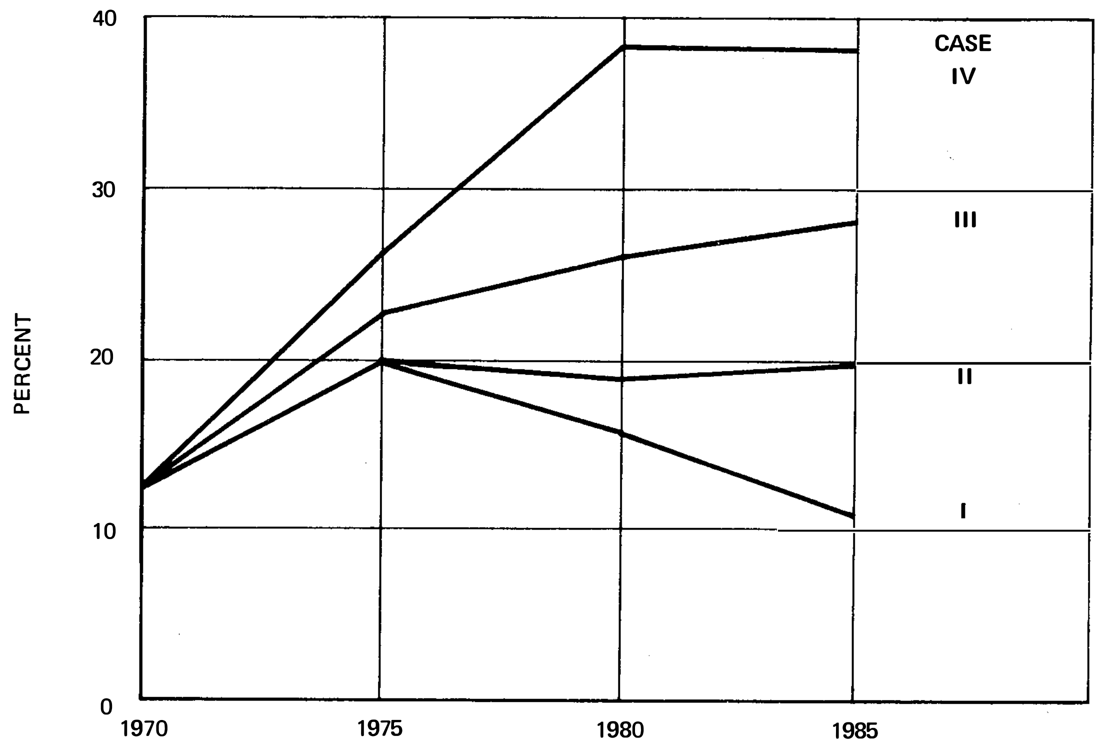


Figure 2. U.S. Energy Imports as Percent of Total U.S. Energy Consumption.

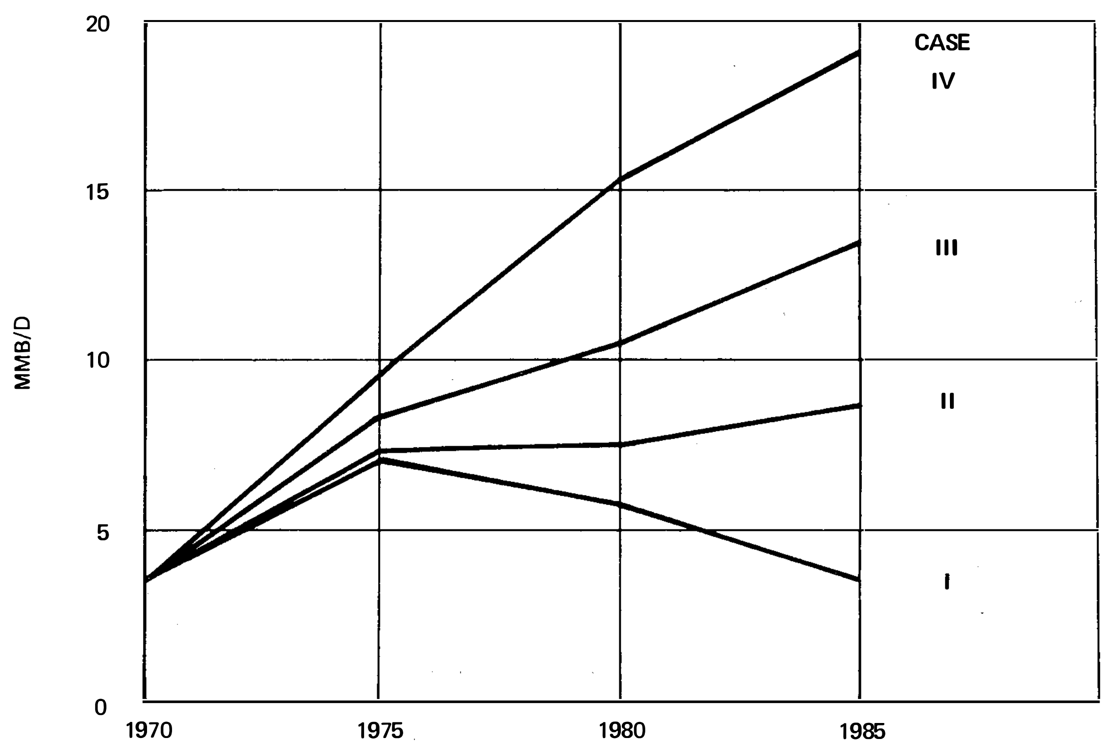


Figure 3. Oil Imports.

utilities would raise or lower oil imports by the same amount.

Table 12 shows this effect on required oil imports as electric conditions are varied.

For Conditions 1, 2 and 3, the percentage of oil-plus-gas in the utility fuel mix in 1985 remains essentially constant at 18 to 19 percent, and the required oil imports also remain essentially constant at about 13.5 MMB/D. For Conditions 4 and 6, when the oil-plus-gas share is increased to 36 percent and 27 percent respectively, the required oil imports are increased to 17.1 and 15.2 MMB/D.

TABLE 12

EFFECT OF VARIED ELECTRIC CONDITIONS ON OIL IMPORTS

	Oil Imports* (MMB/D)					
	1975		1980		1985	
Condition	Case II	Case III	Case II	Case III	Case II	Case III
1	7.4	8.5	7.5	10.6	8.7	13.5
2	7.4	8.5	7.5	10.6	8.7	13.5
3	6.9	8.1	6.9	10.2	8.5	13.3
4	7.9	9.0	10.5	13.7	12.3	17.1
5	7.9	9.0	10.5	13.7	6.6	11.7
6	6.9	8.1	6.9	10.2	10.4	15.2

* Intermediate energy demand used for all calculations.

TABLE 13

EFFECTS OF COMBINATIONS OF REQUIRED FUELS ON OIL IMPORTS

	Supply Case Numbers*					Oil Imports (MMB/D)		
	Oil	Gas	Coal	Nuclear	Others	1975	1980	1985
(a)	III	III	III	III	III	8.5	10.6	13.5
(b)	II	III	III	III	III	8.1	9.2	11.2
(c)	III	II	III	III	III	7.8	8.9	10.9
(d)	IV	IV	IV	IV	IV	9.7	16.4	19.2
(e)	IV	IV	I	I	IV	8.8	15.0	18.5
(f)	I	I	IV	IV	IV	8.1	7.6	6.5

* Electrical Condition 1 and intermediate demand case.

For Condition 5, the oil-plus-gas share is decreased to 9 percent and required oil imports are decreased to 11.7 MMB/D. For every 5 percent of the electricity requirements provided by oil and gas, oil imports change 1 MMB/D.

Different Combinations of Supply Case for Individual Fuels

The preceding analyses assume similar conditions were influencing the supply of each indigenous fuel. Thus, for example, the Case III energy supply condition was the summation of Case III conditions for each principal major fuel (line **a** in Table 13). In this section, different combinations of the four basic supply cases for individual fuels were investigated (lines **b**, **c**, **e** and **f**). The results of these various combinations of required fuel and required oil imports are shown in Table 13.

In comparison with Case III, if either oil or gas experiences the higher discovery rate associated with Case II, required oil imports are reduced. (The amount imports are reduced is apparent by comparing lines **b** and **c** with **a**.) With coal and nuclear at very high supply levels (Case I), the amount of oil imports is reduced only modestly. (Compare lines **d** and **e**.) This is because there are not enough electric utility plants in the United States to use the additional fuel.

On the other hand if domestic supplies of oil and gas are increased to Case I levels, there will be a major decrease in oil imports. (The extent of the import reduction is apparent by comparing lines **d** and **f**.)

Variation in Demand

The projections of required oil imports which resulted when all three demand cases were applied to the balance for intermediate supply cases (Cases II and III) are shown in Table 14.

In comparison with the intermediate case, the low energy demand case would reduce required oil imports in 1985 by about 6 MMB/D, and the high case would increase them by about 2.5 MMB/D.

Figure 4 compares Cases II and III in combination with the three demand cases for the period 1970-1985. Both illustrations depict the expected growing role of imports in supplying U.S. energy requirements.

TABLE 14

OIL IMPORTS–REQUIRED
(MMB/D)

	Supply Case II*		Supply Case III*	
Energy Demand Case	1980	1985	1980	1985
Low	4.2	2.8	7.4	7.6
Intermediate	7.5	8.7	10.6	13.5
High	8.8	11.1	11.9	15.9

* Electrical Condition 1.

Increased Use of Electrical Energy

All of the energy balances previously discussed used the Energy Demand Task Group's projection of total electric utility primary energy demand. In all balances, energy imports were required, but in some of these balances not all domestic energy supplies were utilized. As discussed earlier, nuclear energy and coal consumption are concentrated in electric power generation because they cannot readily be employed in other energy applications. Thus, supplies of these two fuels not needed by electric utilities will go unutilized. It was deemed appropriate, therefore, to examine the effects of substituting electrical energy generated by domestic coal and nuclear fuel for imported oil and gas. Such a substitution would call for an increase in construction of electric power plants to utilize these surplus fuels and would require electric utility fuel consumption to grow 8.8 percent per year. An increase in the electric utility industry's annual growth rate of 2.1 percentage points above the 6.7 percent projected by the Energy Demand Task Group would be difficult. If there were no change in system load factors, additional capital expenditures for generating and transmission facilities could range as high as $130 billion to $150 billion (in constant 1970 dollars) over the 15 years 1971-1985. If, as is more likely, much of the incremental electricity consumption were due to increased electric space and process heating, there would be a tendency toward improved load factors, and the incremental capital requirements for power plants

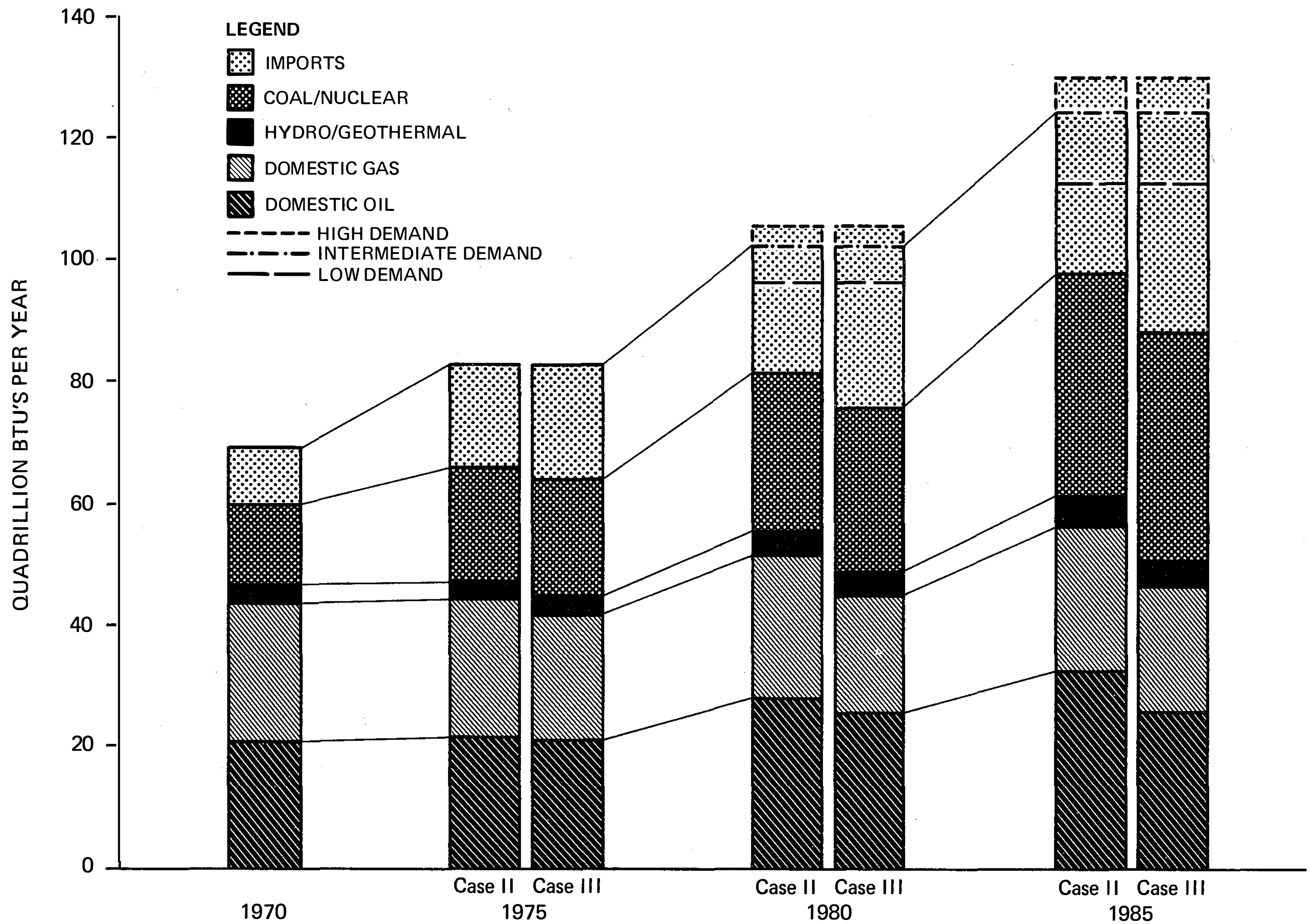


Figure 4. Energy Supply and Consumption, Cases **II and III.**

and transmission lines would be correspondingly less. Considerable additional expenditures on distribution systems would be necessary in either case. No attempt was made to calculate the corollary effects on overall capital requirements for energy of the high electricity case although some offsetting reductions in capital expenditures in other energy areas may occur.

TABLE 15

ELECTRIC UTILITY GROWTH RATES–INTERMEDIATE DEMAND CASE AND HIGH ELECTRICITY CASE

	Fuel Requirements BTU x 10^{12} per Year			
	1970	1975	1980	1985
Intermediate Demand Case	16,695	23,525	32,996	44,363
Additional	0	2,001	5,841	14,929
New Total	**16,695**	**25,526**	**38,837**	**59,292**
	Growth Rates Average Annual %			
	1970-75	1975-80	1980-85	1970-85
Intermediate Demand Case	6.9	6.9	6.0	6.7
Additional	1.9	1.9	2.8	2.1
New Total	**8.8**	**8.8**	**8.8**	**8.8**

Table 15 shows the comparison of the growth rates for the electric utility sector in the intermediate demand case and the high electricity case.

Table 20 shows that in 1975 and 1980, this increase is not enough to eliminate imports, but in 1985 only 88 percent of the total coal and nuclear supplies available are utilized in order to satisfy total U.S. energy demand solely from domestic sources. It should be noted, however, that under these conditions, in 1985 over 47 percent of U.S. energy is being consumed for the generation of electricity versus 25 percent in 1970.

The following tabulation compares the Case I import levels with those of the high electricity case for the years 1975, 1980 and 1985.

	Oil Imports Required (MMB/D)		
	1975	1980	1985
Case I	7.2	5.8	3.6
High Electricity Case	6.3	3.0	0.0

TABLE 16

PROJECTED ENERGY BALANCE FOR UNITED STATES—CASE I

	Trillion (10^{12}) BTU's/Year				Percent			
	Actual	Projected			Actual	Projected		
	1970	1975	1980	1985	1970	1975	1980	1985
Domestic Supply								
Oil—All Sources	21,048	20,735	28,229	34,656	31	25	27	28
Gas—All Sources	22,388	24,513	27,464	35,214	33	29	27	28
Hydropower	2,677	2,990	3,240	3,320	4	4	3	3
Geothermal	7	120	782	1,395	*	*	1	1
Coal & Nuclear Utilized	13,302	18,649	26,708	36,910	20	22	26	29
Total Domestic Supply	**59,422**	**67,007**	**86,423**	**111,495**	**88**	**80**	**84**	**89**
Imported Supply to Balance								
Oil Including Liquids for Gasification	7,455	15,274	12,258	7,547	11	18	12	6
Gas (Excluding Gas from Liquids)	950	1,200	3,900	5,900	1	2	4	5
Total Imported Supply	**8,405**	**16,474**	**16,158**	**13,447**	**12**	**20**	**16**	**11**
Total Domestic Consumption	**67,827**	**83,481**	**102,581**	**124,942**	**100**	**100**	**100**	**100**
Memo: Coal Supply	13,062	16,650	21,200	27,100	98	81	65	48
Nuclear Supply	240	4,000	11,349	29,810	2	19	35	52
Total Coal & Nuclear Available	**13,302**	**20,650**	**32,549**	**56,910**	**100**	**100**	**100**	**100**
Memo: Oil Supply								
Domestic Conventional	21,048	20,735	27,758	31,689	74	58	69	74
Syncrude from Shale	0	0	296	1,478	0	0	1	4
Syncrude from Coal	0	0	175	1,489	0	0	*	4
Imports (Including Liquids for Gasification)	7,455	15,274	12,258	7,547	26	42	30	18
Total Oil	**28,503**	**36,009**	**40,487**	**42,203**	**100**	**100**	**100**	**100**
Oil Imports to Balance—MMB/D	3.4	7.2	5.8	3.6				
Memo: Gas Supply								
Domestic Natural Gas	22,388	24,513	26,746	31,604	96	95	85	76
Gas from Nuclear Stimulation	0	0	206	1,341	0	0	1	3
Syngas from Coal	0	0	512	2,269	0	0	2	6
Imports—Pipeline	950	1,000	1,600	2,700	4	4	5	7
Imports of LNG	0	200	2,300	3,200	0	1	7	8
Total Gas (Excluding Gas from Liquids)	**23,338**	**25,713**	**31,364**	**41,114**	**100**	**100**	**100**	**100**
Gas Imports—TCF/yr	0.9	1.2	3.9	5.9				

* Less than 0.5 percent.

TABLE 17

PROJECTED ENERGY BALANCE FOR UNITED STATES—CASE II

	Trillion (10^{12}) BTU's/Year				Percent			
	Actual	Projected			Actual	Projected		
	1970	1975	1980	1985	1970	1975	1980	1985
Domestic Supply								
Oil—All Sources	21,048	20,630	26,653	29,440	31	25	26	23
Gas—All Sources	22,388	24,300	25,475	29,357	33	29	25	23
Hydropower	2,677	2,990	3,240	3,320	4	4	3	3
Geothermal	7	120	401	661	*	*	*	1
Coal & Nuclear Utilized	13,302	18,649	27,089	37,644	20	22	27	30
Total Domestic Supply	**59,422**	**66,689**	**82,858**	**100,422**	**88**	**80**	**81**	**80**
Imported Supply to Balance								
Oil Including Liquids for Gasification	7,455	15,592	15,823	18,420	11	19	15	15
Gas (Excluding Gas from Liquids)	950	1,200	3,900	6,100	1	1	4	5
Total Imported Supply	**8,405**	**16,792**	**19,723**	**24,520**	**12**	**20**	**19**	**20**
Total Domestic Consumption	**67,827**	**83,481**	**102,581**	**124,942**	**100**	**100**	**100**	**100**
Memo: Coal Supply	13,062	15,554	18,284	21,388	98	80	62	46
Nuclear Supply	240	4,000	11,349	25,249	2	20	38	54
Total Coal & Nuclear Available	**13,302**	**19,554**	**29,633**	**46,637**	**100**	**100**	**100**	**100**
Memo: Oil Supply								
Domestic Conventional	21,048	20,630	26,456	28,477	74	57	62	60
Syncrude from Shale	0	0	197	788	0	0	1	2
Syncrude from Coal	0	0	0	175	0	0	0	*
Imports (Including Liquids for Gasification)	7,455	15,592	15,823	18,420	26	43	37	38
Total Oil	**28,503**	**36,222**	**42,476**	**47,680**	**100**	**100**	**100**	**100**
Oil Imports to Balance—MMB/D	3.4	7.4	7.5	8.7				
Memo: Gas Supply								
Domestic Natural Gas	22,388	24,300	25,043	27,324	96	95	85	77
Gas from Nuclear Stimulation	0	0	103	825	0	0	*	2
Syngas from Coal	0	0	329	1,208	0	0	1	3
Imports—Pipeline	950	1,000	1,600	2,700	4	4	6	8
Imports of LNG	0	200	2,300	3,400	0	1	8	10
Total Gas (Excluding Gas from Liquids)	**23,338**	**25,500**	**29,375**	**35,457**	**100**	**100**	**100**	**100**
Gas Imports—TCF/yr	0.9	1.2	3.9	6.1				

* Less than 0.5 percent.

TABLE 18

PROJECTED ENERGY BALANCE FOR UNITED STATES–CASE III

	Trillion (10^{12}) BTU's/Year				Percent			
	Actual	Projected			Actual	Projected		
	1970	1975	1980	1985	1970	1975	1980	1985
Domestic Supply								
Oil–All Sources	21,048	19,754	23,986	25,309	31	23	23	20
Gas–All Sources	22,388	22,766	21,473	23,082	33	27	21	19
Hydropower	2,677	2,990	3,240	3,320	4	4	3	3
Geothermal	7	120	343	514	*	*	*	*
Coal & Nuclear Utilized	13,302	18,649	27,147	37,791	20	22	27	30
Total Domestic Supply	**59,422**	**64,279**	**76,189**	**90,016**	**88**	**77**	**74**	**72**
Imported Supply to Balance								
Oil Including Liquids for Gasification	7,455	18,002	22,492	28,526	11	22	22	23
Gas (Excluding Gas from Liquids)	950	1,200	3,900	6,400	1	1	4	5
Total Imported Supply	**8,405**	**19,202**	**26,392**	**34,926**	**12**	**23**	**26**	**28**
Total Domestic Consumption	**67,827**	**83,481**	**102,581**	**124,942**	**100**	**100**	**100**	**100**
Memo: Coal Supply	13,062	15,554	18,284	21,388	98	80	65	
Nuclear Supply	240	4,000	9,787	20,220	2	20	35	
Total Coal & Nuclear Available	**13,302**	**19,554**	**28,071**	**41,608**	**100**	**100**	**100**	**100**
Memo: Oil Supply								
Domestic Conventional	21,048	19,754	23,789	24,346	74	52	51	45
Syncrude from Shale	0	0	197	788	0	0	1	2
Syncrude from Coal	0	0	0	175	0	0	0	*
Imports (Including Liquids for Gasification)	7,455	18,002	22,492	28,526	26	48	48	53
Total Oil	**28,503**	**37,756**	**46,478**	**53,835**	**100**	**100**	**100**	**100**
Oil Imports to Balance–MMB/D	3.4	8.5	10.6	13.5				
Memo: Gas Supply								
Domestic Natural Gas	22,388	22,766	21,041	21,049	96	95	83	71
Gas from Nuclear Stimulation	0	0	103	825	0	0	*	3
Syngas from Coal	0	0	329	1,208	0	0	1	4
Imports–Pipeline	950	1,000	1,600	2,700	4	4	7	9
Imports of LNG	0	200	2,300	3,700	0	1	9	13
Total Gas (Excluding Gasfrom Liquids)	**23,338**	**23,966**	**25,373**	**29,482**	**100**	**100**	**100**	**100**
Gas Imports–TCF/yr	0.9	1.2	3.9	6.4				

* Less than 0.5 percent.

TABLE 19

PROJECTED ENERGY BALANCE FOR UNITED STATES—CASE IV

	Trillion (10^{12}) BTU's/Year				Percent			
	Actual	Projected			Actual	Projected		
	1970	1975	1980	1985	1970	1975	1980	1985
Domestic Supply								
Oil—All Sources	21,048	19,502	18,112	21,623	31	23	18	17
Gas—All Sources	22,388	22,421	18,071	15,968	33	27	17	13
Hydropower	2,677	2,990	3,240	3,320	4	4	3	3
Geothermal	7	120	191	257	*	*	*	*
Coal & Nuclear Utilized	13,302	16,761	24,338	36,426	20	20	24	29
Total Domestic Supply	**59,422**	**61,794**	**63,952**	**77,594**	**88**	**74**	**62**	**62**
Imported Supply to Balance								
Oil Including Liquids for Gasification	7,455	20,487	34,729	40,748	11	25	34	33
Gas (Excluding Gas from Liquids)	950	1,200	3,900	6,600	1	1	4	5
Total Imported Supply	**8,405**	**21,687**	**38,629**	**47,348**	**12**	**26**	**38**	**38**
Total Domestic Consumption	**67,827**	**83,481**	**102,581**	**124,942**	**100**	**100**	**100**	**100**
Memo: Coal Supply	13,062	15,100	17,550	20,300	98	90	72	56
Nuclear Supply	240	1,661	6,788	16,126	2	10	28	44
Total Coal & Nuclear Available	**13,302**	**16,761**	**24,338**	**36,426**	**100**	**100**	**100**	**100**
Memo: Oil Supply								
Domestic Conventional	21,048	19,502	18,112	21,426	74	49	34	34
Syncrude from Shale	0	0	0	197	0	0	0	*
Syncrude from Coal	0	0	0	0	0	0	0	0
Imports (Including Liquids for Gasification)	7,455	20,487	34,729	40,748	26	51	66	65
Total Oil	**28,503**	**39,989**	**52,841**	**62,371**	**100**	**100**	**100**	**100**
Oil Imports to Balance—MMB/D	3.4	9.7	16.4	19.2				
Memo: Gas Supply								
Domestic Natural Gas	22,388	22,421	17,906	15,474	96	95	81	69
Gas from Nuclear Stimulation	0	0	0	0	0	0	0	0
Syngas from Coal	0	0	165	494	0	0	1	2
Imports—Pipeline	950	1,000	1,600	2,700	4	4	7	12
Imports of LNG	0	200	2,300	3,900	0	1	11	17
Total Gas (Excluding Gas from Liquids)	**23,338**	**23,621**	**21,971**	**22,568**	**100**	**100**	**100**	**100**
Gas Imports—TCF/yr	0.9	1.2	3.9	6.6				

* Less than 0.5 percent.

TABLE 20

PROJECTED ENERGY BALANCE FOR UNITED STATES–HIGH ELECTRICITY CASE

	Trillion (10^{12}) BTU's/Year				Percent			
	Actual	Projected			Actual	Projected		
	1970	1975	1980	1985	1970	1975	1980	1985
Domestic Supply								
Oil–All Sources	21,048	20,735	28,229	34,656	31	25	27	28
Gas–All Sources	22,388	24,513	27,464	35,214	33	29	27	28
Hydropower	2,677	2,990	3,240	3,320	4	4	3	3
Geothermal	7	120	782	1,395	*	*	1	1
Coal & Nuclear Utilized	13,302	20,650	32,549	50,357	20	24	32	40
Total Domestic Supply	**59,422**	**69,008**	**92,264**	**124,942**	**88**	**82**	**90**	**100**
Imported Supply to Balance								
Oil Including Liquids for Gasification	7,455	13,273	6,417	0	11	16	6	0
Gas (Excluding Gas from Liquids)	950	1,200	3,900	0	1	2	4	0
Total Imported Supply	**8,405**	**14,473**	**10,317**	**0**	**12**	**18**	**10**	**0**
Total Domestic Consumption	**67,827**	**83,481**	**102,581**	**124,942**	**100**	**100**	**100**	**100**
Memo: Coal Supply	13,062	16,650	21,200	27,100	98	81	65	48
Nuclear Supply	240	4,000	11,349	29,810	2	19	35	52
Total Coal & Nuclear Available	**13,302**	**20,650**	**32,549**	**56,910**	**100**	**100**	**100**	**100**
Memo: Oil Supply								
Domestic Conventional	21,048	20,735	27,758	31,689	74	61	80	92
Syncrude from shale	0	0	296	1,478	0	0	1	4
Syncrude from Coal	0	0	175	1,489	0	0	*	4
Imports (Including Liquids for Gasification)	7,455	13,273	6,417	0	26	39	19	0
Total Oil	**28,503**	**34,008**	**34,646**	**34,656**	**100**	**100**	**100**	**100**
Oil Imports to Balance–MMB/D	3.4	6.3	3.0	0				
Memo: Gas Supply								
Domestic Natural Gas	22,388	24,513	26,746	31,604	96	95	85	90
Gas from Nuclear Stimulation	0	0	206	1,341	0	0	1	4
Syngas from Coal	0	0	512	2,269	0	0	2	6
Imports–Pipeline	950	1,000	1,600	0	4	4	5	0
Imports of LNG	0	200	2,300	0	0	1	7	0
Total Gas (Excluding Gas from Liquids)	**23,338**	**25,713**	**31,364**	**35,214**	**100**	**100**	**100**	**100**
Gas Imports–TCF/yr	0.9	1.2	3.9	0				

* Less than 0.5 percent.

Chapter Three
Energy Demand

Introduction

In conjunction with the preparation of many different energy supply cases, this second phase of the energy study has developed alternative projections of demand based on different sets of assumptions with respect to economic, political and social conditions. The main steps of the analysis are (1) selection of the more significant factors that will be used in variant analyses, (2) estimation of the likely ranges of those factors, (3) measurement of the sensitivities of energy demand to the factors (e.g., price, economic growth, etc.), and (4) combination of the many alternatives into several "scenarios" of future energy demand. Wherever feasible, the estimates are expressed in quantitative terms.

The quantitative projections and conclusions deal with likely circumstances and practical, achievable results. Theoretically, if consumers were forced by government edict to alter radically their modes and standards of living, large decreases in energy consumption could be achieved. However, it is unlikely that the public would support such a course of action. Therefore, the impacts of supply disruptions and mandatory regulation have been discussed primarily in qualitative terms, with the important exception of environmental controls.

Summary and Conclusions

The Initial Appraisal indicated that U.S. energy consumption would grow at an average rate of 4.2 percent per year during the 1971-1985 period and that the United States probably would face increasingly tighter energy supply and higher energy costs during the period. The present study has adopted the 4.2-percent growth rate as a base case and has analyzed the potential variations in future energy demand under different sets of assumptions than those used for the Initial Appraisal. The following variables were deemed to be the most significant long-range determinants of energy demand: (1) economic activity (GNP), (2) cost of energy (including cost-induced efficiency improvements), (3) population, and (4) environmental controls.

The four selected parameters, in combination, seem to explain most of the past changes, in energy demand, as indicated by special background studies. The sensitivities of energy demand to each of these parameters were estimated for each market sector, and the parameters were varied systematically around the Initial Appraisal estimates. In this manner, a series of energy demand cases were developed for different sets of assumptions. Since the number of possible variations is extremely large, two projections were selected for each of the four variables that would bracket most of the likely energy demand cases. They are called the "high" and "low" energy demand cases, and the Initial Appraisal projection of energy consumption, which falls between these two cases, is termed the "intermediate" demand case.

Simultaneous consideration of more than one parameter—for the United States and for each market sector—must be done on a judgmental basis because the parameters are not entirely independent of each other. For example, it is believed that conditions leading to very stringent environmental standards (which are characteristic of the high demand case) probably would be associated with low economic growth and high energy costs, which are characteristic of the low case. Furthermore, it is unlikely that all factors would reach their "lows" and their "highs" simultaneously. Table 21 presents a likely summary for the United States which takes such relationships into account.

A probability analysis indicated that approximately 85 percent of the possible variations would fall within the high-low ranges shown in Table 21. Breakdowns of these ranges, by major consuming

TABLE 21

PROJECTIONS OF U.S. TOTAL ENERGY DEMAND UNDER THREE DIFFERENT SETS OF ASSUMPTIONS

	Growth Rate (Average Annual % Gain)			Volume (Quadrillion BTU's)	
Case	1970-1981	1981-1985	1971-1985	1980	1985
High	4.5	4.3	4.4	105.3	130.0
Intermediate (Initial Appraisal)	4.2	4.0	4.2	102.6	124.9
Low	3.5	3.3	3.4	95.7	112.5

sector, appear in Table 22. While these are considered to be the probable ranges of demand based on the variables deemed to be the most significant long-range determinants of energy demand, there are many other possibilities.

The estimates shown in Tables 21 and 22 are based on the assumption that the Nation will continue to rely on private enterprise and free consumer choice; they do not contemplate reduced energy consumption because of supply limitations or political decisions. In such cases, growth rates for energy and economic activity would be much lower, and achievement of important social goals such as full employment, higher standards of living and improvements in the environment, would be seriously impeded.

A substantial portion of the reduction in energy consumption shown in the low case is estimated to result from improved efficiency of energy use initiated by consumers in response to higher costs and improved technology. Additional forced reductions in energy consumption would lower economic growth and/or reduce consumer satisfaction. A few simple examples from the several consuming sectors which serve to illustrate these distinctions are shown in Table 23.

Economic and Social Trends

This section discusses some of the basic economic and social forces that will affect energy demand in the future. Although many of these background conditions can only be evaluated qualitatively, they will help to explain the likely variations of the specific parameters and their future relationships to energy demand.

General

The Nation's life-style is perhaps the most fundamental determinant of energy demand. While this influence is apparent only over a long period of time, the transformation in life-styles that is expected to occur during the period under study will influence both the level of GNP and the relationship of energy consumption to economic activity.

Future life-styles in the United States will influence and, to some degree, be conditioned by the following factors: (1) urban development (including transportation systems); (2) the rapidity of technological and social change; (3) communication systems; (4) demographic changes; and (5) the relationships among environment, population and industry. Although there could be an infinite variety of "mixes" of these factors, this report focuses on high and low variations in energy demand from the base or intermediate level established in the Initial Appraisal.

Extreme modifications of life-style are not very likely by the year 1985, although the beginnings of change are already evident. Despite a great deal of dissent from existing social, political and economic institutions, substantial changes in living habits during the period through 1985 are precluded by long-established living patterns and the complexities associated with social and economic change.

TABLE 22

VARIANT PROJECTIONS OF U.S. ENERGY DEMAND*
BY MAJOR CONSUMING SECTOR

	Demand Volume—Quadrillion BTU's						
	1970	1980			1985		
	Actual	Low†	Intermediate	High†	Low†	Intermediate	High†
Residential/Commercial	15.8	21.1	22.4	23.4	23.9	26.6	28.5
Industrial	20.0	24.7	26.8	27.2	27.1	30.9	31.9
Transportation	16.3	23.0	23.9	24.4	26.7	28.3	29.0
Electricity Conversion	11.6	20.7	22.8	23.5	26.7	30.2	31.4
Non-Energy	4.1	6.2	6.7	6.8	8.1	8.9	9.2
Total	**67.8**	**95.7**	**102.6**	**105.3**	**112.5**	**124.9**	**130.0**

	Growth Rates—Average Annual Percent Change						
	1960-1970	1970-1980			1980-1985		
	Historical	Low†	Intermediate	High†	Low†	Intermediate	High†
Residential/Commercial	4.0	3.0	3.6	4.0	2.5	3.5	4.0
Industrial	3.4	2.1	2.9	3.1	1.9	2.9	3.2
Transportation	4.2	3.5	3.9	4.1	3.0	3.4	3.5
Electricity Conversion	7.2	5.9	6.9	7.3	5.2	5.8	6.0
Non-Energy	3.4	4.3	5.1	5.3	5.5	5.9	6.2
Total	**4.3**	**3.5**	**4.2**	**4.5**	**3.3**	**4.0**	**4.3**

* Electricity is allocated to each consuming sector and is converted at 3,412 BTU's per KWH and included in the total energy demand for the appropriate sector; the energy used by utilities for generation is shown in the Electricity Conversion category. The following figures show a reconciliation of electricity demands in these sectors with the total electric utility energy inputs, for the intermediate case only:

Demand Volumes—Quadrillion BTU's	1970	1980	1985
Residential/Commercial	2.8	5.7	7.8
Industrial	2.3	4.4	6.3
Transportation	—	0.1	0.1
Electricity Conversion	11.6	22.8	30.2
Total Utility Inputs	**16.7**	**33.0**	**44.4**

† Based on the variables deemed to be the most significant long-range determinants of energy demand.

Urban Development

More than two-thirds of the U.S. population now lives in urban areas and this ratio is growing. Nevertheless, the urban development of the past few decades apparently has created a society and life-style that is unsatisfactory for large segments of the population—particularly those living in the "central cities." Although practical programs for improving urban living are still in very rudimentary stages, several possible future trends are reflected in the three demand cases.

One possibility is that the "urban sprawl" could drift along as it has in the past, creating greater traffic congestion and central city decay. If present trends continue, increasingly serious bottlenecks are likely to appear after 1985 in the movement of goods, as well as people, within and between urban areas because there will be a precarious dependence on motor transportation. This development would help to generate the high energy demand case.

At the other extreme, some progress could be

TABLE 23

METHODS OF REDUCING ENERGY CONSUMPTION

Result	More Efficient Use	Arbitrary Reduction in Use
Lower home fuel consumption	Better home insulation	Lower room temperature
Lower automotive fuel consumption	Increased engine fuel economy	Reduced automobile trips
Lower factory use of fuel	Installation of better machinery	Reduced factory output
Lower electric fuel requirement	Improved power plant heat rate: same light, same air conditioning	Reduced electricity consumption: less light, less air conditioning

made by 1985 toward the development of intermediate-size cities, separated by green belts but closely connected by high speed mass transit suitable for moving freight as well as passengers. Urban planning that would coordinate the various modes of transportation, such as highways, waterways, pipelines and underground mass transit, would be an objective for this scenario. Achievement of such a system probably would be consistent with the low energy case up to 1985 and would be capable of supporting more economic growth and higher standards of living in the longer term.

Taking a middle ground, it might be expected that several new programs for a more rational type of urban development might get out of the "pilot plant" stage in a few years. These plans probably would include provision for more effective transportation systems for moving both passengers and freight. Programs for revival of rural communities also might be implemented. The latter development probably would tend to increase the per capita consumption of energy by dispersing the population outside the city core. Even after a viable urban program is under way, many years will pass before a significant change in life-style, and consequently energy demand, takes place.

Accelerating Change in Technology

The rate of change in technology has been accelerating, the historical evidence of which is well documented and not amplified here. Aside from being accompanied by social upheavals, this rapid technological change has had a variety of effects on energy requirements that are not easily distinguished. For a long period of time—until 1967—changes, on balance, were in the direction of more efficient energy use or at least less energy use per unit of GNP. Several of the many possible examples of higher efficiency are: (1) the trend toward lower heat rates in the production of electric power, (2) the substitution of much more efficient diesel locomotives for steam locomotives, (3) the introduction of high compression automobile engines, and (4) the replacement of coal by oil and gas for space heating and industrial processing. Such improvements more than offset trends in the other direction such as increased use of air conditioning and a growing reliance on electric power accompanied by losses in conversion and transmission.

An apparent reversal of trend was experienced from 1967 through 1970 when the use of energy increased more rapidly than did real GNP. While reasons for the reversal have not been completely identified, lack of technology and increased energy use for environmental improvement activities (the results of which are not measured by GNP) have been cited as possible causes.

In the future, these factors will continue to operate in both directions. The ultimate trend of efficiency in energy use may well be determined by the pace of technological advance. It has been contended that most of the important scientific theories have already been formulated and that new discoveries in science and technology will come more slowly in the future. If this theory proves to be correct, a high energy case would be more probable. Social or political barriers against the introduction of new production techniques also would result in high energy per unit of GNP.

There is ample evidence to indicate that technological advances (in the energy industries as well as elsewhere) will continue even if there should be little progress in fundamental sciences. Many new projects are on the threshold of commercial application, requiring mainly engineering improvements or "breakthroughs" before they can be implemented. In the area of nuclear power and other electric power systems, there are notable examples of potential energy savings but many of these will not make significant impacts until the 1980's. The intermediate case projections were based on estimates that the acceleration in technology up to 1985 would be about sufficient to offset the factors working toward higher energy consumption per unit of GNP, including energy used for environmental improvement and a greater proportionate use of electric power.

Population

The trend toward a slower population growth rate and smaller family sizes definitely will have an impact on life-style, although the results may not be as pictured in some of the environmental concepts. Some of these environmental theories associate lower population growth with low economic growth, a concept which may not necessarily prove to be correct. There are many other factors causing economic growth—labor productivity, capital formations and technological progress, for example — which have greater impact on GNP growth rates than do the population factors. In fact, population change has its greatest impact through its influence on the age groups of the labor force; the current low birthrates will not significantly affect the labor force until after 1985. Up to 1985, the prognosis is for smaller, more affluent families and greater population mobility. This demographic outlook indicates a high economic growth, high energy consumption society.

Environment versus Economic Growth

The desire on the part of society to control the adverse ecological effects of expanding industry and population has been slow to emerge, and it is generally acknowledged that there is a large backlog of corrections to be made. Such corrections, plus conformity to high environmental standards in the future, will require large amounts of energy, as described in the "Energy for Environmental Improvement" section of this chapter. The energy volumes reflected in the intermediate case were judged to be sufficient to meet the environmental standards under consideration in mid-1971 when the case was developed. Since that time, however, considerably more rigorous limits on pollution have been proposed. The high demand case includes the energy requirements to meet those more stringent standards which society may adopt.

Proponents of the zero growth concept disregard the fact that the attainment of other social goals and other backlogs of social needs such as adequate housing, jobs and education would be sacrificed if economic growth were depressed. The successful functioning of the competitive enterprise/freedom-of-consumer-choice system, in effect, depends on profits and economic growth. These other important national policies, therefore, appear to rule out the possibility that the United States will choose to be regimented into a zero economic growth society and the life-style that would accompany it. Instead, some means must be found to make current systems reasonably compatible with the ecological objectives.

There are no automatic trade-offs between economic growth and anti-pollution in a free society. We could get "high pollution" with "low growth" because a poor economy with high unemployment is likely to make the capital expenditures that would be necessary to use energy more efficiently. Recycling solid wastes and purifying air and water are operations requiring technology, capital and energy—inputs that are more available in a growth economy.

The analysis in this report gives a very low probability to the projections that there will be immutable, finite limits on growth for this generation. The major ecological abuses probably could be corrected by 1985 with the expenditure of 2 to 3 percent of the GNP and 8 to 9 percent of the energy consumption. The latter corresponds roughly to the energy volumes included in the high case for environmental factors shown in Table 31. These measures do *not* provide for a broader interpretation of environmental deterioration which includes such problems as urban decay.

Demand Variability Analysis

The following procedure was used for developing three cases for the U.S. energy demand outlook based on different economic and social conditions. The major factors in the long-term energy demand outlook were identified as economic growth, cost of energy (including cost-induced efficiency improvements), demographic changes and the use of energy for environmental control. These variables (or parameters) were analyzed with respect to their effects on energy demand within the following market sectors: (1) residential/commercial, (2) industrial, (3) transportation, (4) electricity, and (5) non-energy uses.

Specific values or guidelines were established for the parameters in order to determine the high, intermediate and low energy demand cases. The environmental control factor could not be assigned very precise quantitative ranges for each sector. However, since this factor is considered to be one of high significance, it is analyzed separately in a later section entitled "Energy for Environmental Improvement." Although the guidelines usually are specific, as described in the following paragraphs, their impacts on energy demand in various markets frequently had to be evaluated on the basis of judgment and experience.

The Initial Appraisal, or the intermediate case, projected total energy demand at an average growth rate of almost 4.2 percent per year between 1970 and 1985, and the major background assumptions that were used for that case were as follows:

- Sustained economic growth—growth in real GNP at a rate of 4.2 percent
- Slower population growth—1.1 percent per year average growth during the 1970-1985 period*
- Increased energy use for environmental development—increasing from about 2 percent in 1970 up to 4 to 5 percent of total energy consumption in 1980-1985
- Little change in "real" prices for energy
- Development of improved technology for fuel substitutions
- Growth in energy demand not restricted by capital limitations or other restrictions on total energy supplies.

Low and High Case Guidelines

Demand sensitivities are very difficult to project with confidence. Historical analogy provides relatively little guidance in estimating sensitivity to energy cost, for instance, because during the past two decades the overall trend of real energy costs has been declining, while energy costs are expected to rise in the future. Therefore, in projecting the response of energy demand to changes in economic conditions, it is necessary to use detailed information on the various markets in addition to rigorous analyses of past data.

The immediate impacts on energy demand of changes in government policy, price technology and other factors generally are minor because obsolescence of equipment and modifications in consuming patterns usually require many years before taking full effect. For this reason, it seemed appropriate to measure demand periods, i.e., 1970-1980 and 1970-1985.

Economic Growth Assumptions

In the sensitivity analysis, changes in energy demand were related to variations in economic growth rates for real GNP, real personal income and industrial production. It was concluded that the future growth rate for real GNP, averaged for the 15-year period, would probably fall within the range of 3.2 percent to 4.4 percent per year. The former rate was used for the low energy demand case and the latter rate for the high demand case. Real personal income and industrial production were assumed to vary proportionately to variations in real GNP.

Cost of Energy, Including Cost-Induced Efficiency Improvements

A competitive price system provides the most efficient means of adjusting demand to supply without seriously retarding economic activity. In connection with essential energy uses, however, the effects of the price factor are gradual and very difficult to measure. Although a higher cost of energy probably causes some immediate reduction of consumption, the more important and long-term effect comes about by inducing consumers to purchase more efficient equipment and to use energy more efficiently. The energy saving can be accomplished in many ways, including the following: improved insulation for buildings, improved heating and cooling systems, more efficient industrial plant and equipment, and smaller and/or

* Census Series D (August 1970).

more efficient vehicles. Conversely, a lower cost of energy may delay the introduction of fuel-saving equipment and lead to higher consumption.

The cost guidelines were established first for the primary markets (defined as oil and gas at the wellhead, coal at the mine, etc.) and were subsequently translated into guidelines for consumer markets. A given price change in primary markets (assuming no inflation) would result in much smaller percentage changes in the higher priced consumer markets, and the percentage changes generally will be smaller the farther the consumer is from the primary market. Thus, a $1-per-barrel increase in the price of crude oil would be about a 30-percent increase at the wellhead. However, it would affect the industrial market by about half that percentage, and it would raise motor fuel cost by an even smaller percentage.

Table 24 summarizes the assumptions on cost ranges and translates the "primary" price changes into consumer price ranges which are more relevant to demand sensitivity analysis.

TABLE 24

ASSUMED PERCENTAGE CHANGES IN COST OF ENERGY—1970-1985
(Constant 1970 Dollars)

	Energy Demand Case		
Type of Market	High	Intermediate	Low
Primary Energy Cost	- 10 %	No Change	+ 100%
Consumer Costs			
Residential/ Commercial	- 2.5%	No Change	+ 25%
Industrial	- 5 %	No Change	+ 50%
Transportation	- 2.5%	No Change	+ 25%
Electric Utility	- 5 %	No Change	+ 50%
Non-Energy	- 5 %	No Change	+ 50%

The sensitivities of energy demand were estimated for the assumed percentage changes in energy cost in each major consuming sector. The high energy demand case is generated by a 10-percent decline in the primary market price, the intermediate demand case is associated with "no change" in price, and the low demand case is obtained with a 100-percent increase.

Population

The term "population" is used as a proxy for all the demographic factors such as age distribution and immigration. The guidelines for the assumptions used in the high, intermediate and low demand cases were the Bureau of the Census Population Series C, D and E,* which projected population growth at average annual rates of 1.3 percent (Series C), 1.1 percent (Series D) and 1.0 percent (Series E) for the 1970-1985 period.

Energy Requirements for Environmental Improvement

The demand projections in the intermediate case (Initial Appraisal) included large amounts of energy that were expected to be used for air and water purification and for treatment of solid wastes. As mentioned earlier, the sum of these requirements equaled about 2 percent of total energy demand in 1970 and were projected to be about 4 to 5 percent of the total demand in the 1980-1985 period.

A sensitivity range has been estimated for this factor which reflects (1) considerably more rigorous standards and early imposition of such standards for the high case and (2) less strict standards (relative to the intermediate case) and more time to conform with regulations for the low case.

Conclusions for Total United States

Table 25 shows the results of the sensitivity analyses for each parameter for all consuming sectors combined. The next five sections will summarize the conclusions as they apply to each of the major individual energy markets—residential/commercial, industrial, transportation, electricity conversion and non-energy.

Residential / Commercial

Taking into account possible variations in the economy, population trends, energy cost and environmental considerations, it was estimated that growth in energy demand in the residential/commercial sector might range between a continuation of the 4.0-percent average annual rate of the 1960's, which would represent the high demand case, and a growth rate of only 2.8 percent per

* Published August, 1970.

TABLE 25

SENSITIVITY ANALYSIS FOR TOTAL ENERGY DEMAND IN 1980 AND 1985—ALL MARKET SECTORS
(Quadrillion BTU's)

Parameter	1980 Low	1980 Intermediate	1980 High	1985 Low	1985 Intermediate	1985 High
Economic Growth Rate (Real GNP)						
Demand	94.8	102.6	104.3	111.0	124.9	128.1
% Change *vs.* Intermediate	(7.6)	—	1.7	(11.1)	—	2.6
Cost of Energy Including Cost-Induced Efficiencies						
Demand	98.5	102.6	102.6	116.4	124.9	125.4
% Change *vs.* Intermediate	(4.0)	—	—	(6.8)	—	0.4
Population Expansion Rate						
Demand	101.4	102.6	103.3	122.8	124.9	126.3
% Change *vs.* Intermediate	(1.2)	—	0.7	(1.7)	—	1.1
Energy for Environmental Improvement						
Demand	101.4	102.6	105.3	122.8	124.9	130.6
% Change *vs.* Intermediate	(1.2)	—	2.6	(1.7)	—	4.6

year for the low case. Compared with the Initial Appraisal, the higher growth rate would increase residential/commercial requirements 1.9 quadrillion BTU's in 1985 (7 percent), whereas the slower rate would reduce 1985 requirements 2.7 quadrillion BTU's (10 percent). As shown in Table 22, the greatest impact of a slower growth in demand would come in the latter part of the 1970-1985 period (see Table 26 for details).

In the Initial Appraisal, it was concluded that many of the factors that caused the residential/commercial sector to grow at a rate of 4 percent per year over the past decade will be operating in the future. Large increases are expected in new households, labor force and family income, and a continuing shift of population to the suburbs or to satellite towns is anticipated. Shopping centers, service facilities and recreational activities are anticipated to expand rapidly, all of which will help to stimulate the growth in energy demand.

Several new conditions will tend to retard growth in the residential/commercial energy market: (1) The population mix is trending toward larger proportions of young adults, (2) there are fewer children per family, and (3) real costs of land and construction have risen substantially. These factors suggest that the recent trend toward smaller dwelling units will continue throughout the 1970's. It is expected that new housing units will include a much larger proportion of apartments, in sharp contrast to conditions of the past 20 years when most new units were single-family dwellings. In the intermediate case, the net impact of these opposing forces results in a 3.6-percent rate of increase for residential/commercial energy consumption over the 15-year projection period.

In making sensitivity analyses of the impact of various factors on energy growth in the residential/commercial sector, the following specific parameters were investigated: (1) population trends, (2) economic activity, (3) energy costs (including induced efficiencies), and (4) energy associated with environmental standards. Each of these is discussed in the following paragraphs, with the exception of the environmental factor which is expected to have only a minor effect on residential/commercial energy use.

In general, changes that would tend to raise demand in this sector are expected to have less of an impact on energy consumption than changes

TABLE 26

SENSITIVITY ANALYSIS FOR TOTAL ENERGY DEMAND IN 1980 AND 1985
RESIDENTIAL AND COMMERCIAL DEMAND (INCLUDING ELECTRICITY*)
(Quadrillion BTU's)

Parameter	1980 Low	1980 Intermediate	1980 High	1985 Low	1985 Intermediate	1985 High
Economic Growth Rate (Real GNP)						
Demand	21.5	22.4	22.9	24.8	26.6	27.4
% Change *vs.* Intermediate	40.0	–	2.2	(6.8)	–	3.0
Cost of Energy Including Cost-Induced Efficiencies						
Demand	21.6	22.4	22.4	24.8	26.6	26.6
% Change *vs.* Intermediate	(3.6)	–	–	(6.8)	–	–
Population Expansion Rate						
Demand	22.2	22.4	22.8	26.1	26.6	27.4
% Change *vs.* Intermediate	(0.9)	–	1.8	(1.9)	–	3.0
Energy for Environmental Improvement						
Demand	22.4	22.4	22.5	26.6	26.6	26.9
% Change *vs.* Intermediate	–	–	0.4	–	–	1.1

* Electricity is converted at 100-percent efficiency (or 3,412 BTU's per KWH), and the energy used by utilities for generation is shown in the electricity conversion sector in Table 29.

that would reduce demand. The estimated possible reduction in demand in 1985 is 15 percent compared with a possible increase of 7 percent. This is the case because the Initial Appraisal contained a relatively high use of energy in this sector, and there are diminishing returns for the use of energy by households. The negative influences would have a greater impact, except for the fact that a substantial proportion of residential/commercial energy consumption falls into the "necessity" classification in this country.

Variations in population projections are caused primarily by different assumptions regarding future birthrates. Changes in the birthrate would have a relatively small impact on residential/commercial energy demand in the next 15 years for several reasons. A main element in demand—numbers of households—is determined by the past, not the future, birthrate. A further reduction in the birthrate probably would emphasize the anticipated trend toward smaller housing units, but it would also point to more money available for non-essential consumption such as air conditioning, electric heat and other electric appliances. Conversely, larger families might mean larger, single family houses (which are generally less efficient energy users in terms of consumption per dwelling unit) and more electricity for household appliances such as laundry equipment, but less discretionary income for luxury items requiring electricity to operate them. Compared with the Initial Appraisal, it is estimated that the lower birthrate assumption (Census Series E) would reduce residential/commercial demand 0.5 quadrillion BTU's in 1985 (1.9 percent) whereas the higher birthrate (in Census Series C) would raise requirements 0.8 quadrillion BTU's (3.0 percent) in 1985.

The Initial Appraisal assumed a 4.2-percent average annual increase in real GNP over the next 15 years. Sensitivity analyses were made for (1) a higher rate of growth in GNP, i.e., 4.4 percent per year, and (2) a slowdown in GNP growth to 3.2 percent per year, the results of which are shown in Table 26.

Historically, the growth rates of residential/commercial energy consumption and GNP have been parallel. However, in the past, real energy costs were declining, and it is thought that this fact had some influence on the relationship with GNP.

Short-term variations in the economy would not have a substantial impact on residential/commercial energy consumption because in this country much of the energy used in this sector is classified as essential (e.g., heating, cooking, hot water and lighting). The main fluctuations would come in the use of electricity (e.g., air conditioning) and in the commercial sector. In contrast, longer term shifts in the level of disposable income are important determinants of energy consumption in this sector. A slowdown in GNP growth would have a greater impact on consumption than a higher rate of increase in GNP because there are diminishing returns on the application of energy for appliances in this sector.

In summary, it was estimated that the higher growth rate for GNP would raise 1985 residential/commercial energy requirements by 0.8 quadrillion BTU's (3.0 percent) and that the slower GNP growth would reduce requirements by 1.8 quadrillion BTU's (6.8 percent).

In the Initial Appraisal, it was assumed that real energy prices would remain fairly stable in the future in contrast to declining prices in the past. In this report, the price range guidelines used to estimate sensitivities were (1) low demand case, based on an increase of 25 percent in consumer prices, stemming from a 100-percent increase in primary energy costs and (2) a high demand case assuming a 2.5-percent decrease in real energy costs to the consumer caused by a 10-percent decrease in primary energy costs. It is believed that there is a much greater probability of significant price increases rather than decreases over the period encompassed by this analysis. This accounts for the large upward price variation. It was concluded that the small decline in energy costs would have no measurable impact on demand in this sector but that a 25-percent increase in energy cost to the consumer by 1985 would reduce residential/commercial consumption by 1.8 quadrillion BTU's, or 6.8 percent.

The conclusion that residential/commercial energy demand is relatively insensitive to price changes is supported by an econometric analysis of historical data. The analysis (to be described in the Energy Demand Task Group's report on methodology) indicates a price elasticity of about –0.4 which is reasonably close to the task group consensus described above. This means that a 10-percent increase in energy cost would result in a relatively small 4-percent drop in energy use, other things being equal.

Lower energy costs would provide some extra stimulus for purchasing and using electrical appliances, air conditioning and electric heat. However, rapid growth in these items is expected with stable prices, so it is doubtful that very gradual declines in prices would add much to demand. The impact of higher costs would, however, be more noticeable. The greatest savings in energy would result from more widespread use of insulation and improved heating/cooling systems, which would become more economically attractive with rising energy costs. Also, higher energy prices probably would lead to more efficient temperature controls, thus tending to restrain growth in energy used for air conditioning and heating.

Industrial

Historically, the net effect of the factors influencing industrial energy use has tended to favor greater efficiency, causing the demand for energy to grow more slowly than industrial output. While strong efficiency factors will continue to operate in the future, many have reached the point of diminishing returns, and gains in efficiency of energy use are expected to be more modest in future years. Some of the more important elements in the trend towards more efficient energy use were identified and discussed at length in the Energy Demand Task Group report for the Initial Appraisal.*

The most important influence on the future consumption of industrial energy is the rate of industrial production as measured by the Federal Reserve Board Index of Industrial Production (FRB). The industrial production rate in turn is closely linked to GNP growth. If GNP were to increase more or less rapidly than the Initial Appraisal projection, there would be a very noticeable impact upon industrial energy consumption.

* NPC, *U.S. Energy Outlook, An Interim Report, An Initial Appraisal by the Energy Demand Task Group 1971-1985* (April 1972).

The Initial Appraisal indicated that a 1.0-percent change in FRB or GNP would change industrial energy consumption by about 0.8 percent. The many factors that have influenced this relationship between the FRB and energy in the past and those that might change it in the future were carefully analyzed and weighed in order to determine the possible variations in industrial energy demand.

Table 27 shows the impact of the range of alternative economic growth rates considered in this study upon industrial energy consumption. In the guidelines, it was assumed that the low GNP growth rate would be 1.0 percentage point below the 4.2-percent rate of the intermediate case while the high GNP rate would be only 0.2 percentage points above the intermediate case. The energy demand range reflects the same imbalance. In 1985, for example, the low case for economic growth would reduce energy demand by 3.6 quadrillion BTU's or 11.7 percent while the high case would show energy consumption higher by 0.6 quadrillion BTU's, or 1.9 percent.

Another major determinant of industrial energy consumption is its cost. The effects of rising energy costs on energy consumption are particularly strong in the industrial market where energy, capital goods and labor compete over the long term as inputs in the industrial production process.

In order to determine the impact of the energy cost factor on future industrial energy consumption, it is necessary to estimate not only the price elasticity. It is also important to determine future changes in the prices and in other inputs, such as industrial labor and capital, so that the direction and degree of substitution can be determined. These estimates are important since competition in the future undoubtedly will be centered increasingly on cost reduction. Greater productivity is essential if the international competitive position of the United States is to be improved.

TABLE 27

SENSITIVITY ANALYSIS FOR TOTAL ENERGY DEMAND IN 1980 AND 1985
INDUSTRIAL (INCLUDING ELECTRICITY*)
(Quadrillion BTU's)

	1980			1985		
Parameter	Low	Intermediate	High	Low	Intermediate	High
Economic Growth Rate (Real GNP)						
Demand	24.5	26.8	27.1	27.3	30.9	31.5
% Change *vs.* Intermediate	(8.6)	—	1.1	(11.7)	—	1.9
Cost of Energy Including Cost-Induced Efficiencies						
Demand	25.4	26.8	26.8	28.4	30.9	31.1
% Change *vs.* Intermediate	(5.2)	—	—	(8.1)	—	0.6
Population Expansion Rate						
Demand	26.3	26.8	26.9	30.2	30.9	31.1
% Change *vs.* Intermediate	(1.9)	—	0.4	(2.3)	—	0.6
Energy for Environmental Improvement						
Demand	26.3	26.8	27.8	30.0	30.9	32.9
% Change *vs.* Intermediate	(1.9)	—	3.7	(2.9)	—	6.5

* Electricity is converted at 100-percent efficiency (or 3,412 BTU's per KWH), and the energy used by utilities for generation is shown in the electricity conversion sector in Table 29.

It is likely that the real cost of labor will rise more rapidly than the cost of capital. Trends toward a shorter work week and shorter working careers due to longer schooling and earlier retirement are factors that will contribute toward a higher price for labor. Rising employment in government and service industries combined with changing work attitudes may make productivity gains more difficult, while more liberal pension plans and higher payroll taxes will tend to increase unit labor costs.

The dramatic change, however, is expected to be in energy costs which may trend upward very rapidly, increasing industrial energy costs disproportionately. The industrial community will no longer be a beneficiary of regulated underpriced natural gas and low-priced coal and imported fuel oil, as all of these commodities are headed toward sharply increased prices. Moreover, industrial users of oil and coal will be required to invest in equipment to reduce atmospheric emissions, adding further to real energy costs. Increased reliance on electric power will provide no cost relief since rising power plant construction and operating costs (including fuel costs) will result in higher electricity prices. It is anticipated that these higher prices will be reflected in industrial power rates.

The combined effect of higher labor and energy costs on industrial energy demand probably would be twofold. First, greater incentives and opportunities to substitute capital for labor would indirectly tend to reduce energy requirements per unit of output. This is because new equipment is generally more efficient in terms of both labor and mechanical energy per unit of product than the equipment or process replaced. Second, rising energy costs would directly discourage energy use. There are, of course, practical limits to this type of substitution, and, as mentioned earlier, many of the efficiency factors which have operated in the past may have reached the point of diminishing returns. However, an in-depth look at the industrial sector shows that, given the incentive of rapidly rising energy costs, numerous opportunities to conserve energy still exist. It seems likely that the use of energy in industry currently is not at equilibrium levels because of lags in equipment replacement. As energy costs rise, therefore, substantial reductions in industrial energy demand per unit of output could be expected. Earlier retirement of the existing inefficient stock of capital equipment and production facilities will be encouraged by the higher energy costs.

In an attempt to quantify the effects of price variations on industrial energy consumption, econometric models were developed to try to determine such price elasticities. The results of testing these models tended to substantiate the hypothesis that increases in the costs of labor would result in capital substitution and decreased energy usage. For example, during the recent historical period, sharp increases in labor costs relative to other costs caused a shift to more capital-intensive production which was more efficient in terms of both energy and labor use. Conversely, if the cost of capital goods should rise, energy usage would be higher since there would be less incentive to introduce newer energy conserving machinery.

The econometric analysis indicated a point elasticity of demand for industrial energy with respect to energy cost of approximately −0.4. This response in energy consumption to energy prices appears to be a reasonable reflection of the relatively inelastic industrial energy demand *over the time period considered.* Other methods yielded somewhat higher price elasticities, particularly in the long run. On the other hand, the task group concensus of demand variability (shown in Table 27) is based on a slightly lower price elasticity for the specified range.

Possible impacts of changes in population growth rates on industrial energy requirements were considered. An alteration in the rate of population growth would directly affect the demand for consumer goods which, in turn, would modify consumption. The growth rate of the labor force, however, is more significant, and this is affected primarily by the birthrate only after a 15-year lag. It is estimated that a shift from Census Series D, assumed in the Initial Appraisal, to Series E would depress the annual rate of increase in industrial energy requirements by only a very small percentage in the 1970-1985 period. The potential increase in consumption as a result of faster population growth is even smaller.

Transportation

In the Initial Appraisal, the consumption of energy for transportation was projected at a gradually declining rate averaging 3.7 percent per year for the 1970-1985 period. This decline, relative to the 4.2 percent per year growth rate of the 1960's, was attributed to lower birthrates, smaller families, a more "saturated" car market and larger proportions of economy cars.

The current phase of the energy study is concerned with the possible deviations from that original projection and the reasons for such variations. The findings summarized here were developed by analyzing the components of energy consumption in transportation markets (cars, trucks, aviation, water transportation, railroads, etc.) and estimating the sensitivities of each component to the four major parameters that have been described in earlier sections.

Looking at the broad picture, the long-term changes in motor fuel consumption (which is by far the largest component) have correlated very closely with real GNP (and disposable personal income), even though there have been marked changes in demographic factors, driving habits, type of vehicles, fuel quality, highway conditions and alternative forms of transportation. The other categories of transportation energy show a variety of relationships to economic growth because of shifts in consumer and military demands and technological change. Aviation demand for fuel has increased sharply while railroad and shipping requirements have been relatively stable. The estimated total transportation demand sensitivity to real GNP (and disposable personal income) is indicated by the ratio of 0.6-percent change in demand for each 1.0-percent change in GNP.

Assuming other conditions unchanged, the low case for economic growth would reduce the 1985 estimate of transportation energy demand by 2.1 quadrillion BTU's (or 7.4 percent) below the intermediate case level, and the high case would raise demand by 0.7 quadrillion BTU's (2.5 percent). The demand sensitivities for economic growth as well as for the other parameters are summarized in Table 28.

According to the overall guidelines, the primary energy costs (i.e., costs at the wellhead, mine mouth, etc.) in 1985 are assumed to reach 100 percent *above* the 1970 level for the low demand

TABLE 28

SENSITIVITY ANALYSIS FOR TOTAL ENERGY DEMAND IN 1980 AND 1985
TRANSPORTATION (INCLUDING ELECTRICITY*)
(Quadrillion BTU's)

	1980			1985		
Parameter	**Low**	**Intermediate**	**High**	**Low**	**Intermediate**	**High**
Economic Growth Rate (Real GNP)						
Demand	22.7	23.9	24.3	26.2	28.3	29.0
% Change *vs.* Intermediate	(5.0)	—	1.7	(7.4)	—	2.5
Cost of Energy Including Cost-Induced Efficiencies						
Demand	23.2	23.9	23.9	26.8	28.3	28.3
% Change *vs.* Intermediate	(2.9)	—	—	(5.3)	—	—
Population Expansion Rate						
Demand	23.6	23.9	24.0	27.8	28.3	28.5
% Change *vs.* Intermediate	(1.3)	—	0.4	(1.8)	—	0.7
Energy for Environmental Improvement						
Demand	23.7	23.9	24.7	27.9	28.3	29.8
% Change *vs.* Intermediate	(0.8)	—	3.3	(1.4)	—	5.3

* Electricity is converted at 100-percent efficiency (or 3,412 BTU's per KWH), and the energy used by utilities for generation is shown in the electricity conversion sector in Table 29.

case and 10 percent *below* the 1970 level for the high case. Such primary cost changes, of course, would result in smaller percentages in the prices that consumers pay for transportation energy. Thus, the 1985 cost variation at the consumer level would range from +25 percent for the low case to –2.5 percent for the high case, relative to 1970. Most of the following discussion will be concerned with the low case because it was concluded that a decrease in price as small as 2.5 percent would have a negligible effect on demand.

There are several reasons why transportation fuel demand is not likely to be very sensitive to fuel price changes in the short run. They are:

- The consumer regards most automobile mileage to be fairly essential although he may change the type of car.
- The cost of gasoline and oil is only about one-fourth of the total cost of operating a private car.
- In the case of commercial transportation such as trucking, railroads and airlines, the fuel requirements are essential elements of the business.

For the long run, it has been estimated that there will be some transportation energy demand/cost elasticity as a result of the following conditions:

- Although fuel cost is not the major item in the total cost of owning and operating a car, it is an out-of-pocket and highly visible cost. Therefore, it is likely to carry a disproportionate weight in consumer decisions.
- The higher cost of motor fuel is one of a package of economic inducements that would cause consumers to buy economy cars. Because of the difficulty of separating the components of this package, the sensitivity of energy demand to the use of economy cars has been included in this parameter.
- In commercial transportation, the cost of fuel is important enough to play a significant role in operator's decisions relative to type of new equipment and timing of its purchase. In other words, it was thought that a 25-percent rise in the real price of fuel would provide a strong inducement to junk old, inefficient equipment and to emphasize fuel efficiency in new equipment.

The Initial Appraisal, or intermediate case, assumed that there would be a mix of 90 million standard cars and 50 million economy cars in 1985—a ratio of 65:35 compared to 86:14 in 1970. For the low energy demand case, the task group estimated a 1985 mix of about 70 million standards to 70 million economy cars, or a 50:50 ratio. In the high demand case, the mix would differ very little from that of the intermediate case.

Such change in the mix of the car population is the largest factor in the cost-sensitivity calculation. In addition, there would be a small decrease in driving mileage and some efficiency improvement in commercial vehicle and aircraft efficiencies if fuel costs were considerably higher. Generally speaking, transportation energy demand is not highly sensitive to changes in the costs of fuel. Referring again to Table 28, the column for low demand in 1985 shows a reduction of 5.3 percent in energy consumption as a result of a 25-percent increase in the real cost of transportation energy and the increases in numbers of economy cars.

Potential differences in the rate of population growth between 1970 and 1985 would not be likely to affect the consumption of transportation energy significantly, because higher birthrates would not change the "driving age" groups during this period. As shown in Table 28, a shift in the assumptions to the faster population growth of Census Series C would increase the 1985 energy consumption in this sector by less than 1.0 percent. Likewise, a shift down to Census Series E would decrease 1985 energy consumption by only 1.8 percent.

Electricity Conversion

Electricity conversion refers to the energy loss that occurs in the utility plant when fuels are converted into electric power.* In the intermediate case, it was estimated that the heat loss in converting fuels into electricity would grow at a rate of 6.7 percent per year, or 0.5 percent more slowly

* 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, electric utilities are users of *primary* energy sources and suppliers of *secondary* energy. For all stages of their operation—production, transmission and distribution—approximately two-thirds of the BTU input goes into waste heat.

than electricity consumption. The difference would be the result of improvement in the "heat rate," i.e., improvement in the efficiency of processes for converting primary fuels into electricity. The variance in this sector, therefore, would be caused by the sensitivities of electricity demand and the heat rate to variations in the four major parameters.

Of the four parameters considered, the growth rate of real GNP is likely to have the greatest influence on the range of electricity consumption and on the electric utility demand for fuels. As indicated, electricity conversion losses would have to vary almost proportionately with the generating plant output because losses are equivalent to about two-thirds of the plant's energy input. This is a reason for expecting economic growth to be the main influence on the electricity conversion sector.

A *reduction* in the average annual growth of real GNP to 3.2 percent from the 4.2-percent rate of the Initial Appraisal is estimated to reduce the 1985 utility requirements for conversion by 5.3 quadrillion BTU's (17.6 percent) below the 30.2 quadrillion BTU's of the intermediate case (see Table 29). The predominant impact of a lower rate of increase in real GNP would be on the industrial and commercial consumption of electricity in the 1970-1980 period, although significant effects on residential consumption also could be expected by 1985. Part of the reduction in utility energy requirements up to 1980 (because of slowdown in demand for electricity) would be attributable to less utilization of older, thermally inefficient generating plants. This observation stems from the fact that plant expansion plans for the electric utilities are now fairly firm up to and including 1980, and any reduction in overall electric energy requirements would permit the supply of a higher percentage of total kilowatt hours (KWH) required from the more efficient facilities. By 1980, utilities presumably would have adjusted their construction programs to the new lower growth rates, and thereafter the reduction in primary energy requirements would reflect essentially the lower demand for electricity by ultimate consumers.

An increase in the annual growth of real GNP from 4.2 percent to 4.4 percent is estimated to raise the primary energy requirement for electricity conversion by 1.8 percent over the 1980 intermediate case and by 3.0 percent over the corre-

TABLE 29

SENSITIVITY ANALYSIS FOR TOTAL ENERGY DEMAND IN 1980 AND 1985
ELECTRICITY CONVERSION
(Quadrillion BTU's)

Parameter	1980 Low	1980 Intermediate	1980 High	1985 Low	1985 Intermediate	1985 High
Economic Growth Rate (Real GNP)						
Demand	20.0	22.8	23.2	24.9	30.2	31.1
% Change *vs.* Intermediate	(12.3)	—	1.8	(17.6)	—	3.0
Cost of Energy Including Cost-Induced Efficiencies						
Demand	21.8	22.8	22.8	27.9	30.2	30.5
% Change *vs.* Intermediate	(4.4)	—	—	(7.6)	—	1.0
Population Expansion Rate						
Demand	22.7	22.8	22.9	30.1	30.2	30.3
% Change *vs.* Intermediate	(0.4)	—	0.4	(0.3)	—	0.3
Energy for Environmental Improvement						
Demand	22.3	22.8	23.6	29.4	30.2	32.1
% Change *vs.* Intermediate	(2.2)	—	3.5	(2.7)	—	6.3

sponding 1985 estimate. Also, as in the case of a reduced GNP growth, heat rate effects would account for some of the change in requirements up to 1980. This would result from the short-term need to use less efficient plants to meet a large part of the increase in electricity demand since construction lead times preclude a major change in expansion programs for the base-load plants. After 1980, however, heat rates could be expected to resume their "normal" levels, and the additional utility energy requirement would result mainly from greater electricity sales. In fact, more rapid gains in efficiency should be attainable as the addition of a large number of new efficient generating plants would increase the average efficiency level of the power generation industry.

An increase of 50 percent in the cost of fuel to electric utilities by 1985 could result in as much as 2.3 quadrillion BTU's or 7.6 percent below the intermediate case projection. These reductions would result from further improvements in the efficiency of power generation and consumer efforts to reduce consumption in response to higher prices.

The potential for increasing efficiency would be extremely limited up to 1980 because of the constraints imposed on utilities by the characteristics of their existing plants (both those in service and those under construction). Some very marginal improvements might be achieved, however, through additional transmission interconnections between systems in order to make the fullest use of new low heat rate equipment, if the fuel savings involved could justify such steps. By 1985, however, a considerable improvement in efficiency may be achieved. Presumably, greater emphasis will be placed on more efficient combined-cycle generating plants and supercritical (temperature) steam plants that have higher capital costs but are more efficient in the use of fuel.

Through 1985, the consumption of energy for electricity conversion is less sensitive to variations in the population growth parameter than to any of the other three parameters being considered. A population growth equivalent to the higher Census C projections could raise requirements by only 0.3 percent above the intermediate case level in 1985. This small increase presumably would be the result of marginal increases in electricity consumption in all consuming sectors. A reduction in the population growth rate to the Census E projection would have similar minor effects on the projections of energy for electricity conversion in 1985. In fact, significant effects could be expected only in the post-1990 period.

Non-Energy and Miscellaneous

Inclusion of a non-energy category in a projection of energy consumption requires a word of explanation. The reason is that primary consumption of coal, oil and gas is measured at the wellhead or mine where these minerals are produced, and considerable volumes of these minerals wind up in chemicals, lubricants, asphalts and similar products. These are not properly called energy uses, but they must be included if the consuming sectors are to add up to the primary energy supply.

Table 30 compares the Initial Appraisal projection levels with those which result from changing the basic economic determinants—GNP, fuel costs (and cost-induced efficiencies), population and pollution controls. It is clear from Table 30 that the largest sensitivities result from changes in real GNP and energy costs. In part, this is a result of the judgment that substantial deviations from intermediate case levels of GNP and price are considered realistic or at least relevant for study, and to the relatively higher elasticity of the non-energy category with respect to GNP.

The assumed changes in population growth are estimated to have only minor impacts, and no effect at all is shown for the different assumptions on pollution controls.

In order to understand the sensitivities of the sector totals to these economic determinants, it is necessary to analyze the results in terms of (1) the sector's composition by fuel and by use and (2) the elasticities of the individual fuel-use elements. The sector totals are largely composed of three fuels—oil, gas and coal—and two major uses—chemicals and "raw materials." The largest and most dynamic elements are the liquid and gas feedstocks of the chemical-use category and the oil component (mainly lubricants and asphalts) of the raw materials category.

The demand for petrochemical feedstocks historically has been noticeably responsive to changes in GNP, which is a direct reflection of the fact that feedstock demand is derived from the demand for chemical end-products that are used through-

TABLE 30

SENSITIVITY ANALYSIS FOR TOTAL ENERGY DEMAND IN 1980 AND 1985
NON-ENERGY AND MISCELLANEOUS
(Quadrillion BTU's)

Parameter	1980 Low	1980 Intermediate	1980 High	1985 Low	1985 Intermediate	1985 High
Economic Growth Rate (Real GNP)						
Demand	6.1	6.7	6.8	7.8	8.9	9.1
% Change *vs.* Intermediate	(9.0)	—	1.5	(12.4)	—	2.2
Cost of Energy Including Cost-Induced Efficiencies						
Demand	6.5	6.7	6.7	8.5	8.9	8.9
% Change *vs.* Intermediate	(3.0)	—	—	(4.5)	—	—
Population Expansion Rate						
Demand	6.6	6.7	6.7+	8.6	8.9	9.0
% Change *vs.* Intermediate	(1.5)	—	0.5	(3.4)	—	1.1
Energy for Environmental Improvement						
Demand	6.7	6.7	6.7	8.9	8.9	8.9
% Change *vs.* Intermediate	—	—	—	—	—	—

out the economy. The responsiveness with respect to price largely indicates the price competition between petrochemical end-products and substitute materials such as wood, glass and metals. The intensity of the response is heightened by the fact that feedstock costs represent a rising share of total chemical costs. A projection of rising feedstock prices is based on the following considerations:

- The current shortage of natural gas is likely to worsen, and the prospective increase in its price is likely to drive up the price of light feedstocks (ethane, propane and butane).
- The demand for ethylene/propylene is likely to remain strong though its growth will probably be less rapid than in the 1950's and 1960's.
- There are likely to be substantial cost increases for heavy feedstock (naphthas and gas oils) costs somewhat later in the projection period.

The gas component of the chemicals sector consists of gas feedstocks for the production of ammonia and a number of other chemicals, the most important of which are urea, methanol and acetylene. Ammonia, which accounts for 60 percent of methane-derived chemicals, is used very largely in the production of fertilizers. U.S. fertilizer production, and with it demand for gas feedstocks, is expected to show a slower growth in the future than in the 1960's. This is due to such factors as diminishing returns to increasing application of fertilizers, the approaching saturation levels in percent of crop acreages fertilized, and deterioration of the export market as developing countries establish their own fertilizer plants.

The other important component in the non-energy projection is the demand for petroleum-based raw materials, almost 90 percent of which is accounted for by lubricating oil and asphalt/road oil. Analysis of past experience indicates that demand for lubes is highly dependent on industrial output, automotive vehicle use and exports, while demand for asphalt/road oil is dependent mainly on road construction and maintenance. These have a much higher elasticity with respect to the level of economic activity than with respect to price, although to a certain extent, asphalt/road oil has to compete on a price basis with cement.

Energy for Environmental Improvement

The harnessing of the earth's energy resources during the Industrial Revolution provided the opportunity for higher standards of living and an expanding population. By using increasing amounts of energy, the industrial nations have attained a mode of living characterized by relative comfort and convenience. However, unexpectedly in some areas, population and economic activity have increased to the point that the natural environment is less able to absorb the many kinds of pollution that long were accepted as necessary evils of a contemporary and progressive society. The problem has become an international issue, and apparently some governments have been given mandates to develop the means for dealing with it effectively.

There has been much debate regarding the levels of permissible auto emissions. Although the specific technical capability of meeting the environmental goals is not yet available, the magnitude of the job and the penalties involved are reasonably well defined. In most other areas of private, commercial and industrial activity, the penalties and trade-offs associated with higher ecological goals and standards have not been completely defined. It has become quite apparent, however, that very large amounts of energy will be required to abate pollution and improve the quality of the environment.

Table 31 gives a breakdown by major categories of projected energy consumption required to meet anticipated environmental controls in 1980 and 1985. Two alternate cases are shown in this table: (1) energy consumption standards assumed in the Initial Appraisal or intermediate case and (2) additional energy required to meet more severe standards such as those assumed in the high demand case. Individual environmental problems are discussed in the following paragraphs.

Automotive Emissions

The automobile emissions controls required by federal and state standards already have substantially reduced the number of miles per gallon obtained by newer model cars and have lowered their overall performance. It is expected that this trend will continue, thus increasing automotive fuel requirements by 20 to 30 percent during the 1970-1980 period. The estimates shown in Table 31 assume that the octane pool level will remain no higher than 91-93 and that technological improvements will be made in motor fuel, automobile engine design and vehicle weight that will eventually overcome many of the penalties that are apparent in current year models.

Table 28 shows estimates of all transportation energy demand variability. Although automotive consumption is the major item, it is expected that there will be significant modifications in all types of vehicles, aircraft, etc., so that the new air quality standards will be met. As a rule, such changes will lower engine efficiency for at least another decade. Since it would be difficult to separate the efficiency improvement trends from the efficiency reductions resulting from anti-pollution devices, these effects are all combined under the environmental control parameter. The estimated variability in Table 28 indicates a strong possibility that transportation energy use will be increased as a result of air quality standards.

Observing the current "state-of-the-art" in automobile anti-pollution devices and assuming that no-lead gasoline with an octane number of 91-93 will be required for 1976 models, the average efficiency of new cars of that vintage probably will be substantially below current levels. It will be many years, however, before the older cars are scrapped and the entire car population reflects the new standards. In the meantime, a variety of changes in the engine and system design are likely to increase efficiency. Many of these trends have been incorporated into the intermediate case. The high demand variant case is based on the possibilities that (1) strict standards for nitrogen oxide (NO_x) control will be enforced as early as 1975-1976 and (2) anti-pollution standards will be applied to all cars on the road.

Waste Heat Control

The waste heat control category includes the energy requirement to convert condenser cooling of electric power plants (presently cooled by rivers and streams) to wet and/or dry cooling towers. The estimates of added energy requirements in

TABLE 31

ENERGY CONSUMPTION TO MEET ENVIRONMENTAL STANDARDS
(BTU x 10^{12})

Activity	1980 (1)*	1980 (2)†	1985 (1)*	1985 (2)†
Auto Emissions Controls	914	–	400	–
Electric Utility Industry				
For Control of Waste Heat	–	247	–	1,331
For Control of NO_x (Coal)	–	252	–	471
For Control of NO_x (Residual Fuel Oil)	–	45	–	76
For Fuel Desulfurization (Residual)	120	119	202	202
For Stack Gas Scrubbing (Coal)	63	63	117	118
Total	**183**	**726**	**319**	**2,198**
Sewage, Water and Solid Waste Treatment	2,000	2,542	2,432	2,580
Other Solid Waste‡	–	–	–	–
Industrial Sector				
Residual Oil Desulfurization (to 0.3% S)	–	167	–	304
Coal Gas Scrubbing (Equivalent to 0.3% S)				
Coking	–	50	–	71
Industrial§	–	35	–	43
Other Environmental Control by Industry	976	244	1,298	972
Total	**976**	**496**	**1,298**	**1,390**
Consumption for All Environmental Controls	4,073	3,764	4,449	6,168
Total Energy Consumption—Initial Appraisal	102,581	–	124,942	–
Environmental as % of a Total Energy Consumption	4.0	3.7	3.6	4.9

* Approximate quantities included in Initial Appraisal.

† Additional energy requirements because of higher environmental standards subsequent to the Initial Appraisal.

‡ Forecast that BTU's gained by burning will equal BTU's required for gathering and disposal.

§ Including a relatively small amount for residential/commercial.

column (2) of Table 31 are based on the assumption that one-fourth of all power generated will be utilizing wet and dry cooling facilities for waste heat (rather than rivers and streams) by 1980. The 1985 estimate assumes that the equivalent of one-half of all electric power generated will require cooling towers.

Control of Nitrogen Oxide Emissions

The estimates for the high case in the NO_x categories are based on the assumption that an 85-percent reduction in emissions of NO_x from power plants would be required by 1985. This, in turn, would reduce boiler efficiency. Thus, the consumption increments reflect the additional energy that would be required if two-thirds of all coal and residual oil-fired power plants were to have this standard (85-percent reduction) imposed before 1980 and if all plants were required to meet the standard by 1985.

Desulfurization

Sulfur emission levels now are imposed on *new* power plants in most areas and on all plants in certain areas. For oil, there is an extra energy requirement to process the fuel before burning. This requirement is shown in Table 31 in the electric utility category, although it could be classified as either industrial or electric utility. The estimate reflects the assumption that desulfurized fuel oil will be required for two-thirds of the residual oil demand projected for power generation by 1980 and for all of the demand by 1985. For coal, it is assumed that stack gas scrubbing will become technically and economically feasible so that the process can be employed widely by 1980. It is also assumed that stack gas scrubbing will be required for one-third of the demand projected by 1980 and one-half of the 1985 demand.

In Table 29, the sensitivity of energy demand to variations in environmental standards is estimated for electricity conversion consumption. These calculations take into account the major factors discussed above except for the portion of fuel desulfurization that is carried on outside of the electric utility plant.

Assuming environmental protection regulations are stricter than those used for the intermediate projection, energy requirements of electric utilities could be higher by 3.5 percent in 1980 and 6.3 percent in 1985. These increases would result primarily from additional requirements for the control of waste heat disposal through the operation of cooling towers and for moving water in and out of cooling ponds. Losses in boiler efficiency due to NO_x control would be the second most important factor contributing to the increase in requirements. Stack gas desulfurization scrubbers for eliminating sulfur dioxide (SO_2) emissions would account for most of the remainder of the increase.

A relaxation of regulations below those implied in the intermediate case could reduce demand by as much as 2.2 percent in 1980 and 2.7 percent in 1985. The reduction in energy requirements would most probably result from less severe limitations on cooling water disposal, particularly for nuclear plants.

Sewage and Water Treatment

Treatment of sewage, water and solid waste have been familiar problems to the general public because the expansion of cities and suburbs across the Nation have required improved sewage treatment, better garbage disposal and increased water supply. Unfortunately, nationwide data describing the magnitude of the current effort are not readily available, so estimates were prepared from county and municipal data. These data were ultimately expanded for the entire country using the Census Series D population forecast.* The additional energy needs are mainly requirements for pumping and filtering and were derived from EPA sources. It is assumed that by 1985 high standards of sewage treatment will be in effect across the Nation; thus requirements for both sewage and water treatment will become significant parts of total energy consumption.

Other Solid Waste Disposal

Little is known yet about the nationwide energy requirements and cost of solid waste disposal (wastes include municipal trash, garbage and other refuse) except that great efforts are being made to minimize costs. Some facilities in Europe have converted waste products to useful energy, and it is expected that future research will demonstrate many more opportunities for utilizing waste products to generate energy. Therefore, it is assumed that in the long run the energy derived from such efforts will about equal the energy required for the gathering and preparation of wastes. However, it is doubtful that these conservation systems can be in general use before 1980.

Residual Fuel Oil and Coal

In Table 31, residual oil desulfurization and coal gas scrubbing reflect the estimates of energy consumed in the manufacture of low-sulfur (0.3-percent) fuel oil and desulfurization of coal gases (through stack gas scrubbing, chemical treatment or other means) for the volume of fuels consumed in the industrial sector. The greatest changes will take place in the industrial sector, and the smaller amounts of energy used for processing fuels for the residential/commercial sector also are added to the industrial category. The increased energy usage was calculated by assuming that about two-thirds of these sectors' fuel consumption would be required to meet the low sulfur standards by 1980 and that all must meet such standards by 1985.

* Published August, 1970.

Consumption by Large Industrial Users

The Edison Electric Institute developed some estimates of energy requirements for pollution abatement by means of a broad survey of electric utility customers. The responses from the survey indicated that about 8.4 percent of the electricity consumed by large industrial customers currently is for pollution abatement and that the proportion will rise to 12.9 percent by 1985. It is believed that this is a conservative projection for this category of electric energy users.

The sensitivities of industrial energy to more or less stringent emissions standards are noted in Table 27. The high demand case indicates the additional energy that would be required to meet the much tigher controls under consideration in 1972 for possible adoption in 1975 or thereafter (i.e., about 2.0 quadrillion BTU's, or a 6.5-percent increase). Although the low case shows the sensitivity to the imposition of lower standards than those envisioned in the Initial Appraisal, the potential variation on the low side is much less, and it has a low probability.

A greater measure of uncertainty surrounds the impact of environmental improvement standards on industrial energy consumption relative to the other sectors. There is no doubt that large amounts of energy will be required to clean up industrial wastes, but the stringency of the regulations, the degree of enforcement and the level of voluntary compliance to regulations will have marked effects on the amount of energy that ultimately will be required.

Overall Costs

Estimates of the annual total cost of pollution abatement and environment restoration vary from \$25 to \$50 billion, projected over a rather indefinite time frame. The real dollar cost must necessarily reflect the rate of imposition and enforcement of pollution standards and the technological capability (including manufacturing facilities and adequately trained operating manpower) to perform a task that is not yet too well understood. The EPA has estimated that in 1970 total expenditures for all kinds of air, water and waste treatments amounted to \$9.3 billion.

About 4 percent of 1980 projected energy requirements, or 4.1 quadrillion BTU's, was included in the NPC's Initial Appraisal as energy consumption for environmental improvements. It now seems that new standards might require a commitment of an additional 3.8 quadrillion BTU's in 1980. For 1985, the comparable figures are 4.4 and 6.2 quadrillion BTU's, respectively. Thus the 1985 high level of energy consumption of 10.6 quadrillion BTU's for environmental controls is equivalent to 8.5 percent of the total U.S. consumption cited in the Initial Appraisal, or a doubling of the share of energy used for those purposes.

Effects of Reduced Energy Consumption

The total value of energy contributes almost 10 percent to the GNP, and it is an absolutely vital link in the production process. Since lower energy consumption could be very costly in terms of lost production and human welfare, the full implications of proposals to reduce energy growth require careful examination.

Voluntary improvements in efficiency of energy use by individuals and industry are effective and compatible with other national goals. This type of conservation has been and will continue to be developed fairly rapidly through technological advances and the price system. The extent to which this current trend might be accelerated in the future is one of the subjects of the parametric analyses described in other sections of this chapter.

In contrast, arbitrary restrictions on energy use would have predictably undesirable effects on the economy and on individual freedom and welfare. Such restrictions are likely to be discriminatory, especially against low income groups. It is this arbitrary type of reduction in consumption that is evaluated in the following paragraphs.

Effects on Econonic Growth

Arbitrary reductions in energy consumption would have significant impacts on U.S. economic growth as indicated by the following examples. If 1985 energy demand were so reduced by 10 percent, real GNP would be lowered an estimated 7 to 18 percent.* The range in effect on GNP is the result of the different paths the reduction might take. The lower effect would apply if energy-

* The proportions are based upon the relationship between energy consumption and GNP established by input/output analyses of the U.S. Department of Commerce for the year 1963 and NPC projections of trends through 1985.

intensive uses—metals, machinery, chemical industries, etc.—were restricted first; the upper end of the range would apply if all uses were restricted on a proportionate basis. An even more severe effect on the economy would occur if it were assumed that less energy-intensive uses were restricted first. In a more extreme example in which the 1985 energy consumption level would be lowered by 30 percent (equivalent to consumption growth of only 1.7 percent *vs.* 4.2 percent in the Initial Appraisal), the resulting reduction in real GNP would range between 20 and 50 percent.

Employment Effect

Other things being equal, a lower GNP will be accompanied by higher unemployment. A 7-percent decrease in real GNP in 1985 could possibly increase unemployment by about 2 million persons. (The unemployment rate increase used here is based on the Okun formula which relates the unemployment rate to various levels of GNP.*). A 50-percent reduction in GNP, as mentioned in the preceding paragraph, is outside the range of data experienced in the past. However, as a point of comparison, the reduction in real GNP experienced during the Depression period (1929-1933) was 31 percent, and the civilian unemployment rate reached 25 percent (or an increase of 22 percent). At that time, 12.8 million persons were unemployed. A much larger number of unemployed could be expected in the future with a similar percentage reduction in GNP. These calculated unemployment impacts could be partially offset by changes in the economic structure and life-style, but such changes would be slow and difficult to achieve.

Other Effects

The impact of slower energy growth on poverty levels has also been estimated. For example, if the GNP growth rate between 1970 and 1985 were reduced from the 4.2-percent rate of the Initial Appraisal to, say, 3.2 percent per year, total personal income would be much lower, and the number of people within the poverty categories (in 1985) would be increased by 2 to 3 million.

* President's Council of Economic Advisors—study based on 1953-1963 data.

If energy consumption were reduced because of limited supply, a significant increase in market price would be one of the conditions because of the relatively low elasticity of energy demand to price. Higher energy costs presumably would be reflected very soon in the prices of virtually all goods and services. In other words, higher prices would be one of the social costs that the Nation would bear if energy were in short supply. Other economic redistributions also would occur. Energy-intensive industries, for example, would sustain higher operating costs and would have greater difficulty in competing against industries with lower energy requirements per dollar of output.

Undoubtedly, a whole series of such adjustments would take place. Many U.S. products of energy-intensive industries, such as metals, machinery and chemicals, would become less competitive in the world markets (assuming proportionately smaller increases in foreign energy costs), and the United States would become a larger importer of such products. In order to adjust its balance of trade, the United States would have to increase exports of "low-energy" goods and services such as agricultural products and/or technology.

If energy use were lower because of limits placed on specific energy uses for environmental or other reasons while energy prices were controlled, an appearance of price stability could exist. This could impose a partially obscured and very costly set of economic penalties upon society. If, for example, motor gasoline use were curtailed, fewer and/or smaller cars would be purchased thus requiring less output of steel, rubber, plastic, etc. Aside from lower standards of vehicular transportation and more unemployment in the automotive and related industries, the impact of reduced energy usage would be very unevenly distributed throughout society. In effect, the well-being of automobile owners, passengers of all forms of transportation, heads of households, small businessmen, and indeed most individuals would be reduced. The largest relative impact would fall on the lower income groups. The industrial sector would be able to adjust eventually to a lower energy consumption through marginal substitutions of capital and labor for energy, passing on the additional costs in the form of higher prices for goods and services.

Chapter Four
Domestic Oil and Gas Availability

Introduction

Numerous factors affect the supply of oil and gas from domestic sources. Each of these factors must be identified and quantified to develop a projection of supply for any future period of time. This study considered relevant items in the following five broad categories:

- Resource availability
- Industry capability
- Government policies
- Economic climate
- Future technology.

Initial Appraisal

In the NPC's Initial Appraisal, a projection of supply was developed utilizing one specific set of assumptions. For the purpose of simplicity, the Initial Appraisal assumed a "status quo" outlook over the study period, as indicated by the following:

> Supply-demand relationships are projected assuming that current government policies and regulations and the present economic climate for the energy industries would continue without major changes throughout the 1971-1985 period.*
>
> The following assumptions governed the oil and gas analyses:
>
> 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. . . .
>
> 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.*

The Initial Appraisal made no attempt to analyze the economic feasibility of the case presented. Levels of activity and physical results were merely projected into the future using an assumption of constant price, without examining the economic implications.

Objective of Second Phase

The objective of this oil and gas study is to examine in more detail the factors which affect future supplies, with particular attention to increasing indigenous supplies. A methodology capable of analyzing the numerous parameters that could affect future domestic petroleum supply levels was developed.

General Approach—Conventional Supply

Ranges were assumed for drilling levels, finding rates and additional recovery efforts to develop new oil and gas supplies. The costs of achieving these activity levels and resultant production rates were calculated. A range of returns on investment (net income as a percentage of net fixed assets) was selected and "prices" required to provide these re-

* NPC, *U.S. Energy Outlook: An Initial Appraisal 1971-1985*, Vol. II (November 1971), p. *xvii*.

turns on the net fixed assets were computed.* This methodology provides a great deal of information on the relationship between oil and gas supplies and the economic climate required to support the supply projections. It additionally provides a basis for evaluating the impact on supply and unit "price" of varying assumptions on physical, economic and government policy factors.

The method adopted cannot provide precise solutions on price/supply elasticity. Such a determination would have to separate price from all other motivational considerations, and there appears to be no way to isolate price effects from historical data in a purely objective manner. Further, any analysis of future supply/price relationships must recognize that they will undoubtedly change considerably from those experienced in the past. The historical record of oil and gas discoveries reflects the influence of resource availability, technological capabilities, governmental policies and cost factors, none of which will necessarily be duplicated in the future. Shifts in these factors are often difficult to predict or quantify, yet the accuracy of any prediction concerning the response of oil and gas supplies to changes in price is dependent upon future changes in these other factors.

These uncertainties typify some of the risks inherent in oil and gas exploration and development. As a result, any given level of prices may result in increments of new supplies which exceed or fall short of anticipation. However, the methodology adopted does provide insights into supply/price relationships and thus serves as a valuable tool to facilitate the development of sound energy policies by those vested with this responsibility.

The analysis was performed on a geographic region-by-region basis, taking into account variations in drilling, finding experience, costs, degree of maturity, etc. The regional results were subsequently combined to present total U.S. results. The geographic distribution used in the Initial Appraisal (shown in Figure 5) was adopted with minor modifications.

The projection period began with 1971 because the latest published data available at inception of this phase of the study were for 1970. As a result, the 1971 projections will not necessarily agree with actual experience. No attempt has been made in this report to reconcile any minor differences between the 1971 projections and actual data. However, in general, the results to date do not deviate greatly from the projections, and the differences are not of such magnitude as to cast doubt on the validity of the methodology or findings.

A computer program was developed to facilitate the processing of data because of the multitude of variables involved in implementing the methodology and the need for making a large number of repetitive calculations. The program has no internal optimizing logic or mechanisms by which it can relate calculated economic results to investor motivation or incentives.

Within the computer program, oil supply—including associated-dissolved gas and plant liquids—and related economics were calculated for the lower 48 states plus southern Alaska. Non-associated gas supply, including lease and plant liquids, and related economics were computed for only the lower 48 states. Projections of North Slope oil and gas and southern Alaska non-associated gas operations were made independently rather than through the computer program. These segments of Alaskan operations were not included in the "price" calculations because of the lack of operating experience and data and logistic uncertainties. Reserve additions, production and capital requirements for these areas are incorporated later in this chapter. For ease of reference in the remainder of this report, the area analyzed using the computer program will be labeled "lower 48 states" even though southern Alaskan oil operations are included.

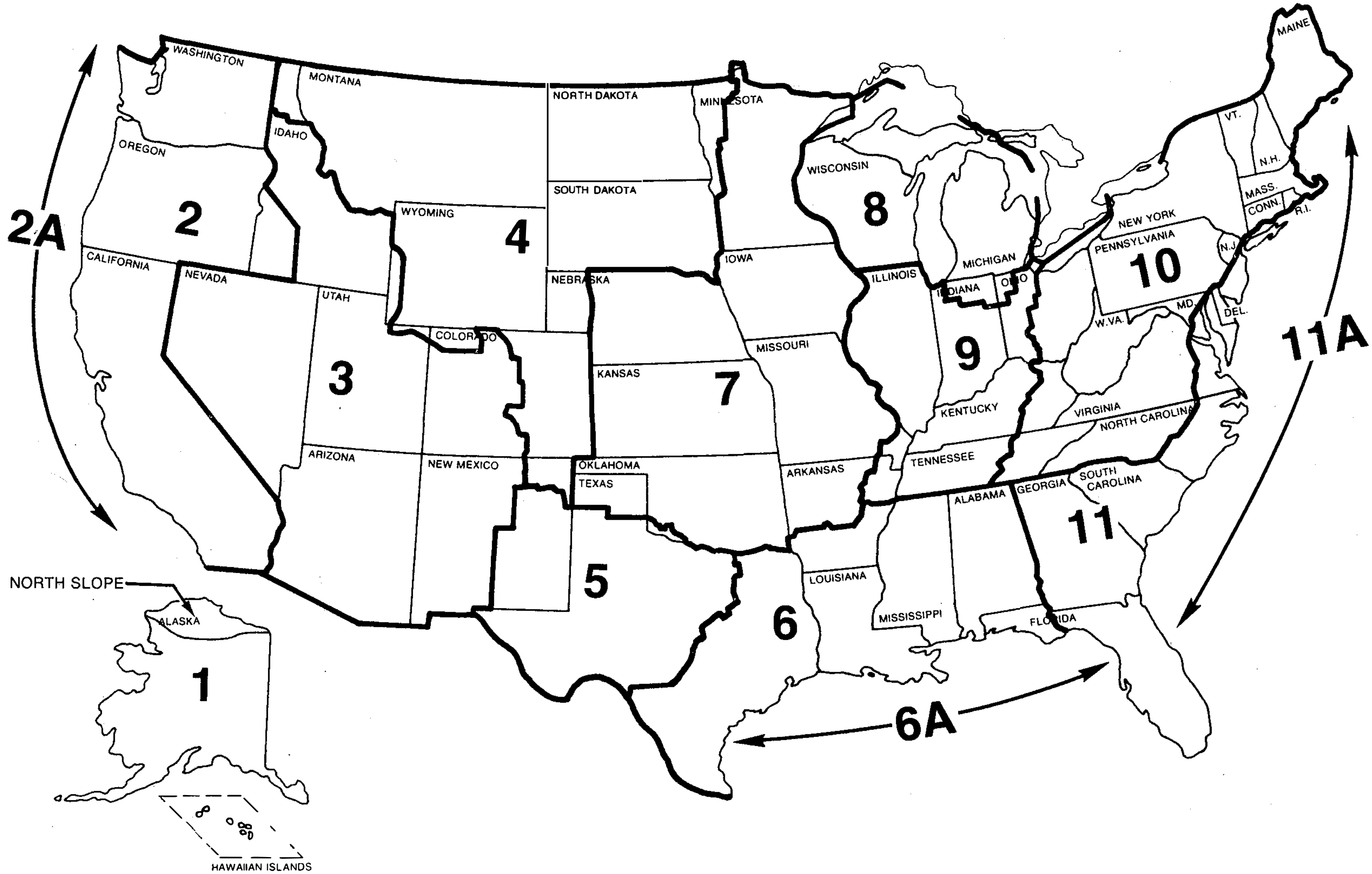
Cases Analyzed

The two most significant variables involved in projecting future domestic production of oil and gas are (1) *finding rate*—the volume discovered per unit of drilling—and (2) *drilling rate*—the footage drilled annually.

Regional analyses of historical finding rates indicate a range of results which cannot adequately be represented by a single line extrapolation. Therefore, high and low finding rates were projected for each region.

To determine the possible range of future do-

* As used in this study, "price" does not mean a specific selling price as between producer and purchaser and does not represent a future market value. The term "price" is used to refer generally to economic levels which would, on the basis of the cases analyzed, support given levels of activity for the particular fuel.



Regional Boundaries: Region 1—Alaska and Hawaii, except North Slope; Region 2—Pacific Coast States; Region 2A—Pacific Ocean, except Alaska; Region 3—Western Rocky Mountains; Region 4—Eastern Rocky Mountains; Region 5—West Texas and Eastern New Mexico; Region 6—Western Gulf Basin; Region 6A—Gulf of Mexico; Region 7—Midcontinent; Region 8—Michigan Basin; Region 9—Eastern Interior; Region 10—Appalachians; Region 11—Atlantic Coast; Region 11A—Atlantic Ocean.

Source: NPC, *Future Petroleum Provinces of the United States* (July 1970)—with slight modification.

Figure 5. Petroleum Provinces of the United States.

mestic production, three drilling rates were investigated: (1) a high rate of drilling growth, (2) a medium rate of drilling growth, and (3) a continuation of the declining historical trend. The highest rate of drilling growth provides by 1985 annual drilling rates exceeding the industry all-time high achieved in 1956 following the rapid expansion after World War II.

Six oil and gas supply cases resulting from combinations of these two finding rates and three drilling rates were analyzed. Also, the initiation of production from the North Slope was delayed in two of the cases. The configuration of these variables, as they define the six cases investigated, is outlined in Table 32.

For brevity, four of these six cases (I, II, III and IV) were selected to display the results whenever possible. These cases represent the three drilling rates and cover the widest range of supply results. Case I is the highest supply case; Cases II and III are intermediate supply cases, combining the medium drilling rate with both the high and low finding rates; and Case IV is the lowest supply case and includes delays in Alaskan development.

General Approach — Supplemental Supply

The principal sources of domestic oil and gas supply during the 1971-1985 period will be conventional production. However, sufficient progress in research and development (R&D) and/or experience in certain energy fuel conversion applications has been made to support a reasonable range of estimates for certain potential supplemental sources of supply. This category of supply includes: liquefaction and gasification of coal, production of liquids from oil shale and tar sands, reforming of certain petroleum liquids to produce substitute natural gas (SNG), and utilization of nuclear explosives to stimulate production in low-productivity natural gas reservoirs.

Analyses of the volumes, capital investments and required "prices" for the production of oil or gas from coal, oil shale and tar sands are contained in Chapters Five, Seven and Eight, respectively. Analyses of SNG production and nuclear explosive stimulation are contained later in this chapter.

Generally, such forms of supply will require large capital investments and "prices" considerably higher than those for conventional supplies at present and will make limited contribution to total supply in the projected period.

Summary

Reserve Additions

Table 33 shows actual and projected reserve additions of petroleum liquids and natural gas in the lower 48 states. In addition to the reserve additions shown, it is estimated that average annual reserve additions in Alaska will range between 0.3 and 0.6 billion barrels of petroleum liquids for Cases IV and I, respectively, and between 1.3 TCF

TABLE 32

OIL AND GAS CASES ANALYZED

Variable	Highest Supply I	IA	II	III	IVA	Lowest Supply IV
Finding Rate	High	Low	High	Low	High	Low
Drilling Rate	High Growth	High Growth	Medium Growth	Medium Growth	Current Downtrend	Current Downtrend
North Slope Production Starts						
Oil	1976	1976	1976	1976	1981	1981
Gas	1978	1978	1978	1978	1983	1983

TABLE 33

SUMMARY OF ANNUAL RESERVE ADDITIONS IN LOWER 48 STATES

	Actual	Projected Case I	Case II	Case III	Case IV
	Petroleum Liquids (Billion Barrels per Year)				
1960	3.1				
1965	3.9				
1970	3.4				
1975		3.8	3.7	2.9	2.5
1980		4.9	4.3	3.5	2.7
1985		5.3	4.7	3.7	2.6
	Total Natural Gas (TCF per Year)				
1960	13.8				
1965	21.2				
1970	11.1				
1975		19.3	17.3	11.6	8.8
1980		27.2	21.8	14.2	7.4
1985		25.9	21.1	14.1	5.9

(Case IV) and 4.2 TCF (Case I) of gas over the 15-year period 1971-1985.

Production

Tables 34 and 35 show the projected daily average production of petroleum liquids and the annual production of natural gas.

TABLE 34

SUMMARY OF WELLHEAD PRODUCTION* PETROLEUM LIQUIDS (MMB/D)

	Actual	Projected Case I	Case II	Case III	Case IV
	Lower 48 States				
1960	8.0				
1965	8.9				
1970	10.9				
1975		9.9	9.9	9.5	9.4
1980		10.8	10.4	9.2	8.6
1985		12.0	11.1	9.3	8.0
	Alaska				
1960	-				
1965	-				
1970	0.2				
1975		0.3	0.3	0.3	0.2
1980		2.8	2.5	2.4	0.3
1985		3.5	2.8	2.5	2.4
	Total United States				
1960	8.0				
1965	8.9				
1970	11.1				
1975		10.2	10.2	9.8	9.6
1980		13.6	12.9	11.6	8.9
1985		15.5	13.9	11.8	10.4

* In addition to these volumes of conventional production, projected volumes of synthetic liquids are discussed in Chapters Five and Seven. Oil supply from all sources is shown in Table 82.

Required "Prices"*

Actual "prices" for several prior years and the computed average "prices" required for a 15-percent return on net fixed assets to achieve the levels of reserve additions and production for all cases investigated are shown in Table 36. These are average "prices" for all vintages and all qualities of oil and gas. Five rates of return on net fixed assets between 10 and 20 percent were investigated; only the mid-level of 15 percent is shown for the projection in Table 36.

Conclusions and Implications

Resources of Oil and Gas

The volume of domestic oil and gas remaining to be found will not be a limiting factor on domestic supply prior to 1985. There remains to be discovered almost as much oil-in-place (OIP) and twice as much non-associated gas as had been found by the end of 1970.

The geographic location of the remaining potential resources is an important factor. About half of the remaining oil and gas is estimated to lie in

* Not a specific selling price as between producer and purchaser and does not represent a future market value. The term "price" is used to refer generally to economic levels which would, on the basis of the cases analyzed, yield the selected level of return on net fixed assets for given levels of activity for the particular fuel under the assumptions made. For a discussion of "constant" and "current" dollars, see Glossary.

TABLE 35

**SUMMARY OF WELLHEAD PRODUCTION*—
TOTAL NATURAL GAS
(TCF/Year)**

	Actual	Projected Case I	Case II	Case III	Case IV
		Lower 48 States			
1960	13.0				
1965	16.3				
1970	22.2				
1975		23.5	23.4	21.8	21.6
1980		24.2	22.8	19.1	17.1
1985		26.2	23.0	17.5	13.2
		Alaska			
1960	—				
1965	—				
1970	0.1				
1975		0.2	0.2	0.2	0.2
1980		1.7	1.5	1.3	0.2
1985		4.4	3.5	2.9	1.8
		Nuclear Stimulation			
1970	—				
1975		—	—	—	—
1980		0.2	0.1	0.1	—
1985		1.3	0.8	0.8	—
		Total United States			
1960	13.0				
1965	16.3				
1970	22.3				
1975		23.7	23.6	22.0	21.8
1980		26.1	24.4	20.5	17.3
1985		31.9	27.3	21.2	15.0

* In addition to domestic wellhead production, volumes of substitute natural gas from liquid hydrocarbon feedstocks (discussed later in this chapter) and coal (discussed in Chapter Five) were projected. Gas supply from all sources is shown in Table 83.

the frontier areas of Alaska and offshore, while very little may be left in some of the mature inland provinces.

The key factors determining the volume of these resources which will be developed during the 1971-1985 period are access to prospective areas, drilling rates and finding rates. Appropriate economic and political conditions are also essential to the attainment of the projected results.

Drilling Rates and Additonal Recovery Activity

The industry has been in a phase of diminishing activity for several years. With positive incentive and areas to explore, the petroleum industry can reverse its recent trend of declining drilling activity and begin expanding to rates achieved in the post-World War II decade. Such a reversal in drilling rates, without a change in the finding rate, results in increasing 1985 total liquids and gas production (including Alaska) by about 2.6 MMB/D and 8 TCF per year above the level that would occur if the historical downtrend in drilling were continued (Case IA *vs.* Case IV).

In addition to increased exploration activity, adequate incentives could stimulate the oil industry to expand its application of secondary and tertiary oil recovery processes. By 1985, these additional recovery methods might account for about half of the oil production from the lower 48 states.

Finding Rates

The difference between the projected high and low finding rates is substantial—the high finding rate discovers approximately half again as much as the low finding rate per foot of hole drilled. Measured in terms of wellhead production in 1985, assuming the medium growth drilling rate (Cases II and III), the high finding rate provides about 2 MMB/D of oil and 6 TCF of gas per year more than the low rate. The impact on required unit "prices" to yield a 15-percent return would be a reduction of $0.42 per barrel and $0.13 per MCF.

Lead Time

The lead time between a producer's decision to expand exploration activity and the resultant increase in oil and gas production is unavoidably long. Geological and geophysical work must be done to identify new drilling prospects, adequate funds to finance the effort must be made available, land must be leased, drilling rigs must be acquired (or built), manpower trained, drilling accomplished, production and transportation facilities built, and gas contracted. The lead time in the frontier areas where the major potential exists can be as long as 5 years or more. Thus, not only are immediate incentives required, but the *expectation* by the in-

TABLE 36

SUMMARY OF AVERAGE REQUIRED "PRICES"—LOWER 48 STATES
(Constant 1970 Dollars)

		Projected (15% Return on Net Fixed Assets)					
		High Finding Rates			Low Finding Rates		
	Actual*	Case I	Case II	Case IVA	Case IA	Case III	Case IV
	Crude Oil "Price" ($/Bbl)						
1960	3.33						
1965	3.26						
1970	3.18						
1975		3.65	3.63	3.54	3.70	3.67	3.57
1980		4.90	4.73	4.26	5.16	4.95	4.39
1985		6.69	6.18	5.06	7.21	6.60	5.28
	Gas Field "Prices" (¢/MCF)						
1960	16.2						
1965	17.8						
1970	17.1						
1975		26.7	26.2	25.1	28.5	27.9	26.6
1980		33.7	31.8	27.6	40.9	37.8	31.6
1985		43.6	39.8	31.2	59.4	53.0	38.7

* Actual data are average wellhead values at unspecified rates of return reported by the Bureau of Mines and converted to constant 1970 dollars.

dustry of a stable, satisfactory economic and political climate is essential.

Price Incentive

The most effective economic incentive would be to allow prices to increase to the level at which the industry can attract and internally generate the risk capital needed to expand activity to its maximum capability. This requires both a fair return on total investment (e.g., return on net fixed assets), as well as the anticipation of attractive returns on current and future investments.

During the last 10 to 15 years, real prices of oil and gas at the wellhead have declined while real costs have been increasing. As a result, both drilling activity and addition of new reserves have declined rapidly. Assuming a 15-percent annual rate of return in constant 1970 dollars, 1985 average oil "prices" may have to range from $5.06 to $7.21 per barrel, and 1985 average gas "prices" may have to range from $0.31 to $0.59 per MCF to support the activity levels assumed (Cases IA and IVA). If prices for gas found prior to 1971 are prevented from increasing by regulatory or contractual restrictions, the required "price" in 1985 for gas found after 1970 would be on the order of 30 to 50 percent greater than the average "prices" calculated.

Even a continuation of drilling activity along the current declining trend will require "price" increases of about $2.00 per barrel and $0.15 per MCF by 1985 if the petroleum industry is to realize a 15-percent return on its net fixed assets.

Government Policies

Price increases alone will not assure substantial increases in the exploration for and development of oil and gas supplies. They must be accompanied by reasonable, consistent and stable governmental policies specifically designed to encourage the development of additional domestic oil and gas production. Policy issues of particular importance include leasing of government lands, environmental conservation, taxation, natural gas price regulation and oil import quotas.

Leasing of Government Lands

Recently, adversary proceedings and procedural uncertainties and delays pertaining to environmental concerns have resulted in severely restricting industry access to the frontier areas that contain the most potential for the recovery of oil and gas. Such issues must be resolved more expeditiously in the future so that long-range project planning, which includes logistical and transportation considerations, may proceed.

The amount of federal lands leased in the offshore areas must increase substantially during the 1971-1985 period to achieve the supplies projected. For example, in Case II, the total offshore acreage required for exploration increases from about 600,000 acres per year actually leased in 1970 to almost 2,300,000 acres per year in 1985—an increase of almost 400 percent. Also, if acreage in the California offshore areas is not added to the Department of the Interior's announced lease sales schedule, the 1985 production rate would be about 700 MB/D less than projected. Announcing a lease sales schedule showing increasing acreage offered per sale, as well as increased sale frequency, would also facilitate more effective industry planning in the exploration for and development of new reserves in federal areas.

In the case of the Alaskan North Slope, not only has exploration access been restricted but efforts to produce the largest oil field found on the North American Continent have also been frustrated. The lack of any return on the more than $1.5 billion already spent on the North Slope by the industry to date has adversely affected the economics of participants and severely restricts the availability of capital to finance further industry expansion.

Unless federal policies are adopted to make the necessary offshore acreage available in a timely fashion and to permit marketing of offshore and Alaskan reserves, the U.S. consumer will be deprived of about 40 percent of projected 1985 domestic production potential.

Environmental Conservation

Use of land and offshore areas for development of natural resources in a manner that is compatible with environmental quality standards is both feasible and necessary. The technology is currently available at reasonable expense to assure compliance with practical and reasonable environmental objectives.

Taxation

The effects of changes in the statutory depletion rate, preference tax rates, job development credit, and implementation of exploration tax credit on required "prices" were calculated, assuming no change in exploratory activity or results.

If the depletion allowance is eliminated under the conditions of Case II and III, then "price" increases ranging up to $1.00 per barrel and $0.07 per MCF would be required to maintain industry profitability at a 15-percent return on net fixed assets. The implementation of a tax credit (12.5 percent for investment in exploration and additional recovery) could result in a reduction of required "prices" of $0.38 per barrel and $0.03 per MCF by 1985.

The motivational forces which are activated by tax changes and their impact on industry response are believed to be substantial, but they cannot be directly quantified by the methodolgy used. Data pertinent only to the exploration and production function cannot be aggregated in a manner that avoids distortion. In other words, the "average" would be an unrealistic composite of corporations, individuals, partnerships, etc., that are each subject to different exposure to tax liabilities.

Natural Gas Price Regulation

During the 1960's, demand for natural gas was artificially stimulated, and development of new supplies was restricted by FPC pricing policies that held gas prices below their competitive level in the marketplace. Wellhead gas production in the United States increased at an unprecedented rate in this decade, from 13.0 TCF in 1960 to 22.3 TCF in 1970. The large backlog of proved reserves of gas which made this rapid increase in production possible is no longer available to support any substantial further growth. Future increases in production must depend primarily on new reserve additions.

If the supply capability of the domestic natural gas industry is to continue to expand in response to demand, the FPC regulatory system must be altered to allow natural gas to reach its competitive price level and thereby provide the incentives necessary to find, develop and market additional natural gas supplies. Similarily, if supplemental domestic sources of supply from coal gasification, SNG and nuclear-explosive stimulation are to make any substantial contribution, the regulatory system must demonstrate sufficient flexibility to permit economic incentive to reflect both the expense and risk involved. This same set of regulatory circumstances must apply to imports of both conventional gas and LNG.

Oil Import Quotas

A system of effective, equitable oil import quotas is essential to providing the incentive to expand domestic supplies of energy so that over-dependence on foreign sources for energy supplies can be avoided. Such over-dependence on foreign sources can make the United States vulnerable to interruption of petroleum supply from either military action or shutdown for political reasons. Without the deterrent effect of a strong domestic oil industry, producing countries could more easily threaten economic sanctions and boycotts to influence U.S. international policies. Moreover, major interruptions of energy imports could severely hamper the functioning of the U.S. economy.

Oil import quotas tend to encourage development of all indigenous energy resources. For example, since oil exploration and gas exploration are generally joint activities using the same people, techniques and equipment, the availabilities of these two fuels are inextricably related. Without oil import quotas, domestic oil and gas availability would decline. The development of domestic synthetic fuels could also be retarded by the lack of economic incentives caused by the threat of unrestricted imports at a price which would not yield an adequate return for domestic producers of these fuels.

Technology

Continuation of past trends of evolving technology have been implicitly assumed in this study. However, if major breakthroughs are experienced, such as the ability to achieve the high finding rate with consistency, the effects could be quite dramatic. A breakthrough in additional recovery technology would result in large supply increases. For example, a 2-percent increase in the cumulative oil recovery factor over the 1971-1985 period could amount to an additional 1 to 2 MMB/D of oil production in 1985.

Technological improvements in drilling capability and in the design and construction of production facilities are essential if the tremendous potential of the Arctic offshore is to be realized. Some assurance that this area will be opened to exploration and development is needed if industry is to undertake the research required for resolution of the problems associated with operations in the Arctic.

Private industry has developed most of the existing exploration and production technology and has the best technical capability to develop the kinds of new technology needed for future development of the Nation's oil and gas resources. This technical capability will be used effectively by private industry, provided there is reasonable incentive to do so.

Methods of Analysis

General

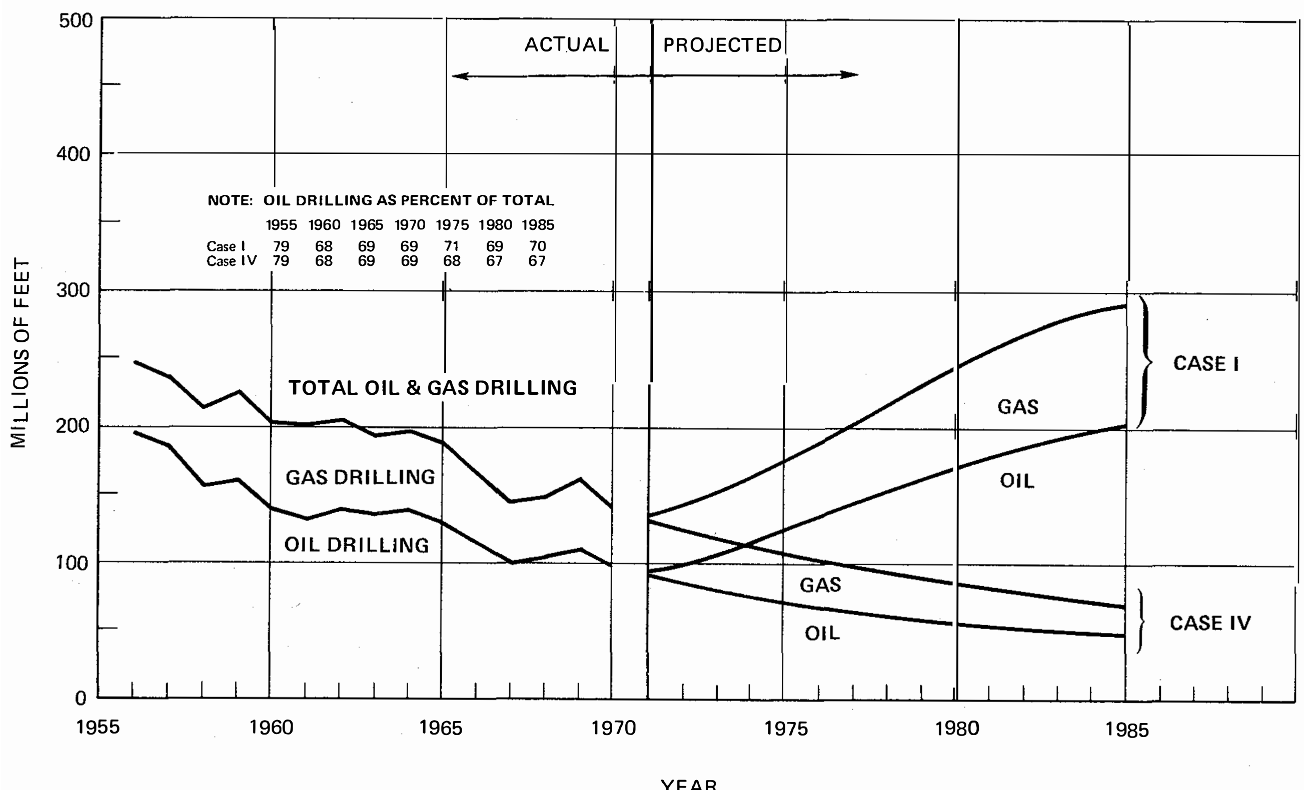
Oil and gas exploration, development and production operations are different but related facets of the same business. Analysis should not totally segregate oil and gas operations because it is inevitable that some volumes of associated-dissolved gas and, occasionally, non-associated gas reservoirs will be found as a result of oil exploration. Conversely, exploration for gas sometimes results in the discovery of oil reservoirs, and gas well production is often accompanied by the recovery of petroleum liquids. Therefore, although pre-selected objectives account for most of the resulting types of production, exploration for either oil or gas ultimately leads to the discovery and production of both.

Two of the key elements of an analytic methodology for projecting the results of oil and gas exploratory and development operations are (1) the amount of drilling done (drilling rate) and (2) the amount of oil and/or gas found per foot drilled (finding rate). Utilizing compatible sets of judgments for oil and gas on finding and drilling rates, as well as for many other variables, allowed the design of a methodology capable of making separate but parallel calculations for each fuel.

This methodology analyzed the historical amounts of oil found as a function of oil drilling and, in like manner, the amount of gas found as a function of gas drilling. These historical relationships were used to project the results of future activity levels. By this approach, past *directionality* (fraction of the times that oil, rather than gas, is found when looking for oil, and vice versa) was implicitly recognized in an empirical manner, and the explicit quantification of directionality in the projection period was unnecessary. The selection of a range of future trends of oil and gas finding rates (as discussed later) also helped eliminate any need to quantify directionality. This treatment is possible only if the ratio of oil drilling footage to gas drilling footage is reasonably constant during both the historical period used for determining the finding rates and for the projection period.

Historically, productive and non-productive footage drilled is reported separately and is further classified as exploratory or development footage. In this analysis, non-productive footage was allocated to oil and gas by region according to productive footage ratios. This resulted in 69 percent of the total footage drilled in 1970 being allocated to oil and 31 percent to gas (see Figure 6). Also shown is the projected drilling footage for Cases I and IV which cover the highest and lowest drilling activity levels. Oil and gas drilling in both cases shown, as well as in the medium growth cases (Cases II and III), remains near the 70- to 30-percent split experienced since 1960.

The extent to which the ratio of oil to gas drilling can deviate from the historical ratio without distorting the calculated results is uncertain. There-



* *Excluding Alaskan drilling footage*

Figure 6. Oil and Gas Drilling Footage—Total United States (Million Feet).*

fore, the methodology used in this analysis is not recommended for general application where the future drilling mix may vary appreciably from historical ratios.

In addition to calculating reserve additions and production, the methodology also calculated required capital investments for specified levels of activity and accompanying required "prices" for oil and gas at a range of rates of return on net assets. Sufficient flexibility has been provided in the method developed (displayed as a schematic in Figure 7) to handle separately such differences in the two fuels as producing characteristics and additional recovery possibilities.

Although oil supply, gas supply and economics are calculated separately, each segment interacts with the others at several appropriate points in the procedure so that oil and gas are interlocked and cannot be analyzed independently. Both oil and gas supply segments are calculated on a regional basis, and the results are then aggregated to provide totals for the regions considered.

Oil Supply Procedures

The first item calculated was reserve additions resulting from oil exploratory drilling. Based on historical data, both a high and low future oil finding rate for each region was established to encompass the range of expectations. These rates were expressed in terms of barrels of oil-in-place found per exploratory foot drilled in search of oil and varied as a function of cumulative exploratory oil drilling.

The volume of oil-in-place found yearly in each region was determined from the product of the oil finding rate and the exploratory drilling rate. The oil reserves added from exploratory drilling were determined by applying the appropriate primary recovery factor to the oil-in-place discovered. The reserves added by application of secondary and tertiary recovery processes were calculated and added to the exploration results, thus determining total annual oil reserve additions.

Annual oil production was scheduled as a function of the remaining reserves at the beginning of

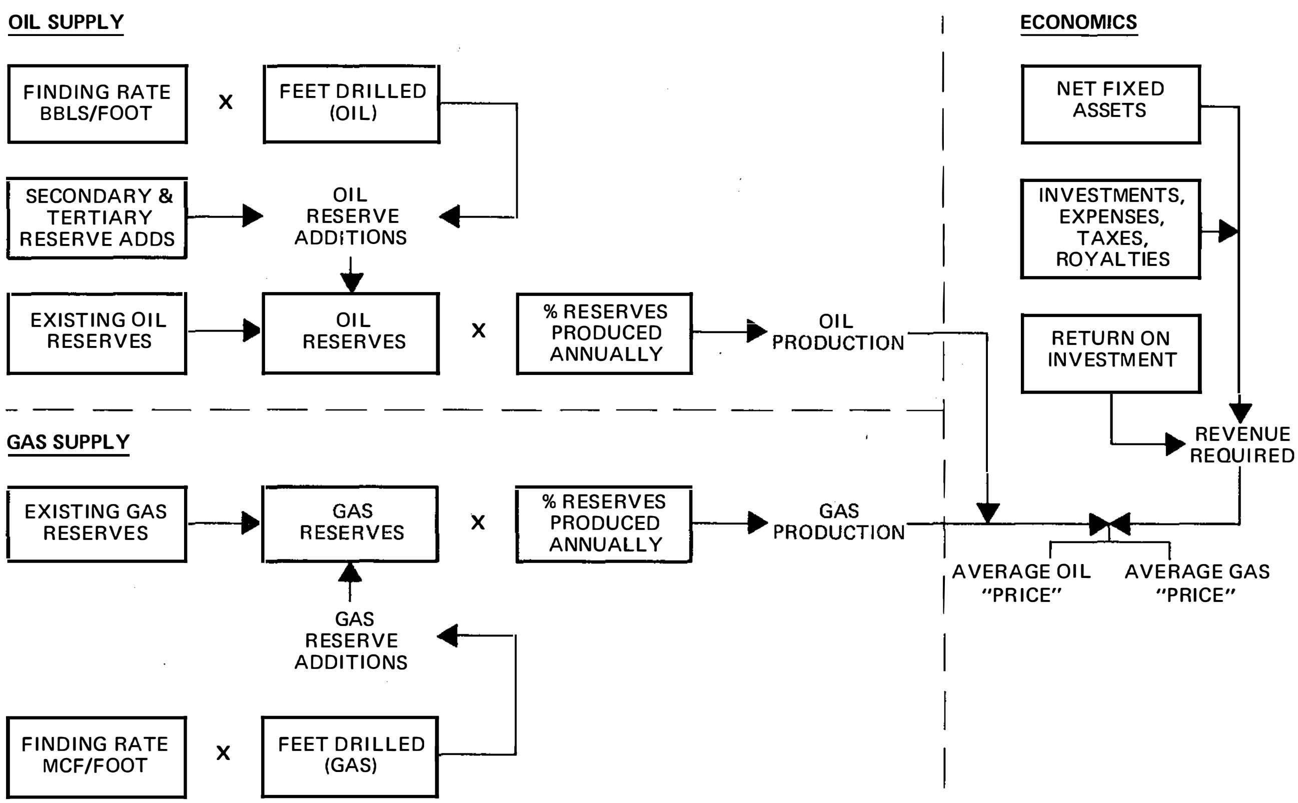


Figure 7. Oil and Gas Supply—Economic Methodology.

each year by applying appropriate factors in the various regions to account for their particular oil recovery mechanisms and reservoir characteristics. Associated-dissolved gas reserves and production were estimated by applying calculated gas/oil ratios to the oil production volumes.

Gas Supply Procedures

Non-associated gas reserve additions and resulting production were determined in a manner very similar to that used in making the oil calculations. However, gas finding rates were expressed as gas reserves found per foot of total gas drilling, including both exploratory and development well footage.

Gas production was calculated regionally, using one schedule of factors which related annual production to proved reserves estimated as of December 31, 1970, and a second schedule of factors which related annual production to reserves subsequently added.

Reserves and production of natural gas liquids contained in the natural gas—both non-associated and associated-dissolved—were calculated by applying gas/liquid ratios derived from historical data.

Because of the inherently high primary recovery factors normally experienced with gas well production, no additional recovery of reserve additions are calculated. Nuclear-explosive stimulation does achieve higher production rates, but its application is regarded as appropriate only in those areas where conventional well completion techniques do not permit commercial operation. Therefore, this technology which is separately discussed could be thought of as increasing the reserve potential.

Economic Procedures

The investments and expenses required to achieve the projected oil and gas drilling and producing levels were calculated from regional historical cost trend relationships and anticipated future drilling depths and locations. Other economic parameters, such as taxes, royalties and depreciation, were also quantified. Beginning with estimates of the industry's net fixed assets both in oil and gas production facilities as of December 31, 1970, the average net fixed assets for each fuel were determined for each subsequent year.

The annual net income necessary to yield various levels of return on the net fixed assets was calculated. These returns are defined as the ratio of the annual net income after tax (before interest charges) to the average net fixed assets (average of beginning- and end-of-year net investment in property, plant and equipment). A broad range of returns was investigated as an alternative to making an arbitrary selection of a specified return level that would be required by an industry composed of numerous individuals and firms experiencing diverse economic conditions. Tax liabilities and all other expenses and burdens on production such as royalties were also computed to arrive at the total revenue required for each rate of return. The revenues from associated-dissolved gas were credited to the oil sector; revenues from gas liquids were credited to the gas sector.

Once the required oil and gas revenues were calculated, they were converted to unit revenue or "price" * schedules. Dollars per barrel and cents per MCF were computed by dividing the required annual oil and gas revenue by the volumes of oil and gas which are marketed. The "prices" calculated in this manner represent *average* U.S. crude oil and natural gas "prices" in the field. The method used makes no attempt to calculate "price" by geographic area, by quality of product, or by year of discovery.

Considerations Regarding Methodology

General

This methodology does not address all of the factors that motivate individual investors either to take the risks necessary to explore for and produce increasing quantities of oil and gas or, conversely, to retrench in their operations. The program has no internal optimizing logic or mechanisms by which it can relate calculated economic results to investor motivation or incentives. Therefore, the method of analysis should not be used to forecast explicitly or calculate the elasticity of supply to price. However, it can be used to estimate unit

* Not a specific selling price as between producer and purchaser and does not represent a future market value. The term "price" is used to refer generally to economic levels which would, on the basis of the cases analyzed, provide a specified rate of return on net fixed assets for given levels of activity for the particular fuel.

revenues for oil and gas required to support assumed levels of exploration and production activity based on the industry achieving specified rates of return on its net fixed assets.

This method does not separately compute the "prices" required to achieve an acceptable return on incremental new investments. Rather, it calculates the *average* "price" needed to yield a specified return on total net fixed assets, thereby combining past discoveries for which the major investments have previously been made and projected future discoveries with their accompanying costs. In an increasing-cost industry, the resultant *average* "prices" tend to be lower than those needed to justify incremental new exploratory and development investments so that the price incentive required to encourage new investments will be higher than the average "prices" calculated.

It is possible to utilize the average "price" calculations from the computer program to estimate the approximate rate of return on new investments provided by such average "prices." This subject is addressed further in the oil and gas economics section.

Returns on net fixed asset calculations were used for oil and gas because they recognize the large base of assets and reserves built up in the past as well as new activities and can be calculated with a minimum of assumptions. This return on net fixed assets is not the same as the more commonly reported *return on shareholders' equity* (also termed *return on invested capital* or *return on net worth*). To attempt to calculate return on shareholders' equity would require making a large number of additional assumptions on allocation of corporate accounts such as working capital (inventories, cash, receivables and payables, etc.), other long-term assets (pre-payments, deferred charges, goodwill etc.), and long-term liabilities (primarily debt) that might be appropriate for domestic exploration and production operations. No historical data are available for estimating these items, and to attempt to do so would add additional uncertainty. Published estimates of historical returns on domestic exploration and production net fixed assets are available and provide a basis for comparison of projections with past performance.* These historical data on returns on net fixed assets are generally parallel but substantially higher than return on shareholders' equity.

To show the sensitivity of the returns to the base used, an estimate of working capital was added to the asset base. Although there are no reliable published data available on working capital assignable to only the exploration/production activities, 20 percent of net fixed assets was considered to be a reasonable estimate. The addition of working capital at that level reduces the return by about one-sixth so that a 15-percent return on net fixed assets would be 12.5 percent on total capital employed.

Oil and Gas Drilling

In establishing the rate at which drilling could increase annually for the high growth case (Case I), it was assumed that the industry could expand at a rate high enough to return to a drilling level equal to the maximum achieved since World War II by oil and exceed the previous peak year of gas drilling in 1961 by almost 50 percent. However, it is also necessary to recognize the obstacles that must be overcome to achieve that result. Since 1956, the industry has experienced a decline in domestic drilling activity which has resulted in dismantling a large number of rigs and having trained drilling personnel seek other employment. As a consequence, there are currently insufficient drilling rigs and experienced crews to support such a reversal in drilling activity without the manufacture of new equipment and an intensive period of personnel training.

Drilling effort cannot be radically and quickly shifted from one region to another. Seismic equipment and techniques used on land cannot be applied to offshore areas without modification. Also, lightweight drilling equipment with relatively shallow depth limitations cannot be utilized in areas where the objective reservoirs, if present, are at extreme depths. Large rigs, designed specifically for deep-well drilling, cannot be used economically to drill shallow wells. In most instances deep onshore drilling equipment cannot be used to implement a substantial increase in offshore drilling activity without extensive, costly and time-consuming modifications. The building or modification of specially designed equipment for Arctic operations

* "Financing the Petroleum Industry During the 1970's," Paper Presented by Kenneth E. Hill at the API Division of Finance and Accounting, Dallas, Texas, June 11, 1970.

is expensive and requires significant lead time. Also, the transportation and other related logistics factors pertaining to Arctic operations impose highly significant seasonal limitations on movement and operation even if cost were not a constraint. Therefore, in addition to an improved economic climate to overcome existing equipment and personnel availability obstacles, reliable expectations of access to frontier and offshore areas having future potential must exist, and continued technological improvement in drilling and logistics must be pursued.

Another obstacle to rapid drilling expansion is the lead time required to conduct increased geophysical and geological activities to locate drilling prospects, as well as the time needed to obtain leases and drilling permits.

Federal Offshore Lease Availability

The offshore areas of the United States account for a large percentage of the Nation's undiscovered oil and gas resources. For this reason, a critical assumption was required concerning the amount of acreage in these areas that would be made available and the time of its availability.

It was assumed that the lease sales schedule announced in 1971 by the Department of the Interior (shown in Table 37) would apply and that there would also be California offshore sales. Since the Department of the Interior's schedule extends only through 1975, an extrapolation was made to cover the remaining 10 years.

The announced schedule did not specify the amount of acreage to be offered for lease at each sale. However, it was assumed that sufficient acreage would be offered to meet the exploration needs projected in these areas. As an example, the offshore exploratory acreage requirements used in Case II for specific years are shown in the following tabulation.

	Thousand Acres per Year
1971	673
1975	1,101
1980	1,663
1985	2,263

During the 15-year period, a total of about 21 million acres would be required. This compares with slightly over 7 million acres that industry leased on the Outer Continental Shelf (OCS) during the 1952-1970 period.

The sensitivity of this critical item is examined in more detail in the parametric studies.

Supply—Oil

Ultimately Discoverable Oil

The NPC's Future Petroleum Provinces report was used to define the discoverable oil-in-place of the United States.* In that report, estimated future discoverable oil was separated into "probable and possible" and "speculative" categories. Only half of the speculative oil was included along with all of the probable and possible for purposes of this study. This represents the "median (expectable) estimate" presented in the Petroleum Provinces study.

Subsequent to publication of the Petroleum Provinces report, its authors were consulted to update the estimates as required and to develop an allocation of the future oil resources between onshore and offshore for the three coastal regions. As a result of recent developments on the North Slope of Alaska, the oil-in-place previously considered speculative is now considered probable and possible. Estimates were also added for speculative oil-in-place for the more prospective portions of the Alaskan Continental Shelf which were not included in the Petroleum Provinces report. Except for the Gulf of Alaska, these Alaskan offshore estimates cannot be considered as discoverable in the near future because of the very hostile operating conditions.

Present estimates are summarized in Table 38. The total discovered and discoverable estimate of 810.4 billion barrels is an increase of 90.6 billion barrels over the 719.8 billion estimated in the Petroleum Provinces report. Taking into account oil-in-place added by discoveries and revisions since the report was written, oil discoverable after 1970 is now estimated to be 385.2 billion barrels—53.3 billion barrels more than estimated in the Petroleum Provinces report. Of this volume, 160.2 billion barrels—42 percent of the oil-in-place remaining to be found—is located in offshore areas.

* NPC, *Future Petroleum Provinces of the United States* (July 1970).

TABLE 37

DEPARTMENT OF THE INTERIOR SCHEDULE OF ANNOUNCED LEASE SALES*

Tentative Schedule—OSC Leasing†

SALES	1971											
	J	F	M	A	M	J	J	A	S	O	N	D
Gulf of Alaska General												
Gulf of Mexico Drainage						4		6	7	SALE		
E. Louisiana Gen. & Gulf of Mexico Dr.	1		2				3	4	5	6	7	SALE
Louisiana Gen. & Gulf of Mexico Dr.						1		2	3	4	5	
E. Texas Gen. & Gulf of Mexico Dr.									1			2
Ala., Miss., & Fla. Gen. & Gulf of Mexico Dr.												
La. & E. Texas Gen. & Gulf of Mexico Dr.												
Gulf of Mexico Drainage												
La. & Texas Gen. & Gulf of Mexico Dr.												
Atlantic General												
Gulf of Mexico Drainage												
Gulf of Mexico Gen. & Dr.												

SALES	1972											
	J	F	M	A	M	J	J	A	S	O	N	D
Gulf of Alaska General	3	4	5			6						
Gulf of Mexico Drainage												
E. Louisiana Gen. & Gulf of Mexico Dr.												
Louisiana Gen. & Gulf of Mexico Dr.	6	7			SALE							
E. Texas Gen. & Gulf of Mexico Dr.		3	4	5		6		7			SALE	
Ala., Miss., & Fla. Gen. & Gulf of Mexico Dr.			1			2		3	4	5		6
La. & E. Texas Gen. & Gulf of Mexico Dr.									1			2
Gulf of Mexico Drainage												
La. & Texas Gen. & Gulf of Mexico Dr.												
Atlantic General								3		4	5	
Gulf of Mexico Drainage												
Gulf of Mexico Gen. & Dr.												

SALES	1973											
	J	F	M	A	M	J	J	A	S	O	N	D
Gulf of Alaska General								THIS SALE, OR ONE OF COMPARABLE POTENTIAL RESERVES, TO BE HELD PRIOR TO 1976				
Gulf of Mexico Drainage												
E. Louisiana Gen. & Gulf of Mexico Dr.												
Louisiana Gen. & Gulf of Mexico Dr.												
E. Texas Gen. & Gulf of Mexico Dr.												
Ala., Miss., & Fla. Gen. & Gulf of Mexico Dr.		7			SALE							
La. & E. Texas Gen. & Gulf of Mexico Dr.		3	4	5		6		7			SALE	
Gulf of Mexico Drainage										4		6
La. & Texas Gen. & Gulf of Mexico Dr.									1			2
Atlantic General		6						THIS SALE, OR ONE OF COMPARABLE POTENTIAL RESERVES, TO BE HELD PRIOR TO 1976				
Gulf of Mexico Drainage												
Gulf of Mexico Gen. & Dr.												

SALES	1974											
	J	F	M	A	M	J	J	A	S	O	N	D
Gulf of Alaska General												
Gulf of Mexico Drainage												
E. Louisiana Gen. & Gulf of Mexico Dr.												
Louisiana Gen. & Gulf of Mexico Dr.												
E. Texas Gen. & Gulf of Mexico Dr.												
Ala., Miss., & Fla. Gen. & Gulf of Mexico Dr.												
La. & E. Texas Gen. & Gulf of Mexico Dr.												
Gulf of Mexico Drainage		7			SALE							
La. & Texas Gen. & Gulf of Mexico Dr.		3	4	5		6		7			SALE	
Atlantic General												
Gulf of Mexico Drainage										4		6
Gulf of Mexico Gen. & Dr.									1			2

SALES	1975											
	J	F	M	A	M	J	J	A	S	O	N	D
Gulf of Alaska General												
Gulf of Mexico Drainage												
E. Louisiana Gen. & Gulf of Mexico Dr.												
Louisiana Gen. & Gulf of Mexico Dr.												
E. Texas Gen. & Gulf of Mexico Dr.												
Ala., Miss., & Fla. Gen. & Gulf of Mexico Dr.												
La. & E. Texas Gen. & Gulf of Mexico Dr.												
Gulf of Mexico Drainage												
La. & Texas Gen. & Gulf of Mexico Dr.												
Atlantic General												
Gulf of Mexico Drainage		7			SALE							
Gulf of Mexico Gen. & Dr.		3	4	5		6		7			SALE	

* "U.S. Will Step Up Offshore Leasing," *Ocean Industry* (July 1971), p. 15.

† Number Code for Tentative Schedule—OCS Leasing: 1—Call for nominations; 2—Nominations due; 3—Hearing notice; 4—First draft of Environmental Quality Statement; 5—Hearing; 6—Environmental Quality Statement; 7—Notice of sale.

Some additional estimates of all ultimately discoverable petroleum liquids originally in place (not just crude oil) have been published. They are shown in Table 39.

To provide more accurate estimates of the results of future finding and developing efforts, an analysis was made of the remaining oil-in-place in each region by geologic horizon and depth.

Oil Finding Rate

Utilizing the results of the resource studies, possible future exploration success rates were established in terms of oil-in-place discovered per foot of exploratory drilling in each region. Since exploratory success varies widely, high and low finding rates were projected for each region.

The technique used to determine regional finding rates was as follows:

- Oil-in-place found per foot of exploratory oil drilling in each region was calculated annually for the period 1956 through 1970. The regional oil-in-place found by the drilling effort in a given year was calculated from the American Petroleum Institute (API) annual reserve additions. This was done by dividing each region's annual reserve additions by the primary recovery factor established for that re-

TABLE 38

OIL-IN-PLACE RESOURCES

Region		Billion Barrels: Ultimate Discoverable Oil-in-Place	Billion Barrels: Oil-in-Place Discovered to 1/1/71	Remaining Discoverable Oil-in-Place: Billion Barrels	Remaining Discoverable Oil-in-Place: % of Ultimate
Lower 48 States—Onshore					
2	Pacific Coast	101.9	80.0	21.9	21.5
3	Western Rocky Mtns.	43.6	5.8	37.8	86.7
4	Eastern Rocky Mtns.	52.4	23.9	28.5	54.3
5	West Texas Area	151.6	106.4	45.2	29.8
6	Western Gulf Coast Basin	109.0	79.7	29.3	26.9
7	Midcontinent	63.0	58.4	4.6	7.3
8–10	Michigan, Eastern Interior and Appalachians	36.5	30.5	6.0	16.4
11	Atlantic Coast	3.8	0.2	3.6	94.7
	Total	**561.8**	**384.9**	**176.9**	**31.5**
Offshore and South Alaska					
1	South Alaska Including Offshore	26.0	2.9	23.1	88.8
2A	Pacific Ocean	49.6	1.9	47.7	96.2
6A	Gulf of Mexico	38.6	11.5	27.1	70.0
11A	Atlantic Ocean	14.4	0.0	14.4	100.0
	Total	**128.6**	**16.3**	**112.3**	**87.3**
Total United States (Ex. North Slope)		**690.4**	**401.2**	**289.2**	**41.9**
Alaskan North Slope					
Onshore		72.1	24.0	48.1	66.7
Offshore		47.9	0.0	47.9	100.0
	Total	**120.0**	**24.0**	**96.0**	**80.0**
Total United States		**810.4**	**425.2**	**385.2**	**47.5**

TABLE 39

ESTIMATES OF ULTIMATELY DISCOVERABLE PETROLEUM LIQUIDS ORIGINALLY IN PLACE*
(Billion Barrels)

	1972 USGS	1969 Hubbert	1959 Weeks	1970 Moore	1968 Elliott and Linden
Lower 48 States	1,519	516	Not Estimated		
Alaska	376	78			
Total United States	**1,895**	**594**	**1,315**	**670**	**1,286**

* P. K. Theobald, S. P. Schweinfurth and D. C. Duncan, *Energy Resources of the United States,* U. S. Geological Survey, Circular No. 650 (July 1972).

gion. The API reserve addition categories of "new fields," "new pools" and "extensions" were used for this purpose since these represent reserves which result from new oil-in-place found. Reserve additions from improved primary recovery and additional recovery projects are reported as "revisions."

- For each region, the historical finding rate was plotted as a function of the cumulative exploratory footage drilled since 1956.
- Trends were established from these plots and were projected into the future using a range of probable rates. A set of lower finding-rate projections was based on a simple semi-logarithmic extrapolation of past trends. Another set of projections was made predicated on the possibility of altering the historical trend through technological improvements, through discovery of some unsuspected "giant" fields (100 MMB or larger), or through additional rewards resulting from increased risk-taking spurred on by improved incentives. These more optimistic trends averaged 50 percent higher than the low cases.

For regions which have no reliable historical data, finding curves were established by assuming similarity with a more mature region. For example, the Atlantic Coast offshore province was assumed to be analogous to the offshore Gulf Coast.

Composite finding trends for the total United States are shown in Figure 8. These composites reflect the changing mix as exploration shifts from the lower 48 states onshore area into the frontier provinces of the offshore areas and Alaska. Since these frontier provinces are still in the early stages of development, their finding rates are projected to remain quite high, while those for the older onshore areas continue to decline.

Oil Drilling Activity

The second parameter that must be considered is exploratory drilling which is expressed in footage drilled per year. It is this activity which discovers the additional oil-in-place that expands the reserve base to support future production levels.

In order to cover the range of possible exploration activities, a spectrum of three U.S. exploration drilling trends was selected for the projection period (see Figure 9). The highest activity level (Case I) assumed a 7.5 percent per year growth rate in exploratory footage. An intermediate activity level (Cases II and III), though still high, assumed a 5 percent per year growth. On the low end of the spectrum (Case IV), a decline in activity of about 3 percent per year was used. All of these trends were assumed to have as their base point the estimated 1971 drilling level.

These exploratory drilling levels for the total United States (excluding North Slope) were distributed by geologic region in accordance with the data on each region's current share of the Nation's drilling effort, future potential and costs. The dis-

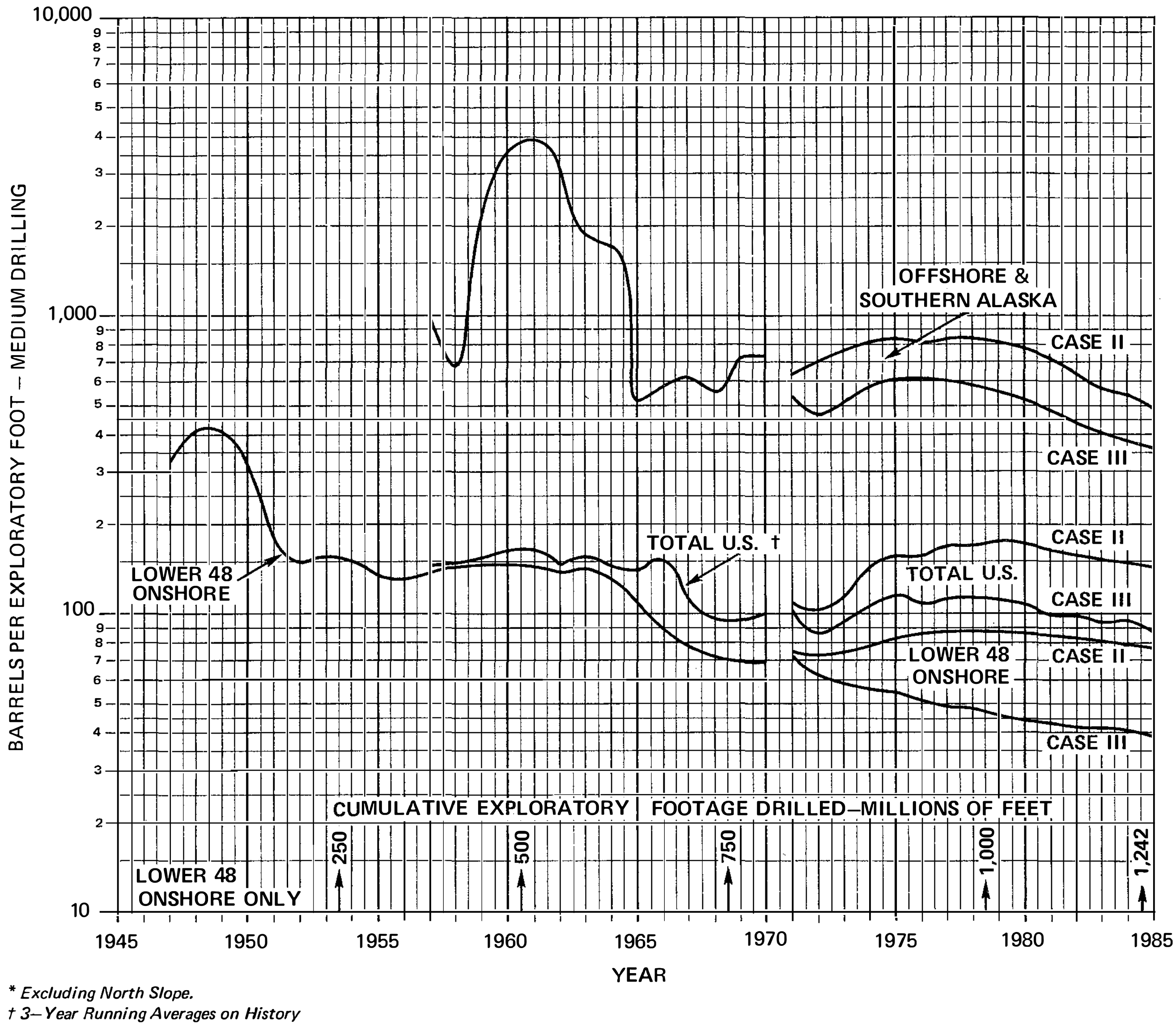


Figure 8. Oil Finding Rates—Medium Drilling.*

tribution used in the analysis is shown in Table 40.

Although exploratory drilling is a key determinant of the oil-in-place that will be discovered in the next 15 years, the total amount of drilling, including development drilling, is important in determining costs of finding and developing oil supplies. The amount of development drilling is related to the assumed exploratory drilling level as a function of the amount of oil found by each exploratory well. If, on an average, exploratory wells find relatively large amounts of oil, more development wells will be required than if exploratory wells find only small reservoirs. In each region a correlation of total drilling to exploratory drilling was derived using data for the last 15 years. These correlations were then used in projecting total drilling as a function of the assumed exploration drilling and success levels. The resulting total oil drilling is shown on Figure 9.

The number of wells resulting from these drilling footages are indicated in Figure 10. As a result of the increasing well depth needed to reach the future oil resources, total wells drilled do not increase as rapidly as the footage drilled.

TABLE 40

PROJECTED REGIONAL ALLOCATION—EXPLORATORY DRILLING EFFORT

Region		Percent of Total U. S. Oil Exploratory Drilling 1970	1975	1980	1985	Initial Appraisal*
1	Alaska†	0.1	0.7	1.0	1.5	0.6
2A	California Offshore	0.5	2.5	3.0	3.0	1.2
6A	Gulf Coast Offshore	2.1	7.0	8.0	9.0	5.8
11A	Atlantic Coast Offshore	—	0.2	0.5	2.0	—
Total Offshore and Alaska		**2.7**	**10.4**	**12.5**	**15.5**	**7.6**
2	Pacific Coast	4.2	4.0	4.0	4.0	5.1
3	Western Rocky Mtns.	6.0	5.0	4.5	5.1	2.0
4	Eastern Rocky Mtns.	28.1	26.5	25.8	24.6	12.9
5	West Texas	14.4	13.5	13.0	12.5	20.0
6	Gulf Coast Onshore	27.8	24.5	23.0	19.6	24.9
7	Midcontinent	14.0	9.7	8.9	8.2	18.9
8–10	Michigan, Eastern Interior and Appalachians	2.3	4.5	5.5	6.5	8.5
11	Atlantic Coast Onshore	0.5	1.9	2.8	4.0	0.1
Total Lower 48 Onshore		**97.3**	**89.6**	**87.5**	**84.5**	**92.4**
Total United States		**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

* Percent of total drilling rather than exploration drilling.

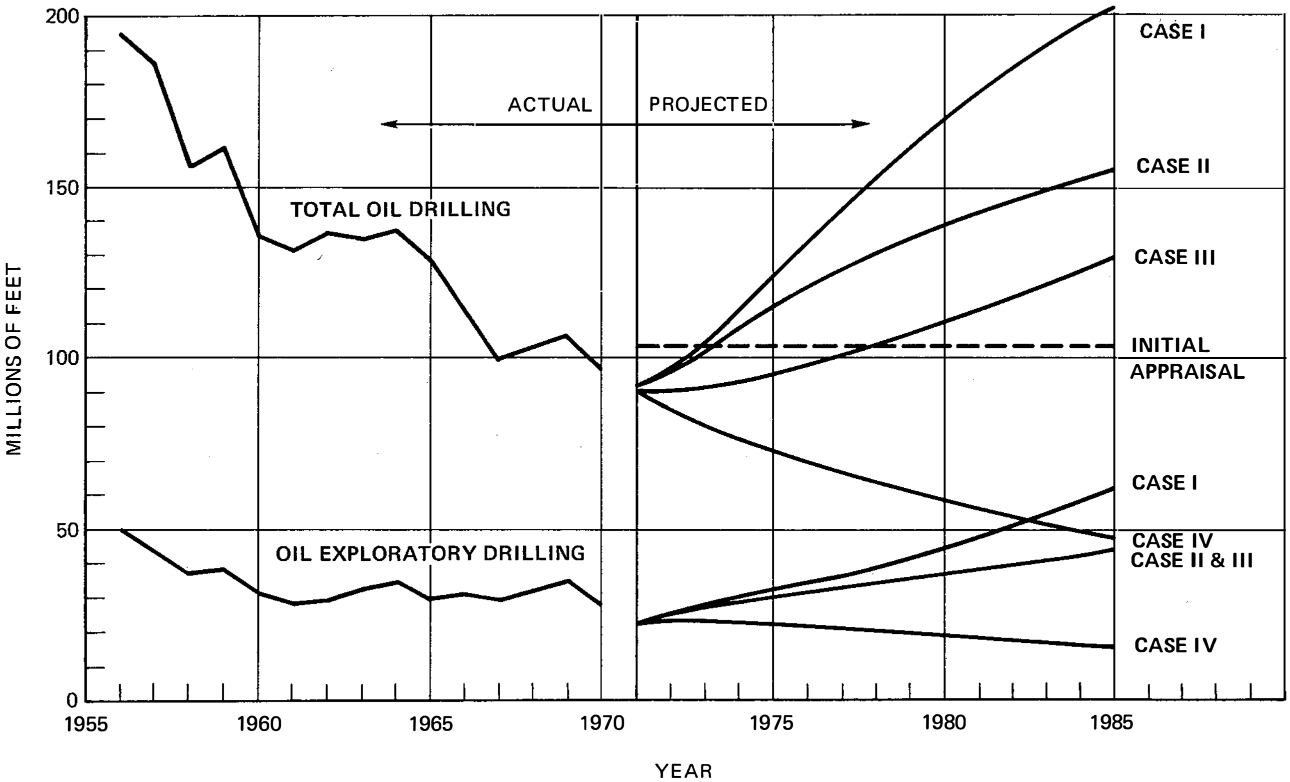
† Excluding North Slope.

Oil-in-Place Found

Once projections of regional oil-in-place finding rates and exploratory drilling rates had been established, the appropriate multiplication of the two resulted in a schedule of oil-in-place found per year by region for the 15-year projection period.

The amount of oil-in-place discovered in the four cases is shown in Figure 11. This plot is a composite U.S. total on a cumulative basis. The lowest discovery case (Case IV) is based on an extrapolation of the drilling and finding rates of the last 15 years. It is also the case which most nearly approximates the findings projected by the Initial Appraisal. Cases I, II and III show various volumes of increase above the declining historical discovery experience because of substantially increased drilling rates and, for Cases I and II, more favorable finding rates. The results of all four cases, as compared to the Initial Appraisal, are presented in Table 41 by geographic region. As indicated, a little over half of the total U.S. ultimate discoverable oil-in-place had been found by 1971. Oil discovered in the 1971-1985 period, with the high and low projections, is summarized in Table 42.

Case I results from the most optimistic level of achievement for all important factors. In order to achieve Case I, it would be necessary to maintain the high drilling growth rate and the high finding rate in each region, each year, for the entire 15-year period. With the North Slope added to these results, 119 billion barrels of oil would be found, which is more than twice as much as the Case IV volume. It would represent an amount equivalent to 30 percent of all the oil found in the United States since the inception of the oil business. Cases II and III fall between Cases I and IV and were used in making more extended studies. The Initial Appraisal results fall between those for Cases III and IV.



* *Excluding North Slope drilling.*

Figure 9. Oil Drilling Rate Projections—Million Feet Drilled.*

In order for the high projections to be met, an enormous amount of exploration will be required in the frontier areas of offshore and Alaska, including the North Slope. For example, Case I projects that 31 percent of the total ultimate oil discoverable in these frontier areas will be found during the next 15 years compared with 16 percent discovered to date. Also, the older onshore areas will be nearing the ultimate discoverable estimates by 1985 as shown in Table 43.

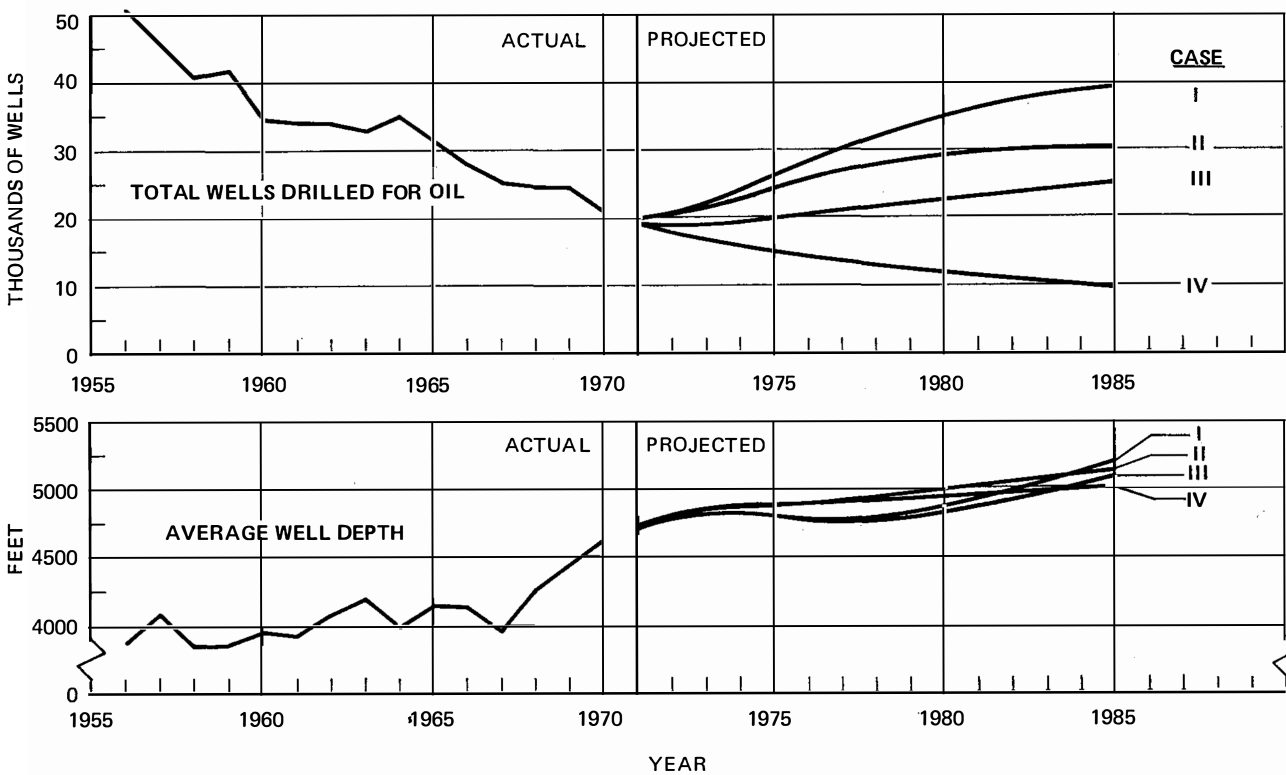
Oil Reserve Additions

The procedure for determining annual oil reserve additions was as follows: Using the regional projections of oil-in-place found per year, primary reserve additions resulting from exploratory effort each year were calculated by applying the regional primary recovery factor to the oil-in-place discovered that year. Reserve additions from application of secondary and tertiary operations originate from both oil-in-place found in prior years and that found during the projection period. Additional reserves from this source were added as a function of length of time since discovery. In each region, the future recovery efficiencies were projected based upon past history, expected reservoir characteristics and related reservoir performance.

The composite U.S. recovery efficiency resulting from application of this methodology was consistent with the trend experienced over the last 15 years, as shown in Figure 12.

In addition to determining crude oil reserve additions in this manner, reserve additions of associated-dissolved natural gas found in the same reservoirs with the oil were estimated. The historical ratios of associated-dissolved gas reserves added per unit of crude oil reserves were applied to the crude reserve additions calculated for each year.

A projection of the total reserve additions resulting from new oil-in-place found and additional recovery efforts on both old and new oil-in-place (excluding the North Slope) is shown in Figure 13. For the last 15 years, the reserve additions from



* *Excluding North Slope drilling.*

Figure 10. Total Oil Wells Drilled and Average Depth.*

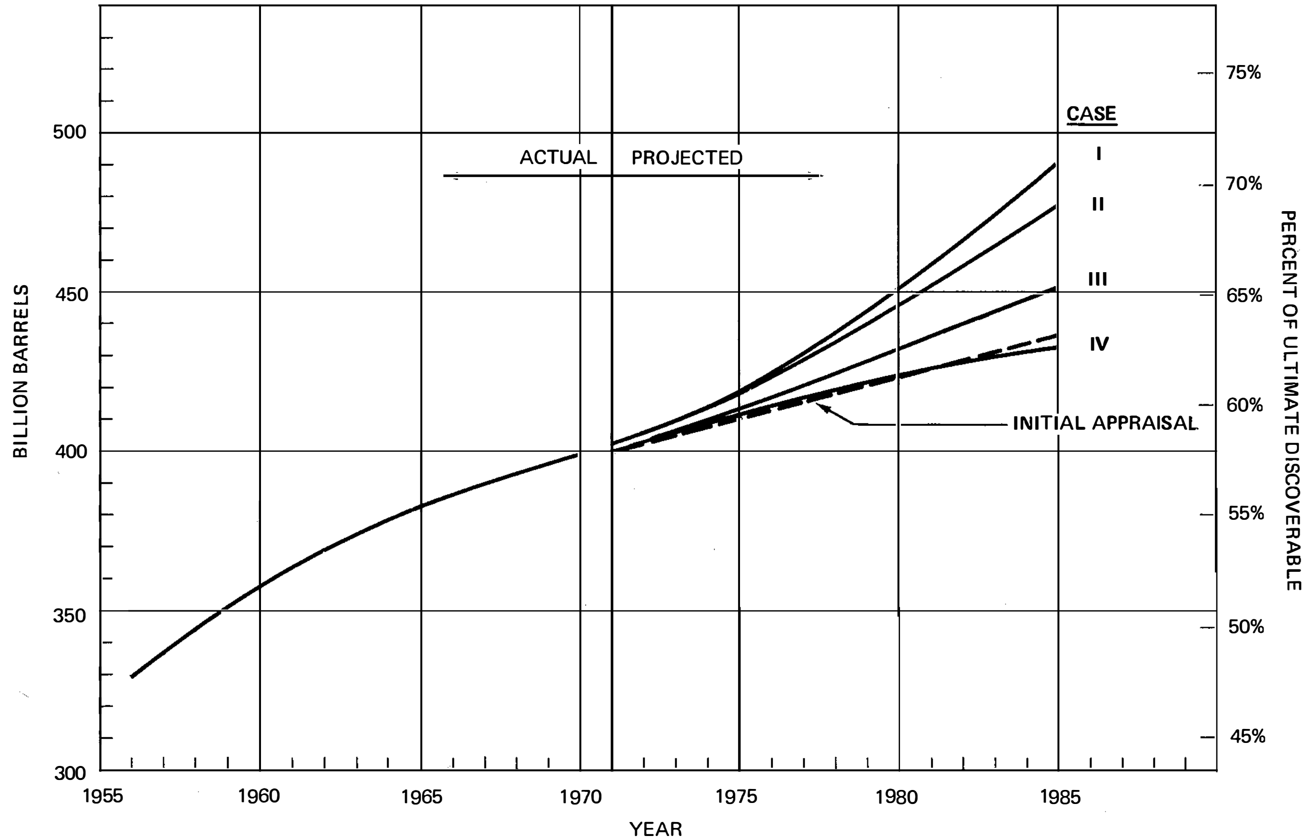
all sources, including revisions, have remained relatively constant at about 2.7 billion barrels per year. Case IV projects annual reserve additions to average about 2.5 billion barrels—about 10 percent below historical levels. The Initial Appraisal showed future reserve additions averaging 2.8 billion barrels per year. Case I reaches a maximum of approximately 4.6 billion barrels per year during the 15-year period and has a yearly average of 3.8 billion barrels. This is 41 percent more than the industry achieved in the last 15 years.

With the North Slope *included* in the comparisons, average annual reserve additions are noted in the following tabulation:

	1971-1985 Projected (Billion Barrels)			
	Case			
1956-1970 Actual	I	II	III	IV
3.3	4.4	4.1	3.5	2.9

The reserve additions by region for the 1971-1985 period are summarized and compared with the experience of the previous 15 years in Table 44. This table demonstrates the sizable contribution that will be required from the frontier areas of offshore and Alaska, including the North Slope. For these areas, 1.7 times the reserves booked in the past 15 years are projected for addition during the 1971-1985 period in Case I. Additions for this case in the more mature lower 48 state onshore areas are projected to be 18 percent higher than historical experience, largely as a result of the application of additional recovery processes.

Figure 14 shows a typical distribution of the reserve additions resulting from different recovery mechanisms for one of the intermediate cases (Case II). This demonstrates the significance of the secondary and tertiary recovery projections. Over the last 15 years, the reserve additions resulting from improved recovery efficiency have steadily increased from about 29 percent of the total reserve additions in 1956 to 67 percent in 1970; however, reserve additions resulting from exploration have steadily declined. During this historical period, improved recovery has averaged about 0.9 billion



* *Excluding North Slope operations.*

Figure 11. Cumulative Oil-in-Place Discovered.*

barrels per year, increasing to 2 billion barrels in 1970.

In 1985 for Case II, the contribution of improved recovery processes is about 60 percent of the annual reserve additions in that year. The impact of tertiary recovery processes gradually increases with time so that in 1985 about 25 percent of the total reserves added are provided by new recovery processes. These processes are now in the research and development stage and are not commercially applicable at present prices.

Oil Production

Oil production was scheduled as a function of the reserves remaining at the beginning of each year for each region using fractions for production as a function of reserves. This fraction is the reciprocal of the commonly used reserves/production ratio (R/P). Over the last 10 years, the total U.S. R/P has declined as excess producing capacity was utilized. This trend is shown in Table 45.

Currently, the net excess capacity (excluding the East Texas field and the emergency reserves in Naval Petroleum Reserve No. 1 [NPR-1]) is less than 0.5 MMB/D. Without any significant excess capacity remaining, the declining R/P trend must level off, and the ratio will be approximately constant in the future at the current level.

Projected total U.S. crude oil production, including the North Slope, for the six cases and the Initial Appraisal is shown in Table 46 and Figures 15 and 16.

Over the last 15 years, crude production has increased gradually from about 7 MMB/D in 1956 to 9.1 MMB/D in 1971. Future production for Case IV, in which drilling activity continues its historical downtrend, is projected to decline to 7.6 MMB/D by 1980. North Slope production is

TABLE 41

REGIONAL OIL-IN-PLACE DISCOVERED—TOTAL UNITED STATES
(Billion Barrels)

Region		Ultimate Discoverable OIP	OIP Discovered to 1/1/71	OIP Discovered 1971–1985 Case I	II	III	IV	Initial Appraisal
Lower 48 Onshore								
2	Pacific Coast	101.9	80.0	2.6	2.1	1.7	1.1	3.4
3	Western Rocky Mtns.	43.6	5.8	1.6	1.4	0.8	0.6	1.2
4	Eastern Rocky Mtns.	52.4	23.9	7.9	6.6	2.9	1.9	5.2
5	West Texas Area	151.6	106.4	8.7	6.9	4.6	3.2	2.0
6	Western Gulf Coast Basin	109.0	79.7	11.8	10.4	6.3	4.0	3.1
7	Midcontinent	63.0	58.4	3.9	3.4	2.3	1.5	2.7
8–10	Michigan, Eastern Interior and Appalachians	36.5	30.5	4.9	4.4	2.2	1.5	2.1
11	Atlantic Coast	3.8	0.2	1.0	0.8	0.5	0.3	–
	Total	**561.8**	**384.9**	**42.4**	**36.0**	**21.3**	**14.1**	**19.7**
Offshore and Alaska								
1	Southern Alaska Including Offshore	26.0	2.9	11.6	10.4	6.7	4.6	4.7
2A	Pacific Ocean	49.6	1.9	20.2	17.0	12.6	7.2	3.7
6A	Gulf of Mexico	38.6	11.5	13.6	12.5	8.8	6.1	13.0
11A	Atlantic Ocean	14.4	0	2.2	1.5	1.3	0.5	–
	Total	**128.6**	**16.3**	**47.6**	**41.4**	**29.4**	**18.4**	**21.4**
Total United States (Ex. North Slope)		**690.4**	**401.2**	**90.0**	**77.4**	**50.7**	**32.5**	**41.1**
Alaskan North Slope								
Onshore		72.1	24.0	29.0	23.3	23.3	15.2	0
Offshore		47.9	0	0	0	0	0	0
	Total	**120.0**	**24.0**	**29.0**	**23.3**	**23.3**	**15.2**	**0**
Total United States		**810.4**	**425.2**	**119.0**	**100.7**	**74.0**	**47.7**	**41.1**

initiated in 1981, and the total U.S. rate increases to 9.4 MMB/D by 1985.

The Initial Appraisal assumed that North Slope oil would begin flowing in 1975, but subsequent delays in approval of the pipeline have proved this to be an unrealistic expectation. Initiation of North Slope production for Cases I through III is assumed to occur in 1976. This explains the sharp increase in total U.S. production in that year. The production decline shown in the near future is a result of the inevitable time lag between increasing exploratory activity and realization of the resulting increased production. Once the results of the increased exploratory activity begin to be felt, along with the impact of North Slope startup, U.S. production is projected to increase to 1985 levels of 10.6 to 13.5 MMB/D for these expansion cases. These volumes exceed the Initial Appraisal starting in the late 1970's, even though the Initial Appraisal had the benefit of higher drilling rates in the early 1970's and North Slope production beginning a year earlier.

Figure 17 depicts, for Case II as an example, the components of U.S. crude production by recovery mechanism as well as showing whether or not the reserves were discovered before 1971. A tremendous amount of reserves have already been found on the North Slope. However, some additional oil

TABLE 42

OIL DISCOVERED—1971-1985

	Oil Discovered 1971-1985 (Billion Barrels)	
	Case I	Case IV
United States (ex. North Slope)	90.0	32.5
North Slope	29.0	15.2
Total United States	**119.0**	**47.7**

	% of Ultimate OIP Discovered		
		To 1/1/86	
	To 1/1/71	Case I	Case IV
United States (ex. North Slope)	58	71	63
North Slope	20	44	33
Total United States	**52**	**67**	**58**

must be found in the future to support 2.0 MMB/D production rate projected for this area. No attempt has been made to split this area between the new and old field categories; rather, it is shown separately to illustrate its impact on production volumes.

Over the last 15 years, production from primary reserves has remained fairly constant at 5.0 to 5.5 MMB/D, while production from fields in which some sort of additional recovery project is underway has grown from about 1.5 to 3.5 MMB/D. Despite declining drilling and reserve additions, no appreciable decline in primary production has been apparent, largely because substantial spare capacity was available during this time period. Now that this spare capacity no longer exists, a normal decline is projected to ensue.

If no new fields were found after 1970, lower 48 states primary production would decline from 5.5 MMB/D in 1970 to about 1.0 MMB/D in 1985—a drop of over 80 percent. Although heavy application of secondary and tertiary recovery processes would mitigate this decline, the current 9.1 MMB/D would still decline by 40 percent to 5.5 MMB/D by the end of the period. By 1985, these additional recovery projects are expected to account for about 80 percent of production from reservoirs discovered before 1971.

Of the total 1985 production rate of 12.2 MMB/D projected for Case II, the North Slope will account for 16 percent, old reserves will contribute 45 percent, and new discoveries made in 1971 and later years must account for 39 percent. The nearly 4.7 MMB/D of production from new discoveries is the equivalent of over two-thirds of the average daily production from 1956 to 1965 for the whole country. Most of these newly discovered reserves will still be producing under primary recovery mechanisms by 1985. However, this new oil will provide the basis for application of current and improved additional recovery techniques. These techniques should have at least as much impact on production from new fields after 1985 as they are projected to have during the next 15 years on currently known reserves.

Figure 18 presents a breakdown of daily production by geographic area for Case II. As shown, lower 48 onshore production just about holds its own throughout the 1971-1985 period. During this same period, production from offshore is projected to almost double. In 1985, for Case II, 61 percent of the total U.S. production will be provided by the onshore areas of the lower 48 states while 39 percent will be provided by offshore and Alaska, including the North Slope. The size of this projected increase in volumes from frontier areas emphasizes the need for making lands available for exploration in these regions.

Figures 19 and 20 demonstrate that the total of petroleum liquids production in 1985 ranges from about 10.4 MMB/D to about 15.5 MMB/D. This amounts to as much as 50 percent more than the supply projected in the Initial Appraisal. However, even in the more optimistic cases, the lead time requirements are such that little improvement is realized until after 1975.

Associated-Dissolved Gas Production

Associated-dissolved gas produced for each of the cases was derived from regional gas/oil ratios based on historical experience. A 13-percent reduction factor for lease use, fuel and losses based on historical data was used to convert associated-dissolved gas production totals to marketed gas volumes.

Supply—Gas

Ultimately Discoverable Gas

The definition of ultimate gas discoverable was

TABLE 43

REGIONAL OIL-IN-PLACE DISCOVERED—TOTAL UNITED STATES
% OF ULTIMATE DISCOVERABLE
(Billion Barrels)

Region		Ultimate Discoverable OIP	% of Ultimate Discovered to 1/1/71	% of Ultimate OIP Discovered to 1/1/86 Case I	II	III	IV
Lower 48 Onshore							
2	Pacific Coast	101.9	79	81	81	80	80
3	Western Rocky Mtns.	43.6	13	17	17	15	15
4	Eastern Rocky Mtns.	52.4	46	60	58	51	49
5	West Texas Area	151.6	70	76	75	73	72
6	Western Gulf Coast Basin	109.0	73	84	83	79	77
7	Midcontinent	63.0	93	99	98	96	95
8–10	Michigan, Eastern Interior and Appalachians	36.5	84	97	96	90	88
11	Atlantic Coast	3.8	5	32	26	18	13
	Total	**561.8**	**69**	**76**	**75**	**72**	**71**
Offshore and Alaska							
1	Southern Alaska Including Offshore	26.0	11	56	51	37	29
2A	Pacific Ocean	49.6	4	45	38	29	18
6A	Gulf of Mexico	38.6	30	65	62	53	46
11A	Atlantic Ocean	14.4	0	15	10	9	3
	Total	**128.6**	**13**	**50**	**45**	**36**	**27**
Total United States (Ex. North Slope)		**690.4**	**58**	**71**	**69**	**65**	**63**
Alaskan North Slope							
Onshore		72.1	33	74	66	66	54
Offshore		47.9	0	0	0	0	0
	Total	**120.0**	**20**	**44**	**39**	**39**	**33**
Total United States		**810.4**	**52**	**67**	**65**	**62**	**58**

derived by combining the volumes of past production and current proved reserves with the Potential Gas Committee (PGC) estimate of the remaining potential supply of natural gas.* The PGC makes an estimate every 2 years of potential gas supply remaining to be discovered. Each revision reflects changes in technology and results of exploration and development that have occurred in the preceding 2 years. Some reallocation was necessary to make the PGC area estimates coincide with NPC regions. All reserves and production volumes reported herein are on the same bases as volumes reported by the American Gas Association (AGA) and the PGC.

As estimated by the PGC, 62 percent of the potential supply of 1,178 TCF of natural gas in the United States, including associated-dissolved, is situated in operationally difficult or frontier areas—approximately 14 percent is below 15,000 feet onshore, 20 percent is offshore and 28 percent is in Alaska.

Associated-dissolved gas potential was estimated by applying historical gas/oil ratios to potential oil

* *Potential Supply of Natural Gas in the United States (as of December 31, 1970)*, a Potential Gas Committee report sponsored by Potential Gas Agency, Mineral Resources Institute, Colorado School of Mines Foundation, Inc. (October 1971).

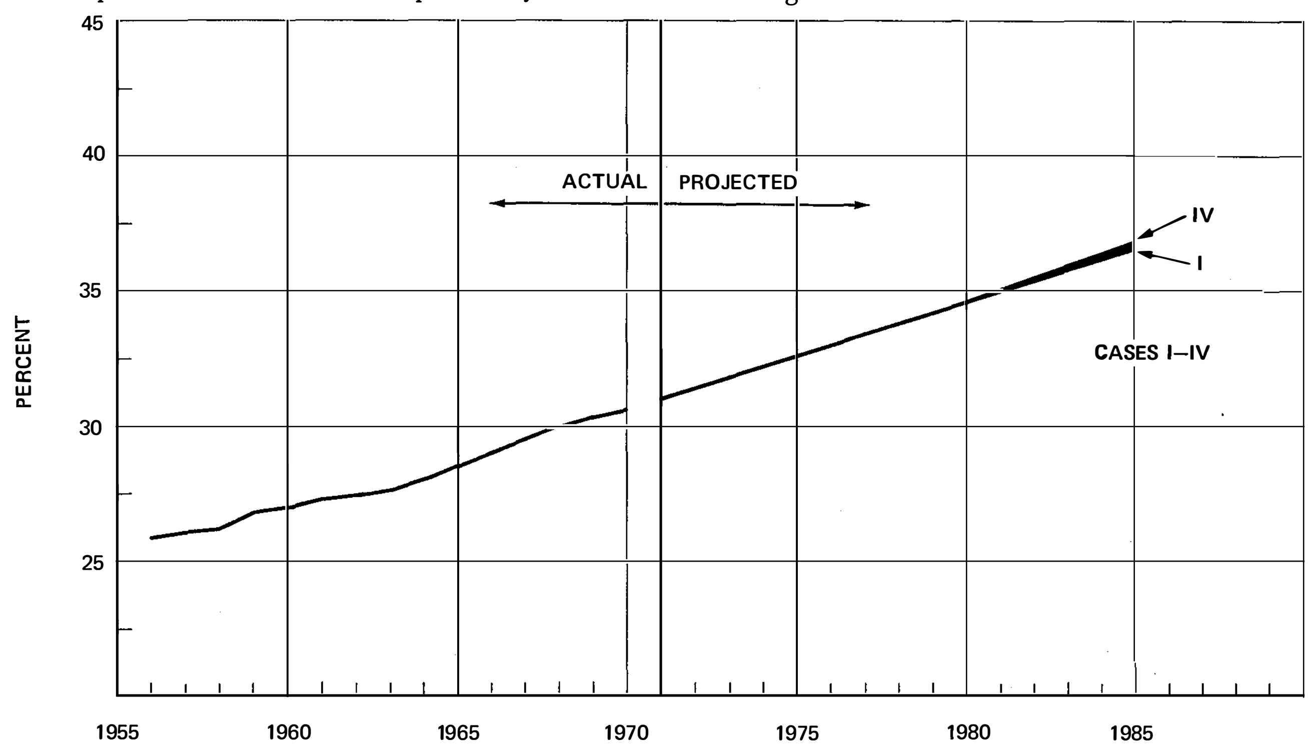
resources. These estimates of associated-dissolved potential gas were subtracted from the PGC estimates to arrive at non-associated potential gas. Table 47 shows non-associated gas potential, previously discovered gas, and ultimate recoverable gas (the sum of potential and discovered) by NPC region. Associated-dissolved gas potential is estimated to be 141.5 TCF, and past discoveries (as of year-end 1970) of associated-dissolved gas amounted to 215.2 TCF. These estimates, when added to ultimate non-associated gas supply of 1,500.6 TCF, result in an estimate of 1,857.3 TCF of ultimate discoverable gas in the United States. Some additional published estimates of ultimately discoverable natural gas originally in place are shown in Table 48.

There is a possibility that utilization of nuclear or other massive fracturing devices might, in the future, recover additional quantities of natural gas from low permeability reservoirs which are not productive in commercial quantities under conventional productive methods. This possibility has not been reflected in PGC estimates of potential supply.

Finding Rates for Non-Associated Gas

The AGA annual estimates of reserve additions in the lower 48 states provided the data used for developing the two finding rates. The AGA's published data for years prior to 1966 does not show non-associated gas reserve additions separately from associated-dissolved gas. Therefore, an allocation was made for these earlier years using U.S. Bureau of Mines production data in conjunction with the published AGA data to arrive at regional non-associated gas reserve additions.

Annual finding rates for non-associated natural gas have fluctuated widely in the past, ranging from 140 MCF to 408 MCF per foot drilled since 1955. Two different statistical methods of analyzing these data were employed to arrive at the projected high and low finding rates. One method was to fit a "growth curve" to the historical relationship between cumulative gas reserves found and cumulative gas footage drilled since 1955 for each region. This statistical treatment resulted in



* *Excluding North Slope operations.*

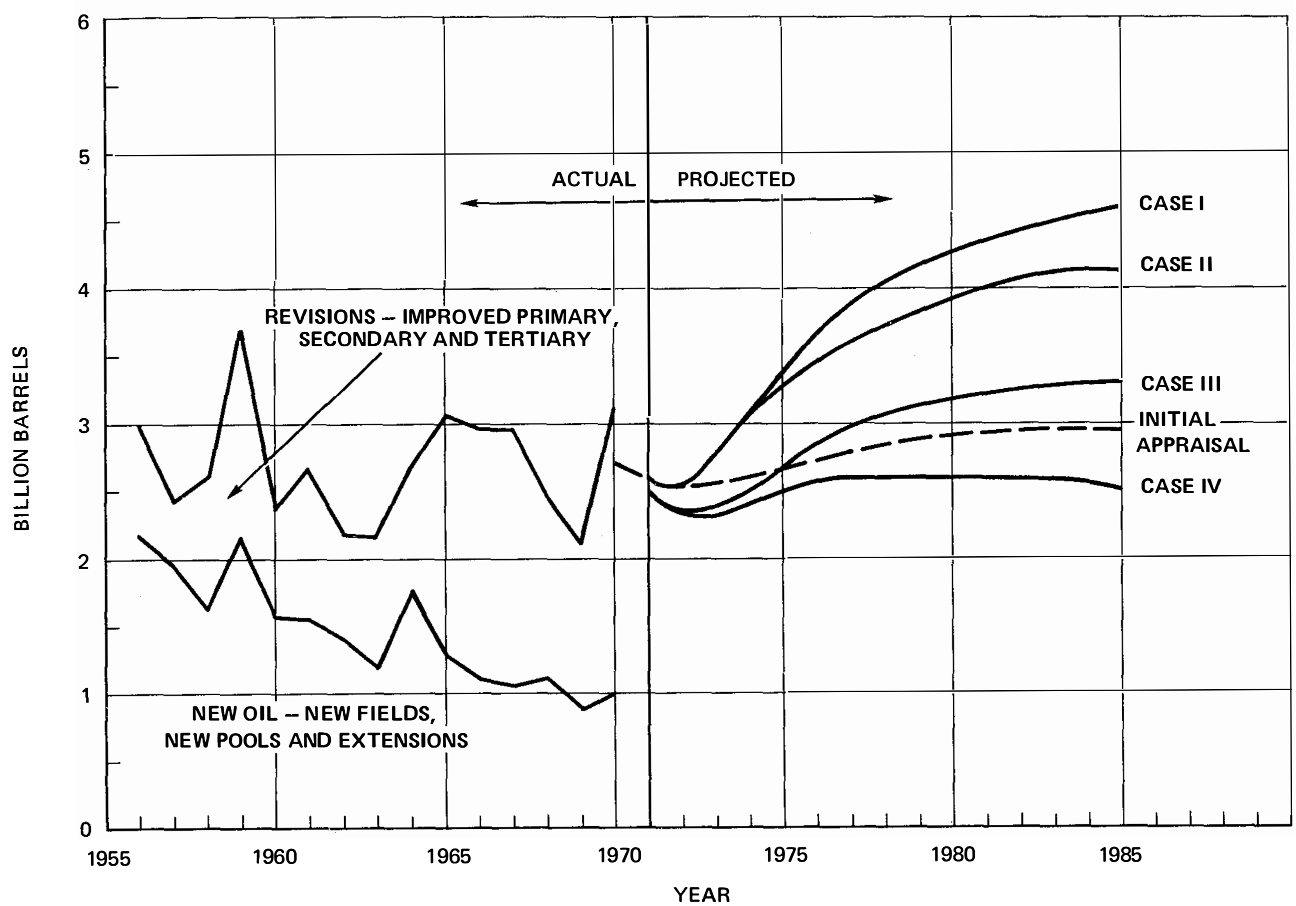
Figure 12. Cumulative Oil Recovery Efficiency (Percent of Oil-in-Place).*

a U.S. gas finding rate, designated the "high finding rate" (Cases I, II and IVA). During the period 1971-1985, this rate is projected to reach a high point of about 350 MCF per foot drilled, and in Case I this rate ultimately drops to approximately 265 MCF per foot drilled.

The "low finding rate" (Cases IA, III and IV) for non-associated gas per foot of hole drilled was estimated regionally by fitting a modified exponential curve to historical data, using the method of least squares. This was statistically applied to the historical relationship between the annual amount of non-associated gas found per foot of hole drilled and cumulative footage drilled for gas during the 15-year period 1956-1970. During the 1971-1985 period, this rate is projected to reach a high of about 240 MCF per foot drilled and to decline gradually to slightly below 200 MCF per foot drilled in Case IA.

In all cases, both the high and low finding rates experience a decline during the 15-year period 1971-1985. The reason is that both statistical systems are properly reflecting the declining probability of maintaining these rates at a constant level as the volume of *remaining* potential reserves to be found decreases.

The average finding rate for the lower 48 states is the weighted average of the projected regional finding rates. Figure 21 shows the average finding rate for the lower 48 states plotted against cumulative footage since 1946 as well as the projected high and low finding rates. The figure shows that the projected finding rates compare favorably with the range and trend of finding rates experienced since 1946.



* *Excluding North Slope reserve additions.*

Figure 13. Oil Reserve Additions.*

TABLE 44

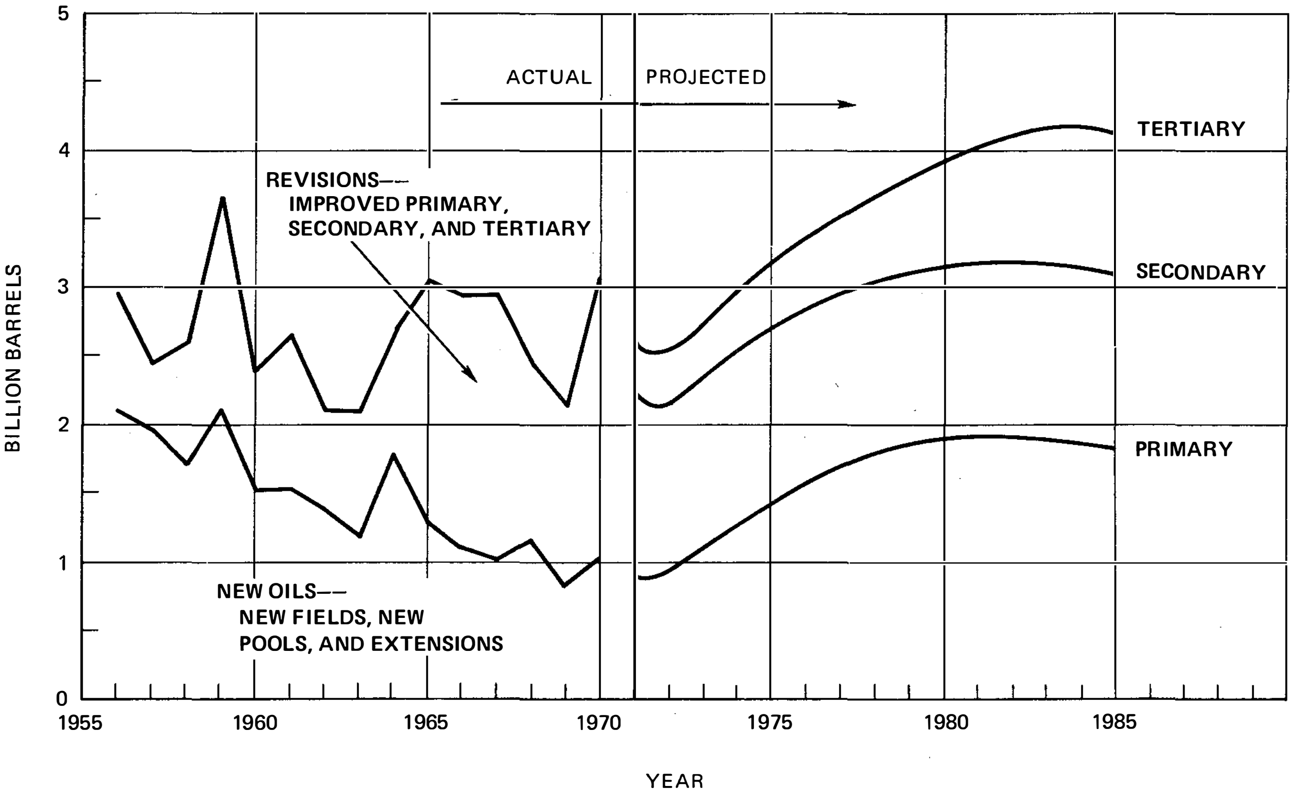
REGIONAL CRUDE OIL RESERVE ADDITIONS—TOTAL UNITED STATES
(Billion Barrels)

Region		Reserves Added 1956–1970	Reserves Added 1971–1985 Case I	II	III	IV	Initial Appraisal
Lower 48 Onshore							
2	Pacific Coast	4.8	4.6	4.5	4.4	4.2	5.1
3	Western Rocky Mtns.	1.1	0.6	0.6	0.4	0.4	0.5
4	Eastern Rocky Mtns.	2.9	3.1	2.7	1.6	1.3	2.4
5	West Texas Area	10.7	10.5	10.1	9.6	9.1	8.9
6	Western Gulf Coast Basin	9.2	15.2	14.5	12.6	11.5	11.0
7	Midcontinent	4.0	3.8	3.7	3.3	3.0	3.4
8–10	Michigan, Eastern Interior and Appalachians	1.4	2.3	2.2	1.4	1.2	1.3
11	Atlantic Coast	0.1	0.3	0.3	0.2	0.1	0
	Total	**34.2**	**40.4**	**38.6**	**33.5**	**30.8**	**32.6**
Offshore and Alaska							
1	Southern Alaska Including Offshore	0.9	3.8	3.4	2.4	1.7	1.7
2A	Pacific Ocean	0.3	4.9	4.2	3.1	1.8	1.0
6A	Gulf of Mexico	5.0	7.0	6.4	4.6	3.3	6.6
11A	Atlantic Ocean	0	0.7	0.5	0.4	0.2	0
	Total	**6.2**	**16.4**	**14.5**	**10.5**	**7.0**	**9.3**
Total United States (Ex. North Slope)		**40.4**	**56.8**	**53.1**	**44.0**	**37.8**	**41.9**
North Slope							
Onshore		9.6	9.7	7.8	7.8	5.1	0
Offshore		0	0	0	0	0	0
	Total	**9.6**	**9.7**	**7.8**	**7.8**	**5.1**	**0**
Total United States		**50.0**	**66.5**	**60.9**	**51.8**	**42.9**	**41.9**

Gas Drilling Activity

Three rates of drilling were projected to encompass a reasonable range of variation in this activity. The high drilling rate (Cases I and IA) assumed that 1971 footage would increase by a 5.4-percent annual average increase over the 15-year period. High growth drilling increases 5 percent the first year, reaching 9 percent in 1980 by 0.5-percent annual increments, and tapers off to a level rate by 1985. The medium drilling rate (Cases II and III) assumes a 3.0-percent annual average over the 15-year period; it follows the same pattern as the high rate but starts at 2 percent and reaches 5 percent in 1980. The low drilling rate (Cases IV and IVA) assumed that the 4-percent average annual decrease in drilling experienced from 1961 to 1970 would continue to 1985.

Figure 22 shows the total allocated footage drilled for gas from 1956 to 1970 and the projected footage for 1971 to 1985 for the three drilling rates. The high drilling rate results in approximately 88 million feet of gas drilling in 1985, compared to the past peak year of 1961 when gas drilling amounted to about 62 million feet.



* *Excluding North Slope Reserve Additions.*

Figure 14. Oil Reserve Additions (Case II).*

The projected number of productive gas wells in 1985 in Cases I and IA total about the same as those drilled in 1961—approximately 6,000 wells in both years (see Figure 23), reflecting that the industry will have to drill to increasingly greater depths in the future and that the average depth of productive gas wells will continue to increase. Average depth of productive gas wells increases approximately 1,700 feet between actual 1970 experience and the projection made for 1985.

Figure 24 shows the increase in actual well depth experienced during the 1956-1970 period and the projection of increasing average well depth through 1985, which is a continuation of the historical trend.

Regional Distribution of Gas Drilling Effort

One of the important judgments required is the regional distribution of gas drilling effort, i.e., the amount of footage drilled for gas in each region for each year for the 1971-1985 period. The three major considerations used in arriving at these projections were the gas potential remaining to be found in each region, the historical trends of gas reserves found per foot drilled in each region, and the historical drilling distribution among the regions.

TABLE 45

PRODUCTION AS A FUNCTION OF RESERVES

	R/P	Production as % of Remaining Reserves
1955	12.2	8.2
1960	12.8	7.8
1965	11.5	8.7
1970	8.9	11.2

The projection of regional drilling distribution for the 1971-1985 period, along with the actual

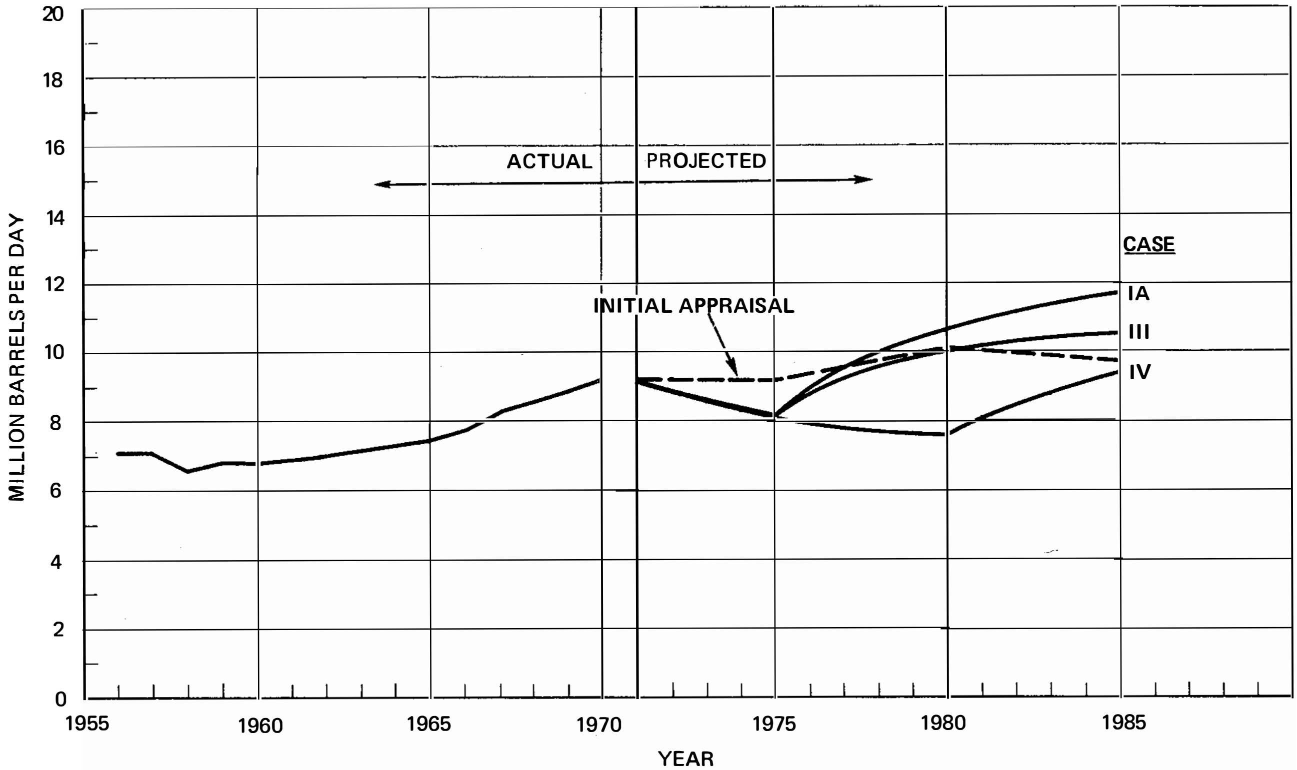


Figure 15. U.S. Crude Oil Production—Low Finding Rate.

distribution for the 3-year period 1968-1970, is shown in Table 49.

Gas Reserve Additions

Natural gas reserve additions projected for the lower 48 states in the case studies, along with the gas footage drilled, are shown in Figures 25, 26 and 27. Figure 28 shows historical annual gas reserve additions and projections for the lower 48 states. Figure 29 shows the cumulative gas discovered through 1970 and the projected cumulative gas discovered for the four principal cases; it shows both absolute volumes and percentages of ultimate discoverable gas. Both non-associated and associated-dissolved additions are included.

During the 1956-1970 period, total gas reserve additions averaged slightly less than 18 TCF per year in the lower 48 states. The peak year in gas reserve additions for all past history was 1956 when nearly 25 TCF were added. During the 3-year period 1968-1970, reserve additions averaged only about 11 TCF per year. In the lowest supply case postulated (Case IV), gas reserve additions are projected to decline from about 11 TCF in 1970 to about 6 TCF in 1985. In the highest supply case (Case I), gas reserve additions are projected to increase to about 26 TCF in 1985.

A little over 31 TCF of gas have been discovered in Alaska, of which 26 TCF of associated-dissolved gas were booked on the North Slope in 1970. Estimated annual average non-associated and associated-dissolved gas reserve additions in Alaska for the 15-year period 1971-1985 are tabulated below.

Case I	4.2 TCF/year
Case II	3.3 TCF/year
Case III	2.4 TCF/year
Case IV	1.3 TCF/year

Table 50 shows by region the cumulative non-associated gas reserve additions projected in the various cases studied. This table also shows the historical non-associated gas reserve additions by region. Table 47, which includes Alaska, shows that 464.1 TCF of non-associated gas had been discovered prior to 1971. This is 30.9 percent of

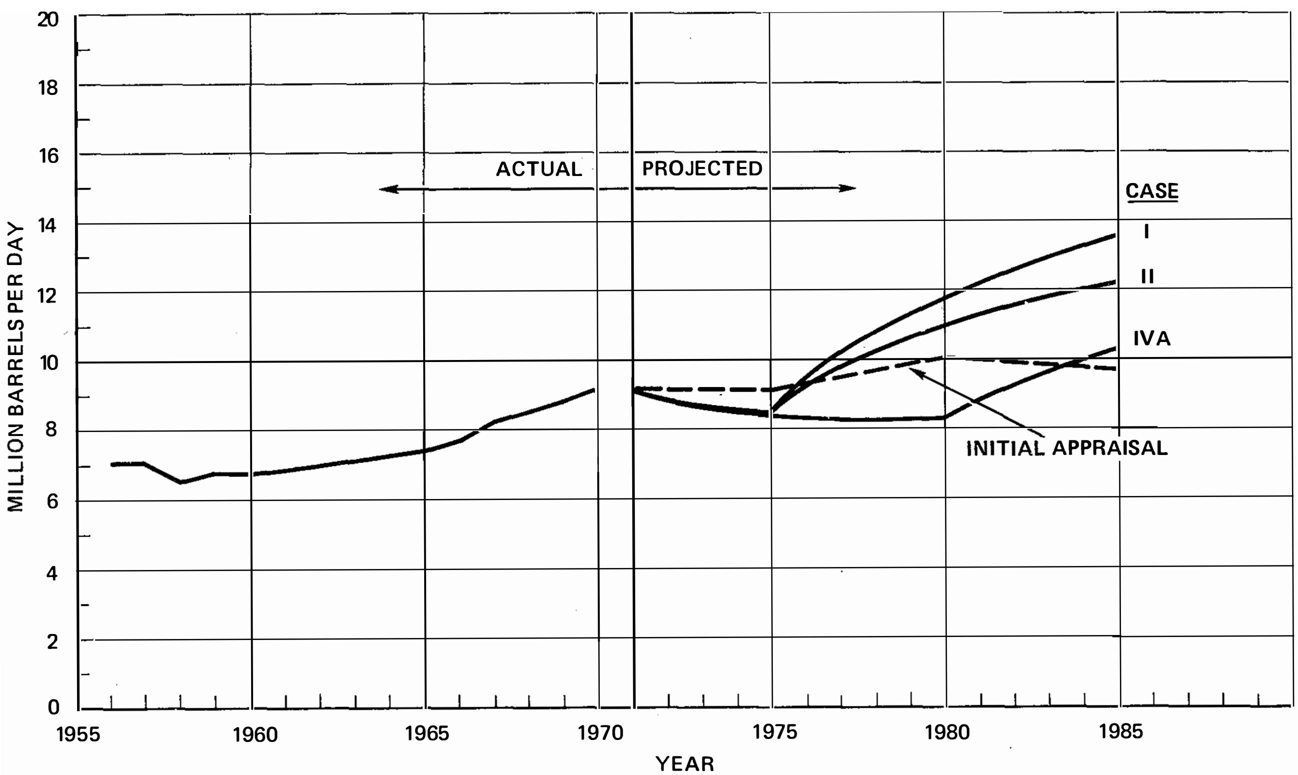


Figure 16. U.S. Crude Oil Production—High Finding Rate.

the estimated ultimate supply of non-associated gas. In the highest supply case (Case I), an additional 358.8 TCF are projected to be discovered in the 1971-1985 period. This would indicate that 54.8 percent of the ultimate non-associated gas supply would be discovered by the end of 1985.

In the lowest supply case (Case IV), a total of 120.1 TCF of non-associated gas reserves are added in the 1971-1985 period, meaning that 38.9 percent of the ultimate would be discovered by the end of 1985.

Table 51 shows regionally the percent of ulti-

TABLE 46

DAILY CRUDE OIL PRODUCTION—TOTAL UNITED STATES (MMB/D)

	Initial Appraisal	Case I	IA	II	III	IVA	IV
1971	9.10	9.10	9.10	9.10	9.10	9.10	9.10
1975	9.15	8.52	8.17	8.48	8.14	8.33	8.04
1980	10.10	11.76	10.58	11.22	10.16	8.28	7.58
1985	9.87	13.54	11.64	12.19	10.55	10.33	9.38

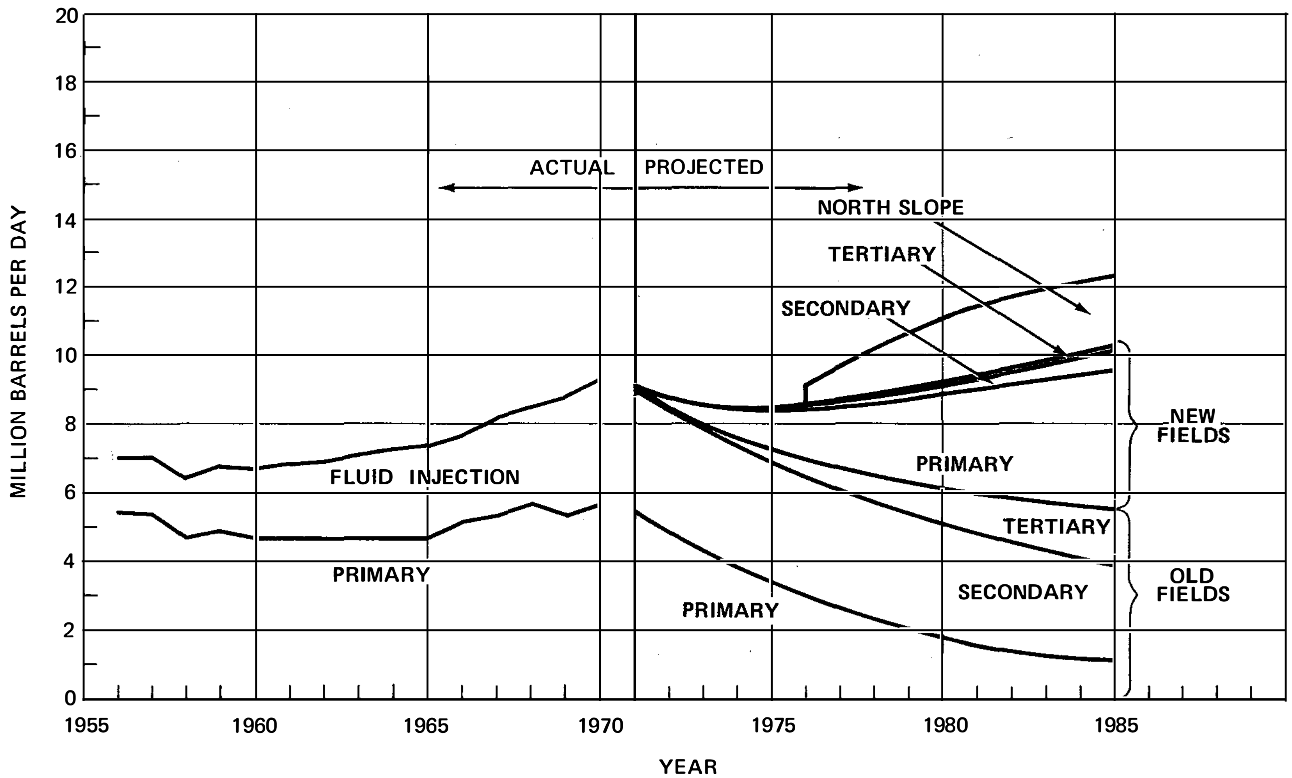


Figure 17. Daily Crude Oil Production (Case II)—Total United States.

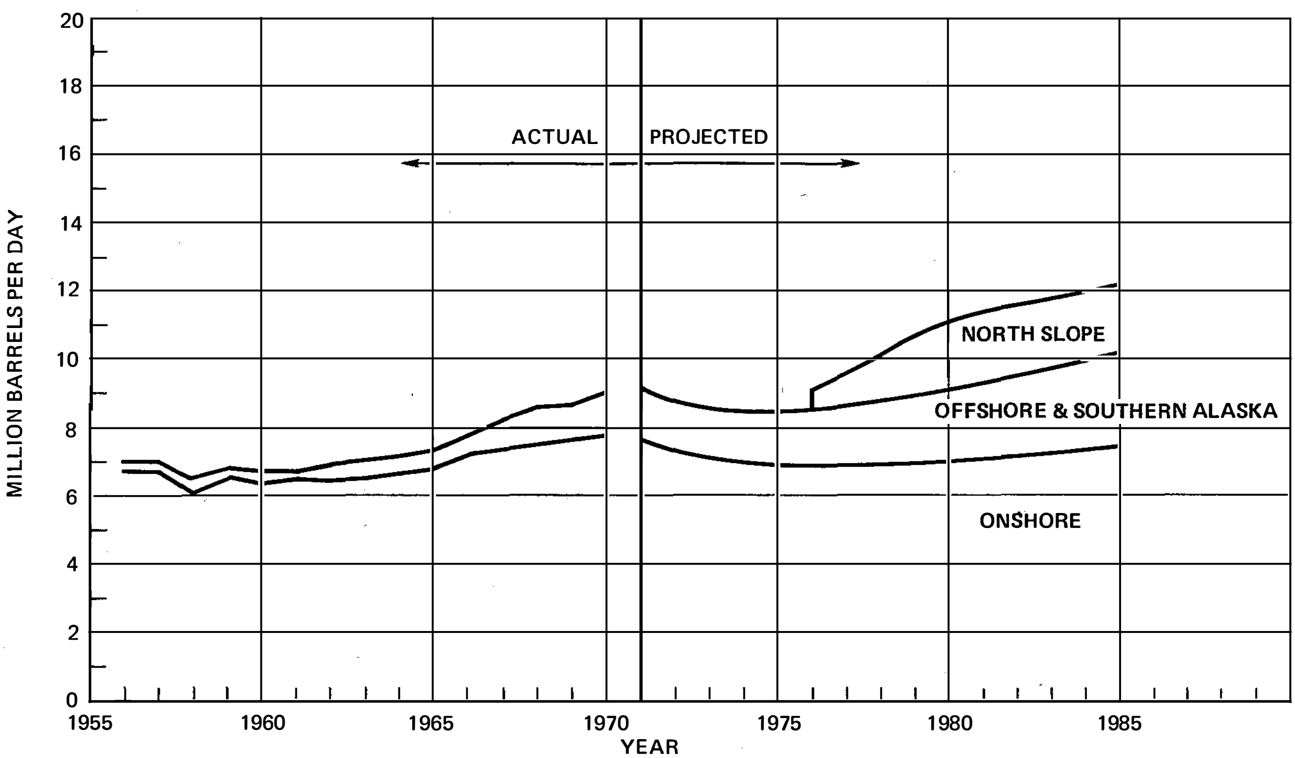


Figure 18. Daily Crude Oil Production (Case II)—Total United States.

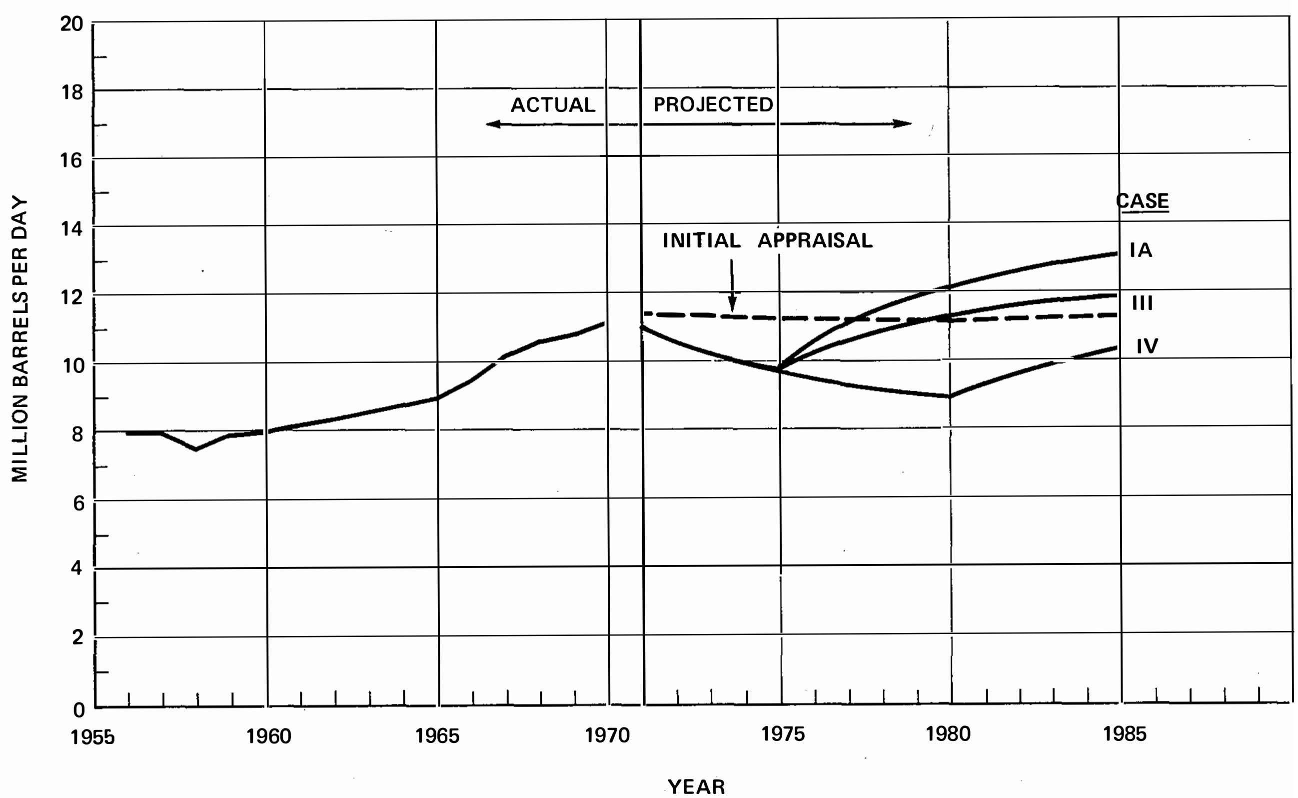


Figure 19. U.S. Total Liquids Production—Low Finding Rate.

mate non-associated gas reserves discovered at the end of 1970 and the percent of ultimate which would be found by the end of 1985 in each of the cases studied.

Gas Production

For the purpose of developing non-associated gas production schedules for each region, percentage/production schedules were established for both proved reserves as of December 31, 1970, and for projected future reserve additions. Each of the schedules was expressed in annual percentages of the particular reserve category involved.

Historical deliverability characteristics applicable to each of the regions were employed in developing these schedules. The availability of gas is principally a function of reservoir characteristics. The average deliverability characteristics of all wells in the lower 48 states were arrived at by analysis of data reported to the FPC on Form 15 reports filed by the interstate pipelines. Based on further regional investigation, availability characteristics for Regions 5, 7 and 11 were assumed to conform to the above average; Regions 3, 4, 8, 9 and 10 were assumed to have 80 percent of the average availability capacity; and Regions 2, 2A, 6 and 6A, and the North Slope were assumed to have 125 percent of the average. Southern Alaska was assumed to produce 4 percent of remaining reserves each year, and the eastern offshore (11A) was assumed to produce 5 percent of the remaining reserves each year. Regional production volumes were summed to obtain total production. A 6.5-percent reduction factor for lease use and fuel, based on historical data, was applied to these production volumes to arrive at marketed non-associated gas production.

Table 52 shows 1970 wellhead production and year-end proved reserves of non-associated gas for the lower 48 states. Figure 30 shows actual wellhead production of non-associated and associated-dissolved gas for the period 1955-1970 for the total United States and projected production for the four primary cases studied. Figure 30 also shows the effect that finding rates have on projected production by comparing Cases II and III. Projected pro-

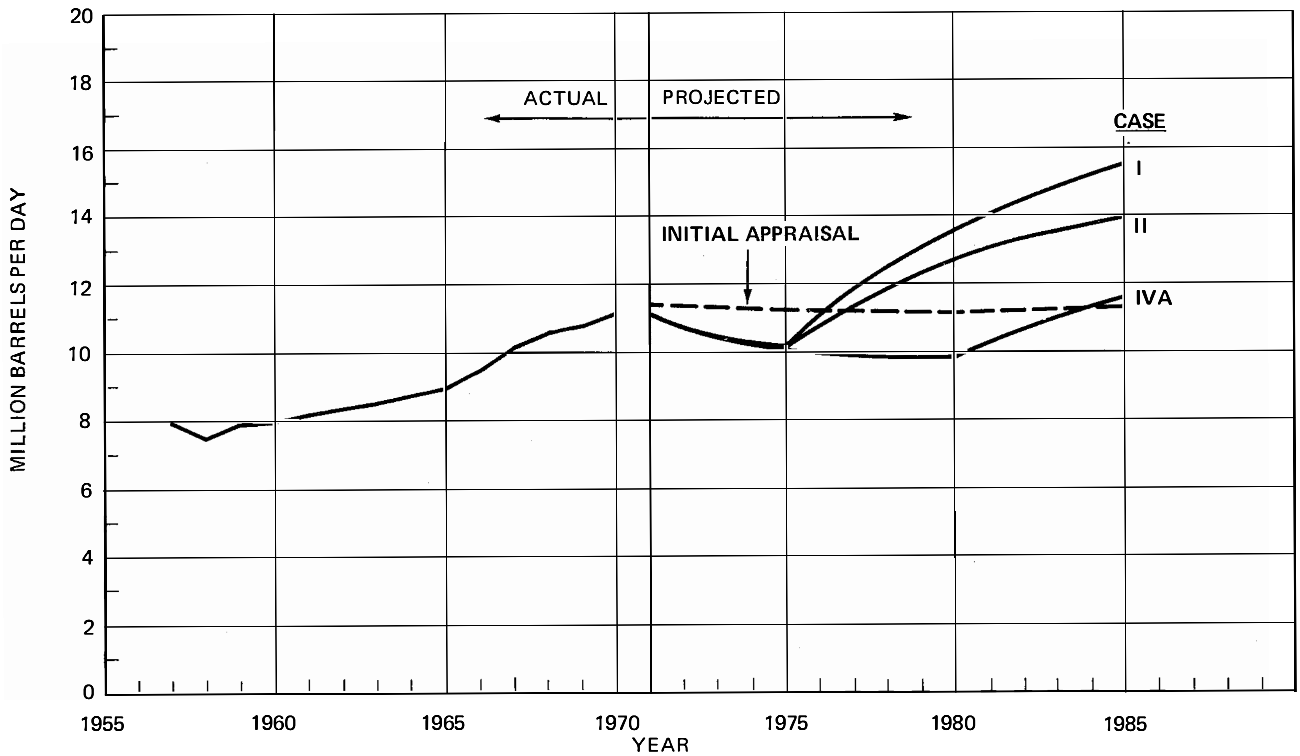


Figure 20. U.S. Total Liquids Production—High Finding Rate.

duction for Case II, which utilizes the high finding rate, is 26.5 TCF annually in 1985. Projected production for Case III, which assumes the same drilling activity as Case II but utilizes the low finding rate, is only 20.4 TCF annually in 1985—a difference of about 6 TCF.

The rapid growth in gas production in the 1960's was a response to the rapid growth in demand. This growth reflected the desirability of gas as a fuel, the large backlog of proved reserves, and FPC pricing policies which held gas prices far below their competitive level in the marketplace. Although demand will continue to grow, there is no longer a backlog of proved reserves to support the approximately 6-percent annual average rate of increase in production achieved in the 1960's. Further increases in gas production will depend on reserve additions made in the future.

Marketed Gas Production

Marketed production volumes are arrived at by reducing non-associated and associated-dissolved wellhead production by factors of 6 percent and 13 percent, respectively. These reductions, which cover lease use, fuel use and losses, are based on historical data.

Table 53 shows, by region, the projected cumulative marketed gas production during the 1971-1985 period for all the cases studied, ranging from approximately 263 TCF (Case IV) to 353 TCF (Case I). Figure 31 shows marketed gas for the United States projected in the cases utilizing the high finding rate (Cases I, II and IVA). Figure 32 shows the marketed gas for the United States projected in the cases utilizing the low finding rate (Cases IA, III and IV).

Natural Gas Liquids (NGL)

Natural gas liquids are produced with both non-associated and associated-dissolved gas. Liquid/gas ratios for both reserve additions and production were calculated by region on the basis of historical data. These calculations were made separately for non-associated and associated-dissolved gas. The ratios derived were then applied to projected gas reserve additions and resulting gas production to determine NGL reserve additions and production. The liquids were subdivided on the basis of recent

TABLE 47

RECOVERABLE GAS SUPPLY

Region		TCF: Ultimate Discoverable Gas	TCF: Gas Discovered to 1/1/71	Remaining Discoverable: TCF	Remaining Discoverable: % of Ultimate
Lower 48 States—Onshore		Non-Associated			
2	Pacific Coast	25.7	8.1	17.6	68.5
3	Western Rocky Mtns.	50.1	17.9	32.2	64.3
4	Eastern Rocky Mtns.	51.6	10.0	41.6	80.6
5	West Texas Area	101.5	27.2	74.3	73.2
6	Western Gulf Coast Basin	397.9	211.7	186.2	46.8
7	Midcontinent	223.3	104.8	118.5	53.1
8–9	Michigan, Eastern Interior	12.5	0.4	12.1	96.8
10	Appalachians	95.9	33.0	62.9	65.6
11	Atlantic Coast	4.6	0.01	4.6	99.8
	Total	**963.1**	**413.1**	**550.0**	**57.1**
Lower 48 States—Offshore					
2A	Pacific Ocean	3.8	0.5	3.3	86.8
6A	Gulf of Mexico	201.8	45.4	156.4	77.5
11A	Atlantic Ocean	54.5	--	54.5	100.0
	Total	**260.1**	**45.9**	**214.2**	**82.4**
Total United States (Ex. Alaska)		**1,223.2**	**459.0**	**764.2**	**62.5**
Alaska		**277.4**	**5.1**	**272.3**	**98.2**
Total United States		**1,500.6**	**464.1**	**1,036.5**	**69.1**
		Associated-Dissolved			
Total United States		**356.7**	**215.2**	**141.5**	**39.7**
		Non-Associated and Associated Dissolved			
Total United States		**1,857.3**	**679.3**	**1,178.0**	**63.4**

historical production into condensate, pentanes and heavier, and LPG.

Table 54 summarizes the annual NGL reserve additions, and Table 55 summarizes daily NGL production in the lower 48 states. In 1985, reserve additions range from about 149 MMB (Case IV) to 692 MMB (Case I), and daily production ranges from 997 to 1,921 MB/D for Cases IV and I, respectively.

Supplemental Supply

Supplemental supplies of gas result from coal gasification, the manufacture of substitute natural gas from liquid feedstocks, and the application of nuclear-explosive technology. Coal gasification is examined in Chapter Five. Discussion of SNG and nuclear-explosive stimulation follows.

Substitute Natural Gas

The shortage of natural gas that will be experienced over the next few years, as well as the long lead times required for large-scale LNG projects and coal gasification plants, has forced gas suppliers and distributors to look for an interim source of supply which could be made readily available. This interim supply source will likely be synthetic pipeline gas formed from petroleum liquids. Industry interest in SNG is evidenced by the fact that close to 40 projects have been announced

TABLE 48

ESTIMATES OF NON-ASSOCIATED AND ASSOCIATED-DISSOLVED GAS*
(TCF)

	1970 PGC	1972 USGS	1969 Hubbert	1959 Weeks	1970 Moore	1968 Elliott and Linden
Lower 48 States	1,877	3,556	1,312	Not Estimated		
Alaska	447	862	188			
Total United States	**2,324**	**4,418**	**1,500**	**1,250**	**1,934**	**2,175**

* P. K. Theobald, S. P. Schweinfurth and D. C. Duncan, *Energy Resources of the United States,* U. S. Geological Survey, Circular No. 650 (July 1972).

having a designed output of over 2.5 TCF of reformer gas per year.

Processes to produce SNG from petroleum liquids have been available for some time. Those currently receiving the most attention are the Catalytic Rich Gas (CRG) process, which was developed by the Gas Council of the United Kingdom; the Methane Rich Gas (MRG) process, developed by the Japan Gasoline Company; and the Lurgi Gasynthan process, which was developed by the Lurgi Company of Germany. These processes, for the most part, use low-temperature catalytic steam. The feedstocks used are naphtha, other lighter hydrocarbons, or methanol. The output will be gas of 1,000-BTU quality which has been upgraded through methanation and carbon dioxide removal. The process operates at 93- to 95-percent thermal efficiency, assuming a naphtha feedstock with a heating value of 5 million BTU's per barrel.

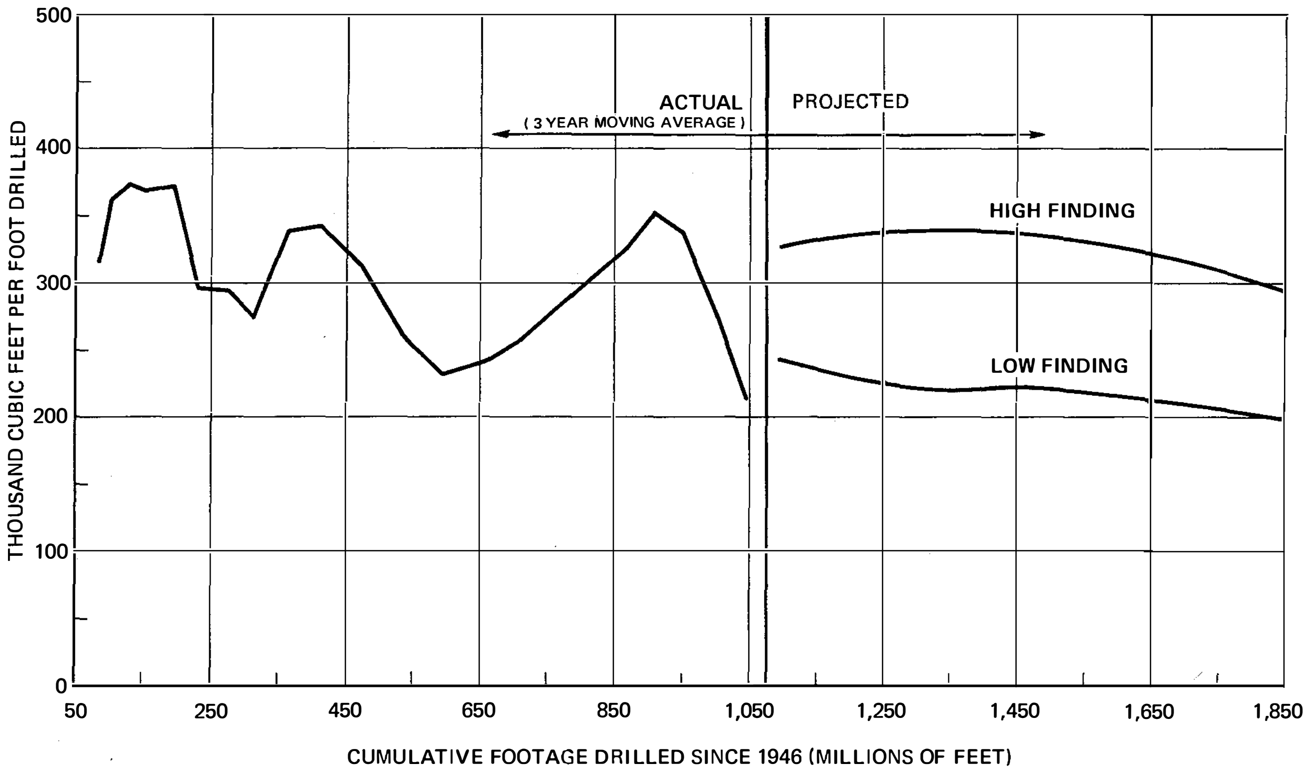
Most of the plant capacities announced assume construction in modules with total capacities ranging from 100 to 500 MCF per day. All plant components, with the exception of catalysts in some cases, are available in the United States. As a general rule, each 100 million cubic feet (MMCF) of plant output will require a raw material input of about 20 to 25 thousand barrels of hydrocarbon feedstock.

Each trillion cubic feet of SNG output will require plant expenditures of approximately $800 million to $1 billion, representing a tailgate cost of some $0.20 to $0.30 per MCF. Feedstock costs represent at least 70 percent of the total. Announced project prices range from $1.00 to $1.60 per MCF.

Construction companies licensed to build such plants are willing to begin construction immediately, contracting for completion on a turn-key basis in less than 2 years. In practice, this relatively short lead time could prove illusory unless the following two principal conditions are satisfied:

- **Feedstock Requirements**—Feedstock requirements for the SNG plants announced to date amount to approximately 1 MMB/D of light hydrocarbons, a volume that could represent about 20 percent of refinery capacity. In turn, the crude oil that would have to be dedicated to provide reforming feedstock would total about 6 MMB/D, or about 10 percent of world petroleum demand at this time. Considering the known requirements of the petrochemical industry, it appears doubtful that light hydrocarbons in such quantities will be available for reforming.
- **Governmental Considerations**—Two forms of federal policy administration could present obstacles to SNG projects. These are the regulatory considerations exercised by the FPC and the import philosophy of the Department of the Interior.

The regulatory considerations will relate to the willingness of the FPC to certificate higher cost gas supplies and to resolve such issues as whether higher depreciation rates and high-



* *Excluding Alaskan gas.*

Figure 21. Non-Associated Gas Finding Rates.*

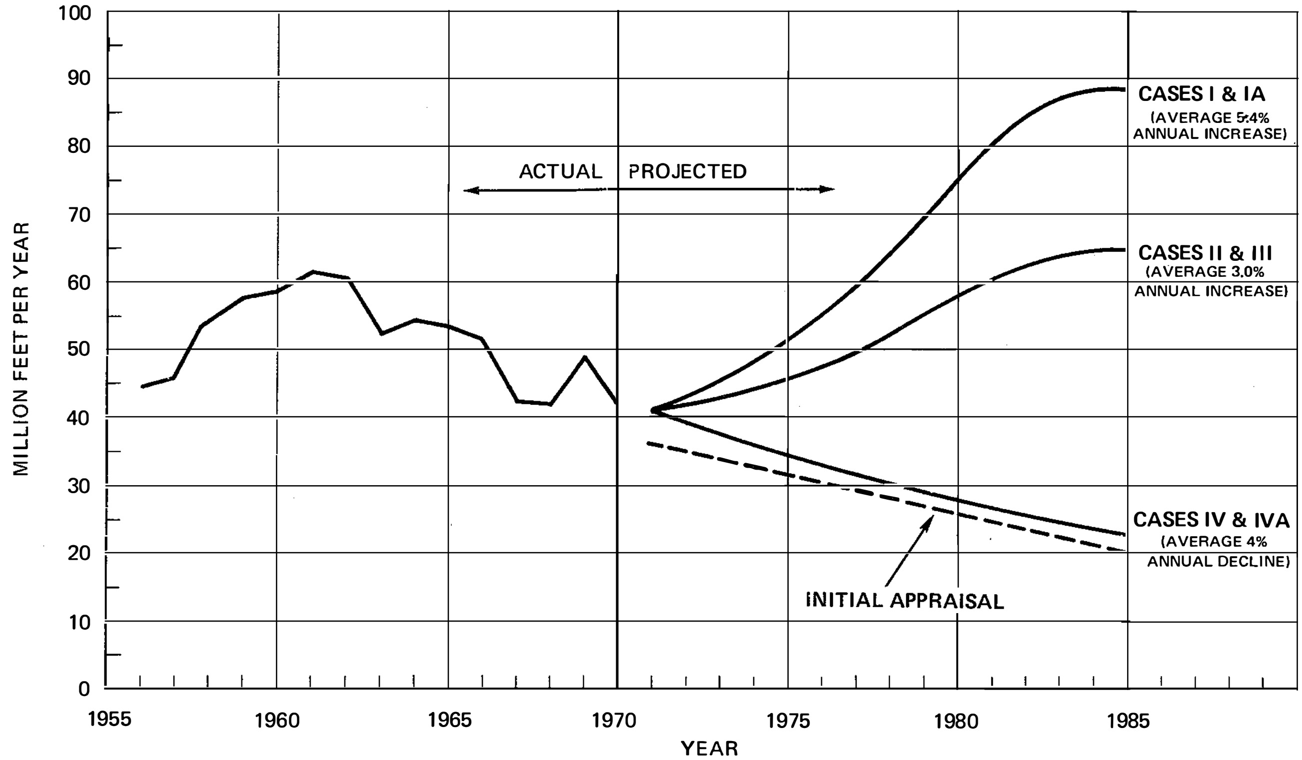
er rates of return on equity than are normally provided for in utility-type construction are appropriate for such innovative activities.

The import question concerns the willingness of the Department of the Interior to permit the import of light hydrocarbons. Approximately two-thirds of the light hydrocarbon feedstock required for these plants is anticipated to be foreign in nature. This has the effect of "exporting" refinery capacity to foreign countries, a concept opposed by the Department of the Interior. To offset such a possible trend, governmental consideration is being given to establishing the Imported Crude Oil Processing (ICOP) plan, described in the oil import section of Chapter Thirteen. This is a plan designed to increase incentive to construct domestic refinery capacity to process imported foreign crude oil. Implementation of this plan could increase the availability of naphtha to be used as feedstock for reformer gas.

The potentially inhibiting effects of regulations and import restrictions and the delays often occasioned by siting difficulties and related administrative-procedural details can, and do, affect timing. Therefore, it has been assumed that only one-third of the announced plants to be in operation by 1975 and one-half of the plants scheduled to be in production in 1980 and 1985 would be completed on a timely basis. Under that assumption, SNG production is estimated at 0.6 TCF in 1975, increasing to 1.3 TCF by 1980 and remaining at that level through 1985.

Nuclear-Explosive Stimulation

Nuclear stimulation of natural gas reservoirs is a method of producing natural gas from tight reservoirs in major basins of the Rocky Mountain area (see Figure 5) where deliverability from conventional wells does not warrant pipeline connections. Approximately 250,000 acres of leased lands have been grouped into three unit areas for the purpose of conducting such operations, and several



* *Excluding Alaskan gas drilling.*

Figure 22. Gas Footage Drilled.*

hundred thousand acres leased outside these units are also believed to have potential for such purposes. It is estimated that there are about 90 TCF of gas in place in such reservoirs currently under lease and that the potential resource base considered appropriate for nuclear stimulation may prove to be much larger.

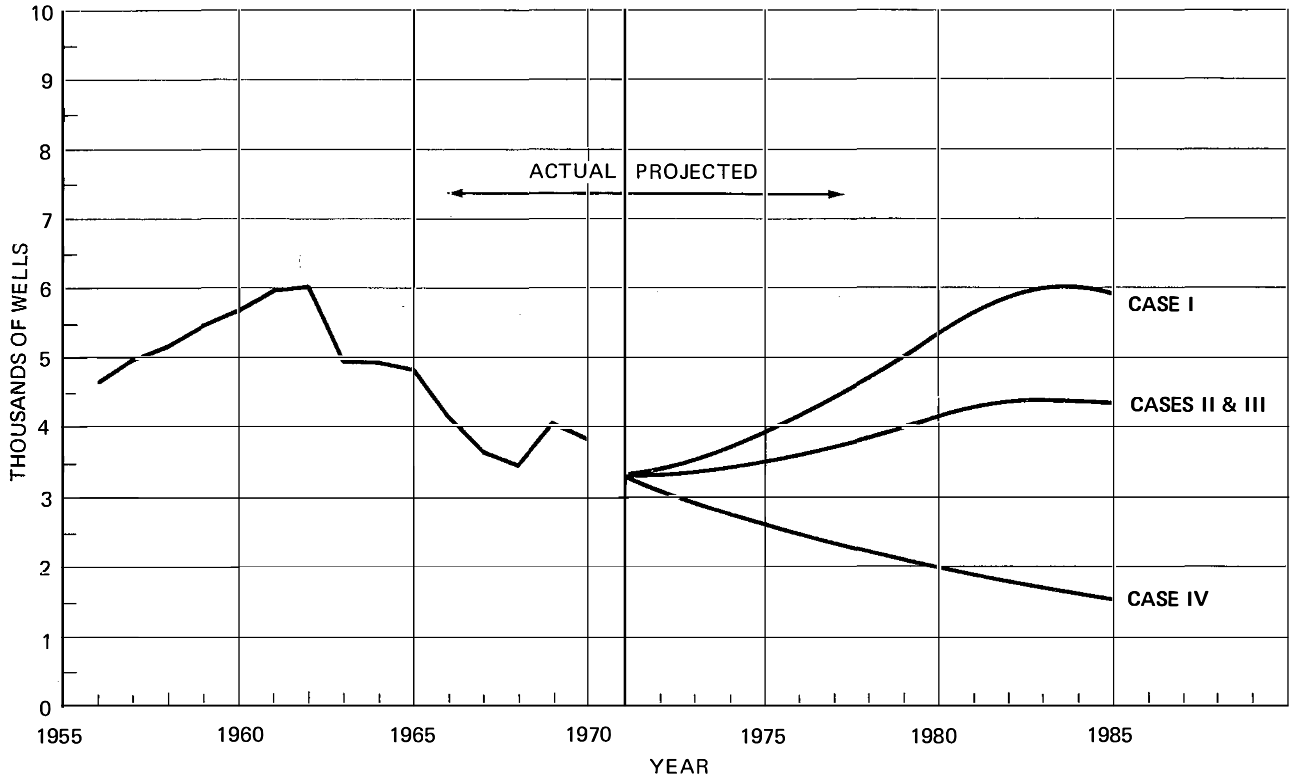
Technical feasibility has been established by the Gasbuggy experiment in northwest New Mexico and the Rulison experiment in Colorado. Two projects (Rio Blanco in Colorado, Wagon Wheel in Wyoming) have been designed which are expected to demonstrate production of about 20 billion cubic feet per well over a 20-year period.

The largest uncertainty in predicting potential future production from a well is establishing formation permeability and the increases in permeability resulting from stimulation. Test results from Gasbuggy and Rulison projects have been extended to other reservoirs by computer modeling and knowledge of formation properties. These results showed, generally, high flow rates during early production decreasing to relatively constant flow rates after about 5 years and a production span that may extend considerably longer than conventionally completed wells.

Assuming favorable results from currently planned experiments and timely resolution of policy issues, estimated annual production in 1980 of 0.1 TCF (Cases II and III) to 0.2 TCF (Case I) may increase to about 0.8 TCF and 1.3 TCF, respectively, in 1985. The corresponding levels of cumulative production for the 1971-1985 period are approximately 2.4 TCF (Cases II and III) and 4.6 TCF (Case I).

These production volumes rest upon activity level assumptions of completion of 676 wells by 1985 in Case I, compared to 500 completed wells in Cases II and III. In Case I, 160 such wells are completed in 1985; in Cases II and III the total is 100. Commercial nuclear stimulation activity does not occur by 1985 under Case IV assumptions, although continued experimentation and technology refinement may be proceeding.

Policy issues relating to availability and cost of nuclear explosives, distribution of natural gas con-



* *Excluding Alaskan gas wells.*

Figure 23. Productive Gas Wells Annually.*

taining small amounts of radioactivity, and wellhead price must be resolved before definitive economic analysis can be performed. However, indications are that the range of prices for such production may compare quite favorably to those for coal gasification, imported LNG, SNG and pipeline imports from Arctic areas.

Alaska

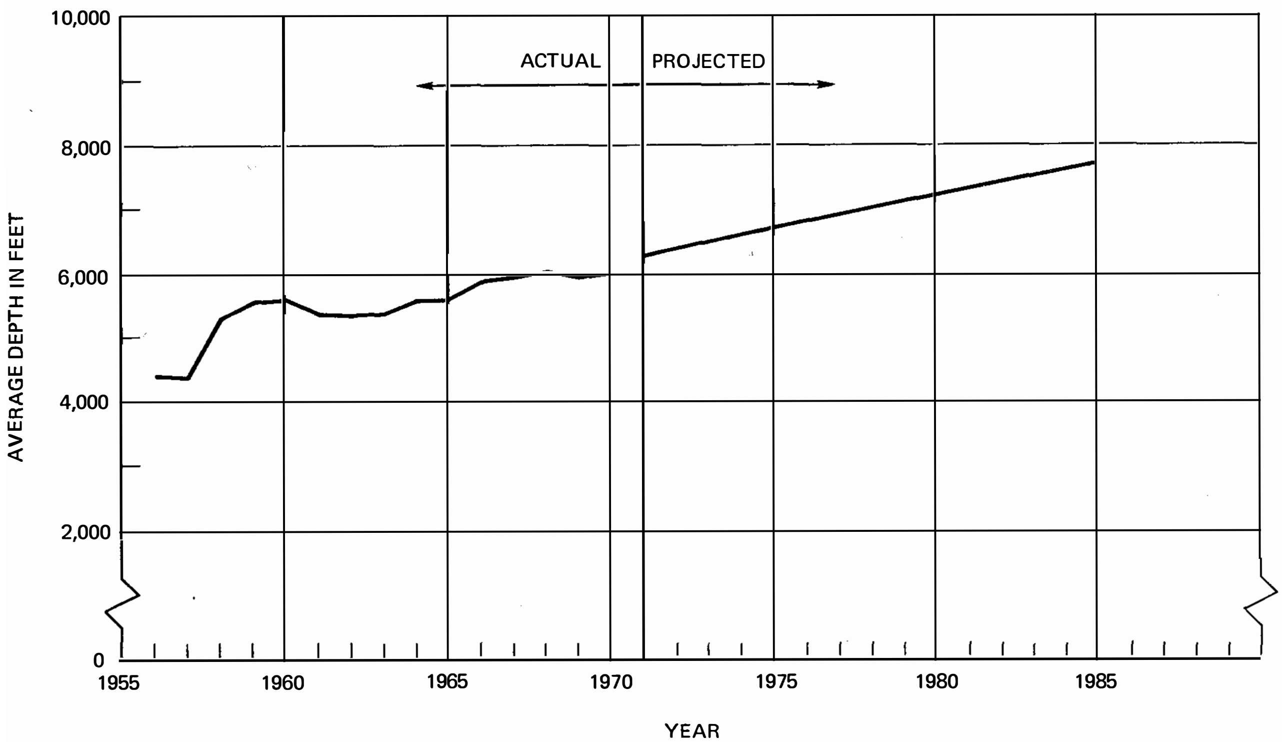
The importance of Alaska and its offshore waters to the Nation's future petroleum supplies is based on the estimate that about 30 percent of the remaining domestic discoverable hydrocarbon resources are located in this area. This amounts to 119 billion barrels of oil-in-place and 327 TCF of recoverable gas. Over 80 percent of this oil and about 52 percent of this gas are believed to be located on the North Slope (north of the Brooks Mountain Range). Figure 33 is a map of Alaska showing the pertinent features and locations.

Southern Alaska

Currently, all of Alaska's production comes from southern Alaska. The area was opened up in 1957 with the discovery of the Swanson River Field (ultimate recovery of about 176 MMB). The most important fields have been discovered on the Kenai Peninsula and offshore in the Cook Inlet. At present these fields are estimated to have ultimate recovery of about 900 MMB and remaining oil reserves of 500 MMB, together with about 5 TCF of remaining gas reserves. Operations in the Cook Inlet, with its icy waters and high tides, are very costly. Such conditions are even more extreme in the Gulf of Alaska, and therefore this should prove to be an even more expensive area of operations.

North Slope

Exploration activity in northern Alaska began in 1944 on Naval Petroleum Reserve No. 4 (NPR #4) under Naval supervision. This work, together with



* *Excluding Alaskan gas drilling.*

Figure 24. Average Depth of Completed Gas Wells.*

detailed mapping by the U.S. Geological Survey, continued until 1953. During this 8- to 9-year period three oil fields and two gas fields were discovered. The reserve estimates for these discoveries range from 30 to 100 MMB of oil and 370 to 900 billion cubic feet of gas.

Private industry exploration started in the late 1950's in the area between NPR #4 and the Arctic Wildlife Refuge. NPR #4 and the Arctic Wildlife Refuge together constitute a major portion of the land on the North Slope, and neither of these is currently available for exploration by the industry. These efforts resulted in the discovery of the Prudhoe Bay Field in 1968. This field, which appears to be by far the largest oil field ever discovered on the North American Continent, is estimated to contain 24 billion barrels of proved oil-in-place, with proved recoverable reserves of 9.6 billion barrels of oil and 26 TCF of associated-dissolved gas.

The main reservoir in the Prudhoe Bay Field is in the Triassic (Sadlerochit) interval which contains all the field's currently booked reserves. Other productive tests have been made in the Mississippian (Lisburne) and the Lower Cretaceous (Kuparuk) zones in the same field. There are other discoveries in Cretaceous sands at other fields outside the Prudhoe Bay Field (Ugnu, East Ugnu and West Sag River). Finds of the apparent magnitude of these discoveries outside the Sadlerochit reservoir would be of major significance in the lower 48 states, but the operating conditions on the North Slope and high costs involved may render them economically marginal.

Extreme cold, stormy and icy seas offshore, permafrost areas on land, and the limited drilling season make exploration and production operations extraordinarily costly and difficult. For example, Joint Association Survey data for 1968-1970 estimate average costs of drilling wells to depths of 10,000 to 14,999 feet at $1,869,000 in Alaska, compared to $598,000 for the offshore and $251,000

TABLE 49

REGIONAL PROPORTION OF GAS DRILLING FOOTAGE IN UNITED STATES*
(Percent)

Region*		1968–1970 Average	Projections 1971	1975	1980	1985
2	Pacific Coast	1.97	2.0	2.0	2.0	2.0
2A	Pacific Ocean	0.01	0.1	0.1	0.2	0.3
3	Western Rocky Mtns.	3.93	4.9	5.0	5.1	5.1
4	Eastern Rocky Mtns.	3.72	4.2	4.7	5.7	6.2
5	West Texas Area	8.82	9.6	10.1	10.2	10.6
6	Western Gulf Coast Basin	40.46	40.5	38.3	34.4	31.2
6A	Gulf of Mexico	9.11	10.0	10.6	11.0	11.8
7	Midcontinent	16.95	15.0	15.3	15.6	15.8
8–9	Michigan, Eastern Interior	0.88	0.7	0.7	0.7	0.7
10	Appalachians	13.90	13.0	13.0	12.6	12.8
11	Atlantic Coast	0.03	—	0.1	0.5	1.0
11A	Atlantic Ocean	—	—	0.1	2.0	2.5
Alaska*		**0.22**	*	*	*	*
	Total	**100.00**	**100.0**	**100.0**	**100.0**	**100.0**

* Alaskan footage handled outside computer program.

for the onshore of the lower 48 states.* North Slope costs are even higher than the Alaskan average.

The offshore area of the North Slope is estimated to contain about 48 billion barrels of oil-in-place. Large potential exists for natural gas accumulations offshore, but it has not been quantified separately. However, because of the enormous costs that would be required and the time needed to fully develop the required technology to conduct operations under these conditions, this study does not contemplate that any of this potential will be developed during the next 15 years. Two of the greatest obstacles are ice floes and polar pack movements that often scour the sea bottoms and move in to impinge on the coast.

Alaskan Pipeline

After the discovery at Prudhoe Bay, plans were made for the transportation of the oil to southern Alaska via an 800 mile, 48-inch pipeline. The pipe was ordered and delivered, and initial crude movement through the system was scheduled for 1973. However, governmental and environmental considerations have postponed this date to at least 1976. To date, the industry has invested $1.5 billion on the North Slope but probably will not realize any revenue from this venture for another 4 years or more.

Projected Oil and Gas Resources Discovered

By the end of 1970, a total of 26.9 billion barrels of oil-in-place and 31.5 TCF of gas had been discovered in all of Alaska.

Estimates of discoveries of oil-in-place during the 1971-1985 period range from 19.8 billion barrels (Case IV) to 40.6 billion barrels (Case I). Estimates of discoveries of total gas (both associated-dissolved and non-associated) range from 19.5 TCF (Case IV) to 63.2 TCF (Case I).

* *Joint Association Survey of the Oil and Gas Producing Industry*, Sponsored by the American Petroleum Institute, Independent Petroleum Association of America and Mid-Continent Oil and Gas Association (published yearly).

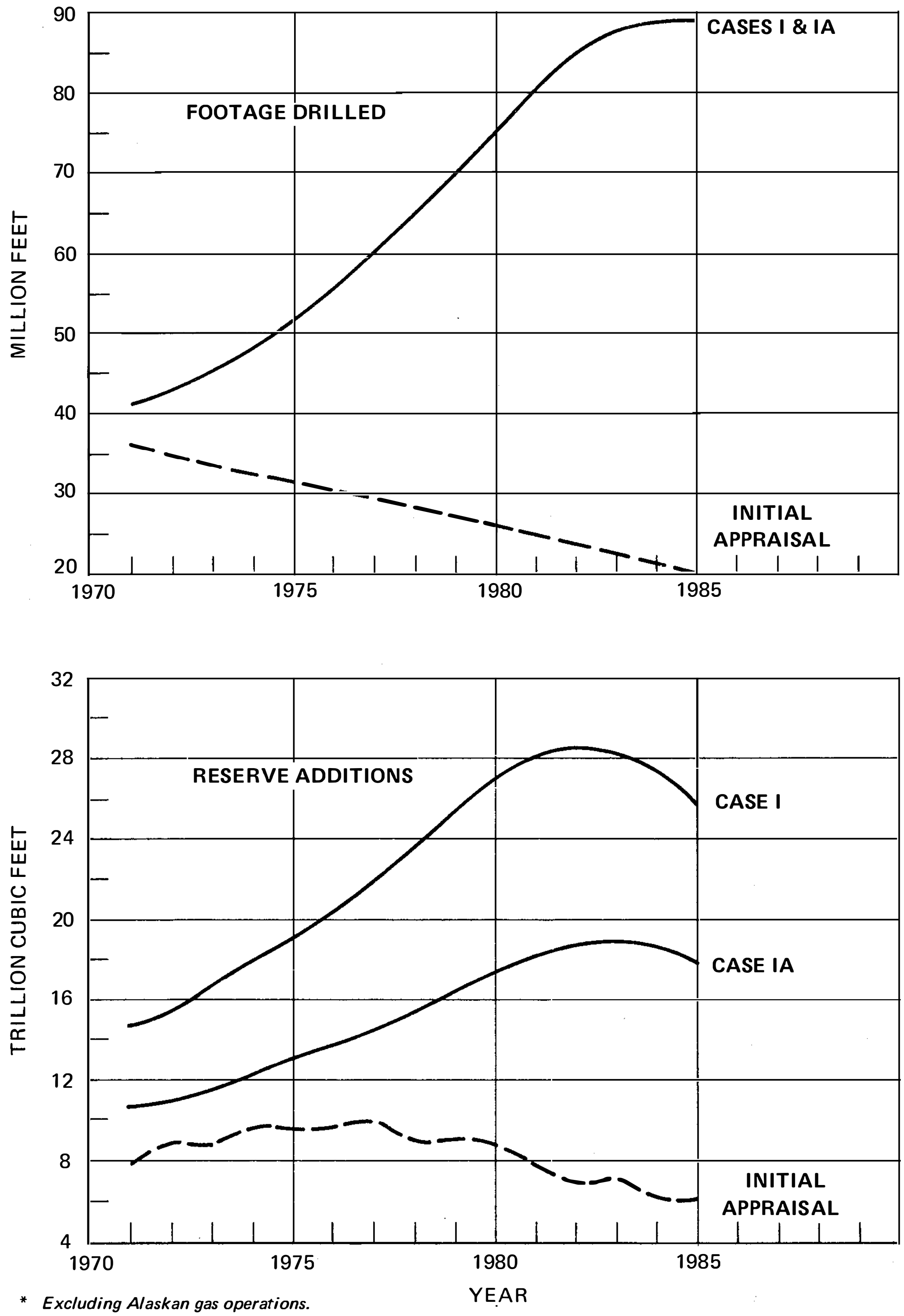
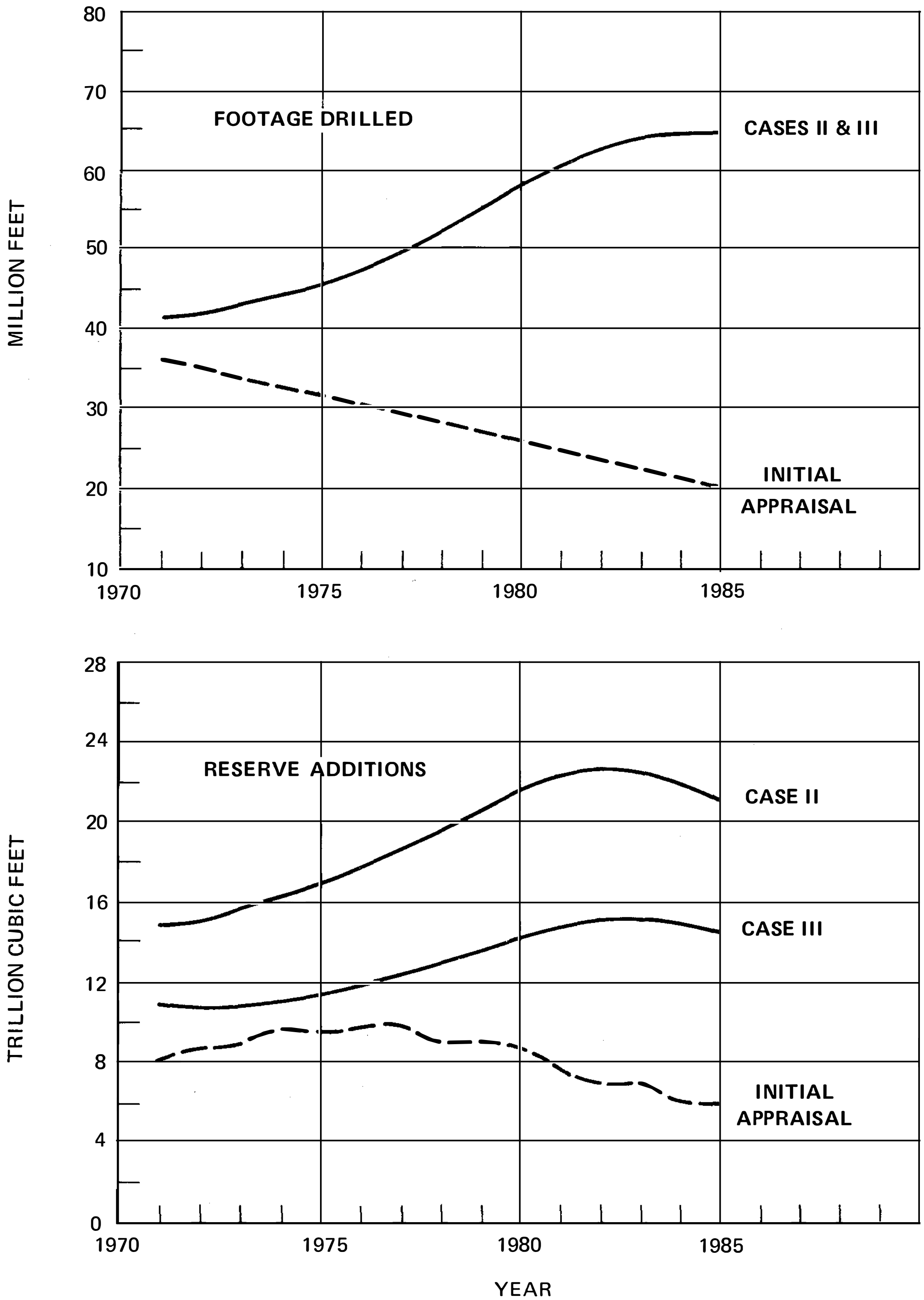
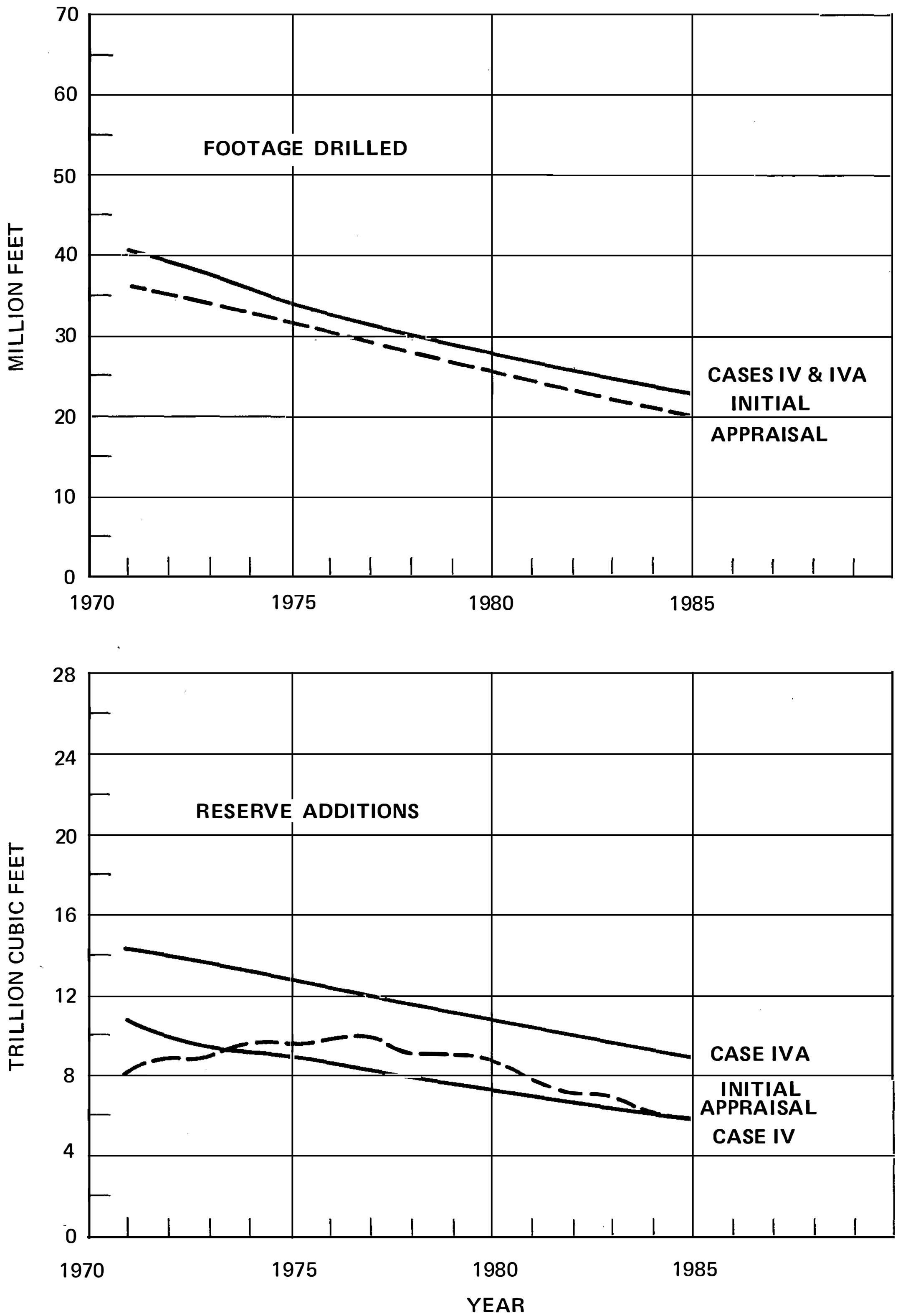


Figure 25. Gas Footage Drilled and Total Gas Reserve Additions (Cases I and IA).*



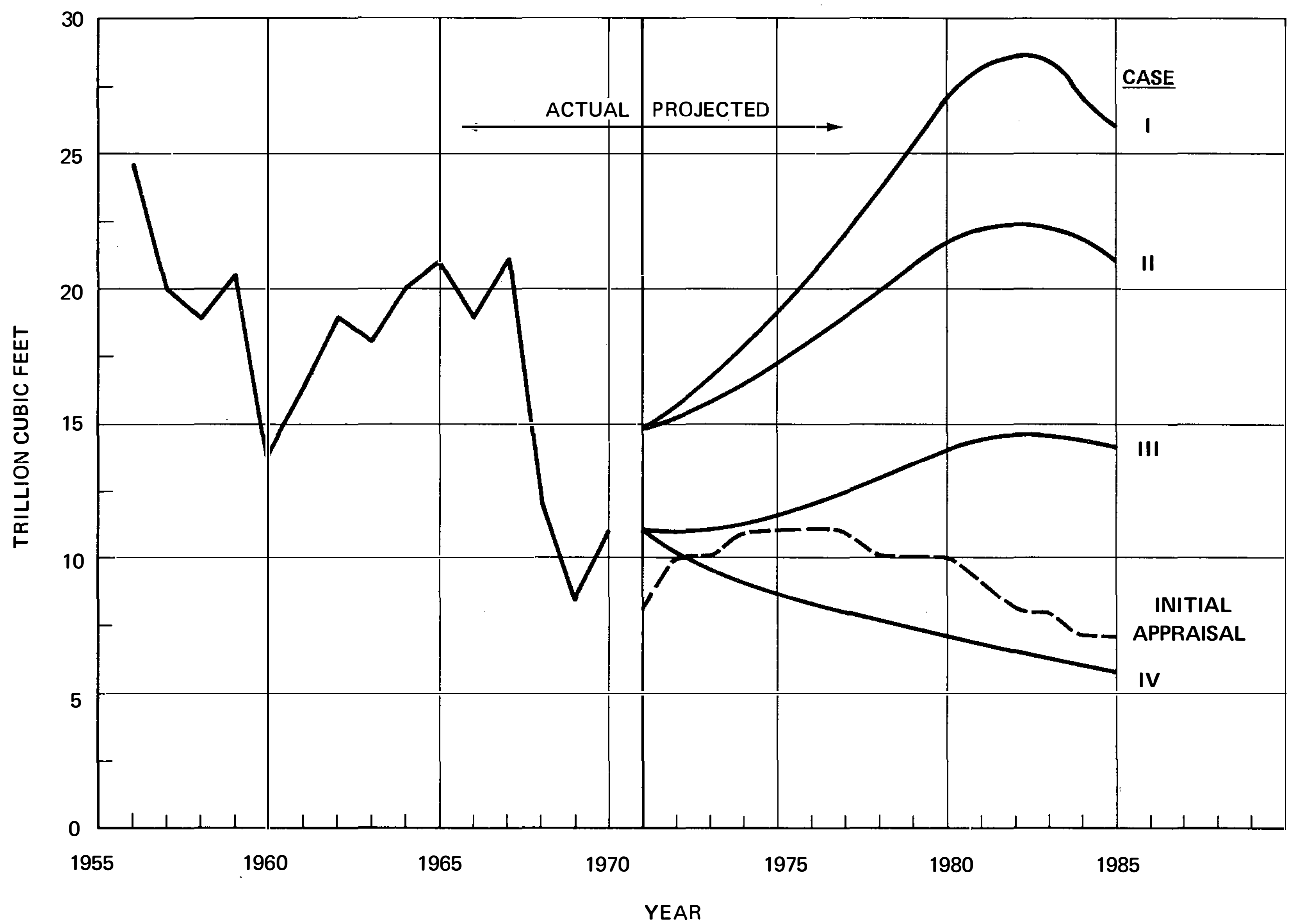
* *Excluding Alaskan gas operations.*

Figure 26. Gas Footage Drilled and Total Gas Reserve Additions (Cases II and III).*



* *Excluding Alaskan gas operations*

Figure 27. Gas Footage and Total Gas Reserve Additions (Cases IV and IVA).*



* *Excluding Alaskan operations.*

Figure 28. Gas Reserve Additions—Non-Associated and Associated-Dissolved (TCF of Dry Gas).*

Estimated Production and Expenditures

The large potential impact of Alaska required that estimates of production schedules and of finding and developing expenditures be developed, even though experience in several of these areas of activity is quite limited. For Cases II through IV, it was assumed that sufficient reserves would be found to support production at pipeline capacity of 2 MMB/D. Case I considered the possibility of a more optimistic outlook for the North Slope, resulting in a production peak of 2.6 MMB/D by 1985.

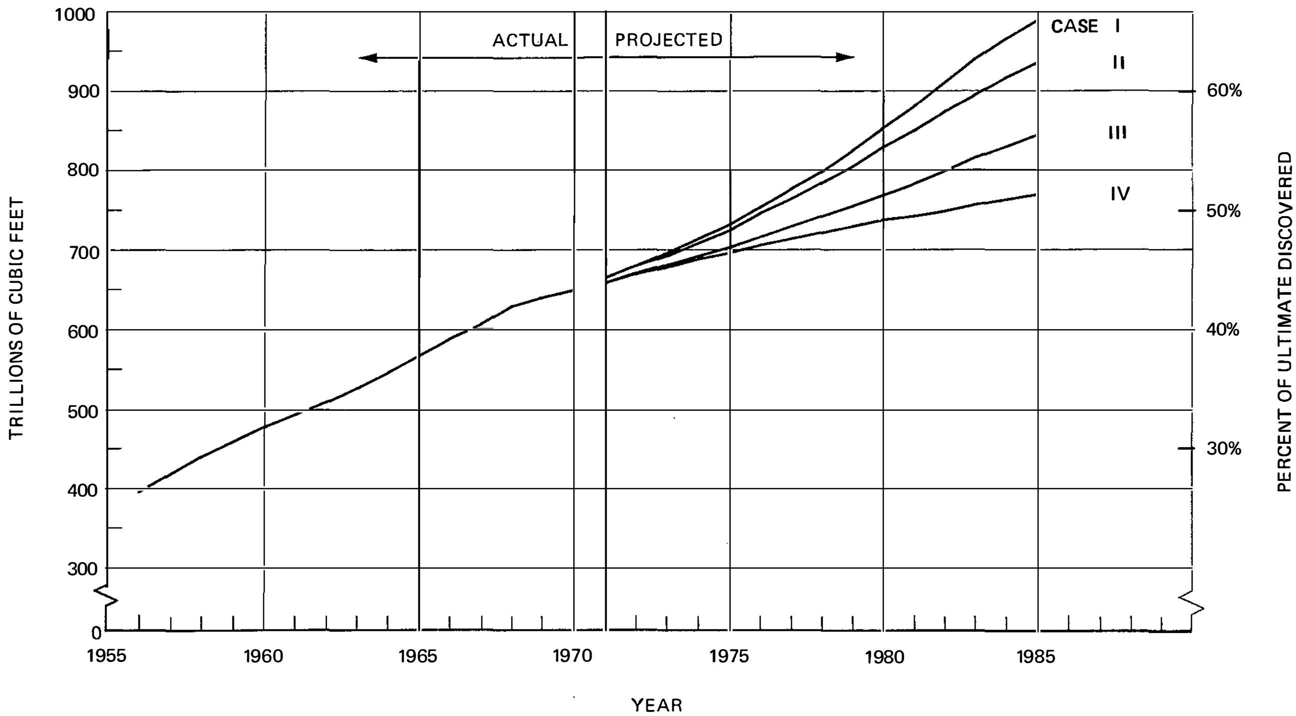
Tables 56 and 57 summarize the estimated production schedules and exploration and development expenditures.

Operating costs for production and transportation for the North Slope cannot be projected with any accuracy until experience in additional drilling and actual production has been achieved. Since these costs and the timing of such activities enter into calculations of "price," the complete impact of Alaska during the next 15 years cannot be projected.

Economics — Oil and Gas

General Background

For any assumed level of return on net fixed assets and exploratory success level (finding rate), it is possible to determine both the total revenue and unit revenue required to support the selected drilling and concomitant producing activities. These are referred to as required "prices" for oil and gas and are presented as a guide to under-



* *Excluding Alaskan operations.*

Figure 29. Cumulative Non-Associated and Associated-Dissolved Gas Discovered.*

standing the economics of the projected supply levels. It is emphasized that the unit revenues were derived *after* estimating the expenditures required for selected finding and drilling levels. The methodology employed in this study does not permit assumption of a unit price and derivation of a supply level and related exploratory activity. Accordingly, the data presented in the following discussion are not elements of a supply-price elasticity curve.

Petroleum exploration and production is an increasing-cost industry, and therefore average "prices" computed by the methodology employed tend to be lower than those needed to justify the new investments required to develop incremental supplies. Motivating factors other than price alone are therefore required to achieve the activity levels and supplies projected. Of particular importance is investor expectation of success and confidence in the direction, intent and stability of government policies. The impact of some of these non-price motivating factors were considered in the parametric studies.

All economic data—both historical and projected—were calculated on the basis of constant 1970 dollars. The historical figures were adjusted from reported current dollars to constant 1970 dollars by employing the Industrial Wholesale Price Index. As a consequence, projected results do *not* reflect inflation.

Oil and Gas Capital Requirements

The expenditures for finding and developing new oil and gas production in the lower 48 states, as projected for the four principal cases, are shown in Figure 34. These costs include exploration expenses, such as geological and geophysical costs, lease rentals and dry holes, as well as capitalized investments required to acquire leases, to drill and equip wells and leases, and to initiate additional recovery projects.

Historically, these costs have remained fairly constant at approximately $5 billion per year. Case IV maintains this level in the future with a slight increase toward the end of the 1970's. The other three cases, based on a significant increase in drilling, require dramatic increases in such expenditures. For Case I these annual expenditures reach

TABLE 50

REGIONAL NON-ASSOCIATED NATURAL GAS RESERVES ADDED
DURING 15-YEAR PERIODS IN ENTIRE UNITED STATES
(Cumulative—TCF)

Region		Actual 1956—1970	Projected 1971—1985: High Finding Rate: High Drilling Rate Case I	Medium Drilling Rate Case II	Low Drilling Rate Case IVA	Low Finding Rate: High Drilling Rate Case IA	Medium Drilling Rate Case III	Low Drilling Rate Case IV
Onshore 48 States								
2	Pacific Coast	2.6	2.6	2.1	1.2	3.5	2.8	1.5
3	Western Rocky Mtns.	4.3	5.6	4.6	2.7	9.4	7.8	4.2
4	Eastern Rocky Mtns.	4.2	8.6	6.8	3.7	10.1	7.6	3.8
5	West Texas Area	19.4	43.5	36.8	22.5	33.6	27.9	16.5
6	Western Gulf Coast Basin	105.1	81.2	68.9	44.1	38.9	34.5	24.2
7	Midcontinent	33.1	30.7	25.2	15.0	17.7	15.2	9.9
8–9	Michigan, Eastern Interior	0.4	0.6	0.5	0.2	0.5	0.4	0.2
10	Appalachians	6.5	9.3	7.6	4.4	8.6	7.0	4.1
11	Atlantic Coast	–	0.4	0.2	0.1	0.3	0.2	0.1
	Total	**175.6**	**182.5**	**152.7**	**93.9**	**122.6**	**103.4**	**64.5**
Offshore 48 States								
2A	Pacific Ocean	0.5	0.4	0.3	0.1	0.4	0.3	0.1
6A	Gulf of Mexico	42.1	111.2	95.6	58.9	74.6	63.3	39.8
11A	Atlantic Ocean	–	15.1	11.4	4.9	10.1	7.6	3.3
	Total	**42.6**	**126.7**	**107.3**	**63.9**	**85.1**	**71.2**	**43.2**
Alaska		**5.1**	**49.6**	**38.4**	**18.4**	**32.9**	**25.6**	**12.4**
Total United States		**223.3**	**358.8**	**298.4**	**176.2**	**240.6**	**200.2**	**120.1**

$17.6 billion in 1985—three and one-half times the current level.

The same data with all of Alaska included is presented in Table 58, which shows total exploration and development expenditures required for the oil and gas business during the 1971-1985 period. These totals range from $88.0 billion in Case IV to $171.8 billion in Case I. For purposes of comparison, the total for similar expenditures in the 1956-1970 period was $79.8 billion expressed in constant 1970 dollars ($70.7 in current dollars).

As an example, expenditures for the various items comprising exploration, development and production for Case II are shown in Table 59 for the lower 48 states.

A combination of several factors is responsible for these increasing expenditures. The primary factor, of course, is the substantial increase in exploration and development activity. Also, future activity necessarily must shift from more mature areas into the unexplored frontier areas where the greater remaining potential lies. These frontiers for both oil and gas are also areas where severe operating conditions and logistical difficulties require high investments and operating expenses, e.g., Alaska and offshore. In addition, drilling depths must increase to reach the deeper potential resources, and consequently drilling costs increase. This is particularly true of gas for which much of the future potential is below 15,000 feet. The cost of drilling and equipping wells increases sharply as their depth increases and operating conditions become more severe as is indicated by Table 60.

The growing application of more secondary and

TABLE 51

PERCENT OF ULTIMATE NON-ASSOCIATED NATURAL GAS RESERVES DISCOVERED IN ENTIRE UNITED STATES AS OF DECEMBER 31, 1970, AND DECEMBER 31, 1985

			Projected as of December 31, 1985					
			High Finding Rate (Percent)			Low Finding Rate (Percent)		
Region		Actual 12/31/70 (Percent)	High Drilling Rate Case I	Medium Drilling Rate Case II	Low Drilling Rate Case IVA	High Drilling Rate Case IA	Medium Drilling Rate Case III	Low Drilling Rate Case IV
Onshore 48 States								
2	Pacific Coast	31.5	41.6	39.7	36.2	45.1	42.4	37.3
3	Western Rocky Mtns.	35.7	46.9	44.9	41.1	54.5	51.3	44.1
4	Eastern Rocky Mtns.	19.4	36.0	32.6	26.6	39.0	34.1	26.7
5	West Texas Area	26.8	69.7	63.1	49.0	59.9	54.3	43.1
6	Western Gulf Coast Basin	53.2	73.6	70.5	64.3	63.0	61.9	59.3
7	Midcontinent	46.9	60.7	58.2	53.6	54.9	53.7	51.4
8–9	Michigan, Eastern Interior	3.2	8.0	7.2	4.8	7.2	6.4	4.8
10	Appalachians	34.4	44.1	42.3	38.9	43.4	41.7	38.7
11	Atlantic Coast	0.2	8.9	4.6	2.4	6.7	4.6	2.4
	Total	**42.9**	**61.8**	**58.7**	**52.7**	**55.6**	**53.6**	**49.6**
Offshore 48 States								
2A	Pacific Ocean	13.2	23.7	21.1	15.8	23.7	21.1	15.8
6A	Gulf of Mexico	22.5	77.6	69.9	51.7	59.5	53.9	42.2
11A	Atlantic Ocean	—	27.7	20.9	9.0	18.5	13.9	6.1
	Total	**17.6**	**66.4**	**58.9**	**42.2**	**50.4**	**45.0**	**34.3**
Alaska		**1.8**	**19.7**	**15.7**	**8.5**	**13.7**	**11.1**	**6.3**
Total United States		**30.9**	**54.8**	**50.8**	**42.7**	**47.0**	**44.3**	**38.9**

tertiary oil recovery techniques also contributes substantially to the increase in costs. Continuation of the recent rising trend in offshore lease bonus payments, combined with the need for additional leases, is another factor behind increasing costs. Also, adequate protection must be provided for the environment as well as for health and safety, each of which further adds to costs.

Oil Revenues and Net Fixed Assets

The net fixed assets (book investment minus depreciation and excluding working capital) attributed to finding, developing and producing oil in the lower 48 states are shown in Figure 35. Since 1964, net fixed assets in the domestic oil exploration and production sector have declined as a result of insufficient investments being made to offset retirement of older assets. In all of the cases studied, this declining investment trend must be reversed. Even in the lowest supply case, the asset base must be increased to $25.5 billion by 1985.

Applying a set of five return assumptions (10, 12.5, 15, 17.5 and 20 percent) to these net fixed assets permits calculating a range of average required "prices" of oil for each case. As an example, these "prices" for Case II are displayed in Figure 36. For simplicity only the resulting "prices" for 10-, 15- and 20-percent returns are shown.

The rate of return on net fixed assets that will be experienced in the future is unknown; however, the range tested is broad enough to allow adequate evaluation of the variables studied. Again, these "prices" are all expressed in constant 1970 dollars —any future inflationary effects would be additive to the values shown.

Over the last 15 years, oil prices (expressed in constant 1970 dollars) have declined. The projections indicate the need for significant "price" increases, a strong reversal of "prices" being required if the industry is to attract the venture capital required.

For comparison, the Initial Appraisal assumption of constant oil price in the future is shown in Figure 36. In 1985, the rate of return on net fixed assets would decline to a completely unacceptable level of about 2 percent—this indicates the Initial Appraisal is not economically viable. While the supply projections could probably be achieved, the price required would have to be substantially higher than assumed for the Initial Appraisal.

Figures 37 and 38 repeat information previously shown for Case II to help illustrate the need for the projected reversal of the past price trend.

As discussed earlier, both the oil and gas segments of the industry are experiencing increasing real costs. With unit revenues declining and costs increasing, the return on investments realized has been insufficient either to attract or internally generate risk capital needed to expand exploration efforts. This is particularly true when no increased

TABLE 52

WELLHEAD PRODUCTION AND YEAR-END PROVED RESERVES OF NON-ASSOCIATED GAS—LOWER 48 STATES

	Wellhead Production (TCF)	Year-End Remaining Proved Reserves (TCF)	R/P
1970	16.9*	199.4*	11.8
1975†	19.4	180.0	9.3
1980†	19.2	172.6	9.0
1985†	19.7	174.6	8.9

* AGA.

† Projections from Case II (medium drilling rate—high finding rate).

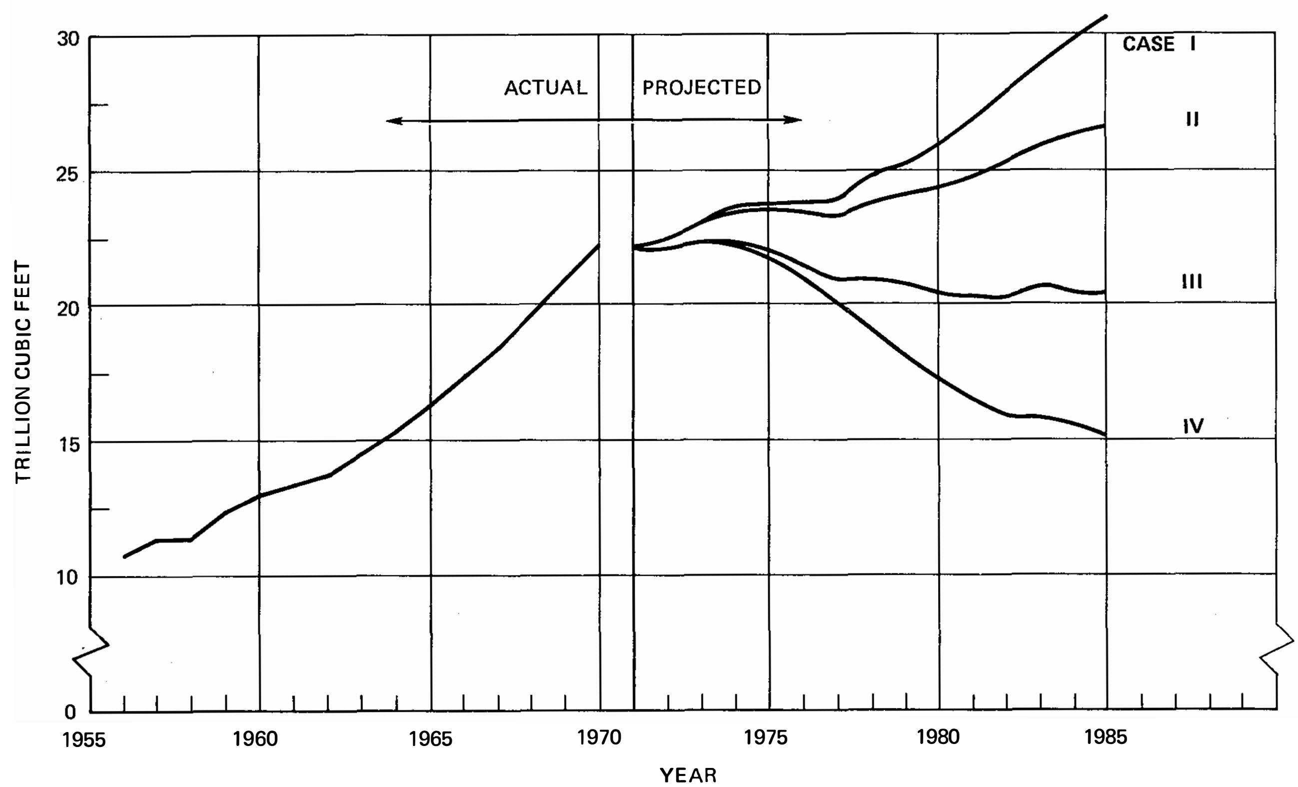


Figure 30. Wellhead Gas Production—Non-Associated and Associated-Dissolved United States (Including Alaska).

TABLE 53

TOTAL MARKETED VOLUMES OF NON-ASSOCIATED AND ASSOCIATED-DISSOLVED NATURAL GAS DURING 15-YEAR PERIOD IN ENTIRE UNITED STATES
(TCF)

		Projected 1971–1985					
		High Finding Rate			Low Finding Rate		
		High Drilling Rate	Medium Drilling Rate	Low Drilling Rate	High Drilling Rate	Medium Drilling Rate	Low Drilling Rate
Region		Case I	Case II	Case IVA	Case IA	Case III	Case IV
Onshore 48 States							
2	Pacific Coast	5.7	5.5	5.3	6.0	5.7	5.4
3	Western Rocky Mtns.	9.4	9.1	8.6	10.3	9.9	9.0
4	Eastern Rocky Mtns.	8.0	7.5	6.6	7.8	7.3	6.4
5	West Texas Area	42.6	40.4	35.7	38.0	36.3	32.7
6	Western Gulf Coast Basin	126.5	122.1	113.0	108.3	106.5	102.2
7	Midcontinent	47.4	45.7	42.6	42.8	42.0	40.2
8–9	Michigan, Eastern Interior	0.4	0.3	0.3	0.3	0.3	0.3
10	Appalachians	7.4	6.9	6.0	7.0	6.6	5.8
11	Atlantic Coast	0.2	0.1	0.1	0.1	0.1	0.1
	Total	**247.6**	**237.6**	**218.2**	**220.6**	**214.7**	**202.1**
Offshore 48 States							
2A	Pacific Ocean	1.8	1.6	1.1	1.4	1.3	0.9
6A	Gulf of Mexico	81.5	75.5	62.5	64.7	60.8	52.6
11A	Atlantic Ocean	1.1	0.9	0.4	0.7	0.6	0.3
	Total	**84.4**	**78.0**	**64.0**	**66.8**	**62.7**	**53.8**
Alaska		**20.8**	**17.8**	**7.9**	**17.6**	**15.1**	**6.8**
Total United States		**352.8**	**333.4**	**290.1**	**305.0**	**292.5**	**262.7**

incentives in forms other than price have been available. In fact, one of these non-price incentives—favorable taxation treatment—was reduced by the 1969 Tax Reform Act. Changes in tax treatment directly affect return on investment by altering the after-tax income realized from the revenue received. The result of the declining economic attractiveness of this high-risk industry has been a reduction of the drilling effort over the last 15 years as shown in Figure 37. Furthermore, the restriction in access to the prospective areas with the highest hydrocarbon potential—the offshore regions—in the last few years has contributed to this decline in activity.

The increased oil and gas drilling activity projected for the future definitely indicates that more risk capital will be required. Thus, the long-standing trend toward decreasing attractiveness of the industry must be reversed quite substantially, and the return on investment must be sufficient to attract the increasing level of required investment. If tax treatment remains unchanged, the only way that this can be accomplished is by increasing revenue and prices to offset projected increasing costs resulting from deeper drilling, more expensive recovery techniques, and operations in hostile environments.

Increased prices alone cannot achieve the projected supply. Exploration for oil and gas involves lead times on the order of several years between the time that the investment decision is made and the first revenue is received. For this reason, it is essential that the investor have a reasonably certain *expectation* that the political and economic situation (including contractual price increases) will be sufficiently favorable in the future to warrant committing large amounts of capital to high risk exploration ventures. Another factor essential to

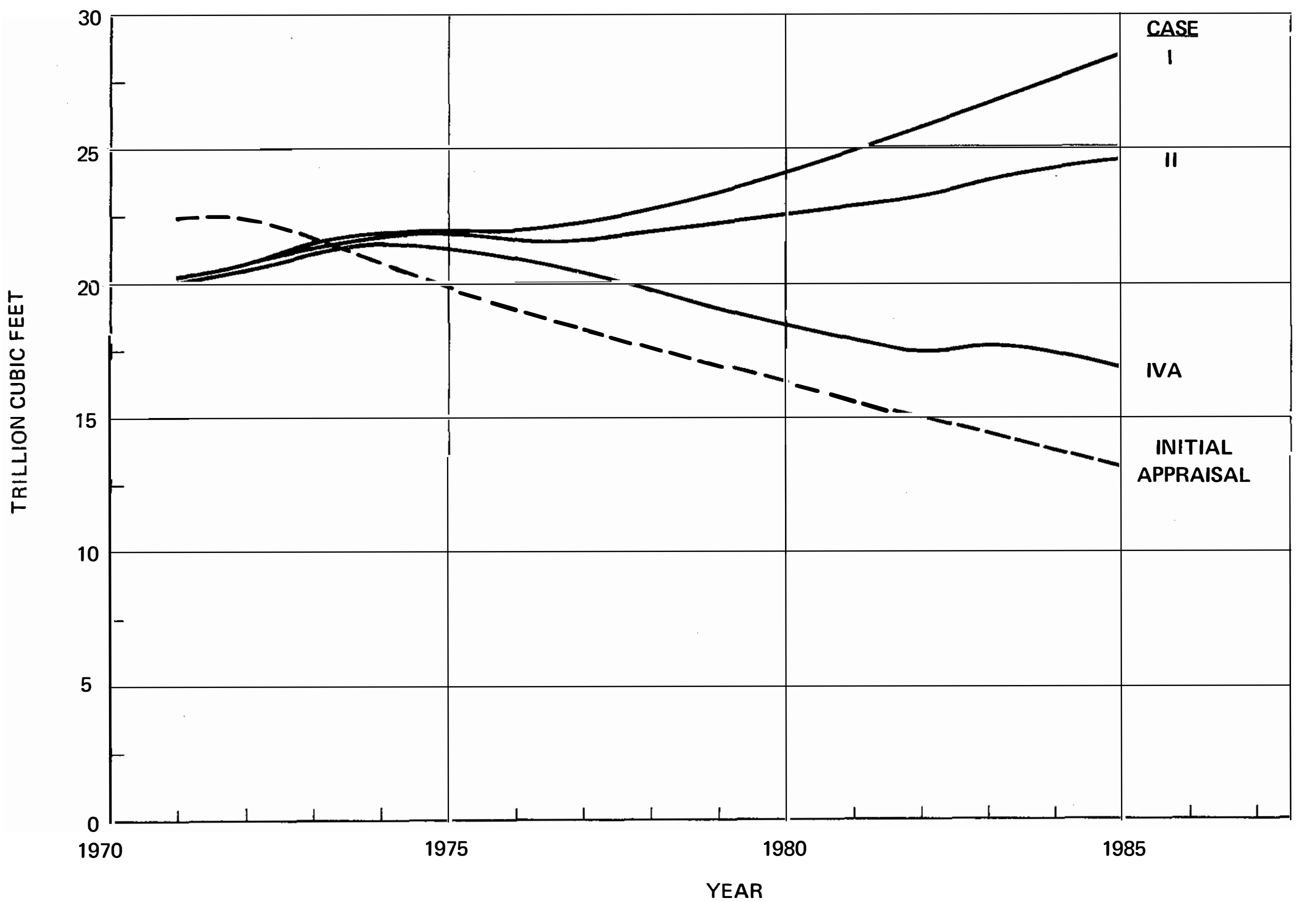


Figure 31. Total Marketed Gas Projections—Total United States (Including Alaska)—High Finding Rate.

expanded exploration efforts is producer confidence in being able to market any production discovered —assuming adequate protection of the environment. The delay of the proposed Alaskan pipeline is an example of this problem. The current hiatus on northern Alaskan exploration activity is a direct result of the uncertainty of market availability.

Only through a satisfactory combination of favorable political, regulatory and economic conditions and expectations will the declining trend in discovery of new primary reserves be improved as projected in Figure 38. Over the past 15 years, the oil industry has been able to maintain annual reserve additions at an almost constant level by increasing application of additional recovery technology to previously discovered reserves. Further substantial improvements of recovery efficiency are projected in the future, but it is recognized that this technology will be costly and will require long lead times. The application of improved techniques is responsible for a considerable amount of future reserves. However, unless the trend in new primary reserve discoveries is soon reversed, the opportunities for applying improved additional recovery methods will rapidly be depleted. This would result in a precipitous decline in total reserve additions, followed in a few years by a corresponding drop in oil production.

For comparative purposes, the calculated unit oil revenues for the low finding rate cases studied are shown in Figure 39. These values are shown only for the mid-range rate of return (15 percent). Similarly, the calculated unit oil revenues for the high finding rate cases are shown in Figure 40. The increases projected in the unit revenues range from a compound growth rate of 3.6 percent in Case IV to 5.4 percent in Case I. These "prices" are the *average* unit revenue computed from all oil

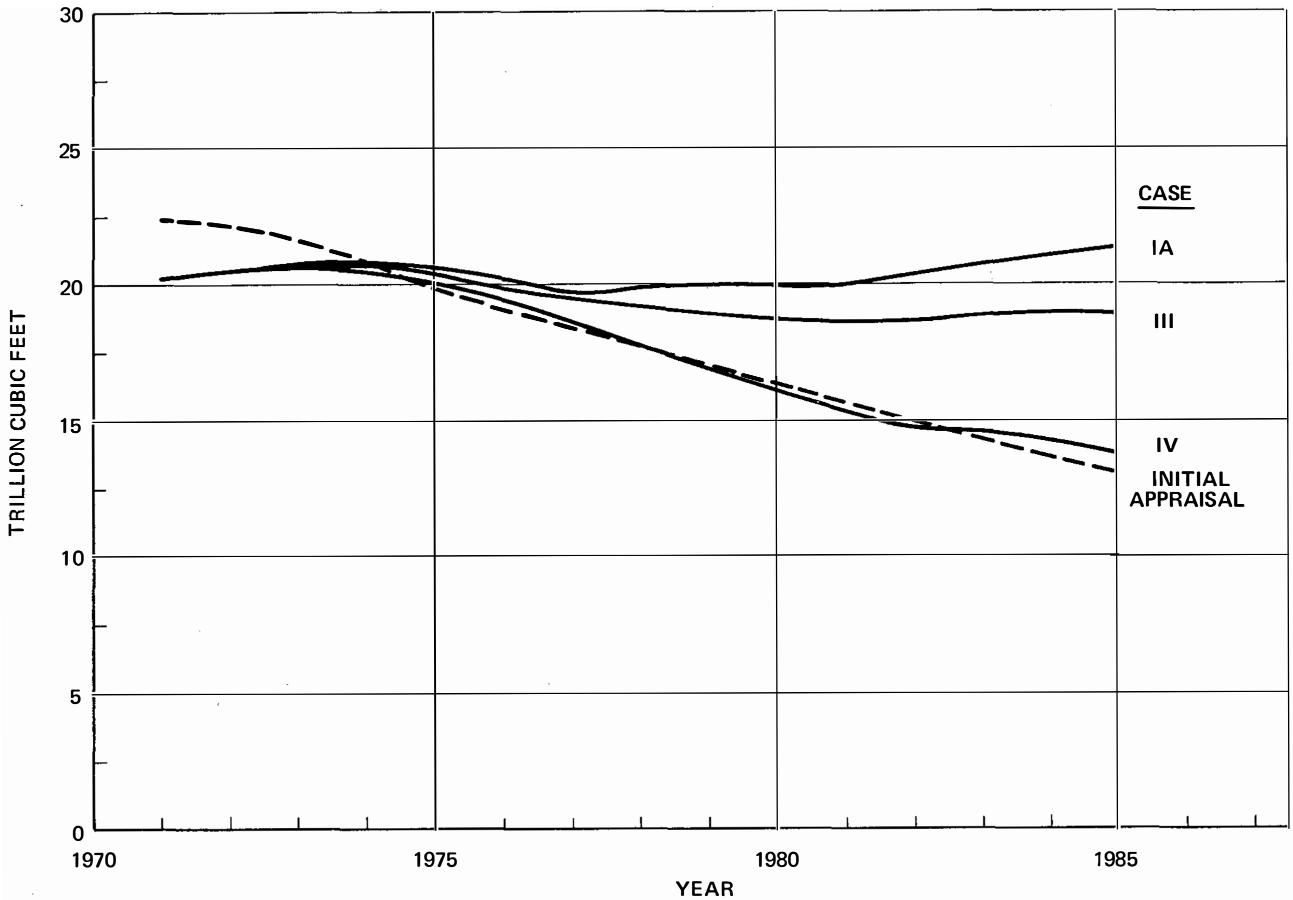


Figure 32. Total Marketed Gas Projections—Total United States—Low Finding Rate.

production, including production from both current proved and future reserves.

Economics of Newly Dicovered Oil—1971-1985

The method of computing the required oil "price" results in an *average* value for both the "old" oil discovered before 1971 and the "new" oil found during the 1971-1985 period. However, it is possible to use these average "prices" to investigate the economic attractiveness of just the new oil exploration and development activity assumed. This can be done by considering, as if it were a single project, all of the effort during the 1971-1985 period to find, develop and produce the new oil reserves. For this purpose, it is appropriate to employ the discounted cash flow (DCF) analysis technique commonly used to evaluate new projects. The DCF return which is calculated in this way can then be checked for reasonableness to see if the result is viable. (It should be kept in mind that this type of return is completely different from return on net fixed assets.)

A DCF calculation was made for Case II as an example, using the detailed assumptions outlined below. These assumptions, particularly on post-1985 performance, can influence the result of such a calculation quite significantly.

- **"Price"**—To calculate revenues for the first 15 years, the required oil "prices" calculated in Case II at a 15-percent return on net fixed assets were used for illustrative purposes. These "prices" increased from \$3.22 per barrel in 1971 to \$6.18 per barrel in 1985. In the absence of any projections after 1985, "price" was assumed constant at \$6.18 per barrel from

TABLE 54

NGL ANNUAL RESERVE ADDITIONS—LOWER 48 STATES
(Million Barrels)

	High Finding Rate			Low Finding Rate		
	High Drilling Rate Case I	Medium Drilling Rate Case II	Low Drilling Rate Case IVA	High Drilling Rate Case IA	Medium Drilling Rate Case III	Low Drilling Rate Case IV
			Condensate			
1971	99.6	99.6	98.3	72.4	72.4	71.4
1975	126.3	112.7	84.8	83.0	74.4	56.8
1980	177.7	141.3	70.6	111.9	90.0	46.4
1985	166.4	136.0	56.6	110.8	88.2	36.8
			Pentane and Heavier			
1971	97.6	97.6	96.5	72.9	72.9	72.1
1975	128.8	115.8	86.9	83.5	75.6	57.6
1980	169.9	136.5	69.7	102.1	83.2	44.0
1985	153.7	127.0	54.3	96.4	77.9	33.7
			LPG			
1971	193.6	193.6	191.4	147.9	147.9	146.3
1975	253.9	228.3	171.4	170.3	154.0	117.2
1980	368.8	294.4	148.5	233.4	188.4	98.2
1985	371.6	297.6	120.8	242.3	190.6	78.6
			Total NGL			
1971	390.8	390.8	386.2	293.2	293.2	289.8
1975	509.0	456.8	343.1	336.8	304.0	231.6
1980	716.4	572.2	288.8	447.4	361.6	188.6
1985	691.7	560.6	231.7	449.5	356.7	149.1

1985 until the time when all reserves would be depleted.

- **Production Rate**—The total new oil production schedule calculated in Case II was used for the 1971-1985 period. This started at zero in 1971 and reached a peak of 4.7 MMB/D in 1985. Production from the reserves remaining in 1985, together with subsequent additions for secondary and tertiary recovery, was scheduled using the same technique as for the 1971-1985 period. Production calculations were continued to the year 2015 which was the practical economic limit.

The total reserves developed in this case for new oil amounted to 37 billion barrels—a recovery efficiency of approximately 48 percent of the 77 billion barrels of oil-in-place discovered.

The cumulative cash flow after income taxes for new drilling reached a *negative* $28 billion by 1985. Production thereafter resulted in a cumulative *positive* cash flow at final depletion of almost $46 billion. The resulting DCF return on new oil was 6 percent.

A 6-percent DCF return is rather low for this type of high risk investment and, as a before-the-fact expectation, would not attract the required risk capital on a single project basis. However, this value is on an after-the-fact basis after all risks have been taken. In addition, it is an industry aggregate and includes both successes and failures —some firms and individuals will have net losses,

TABLE 55

NGL PRODUCTION—LOWER 48 STATES
(MB/D)

	High Finding Rate			Low Finding Rate		
	High Drilling Rate Case I	Medium Drilling Rate Case II	Low Drilling Rate Case IVA	High Drilling Rate Case IA	Medium Drilling Rate Case III	Low Drilling Rate Case IV
			Condensate			
1971	399.7	399.7	399.7	399.7	399.7	399.7
1975	373.2	369.6	361.6	347.1	344.9	399.5
1980	417.3	391.0	337.8	338.9	323.0	289.6
1985	454.5	395.3	274.8	328.8	292.1	217.8
			Pentane and Heavier			
1971	507.4	507.4	507.4	507.4	507.4	507.4
1975	434.5	431.2	422.5	407.4	405.2	399.5
1980	462.5	437.3	383.3	381.6	366.6	334.0
1985	481.9	427.4	312.3	354.5	322.5	254.0
			LPG			
1971	1,068.2	1,068.2	1,068.2	1,068.2	1,068.2	1,068.2
1975	908.8	901.9	885.2	858.0	854.2	843.0
1980	936.4	886.6	781.4	788.5	757.8	691.0
1985	984.9	870.1	633.2	744.7	672.9	524.9
			Total NGL*			
1971	1,975.3	1,975.3	1,975.3	1,975.3	1,975.3	1,975.3
1975	1,716.4	1,702.7	1,669.3	1,613.4	1,604.4	1,581.9
1980	1,816.2	1,714.8	1,502.5	1,509.0	1,477.4	1,314.5
1985	1,921.4	1,692.9	1,220.3	1,427.9	1,287.4	996.7

* Totals may not agree due to rounding.

while others will receive adequate returns. Hence, the return on this composite basis should be expected to be lower than the level that is considered a desirable objective for a single project.

Gas Revenues and Net Fixed Assets

Figure 41 shows the historical level of a year-end net fixed assets in the gas business and the projection of these levels as calculated for various cases studied. Assets have shown a modest increase during the past 15 years. However, in both the medium (Case II and III) or high (Case I) drilling cases, the asset base will have to be rapidly expanded to achieve the projected levels of supply.

In constant 1970 dollars, assets have increased from $3.9 billion in 1956 to $8.7 billion in 1970. By the end of 1985, the high drilling case (Case I) would result in assets increasing to more than $23 billion. The medium drilling case (Case II) would result in asset growth to almost $18 billion by the end of 1985.

In Case IV, where gas drilling declines approximately 4 percent per year, the asset base is calculated at $8.1 billion by the end of 1985. This compares with an asset base of $8.7 billion at year-end 1970.

The range of required average gas "prices" resulting from application of different returns on average net fixed assets are shown for the medium

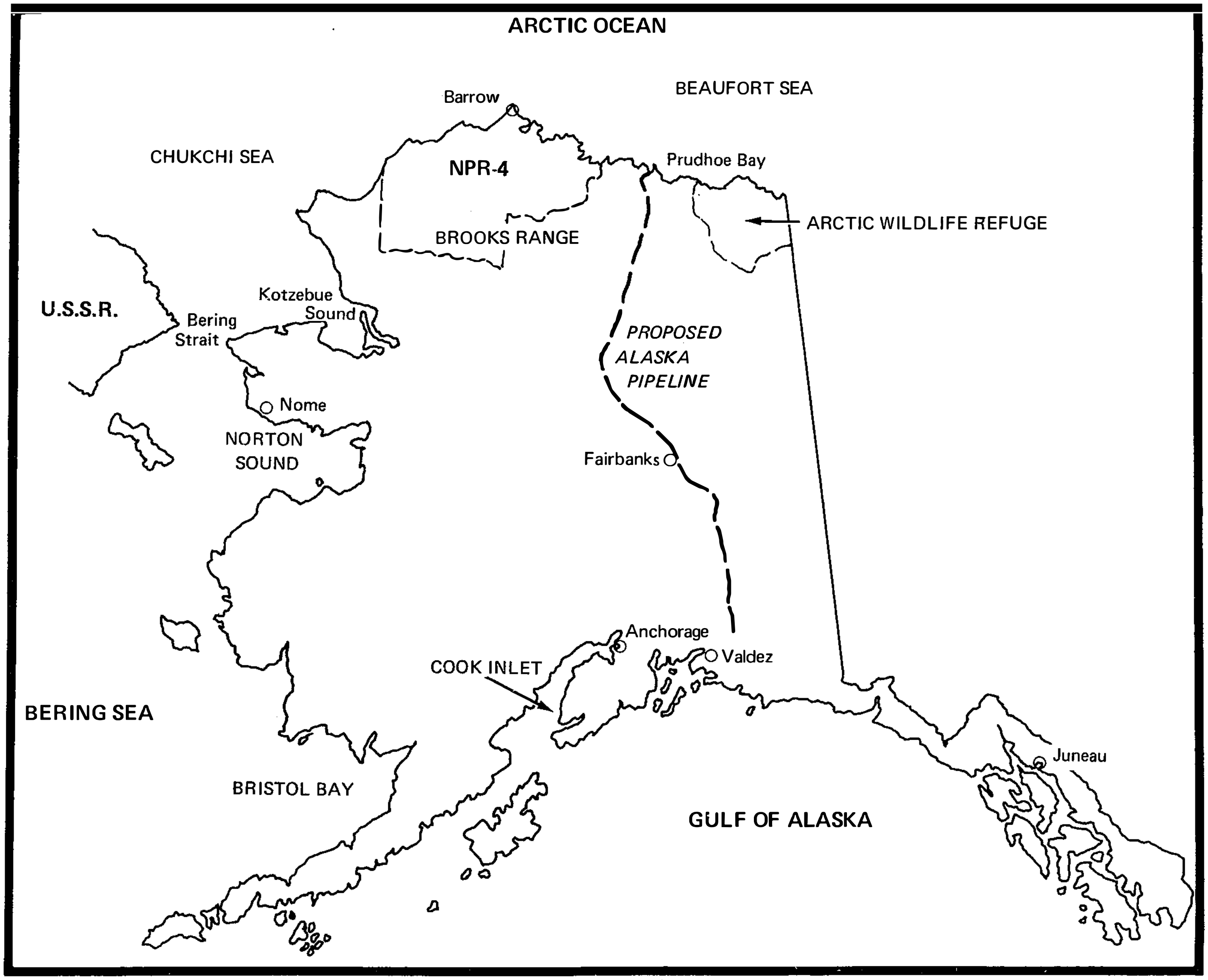


Figure 33. Area Map of Alaska.

drilling rate combined with the high finding rate (Case II) on Figure 42. Figure 43 shows the required "prices" for the same drilling rate combined with the low finding rate (Case III). The returns used are 10, 15 and 20 percent. As Figures 42 and 43 indicate, current earnings from gas are substantially below the range of rates of return used in these studies.

Figure 44 shows the average unit gas revenues required for those cases which utilized the low finding rate (Cases IA, III and IV). Figure 45 shows the average unit gas revenues required for those cases which utilized the high finding rate (Cases I, II and IVA). For illustrative purposes, the 15-percent rate of return shown on both figures was selected because it is at the middle of the range of returns used in these studies.

Figures 44 and 45 clearly show the magnitude of the effect that finding rate has on required unit revenue. For example, Case II (see Figure 45), which utilized the high finding rate and requires a unit revenue of 39.8 cents per MCF in 1985, can be compared with Case III (see Figure 44), which utilized the low finding rate and requires a unit revenue of 53 cents per MCF. Both of these cases involve the same level of drilling activity which can be controlled, as opposed to the finding rate which cannot.

Once discoveries have been made, oil and gas producing and marketing activities vary substantially in many respects. Generally the time lag experienced between the discovery of reserves and the start of production is longer in the case of gas than in the case of oil. When an oil well is completed, production can usually start almost immediately. Oil can be moved by truck or barge if no other facilities exist. Gas production must await the construction of gathering and pipeline facilities. The building of these facilities is dependent on developing a large enough volume of gas to justify the expenditure required for the construction. Certification proceedings before the FPC for interstate sales introduce additional time lags. This means that the capital invested in gas production must wait at least 1 or 2 years longer to begin generating revenue.

TABLE 56

ALASKAN PRODUCTION*

	Case I	Case II	Case III	Case IV
Crude Oil—North Slope (MB/D)				
1975	0	0	0	0
1976	750	600	600	0
1980	2,190	2,000	2,000	0
1981	2,340	2,000	2,000	600
1985	2,600	2,000	2,000	2,000
Non-Associated and Associated-Dissolved Gas—Total Alaska (TCF/Year—Dry Basis)				
	Case I	Case II	Case III	Case IV
North of Brooks Range				
1975	–	–	–	–
1978	0.8	0.8	0.6	–
1980	1.4	1.3	1.1	–
1981	1.6	1.4	1.2	–
1983	2.5	2.2	2.2	0.7
1985	3.3	2.7	2.2	1.3
South of Brooks Range				
1975	0.2	0.2	0.2	0.2
1978	0.2	0.2	0.2	0.2
1980	0.2	0.2	0.2	0.2
1981	0.5	0.5	0.4	0.3
1983	0.7	0.6	0.4	0.3
1985	1.1	0.9	0.6	0.4
Total Alaska				
1975	0.2	0.2	0.2	0.2
1978	1.0	0.9	0.8	0.2
1980	1.7	1.5	1.3	0.2
1981	2.2	2.0	1.7	0.3
1983	3.2	2.8	2.4	1.0
1985	4.4	3.5	2.9	1.8

* None of the estimates include production for North Alaska offshore because severe operating conditions will probably prevent development during the 1971-1985 period. Totals may not agree because of rounding. Years included above in addition to 1975, 1980 and 1985 reflect projected commencement of logistical operations for oil and gas.

Gas generally moves under long-term contracts while oil does not. The field price of about two-thirds of total marketed gas production is regulated by the FPC, and these price ceilings have had a considerable effect on the price of the remaining gas which moves in intrastate commerce. Interstate gas sales prices have been reduced to the FPC area ceiling rates while contracted gas sales prices set below ceilings remain at the contract levels. This standard—i.e., ceiling price or contract price, whichever is lower—has resulted in a 1970 average unit gas revenue of 17.1 cents per MCF.*

Figure 42 shows that for Case II the 1970 average unit revenue (17.1 cents per MCF) is 2.5 cents per MCF lower than the calculated 1971 required average unit revenue of 19.6 cents per MCF at a 10-percent rate of return and 10.3 cents per MCF lower than the calculated unit revenue of 27.4 cents per MCF at a 20-percent rate of return. Extrapolation of these data leads to the conclusion that gas is earning approximately 7 percent on average net fixed assets under current conditions. This is an unattractive return considering the risks assumed by the investor-producer.†

* The 17.1 cents per MCF is the average wellhead value reported by the Bureau of Mines for 1970. For purposes of this discussion, the 17.1 cents per MCF is assumed to be on a comparable basis with the required unit "prices" calculated in this study. However, this value contains some amount for liquid content (estimated to be about 2 cents) and to that extent is overstated for comparative purposes with unit "prices" calculated in this study.

† The Bureau of Mines has recently published the 1971 wellhead value of natural gas as being 18.2 cents per MCF. This would indicate a 1971 rate of return on gas of about 8 percent. However, it should be kept in mind that this return is overstated to the extent that liquid values are a part of the 18.2 cents. If the liquid value were as much as 2 cents per MCF, then the indicated return on gas would be less than 6 percent.

Economics of Newly Discovered Gas — 1971-1985

The results of studies presented herein relate only to average unit gas revenues. No feasible method was found to incorporate into the computer program the vintaged ceiling price system imposed by federal regulation in combination with a second ceiling imposed by contract. The fact that some of the area ceilings are currently under attack in the courts and others are awaiting decision by the FPC adds to the complexity of the problem.

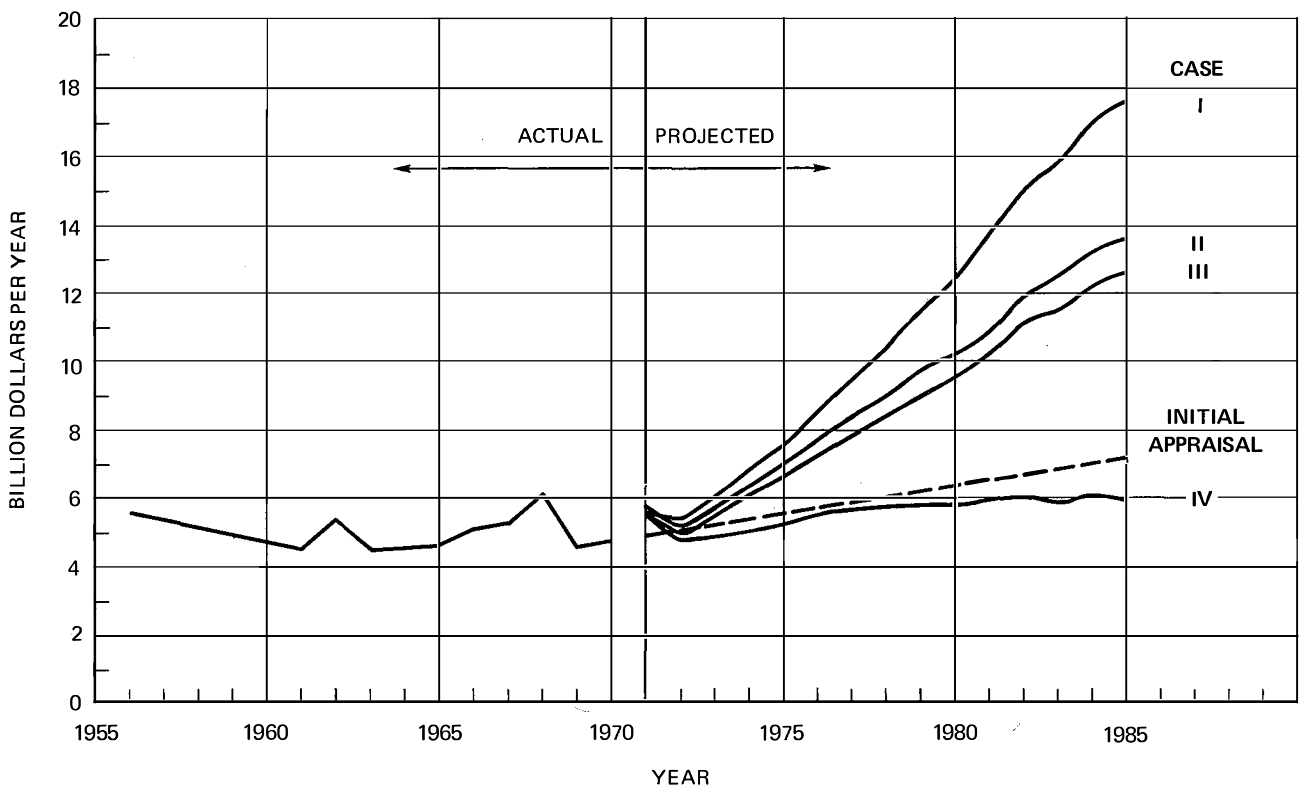
The level of unit revenue required from future gas sales at an assumed rate of return on total gas sales can be calculated by using data generated in the computer program. The program computes the total annual revenue required from gas sales. It also calculates the annual volume of marketed production from reserves found through the year 1970 separately from the volume of marketed production from reserves added in 1971 and subsequent years.

An essential determination which must be made is the annual unit revenue, or "price," to be received for future sales of gas found through the year 1970. The assumed unit "price" is then used

TABLE 57

ALASKAN EXPLORATION AND DEVELOPMENT EXPENDITURES
(Million Dollars)

	Case I	Case II	Case III	Case IV
	Non-Associated Gas—All Alaska			
1971-1975	207	192	192	164
1976-1980	1,226	991	978	543
1981-1985	2,282	1,688	1,648	663
Total	**3,715**	**2,871**	**2,818**	**1,370**
	Oil—North Slope			
1971-1975	835	681	681	227
1976-1980	2,412	2,001	2,001	455
1981-1985	1,696	1,313	1,313	2,001
Total	**4,943**	**3,995**	**3,995**	**2,683**



* *Excluding North Slope oil and Alaskan gas operations.*

Figure 34. Exploration and Development Costs *—Oil and Gas (Constant 1970 Dollars).

TABLE 58

EXPLORATION AND DEVELOPMENT EXPENDITURES
TOTAL UNITED STATES
(Billion Dollars)

		1971	1975	1980	1985	15-Year Total
				Case I		
Oil		3.6	5.4	8.6	12.5	113.1
Gas		2.1	2.7	4.6	5.8	58.7
	Total	5.7	8.1	13.2	18.3	171.8
				Case II		
Oil		3.6	4.9	7.3	9.9	97.7
Gas		2.1	2.4	3.6	4.3	47.1
	Total	5.7	7.3	10.9	14.2	144.8
				Case III		
Oil		3.5	4.5	6.6	8.8	88.8
Gas		2.1	2.4	3.6	4.3	46.3
	Total	5.6	6.9	10.2	13.1	135.1
				Case IV		
Oil		3.5	3.5	4.1	5.0	61.5
Gas		2.0	1.8	1.7	1.5	26.5
	Total	5.5	5.3	5.8	6.5	88.0

to calculate the revenue resulting from such production. This calculated revenue is deducted from the total annual revenue required, and the remainder must be generated from remaining production, i.e., from gas found after 1970. The remaining required revenue figure is divided by the annual produced volumes of gas discovered after 1970 to determine the unit revenue required for this gas. These calculations are performed for each year to derive annual unit "prices."

Table 61 shows marketed volumes of pre- and post-1970 discovered gas under Case III conditions. Table 62 shows the Case III average unit "prices" and calculated "prices" for gas production from reserves discovered post-1970 under three different assumptions. These three assumptions, which relate only to the "price" for gas discovered in 1970 and prior years, are as follows: (1) no escalation, (2) an escalation of 0.5 cents per MCF per year, and (3) an escalation of 1.0 cents per MCF per year. The price escalations are assumed to begin on January 1, 1973.

Table 62 shows that unit revenues required for production from reserves found after 1970 will be in the range of slightly less than $0.60 to a little more than $0.80 per MCF at a 15-percent rate of return in constant 1970 dollars. The level of these required unit revenues is, of course, influenced directly by the "price" received for production from reserves found through the year 1970. In general, the required unit revenues shown are comparable to, or well below, estimates of costs of alternative forms of gas supply with the exception of some overland imports.

Another fact which must be considered in examining the required unit revenues shown in Table 62 is the effect on consumer prices of *not* having adequate domestic supplies of gas. Many of the costs of transporting and distributing gas are fixed, in the sense that a smaller volume does not reduce the total cost but increases the unit costs of the smaller volume. In addition, there are substantial undepreciated investments in pipeline and distribution facilities. If supplies become inadequate, current depreciation rates would need to be increased. These two facts alone would exert substantial upward pressure on consumer prices.

These studies document the fact that gas is currently earning very low returns on investment, which is certainly one of the principal reasons for the present critical condition of domestic gas supply. Until this situation is remedied, there is little reason to expect that achievement of the increased gas drilling rates postulated in certain of these studies can be realized. One obvious approach to the problem of determining adequate economic incentives would be to let gas seek its competitive price level in the marketplace.

The required "prices" for marketed volumes of natural gas are expressed in constant 1970 dollars. Future inflation is of considerable concern to producers selling gas interstate under conventional contracts, most of which specify terms for the life of production or for 20 years. Without implying a future inflationary trend, it is important to quantify the significance of even a relatively small inflationary influence. As an example, the application of a 3-percent average annual inflation factor to the average gas "price" required in Case III in 1985 (Table 62) increases the constant 1970 dollar price of 53.0 cents to 82.6 cents per MCF.

TABLE 59

CASE II EXPENDITURES FOR EXPLORATION, DEVELOPMENT AND PRODUCTION OF OIL AND GAS—1971-1985*
(Million Dollars)

	1971	1975	1980	1985	15-Year Total
Exploration					
Dry Holes	839	1,033	1,364	1,683	18,500
Lease Acquisitions	817	1,420	2,385	3,166	29,509
Lease Rentals	140	162	238	332	3,223
Geological & Geophysical	530	610	771	966	10,713
Total	**2,326**	**3,225**	**4,758**	**6,147**	**61,945**
Development					
Drilling & Equipping Producing Wells	1,916	2,312	3,105	4,076	42,062
Equipping Leases	1,103	1,325	2,246	3,350	31,631
Gas Plant Development	209	167	140	94	2,250
Total	**3,228**	**3,804**	**5,491**	**7,520**	**75,943**
Total Exploration and Development	**5,554**	**7,029**	**10,249**	**13,667**	**137,888**
Production					
Producing Costs	2,533	2,607	3,084	3,767	44,467
Production & Ad Valorem Taxes	958	1,061	1,388	1,893	19,623
Total	**3,491**	**3,668**	**4,472**	**5,660**	**64,090**
Gas Plant Expenses	469	458	435	429	6,688
Overhead Expenses	832	959	1,211	1,518	16,835

* Excludes North Slope oil and all Alaskan gas.

Parametric Studies — Oil and Gas

It is important for decision makers to know how responsive or sensitive supplies and prices would be to changes in basic assumptions about finding rates, drilling costs, changes in government policy, etc. The technique used to provide this information was to vary only one assumption or parameter at a time to determine its effect upon the results. These studies were normally done on Cases II and III in order to keep the number of evaluations to a manageable size. However, in a few instances Cases I and IV were also tested. Unless otherwise indicated, the North Slope oil and Alaskan gas operations were not included in these analyses.

The results of these parametric studies are expressed in terms of the incremental effects on Case II and Case III producing rates and "prices." For "price" effects, five rates of return in the 10- to 20-percent range were investigated; the 15-percent return level is the middle value in the spectrum evaluated and is reported here for illustrative purposes. Higher rates of return would naturally require higher "prices."

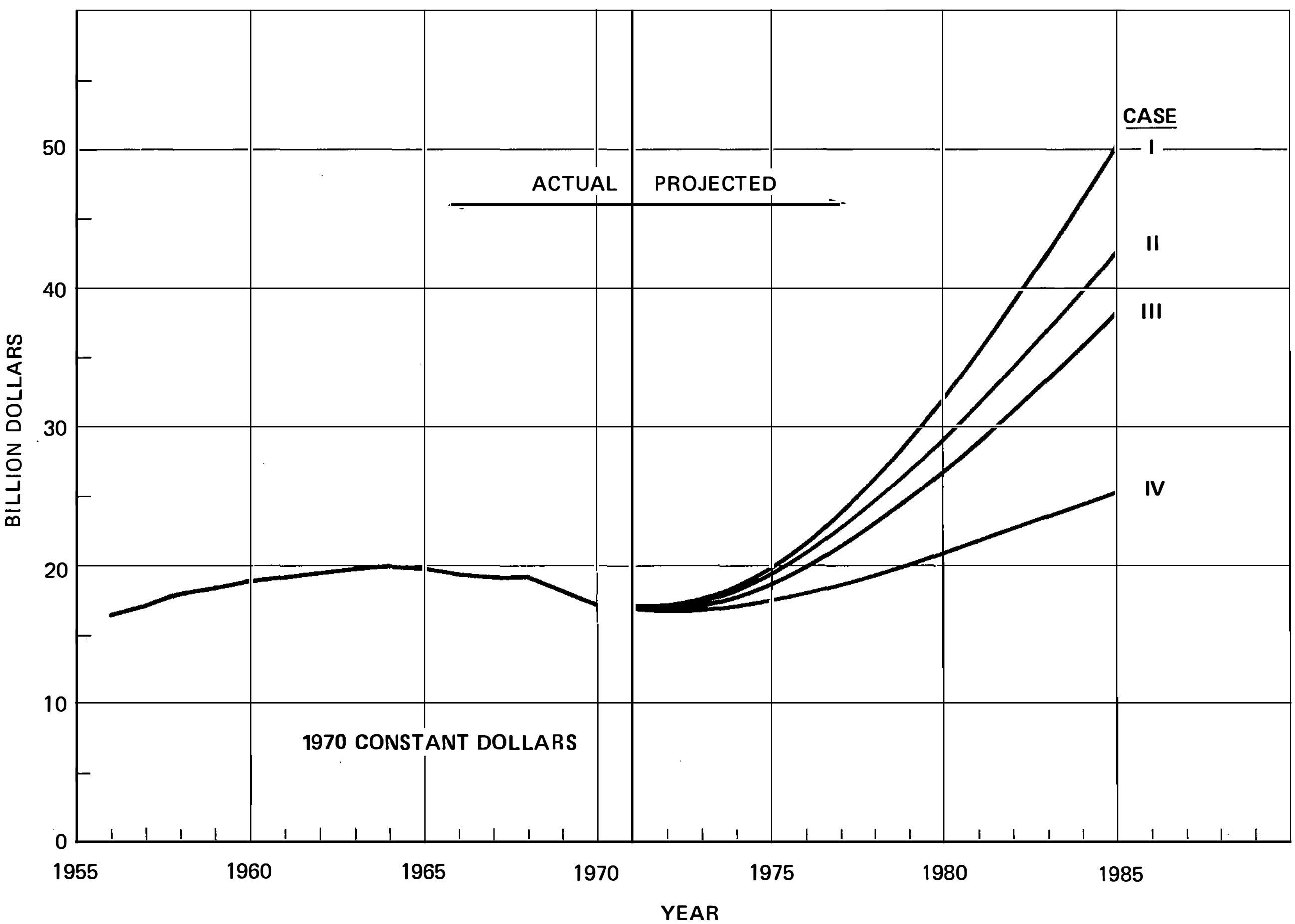
TABLE 60

AVERAGE COST PER WELL DRILLED—1968-1970*

Depth Range (Feet)	Onshore 48 States	Offshore 48 States	Alaska
0 - 4,999	$ 25,000	$ 212,000	$ 382,000
5,000 - 9,999	83,000	367,000	1,508,000
10,000 - 14,999	251,000	598,000	1,869,000
15,000 - 19,999	732,000	1,115,000	2,894,000
20,000 and over	1,485,000	2,690,000	

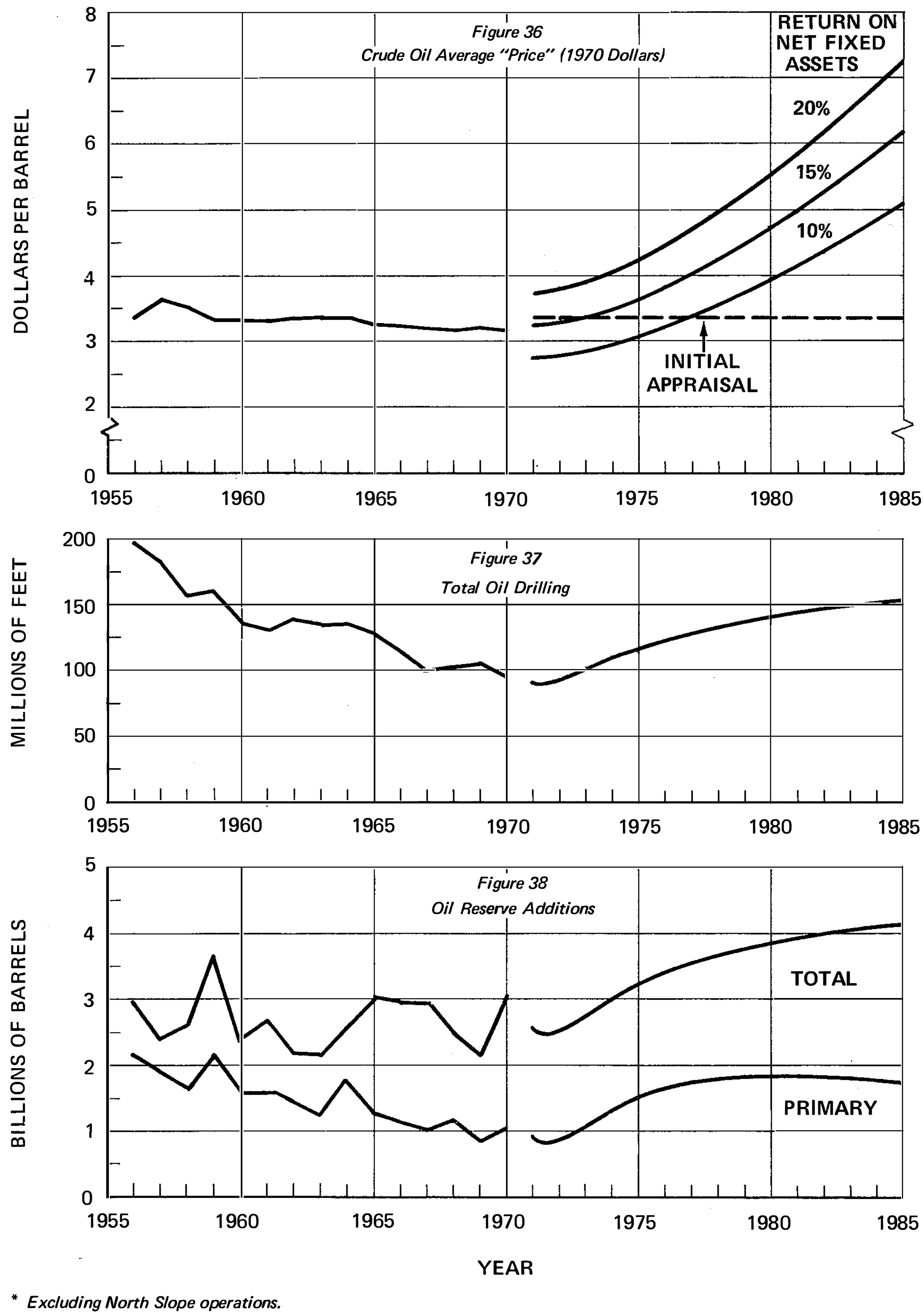
* Developed from *Joint Association Survey of the Oil and Gas Producing Industry,* Sponsored by the American Petroleum Institute, Independent Petroleum Association of America and Mid-Continent Oil and Gas Association (published yearly).

No attempt was made to determine the effect that the different "prices" would have on drilling activity or, in economic terms, to determine the price-elasticity of supply. It should be emphasized that the required "price" is that average "price" required to yield a given rate of return on net fixed assets, which includes a heavy component of previously discovered oil and gas reserves. It is not the "price" required to give the industry adequate incentive to discover and develop new reserves. Nevertheless, these parametric studies do provide an indication of the relative effect on supplies and "prices" of reasonable variations in the basic parameters.

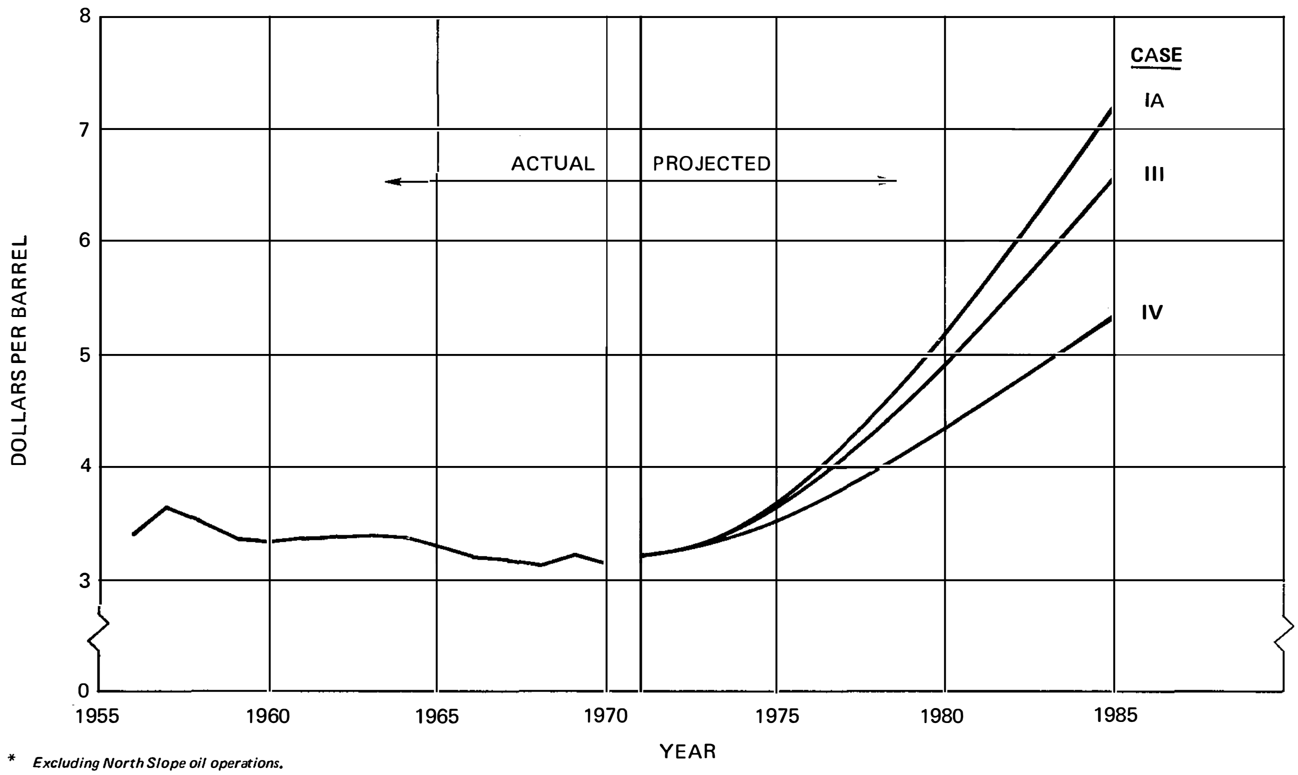


* *Excluding North Slope operations.*

Figure 35. Net Fixed Assets—Oil Operations (Billion Dollars).*



Figures 36-38. Oil Average "Price," Drilling and Reserve Additions.*



* *Excluding North Slope oil operations.*

Figure 39. Required Crude Oil "Price"—Low Finding Rate—15-Percent Return (Constant 1970 Dollars).*

Sensitivity of Physical Assumptions

While a large number of physical assumptions were made in developing the base cases, the most significant of these were finding rates and application of additional recovery processes. Several studies were made to examine the sensitivity of production and "prices" to these parameters.

Finding Rates

The amount of hydrocarbons found per foot drilled strongly influences both production and "prices." This factor—which embraces an element of risk as well as exploratory skill—not only helps determine the projected supply but also heavily influences future required "prices."

Two finding rates were applied to each of the three drilling rates. It is highly unlikely that either the high or low finding rate would occur in all regions every year over a 15-year period, and the actual average finding rate would more probably fall between the two. The resulting supply and required "prices" would then fall within the range established by the two finding rates applied to the assumed drilling rates.

The effect of finding rates on production and required "prices" is shown in Table 63. Case II utilized the medium growth drilling rate and the high finding rate, whereas Case III utilized the same drilling rate but the low finding rate.

Table 63 indicates that the 1985 production rate would be significantly lower and the required "price" in 1985 would be higher if a low rather than a high finding rate were experienced. A similar comparison of cases at the other two drilling rates yields comparable results.

Another parametric study was run to evaluate the possibility that the historical oil found was understated. This might occur if past API data on reserve "revisions" included some oil added as a result of increases in oil-in-place. To the extent that any such additions to oil-in-place had occurred, the historical finding rates would be too low. An analysis of the API data indicated this

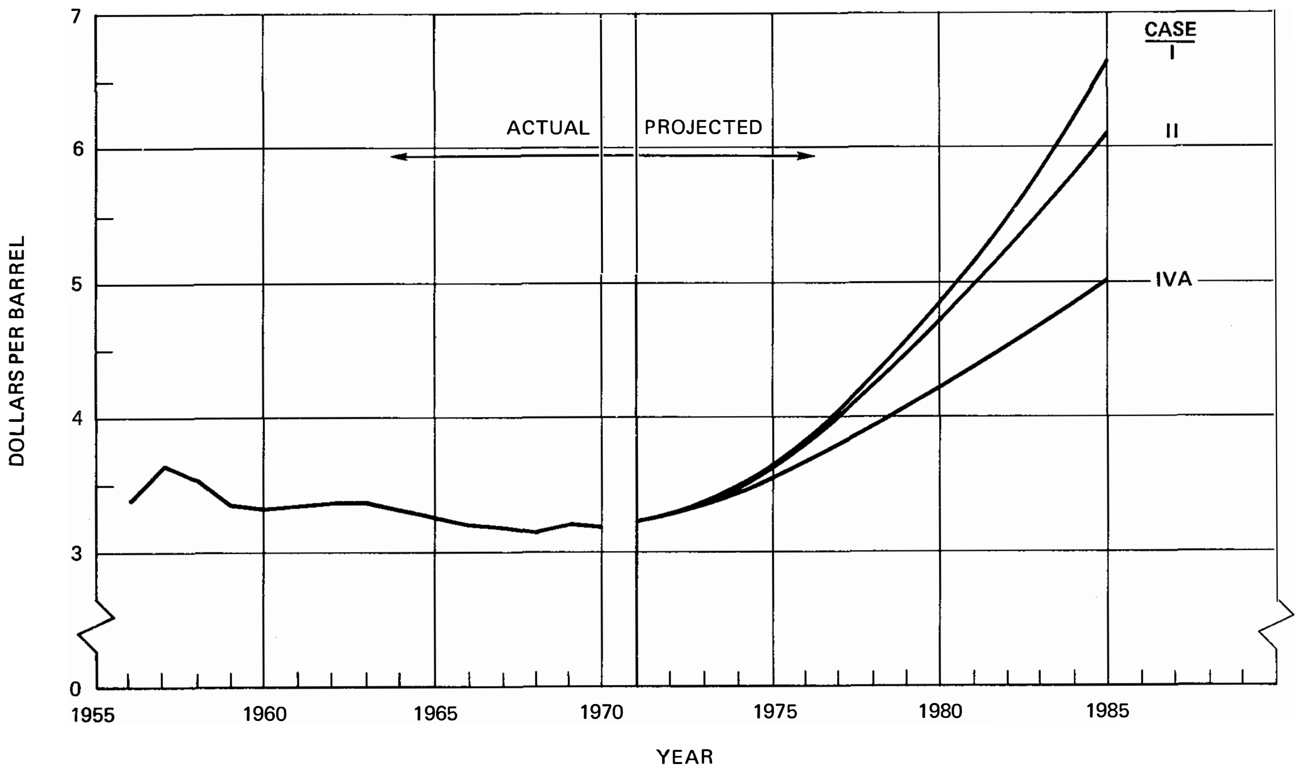


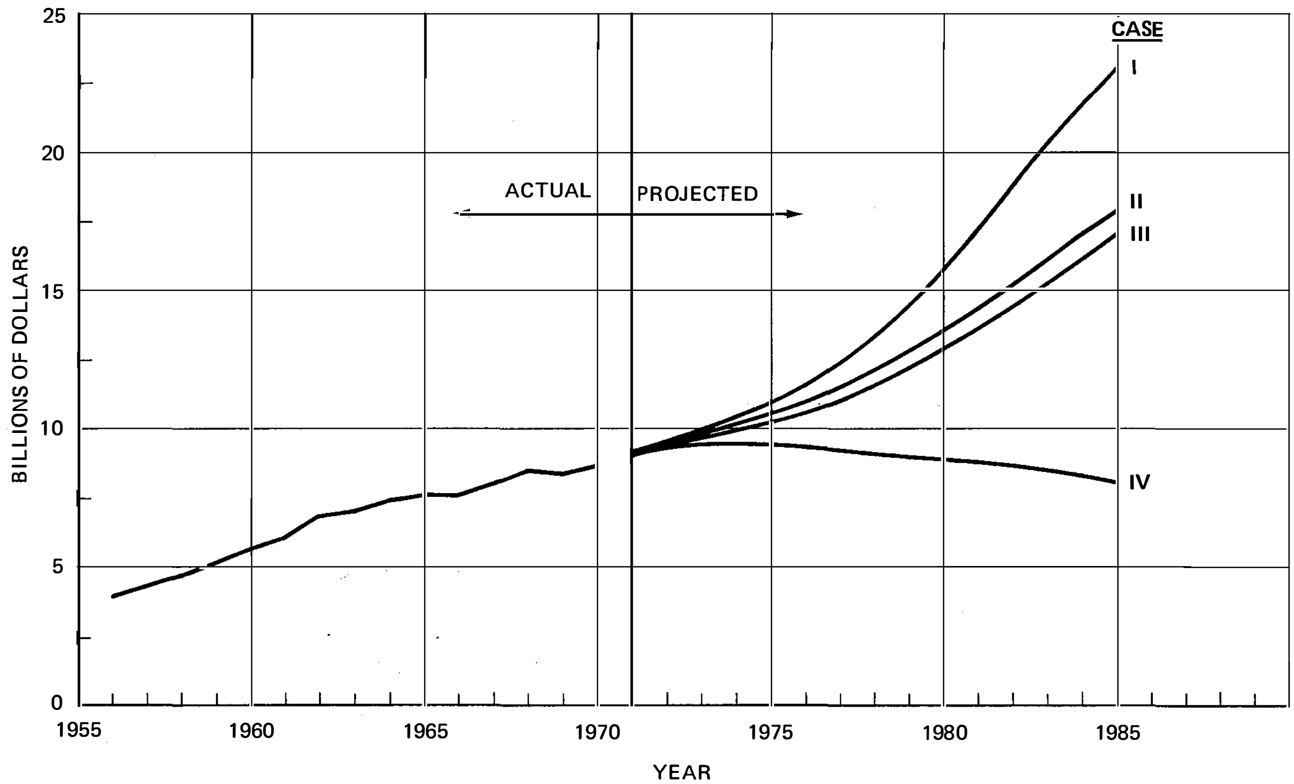
Figure 40. Required Crude Oil "Price"—High Finding Rate—15-Percent Return (Constant 1970 Dollars).*

error should not exceed 5 percent. The results of two cases in which the oil finding rates were increased by twice the potential error (10 percent) are shown in Table 64. As indicated in this table, the maximum effect occurs in Case II, in which the 1985 production rate increases about 0.5 MMB/D (less than 5 percent) and the required "price" is reduced by about 4 percent. These results substantiate the judgment that the method of handling API reserve statistics provides reliable results.

Although the high finding rate projection includes an allowance for discovery of major fields, the possibility exists of discovering another field near the size of the largest producing field in the lower 48 states. The impact of such a find was evaluated by hypothesizing the discovery of a 5-billion-barrel (recoverable oil) offshore field in 1978. The results of this hypothesis on Cases II and III are shown in Table 65. A discovery of this magnitude may have a low probability, particularly when assuming the high finding rate. Nevertheless, it could significantly affect the supply picture for the United States if this oil field were found in an accessible area so that it could be easily marketed. In 1983, the year of peak production, such a field could increase the Nation's oil supply by 16 to 19 percent (exclusive of the North Slope). Furthermore, such a major discovery would also stimulate industry activity resulting in a production increase which would exceed that shown in Table 65. The effect upon "price" is uncertain in that exploration and development investment would be stimulated as would the bidding on leases. The increased revenue would probably be spent on this expanded effort.

Additional Oil Recovery

The rate of application of additional recovery processes assumed was consistent with historical increases in oil recovery efficiency. If, because of increased incentive or a technological break-



* *Excluding Alaskan gas operations.*

Figure 41. Year-End Net Fixed Assets—Gas Operations.*

through, additional recovery projects were implemented earlier and applied to more fields, the of secondary and tertiary recovery projects was increased by about 50 percent and accelerated by 2 years. This had the effect of raising the 1985 cumulative recovery efficiency from 37 percent to 39 percent of the oil-in-place discovered. The results are shown in Table 66. Production would production would be significantly increased. Studies were made against the highest and lowest supply cases (I and IV) in which implementation greatly increase in both cases. In Case IV, significant "price" increases would be required because there is relatively little production to provide required revenues; hence, per barrel revenues must be higher. Since Case I already has a high production base, the per barrel "price" increases required are much less significant. A factor not accounted for is any cost reduction that might be associated with technological improvement.

Oil Reserves/Production Ratio

A parametric study was conducted on Case II to determine the impact of assuming that the oil R/P could be reduced from 8.9 in 1970 to about 8.0 in 1975 and maintained at that level thereafter (see Table 67). It can be seen that U.S. oil production could be increased by as much as 7 percent in 1975. This acceleration of production could result in about a $0.26 reduction in 1985 crude "price."

Basic Cost Parameters

To test the sensitivity of oil and gas "prices" to drilling costs, operating expenses and investments in additional recovery projects, parametric studies were made by separately increasing each of these items by 10 percent. The results are shown in Tables 68, 69 and 70.

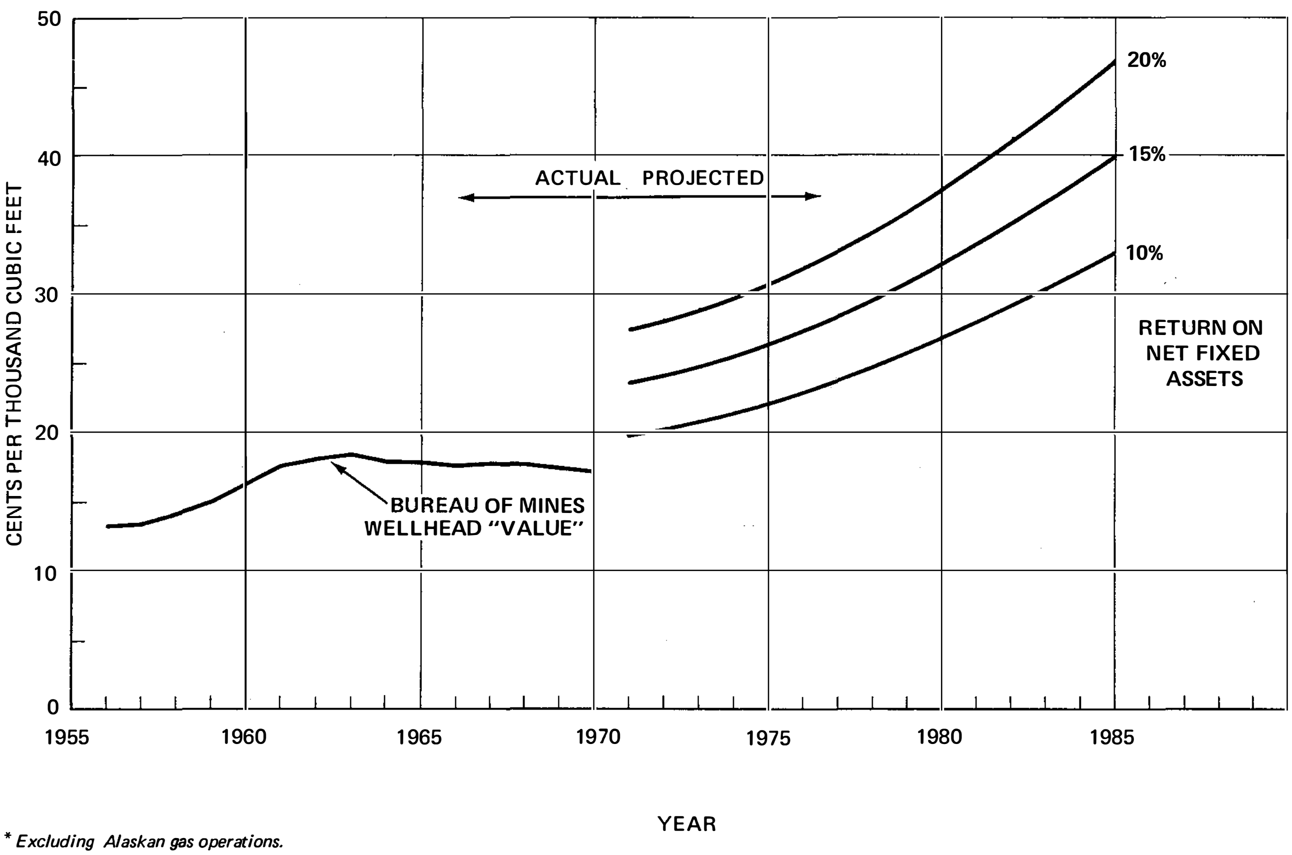


Figure 42. Required Average Gas "Prices"—Case II (Constant 1970 Dollars).*

Environmental, Health and Safety Costs

In the past several years, the oil and gas industry has devoted a significant part of its investments and operating costs to protecting the environment and promoting health and safety. These historical costs are reported by the API and are included in the total investment and expense projections.* However, in 1970 much more stringent regulations of this type governing offshore operations were implemented, causing a significant rise in costs. These costs were projected separately in the methodology used in this parametric study.

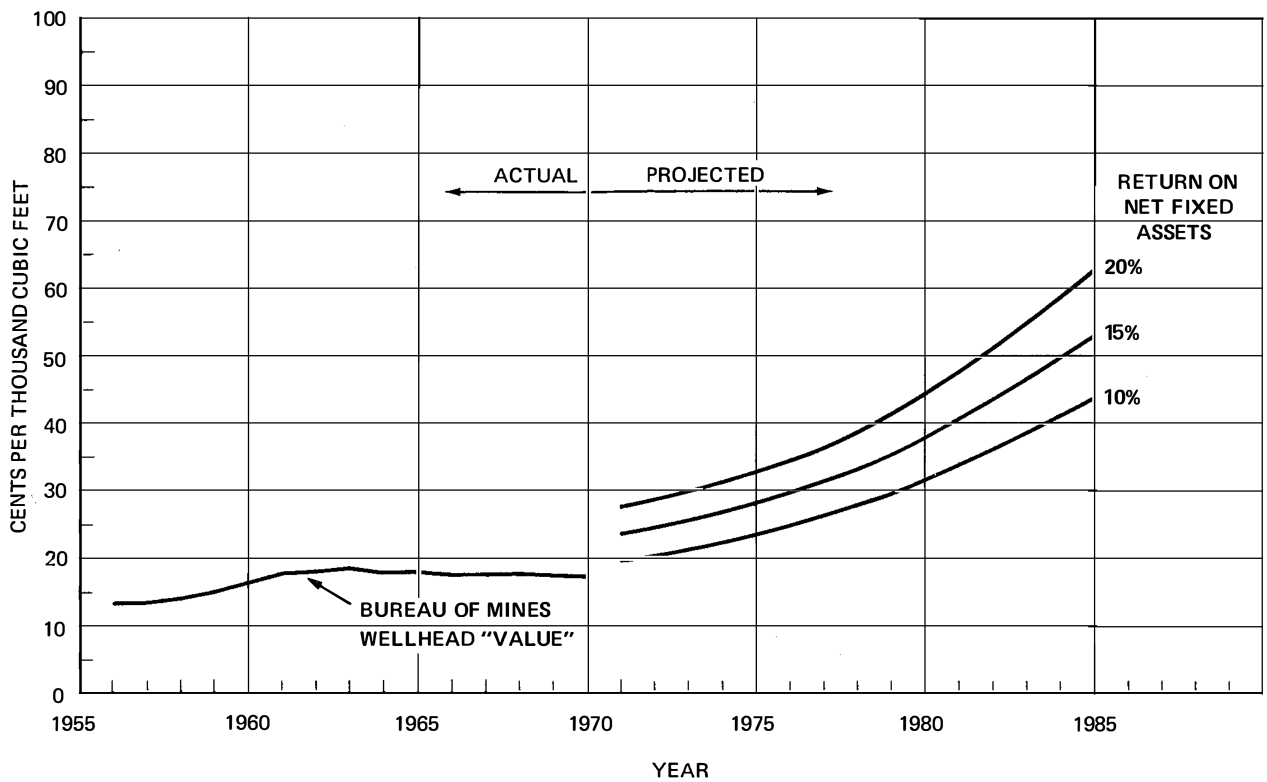
To determine the economic impact of further regulations of this nature, a parametric study was made in which these costs were arbitrarily doubled. The impact of this doubling on exploration and production economics is quite substantial, as shown in Table 71.

Thus, increasing restrictions by this amount could effectively increase required revenues by about $1 billion in 1985—an amount equivalent to one-fifth of the total drilling expenditures in that year. This emphasizes the importance of promulgating more stringent regulations only when the benefits to be obtained warrant the costs involved. This is particularly true when consideration is given to the fact that most of these increased costs will affect the economics of the offshore areas which are so important to developing increased future supplies.

Impact of Government Policy Changes

Parametric studies were designed to evaluate the impact of the critical policy options available to the Federal Government, primarily in two areas:

* API, *Report on Air and Water Conservation Expenditures of the Petroleum Industry in the United States, 1966-1970*, API Publication No. 4075 (February 1971).



** Excluding Alaskan gas operations.*

Figure 43. Required Average Gas "Prices"—Case III (Constant 1970 Dollars).*

(1) leasing policy on federal lands in offshore and frontier areas and (2) taxation policy. Several alternatives were examined in each of these categories.

Federal Leasing Policy—Lease Availability

The base cases assumed that, with California added, the announced Department of the Interior lease sales schedule will be representative of future sales. Only a 5-year period was covered by the schedule, so it was necessary to extrapolate sales beyond 1975. Although Interior's schedule does not state the amount of acreage to be offered, it is assumed that sufficient acreage will be made available to provide the drilling opportunities projected. Analysis of potential acreage currently unleased and the acreage required for drilling indicates that this is a reasonable assumption if a national energy policy were designed to encourage increasing domestic supplies.

Recently, extreme concern for protection of the environment has created opposition to the granting of any additional offshore leases. Parametric studies were made to determine the effect on domestic U.S. production of eliminating or deferring all new federal lease sales.

The first analysis assumed that no new sales would be held offshore; however, existing acreage under lease could be developed. Table 72 shows the impact that this would have on U.S. production. If such an action were taken, it would decrease domestic production for Case II by over 2 MMB/D of crude oil and 5 TCF per year of gas in 1985—over one-fifth of the oil and gas production from the lower 48 states. Figure 46 shows the areas in which the oil production would be lost. Also shown on Figure 46 is the amount of North Slope production that would also be lost if it is not brought to market. Environmental overreaction could reduce total U.S. oil producing capacity in 1985 to two-thirds of its potential.

Similarly, the amount of gas production that would be lost from each area without additional leasing by the government is shown in Figure 47. In this case, up to 35 percent of the 1985 gas supply would be eliminated.

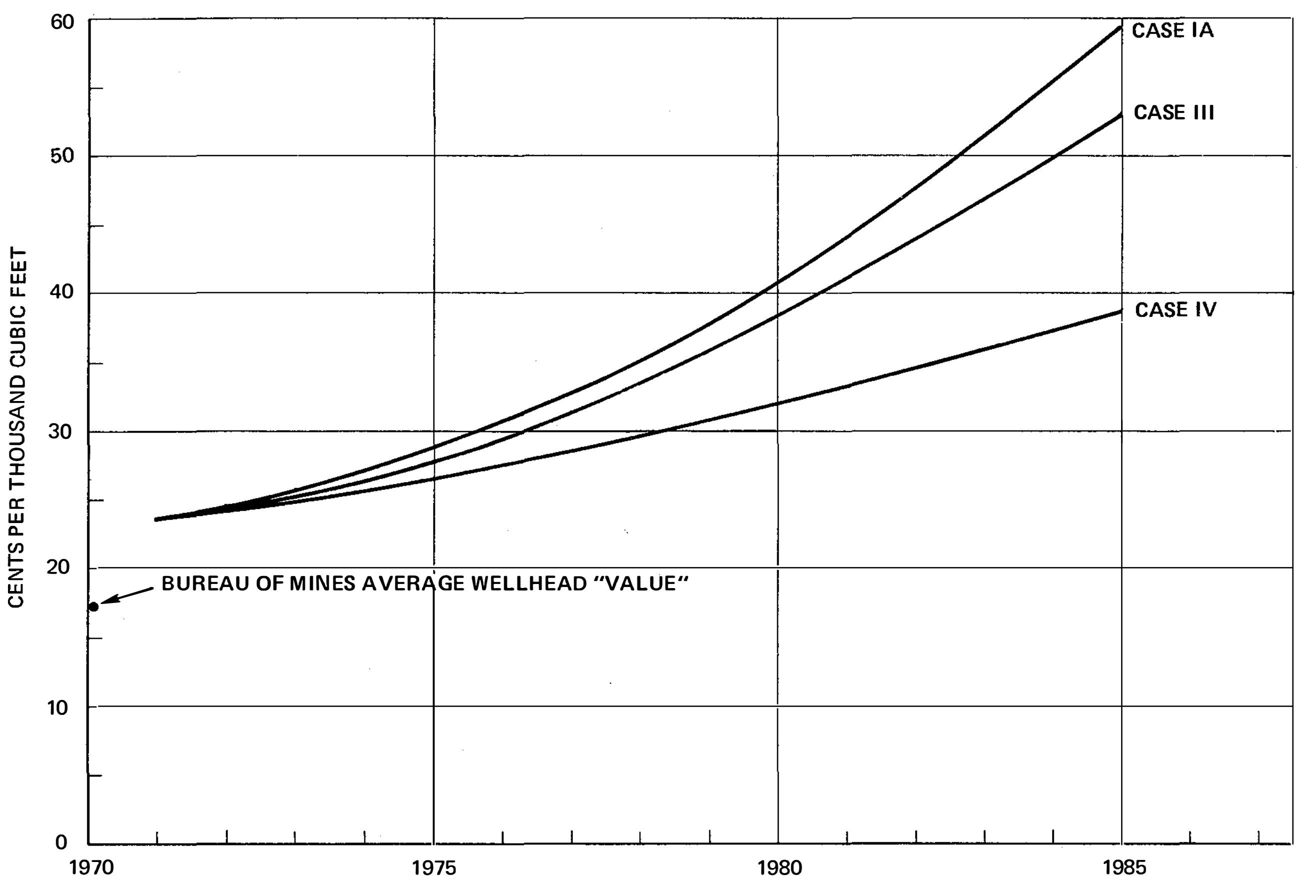
Table 73 shows the production cutback which would occur if new offshore leasing on the Gulf Coast were delayed until 1975 and eliminated in all the other areas. Under this condition, the country would be denied in excess of 1 MMB/D of oil and over 1 TCF of gas per year at the end of the period.

The effect on supply of delaying all offshore leasing for 5 years is shown in Table 74, while the effects of delaying only Pacific Coast offshore leasing for 5 years are depicted in Table 75.

Federal Leasing Policy—Leasing Method

Large bonus payments made to the Federal Government for leases have a very significant impact on the cost of oil and gas. A quantitative assessment was developed of the portion of future oil and gas "prices" that results from the assumptions used as to the cost of cash-bonus payments for offshore federal leases. The results are shown in Table 76.

It is obvious that an elimination of sealed, cash-bonus payments would have a sizable impact on both oil and gas "prices" in the longer term. By 1985, eliminating bonus payments would decrease "prices" by \$1.14 to \$1.33 per barrel of oil and 9.2¢ to 12.3¢ per MCF on all production under Case II or Case III conditions. The impact on off-



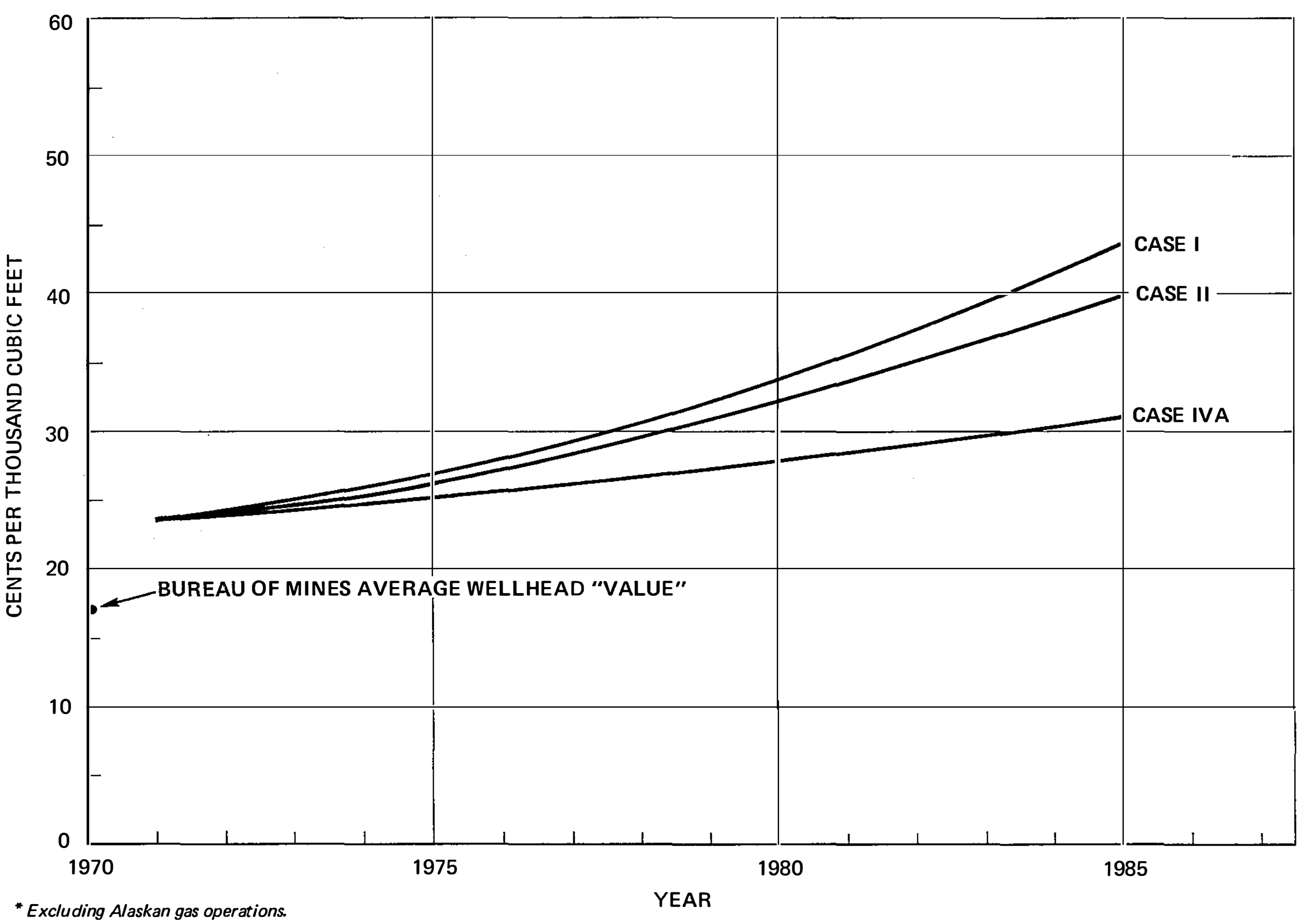
* *Excluding Alaskan gas operations.*

Figure 44. Required Average Gas "Price" Projections—15-Percent Return on Net Fixed Assets—Low Finding Rate.

shore economics would be even more than indicated—about four times as great—if all the bonus costs were related strictly to *offshore* production from reserves found after 1970.

One option open to the Federal Government for affecting activity and prices is the method used to grant the leases. Several types and variations of systems have been proposed as alternatives to the current system of sealed, cash-bonus payments assumed in all of the base cases. Two systems were considered for evaluation—royalty bidding and work programs. These are representative of the spectrum of alternatives that are available.

The effect of royalty bidding on supply and "price" is not subject to quantitative analysis in the abstract. Its impact depends on the detailed specification of how bids must be submitted, how the leases are administered once awarded, whether bids contain work commitments, as well as a host of other complex issues. The cost-benefit relationship from the public point of view depends on such unknowns as the specific royalty bid *vs.* the cash alternative bids that might be made on each tract. It also depends on whether the exploratory well is successful or dry, on the size of any reserve that might be found, on whether it is oil or gas that is found, and on the inclusion of any provisions for royalty reduction in the lease. All of these factors contributed to the conclusion that such a system could not be effectively analyzed in this study. They similarly constitute the major drawback of the system from a public interest point of view—the inability to evaluate which royalty bid on a tract is the "highest bid" and whether it is more advantageous than the cash-bonus alternative.



* *Excluding Alaskan gas operations.*

Figure 45. Required Average Gas "Price" Projections—15-Percent Return on Net Fixed Assets—High Finding Rate.*

TABLE 61

ANNUAL MARKETED VOLUMES OF ALL NATURAL GAS IN LOWER 48 STATES—
CASE III, LOW FINDING RATE, MEDIUM DRILLING RATE
(TCF)

	Volume Marketed from All Reserves Found Before 1971	Volume Marketed from All Reserves Found After 1970	Total Volume Marketed from All Reserves
1975	16.9	3.3	20.2
1980	10.6	7.0	17.6
1985	6.4	9.8	16.2

Work programs similar to the systems used by the United Kingdom in the North Sea were evaluated in a parametric study. In this system, leases are granted to operators who in turn agree to perform a stipulated amount of exploratory activity on these tracts. Only a minimal bonus or no bonus at all is charged. If a workable and equitable work program system could be developed within the confines of the political structure of the United States, it would be reasonable to expect an increase in drilling. A parametric study was made on Cases II and III assuming work programs would increase drilling to Case I levels in offshore regions. The reduction in bonus would be more than adequate

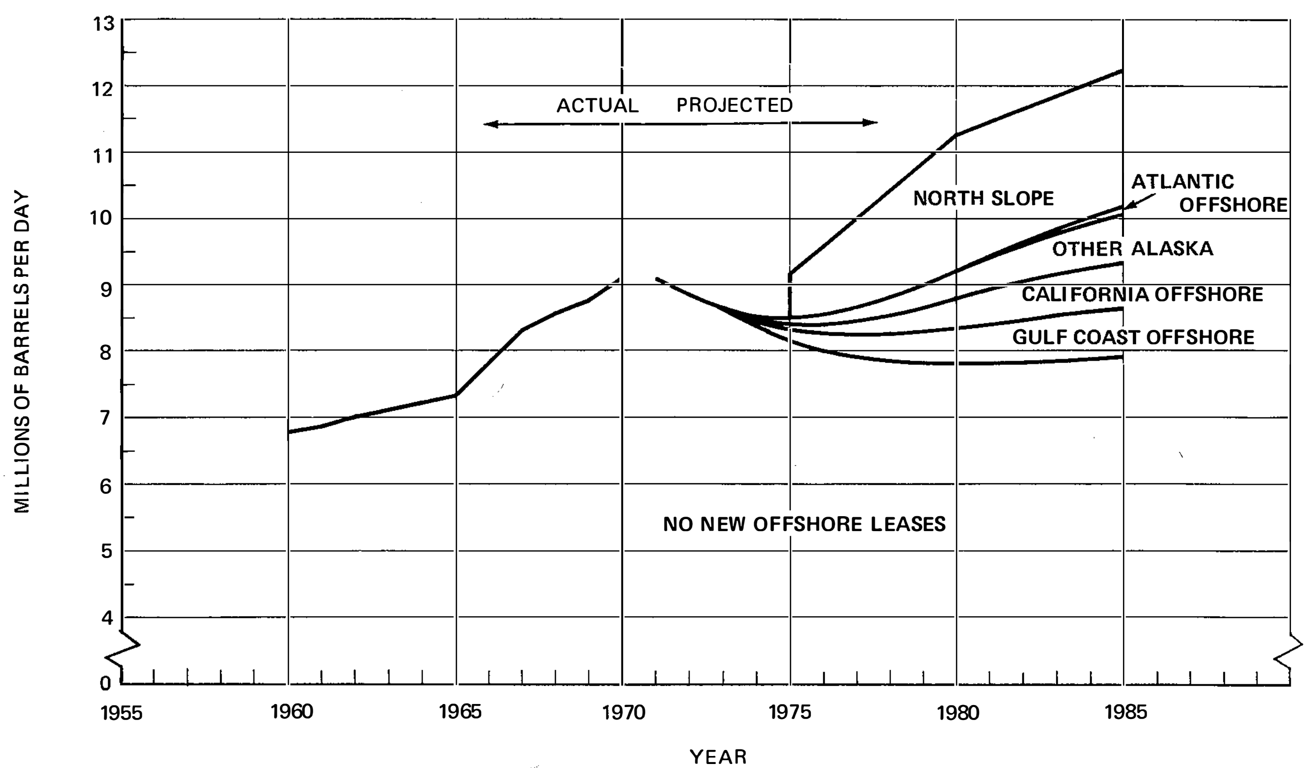


Figure 46. Effect of No New Offshore Leases or North Slope Production—Daily Oil Production (Case II).

TABLE 62

REQUIRED "PRICES" FOR MARKETED VOLUMES OF ALL NATURAL GAS IN LOWER 48 STATES TO ACHIEVE A 15-PERCENT RETURN ON NET FIXED ASSETS–CASE III, LOW FINDING RATE, MEDIUM DRILLING RATE
(Cents per MCF in Constant 1970 Dollars)

		Escalation of "Prices" Effective 1/1/73 for Marketed Volumes from Reserves Found Prior to 1970					
		No Escalation		0.5¢/MCF per Year		1.0¢/MCF per Year	
	Avg. "Price" for Total Volume Marketed from All Reserves	"Price" for Vol. Mktd. from All Reserves Found Before 1971	"Price" for Vol. Mktd. from All Reserves Found After 1970	"Price" for Vol. Mktd. from All Reserves Found Before 1971	"Price" for Vol. Mktd. from All Reserves Found After 1970	"Price" for Vol. Mktd. from All Reserves Found Before 1971	"Price" for Vol. Mktd. from All Reserves Found After 1970
1970	17.1	17.1	-	17.1	-	17.1	-
1975	27.9	17.1	82.5	18.6	74.9	20.1	67.3
1980	37.8	17.1	69.3	21.1	63.2	25.1	57.1
1985	53.0	17.1	76.4	23.6	72.2	30.1	67.9

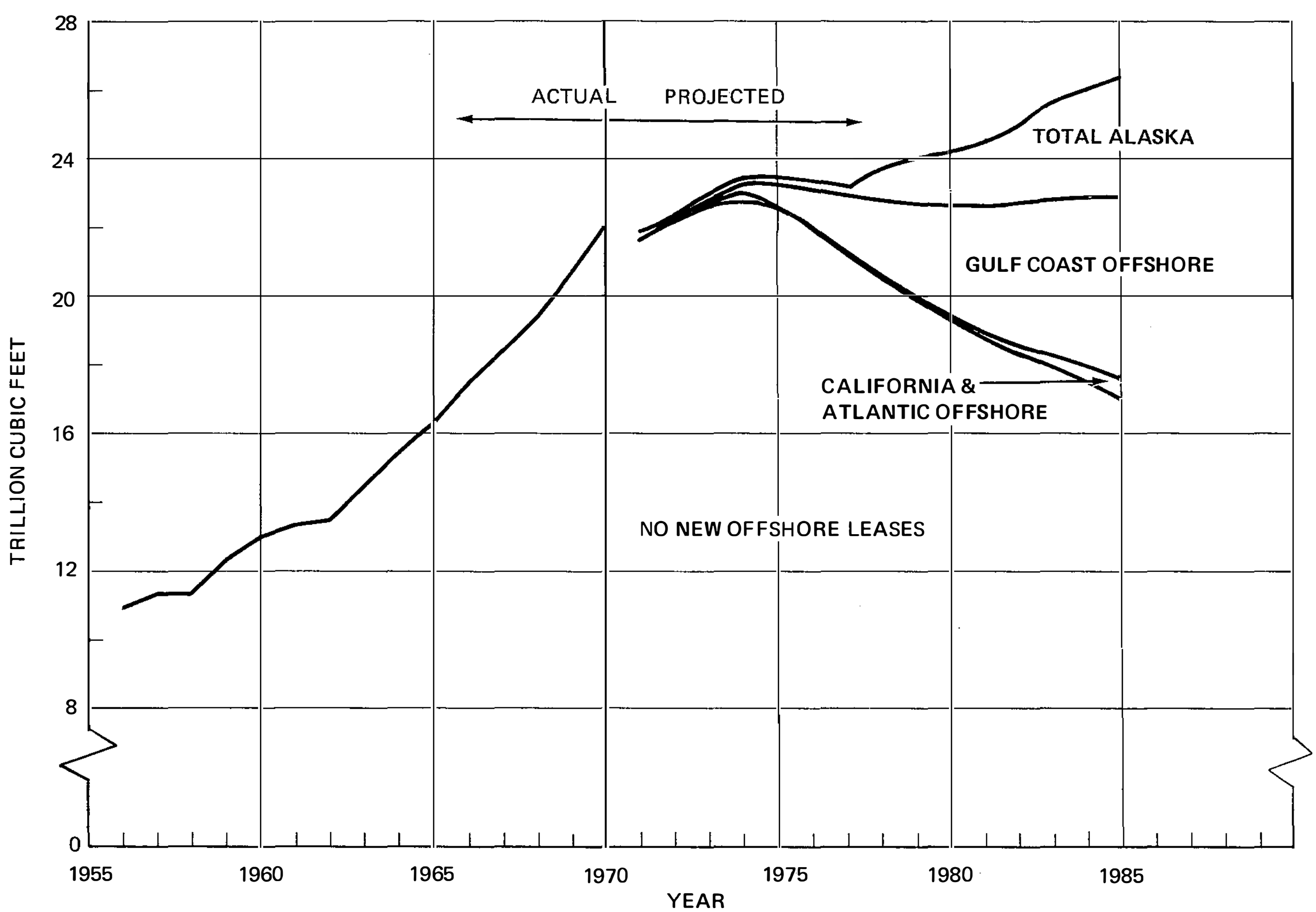


Figure 47. Effect of No New Offshore Leases or Alaskan Production—Wellhead Gas Production (Case II).

TABLE 63

CHANGE OF FINDING RATE FROM HIGH TO LOW
(Medium Drilling Growth Rate)

	Production			
	MMB/D		TCF/Yr Marketed	
	Case II Oil	Change to Case III	Case II Gas	Change to Case III
1971	9.1	–	20.0	–
1975	8.5	- 0.4	21.6	- 1.4
1980	9.2	- 1.0	21.1	- 3.5
1985	10.2	- 1.6	21.3	- 5.1
	"Prices" at 15% Return			
	$/Bbl		¢/MCF	
	Case II Oil	Change to Case III	Case II Gas	Change to Case III
1971	3.22	–	23.5	–
1975	3.63	+ 0.04	26.2	+ 1.7
1980	4.73	+ 0.22	31.8	+ 6.0
1985	6.18	+ 0.42	39.8	+ 13.2

TABLE 64

INCREASE OF OIL FINDING RATES
BY 10 PERCENT

	Oil Production (MMB/D)			
	Case II		Case III	
	Base	Change	Base	Change
1971	9.1	-	9.1	-
1975	8.5	+0.1	8.1	+0.1
1980	9.2	+0.3	8.2	+0.2
1985	10.2	+0.5	8.5	+0.3
	"Prices" at 15% Return ($/Bbl)			
	Case II		Case III	
	Base	Change	Base	Change
1971	3.22	-	3.23	-
1975	3.63	-0.05	3.67	-0.04
1980	4.73	-0.15	4.95	-0.12
1985	6.18	-0.25	6.60	-0.20

to finance the additional drilling, and it was assumed that the difference would be reflected in lower "prices." The results are shown in Table 77.

It is apparent that implementation of a work program system could have a substantial effect on both supply and "price." However, the political reality of such a system must be seriously questioned. The impact on price could be a reduction of as much as $1.00 per barrel and $0.11 per MCF on total domestic production from the base case "prices" calculated. These calculated results make no allowance for the possible inefficient use of capital and equipment to satisfy work commitments on tracts which prove to be only marginally attractive following initial exploratory work. There might also be a tendency to defer activity under a work program bid as compared to a cash-bonus-payment system, which is also not evaluated.

TABLE 65

DISCOVERY OF A 5-BILLION-BARREL OIL FIELD IN 1978

	Oil Production (MMB/D)			Percentage Increase in U. S. Production	
	Case II	Case III	Increase Due to Discovery	Case II	Case III
1979	9.0	8.1	0.1	1	1
1980	9.2	8.2	0.7	7	9
1981	9.4	8.2	1.0	11	12
1982	9.6	8.3	1.3	13	16
1983	9.8	8.4	1.6	16	19
1984	10.0	8.4	1.4	14	17
1985	10.2	8.5	1.2	11	14

TABLE 66

INCREASE OF OIL RECOVERY EFFORTS

	Oil Production (MMB/D)			
	Case I	Change	Case IV	Change
1971	9.1		9.1	-
1975	8.5	+0.8	8.0	+0.8
1980	9.6	+2.0	7.6	+1.8
1985	10.9	+1.8	7.4	+1.2
	Oil "Prices" at 15% Return ($/Bbl)			
	Case I	Change	Case IV	Change
1971	3.22	-	3.22	-
1975	3.65	+0.44	3.57	+0.48
1980	4.90	+0.71	4.39	+1.02
1985	6.69	+0.51	5.28	+1.11

TABLE 67

REDUCTION OF THE OIL RESERVES TO PRODUCTION RATIO

	Production		"Prices" at 15% Return	
	Oil (MMB/D)		Oil ($/Bbl)	
	Case II	Change	Case II	Change
1971	9.1	–	3.22	–
1975	8.5	+0.6	3.63	-0.22
1980	9.2	+0.4	4.73	-0.28
1985	10.2	+0.2	6.18	-0.26

TABLE 68

INCREASE OF 10 PERCENT IN DRILLING COSTS

	Oil "Prices" at 15% Return ($/Bbl)			
	Case II	Change	Case III	Change
1971	3.22	–	3.23	–
1975	3.63	+ 0.05	3.67	+ 0.05
1980	4.73	+ 0.10	4.95	+ 0.10
1985	6.18	+ 0.15	6.60	+ 0.14
	Gas "Prices" at 15% Return (¢/MCF)			
	Case II	Change	Case III	Change
1971	23.5	+ 0.1	23.5	+ 0.2
1975	26.2	+ 0.4	27.9	+ 0.5
1980	31.8	+ 0.9	37.8	+ 1.2
1985	39.8	+ 1.4	53.0	+ 1.9

TABLE 69

INCREASE OF 10 PERCENT IN OPERATING COSTS

	Oil "Prices" at 15% Return ($/Bbl)			
	Case II	Change	Case III	Change
1971	3.22	+0.07	3.23	+0.07
1975	3.63	+0.07	3.67	+0.07
1980	4.73	+0.08	4.95	+0.08
1985	6.18	+0.09	6.60	+0.10
	Gas "Prices" at 15% Return (¢/MCF)			
	Case II	Change	Case III	Change
1971	23.5	+0.2	23.5	+0.2
1975	26.2	+0.2	27.9	+0.2
1980	31.8	+0.3	37.8	+0.4
1985	39.8	+0.3	53.0	+0.5

TABLE 70

INCREASE OF 10 PERCENT IN ADDITIONAL OIL RECOVERY INVESTMENTS

	Oil "Prices" at 15% Return ($/Bbl)			
	Case II	Change	Case III	Change
1971	3.22	–	3.23	–
1975	3.63	+0.04	3.67	+0.04
1980	4.73	+0.09	4.95	+0.10
1985	6.18	+0.14	6.60	+0.16

Federal Taxation Policy

The base cases assumed that the existing taxation structure would continue unchanged. In order to determine the impact that changes in this policy area could have, parametric studies were run to evaluate changes in the statutory depletion rate, preference tax rate, job development credit, and implementation of an exploration and additional-recovery tax credit.

The results of these studies were expressed in terms of the effect on the average "prices" of oil and gas. It was also recognized that the method of analysis assumed that industry performs as a homogeneous group of corporate taxpayers with only domestic exploration and production activi-

TABLE 71

DOUBLING OF ENVIRONMENTAL, HEALTH AND SAFETY COSTS

Increased Revenue Requirements (Million Dollars per Year)

	Oil Operations		Gas Operations		Total	
	Case II	Case III	Case II	Case III	Case II	Case III
1971	60	60	22	22	82	82
1975	259	243	104	105	363	348
1980	501	451	188	190	689	641
1985	803	671	301	303	1,104	974

TABLE 72

NO NEW OFFSHORE LEASES

Oil Production (MMB/D)

	Case II	Change	Case III	Change
1971	9.1	-	9.1	-
1975	8.5	-0.3	8.1	-0.22
1980	9.2	-1.4	8.2	-1.04
1985	10.2	-2.3	8.6	-1.63

Marketed Gas Production (TCF/Yr)

	Case II	Change	Case III	Change
1971	20.0	-	20.0	-
1975	21.6	-0.7	20.2	-0.5
1980	21.1	-3.2	17.6	-2.1
1985	21.3	-5.5	16.2	-3.6

TABLE 74

DELAY OF ALL OFFSHORE LEASING FOR 5 YEARS

Oil Production (MMB/D)

	Case II	Change	Case III	Change
1971	9.1	–	9.1	–
1975	8.5	- 0.3	8.1	- 0.2
1980	9.2	- 1.1	8.2	- 0.8
1985	10.2	- 0.4	8.6	- 0.3

Marketed Gas Production (TCF/Yr)

	Case II	Change	Case III	Change
1971	20.0	–	20.0	–
1975	21.6	- 0.7	20.2	- 0.5
1980	21.1	- 2.6	17.6	- 1.6
1985	21.3	- 1.6	16.2	- 1.0

TABLE 73

DISCONTINUANCE OF OFFSHORE LEASING EXCEPT ON GULF COAST POST-1974

Oil Production (MMB/D)

	Case II	Change	Case III	Change
1971	9.1	-	9.1	-
1975	8.5	-0.3	8.1	-0.2
1980	9.2	-1.1	8.2	-0.8
1985	10.2	-1.5	8.6	-1.1

Marketed Gas Production (TCF/Yr)

	Case II	Change	Case III	Change
1971	20.0	-	20.0	-
1975	21.6	-0.7	20.2	-0.5
1980	21.1	-2.0	17.6	-1.3
1985	21.3	-1.6	16.2	-1.1

TABLE 75

DELAY OF PACIFIC OCEAN LEASING FOR 5 YEARS

Oil Production (MMB/D)

	Case II	Change	Case III	Change
1971	9.1	-	9.1	-
1975	8.5	-0.1	8.1	-0.1
1980	9.2	-0.3	8.2	-0.2
1985	10.2	-0.2	8.6	-0.1

Marketed Gas Production (TCF/Yr)

	Case II	Change	Case III	Change
1971	20.0	-	20.0	-
1975	21.6	-	20.2	-
1980	21.1	-0.1	17.6	-
1985	21.3	-0.1	16.2	-0.1

TABLE 76

ELIMINATION OF BONUS PAYMENTS OFFSHORE

	Oil "Prices" at 15% Return ($/Bbl)			
	Case II	Change	Case III	Change
1971	3.22	-0.01	3.23	- 0.01
1975	3.63	-0.23	3.67	- 0.24
1980	4.73	-0.70	4.95	- 0.80
1985	6.18	-1.14	6.60	- 1.33
	Gas "Prices" at 15% Return (¢/MCF)			
	Case II	Change	Case III	Change
1971	23.5	-0.2	23.5	- 0.2
1975	26.2	-2.3	27.9	- 2.5
1980	31.8	-5.2	37.8	- 6.2
1985	39.8	-9.2	53.0	-12.3

ties. In reality, of course, this is not true; a sizable source of risk capital in the industry is from individual investors who have a higher tax rate than corporations. An attempt was made to investigate the sensitivity of this assumption by analyzing several cases using a 70-percent maximum individual tax rate.

Statutory depletion rates were investigated by comparing the current value of 22 percent to a range of 0 to 35 percent, as shown in Table 78.

Eliminating the depletion allowance would require an increase in the computed average oil "price" of 15 percent and gas "price" of 13 percent or, alternatively, it would have a much more substantial negative effect on the desirability of searching for oil and gas if the prices did not increase by these amounts. If gas prices are not permitted to increase because of contract or regulatory limitations, then an equivalent amount of revenue would have to be generated by increased oil prices. Increasing the depletion allowance to 35 percent would permit an 8-percent reduction in the average "price" of oil and a 7-percent reduction in the gas "price," or without price changes it would create a sizable incentive to develop new supplies.

As indicated in Table 79, the impact on the investor in the highest tax bracket is nearly twice that of a corporate taxpayer. Thus, he is very sensitive to such tax incentives in deciding where to make his investments. Many of these investors are the source of funds for the independent oil producers who play a substantial role in the discovery of new fields. Therefore, future discoveries

TABLE 77

REPLACEMENT OF CASH BONUS PAYMENTS WITH WORK PROGRAM

	Production							
	Oil (MMB/D)				Marketed Gas (TCF/Yr)			
	Case II	Change	Case III	Change	Case II	Change	Case III	Change
1971	9.1	—	9.1	—	20.0	—	20.0	—
1975	8.5	—	8.1	—	21.6	—	20.2	—
1980	9.2	+ 0.2	8.2	+ 0.1	21.1	+ 0.5	17.6	+ 0.4
1985	10.2	+ 0.4	8.6	+ 0.3	21.3	+ 1.2	16.2	+ 0.8
	"Prices" at 15% Return							
	Oil "Prices" ($/Bbl)				Gas "Prices" (¢/MCF)			
	Case II	Change	Case III	Change	Case II	Change	Case III	Change
1971	3.22	- 0.01	3.23	- 0.01	23.5	- 0.2	23.5	- 0.2
1975	3.63	- 0.23	3.67	- 0.24	26.2	- 2.2	27.9	- 2.4
1980	4.73	- 0.65	4.95	- 0.72	31.8	- 5.0	37.8	- 5.8
1985	6.18	- 0.93	6.60	- 1.14	39.8	- 8.7	53.0	- 11.3

TABLE 78

CHANGE OF STATUTORY DEPLETION RATES WITH 50-PERCENT TAX RATE

	Case II	Change to 35% Depletion	Change to 27.5% Depletion	Change to 0% Depletion	Case III	Change to 35% Depletion	Change to 27.5% Depletion	Change to 0% Depletion
	Oil "Prices" at 15% Return ($/Bbl)							
1971	3.22	- 0.26	- 0.09	+ 0.49	3.23	- 0.26	- 0.09	+ 0.49
1975	3.63	- 0.29	- 0.10	+ 0.55	3.67	- 0.29	- 0.10	+ 0.55
1980	4.73	- 0.37	- 0.13	+ 0.71	4.95	- 0.39	- 0.13	+ 0.74
1985	6.18	- 0.48	- 0.16	+ 0.92	6.60	- 0.52	- 0.17	+ 0.99
	Gas "Prices" at 15% Return (¢/MCF)							
1971	23.5	- 1.6	- 0.5	+ 2.7	23.5	- 1.5	- 0.5	+ 2.8
1975	26.2	- 1.8	- 0.6	+ 3.3	27.9	- 1.9	- 0.7	+ 3.5
1980	31.8	- 2.2	- 0.7	+ 4.0	37.8	- 2.6	- 0.8	+ 4.8
1985	39.8	- 2.7	- 0.9	+ 5.1	53.0	- 3.7	- 1.2	+ 6.8

TABLE 79

CHANGE OF 22-PERCENT STATUTORY DEPLETION RATE
WITH 50-PERCENT AND 70-PERCENT INCOME TAX RATES

	50% Income Tax Rate			70% Income Tax Rate		
		Change 22% Depletion Rate to			Change 22% Depletion Rate to	
	Case III	35%	0%	Case III	35%	0%
	Oil "Prices" at 15% Return ($/Bbl)					
1971	3.23	-0.26	+0.49	3.59	-0.51	+1.20
1975	3.67	-0.29	+0.55	4.05	-0.57	+1.35
1980	4.95	-0.39	+0.74	5.58	-0.79	+1.86
1985	6.60	-0.52	+0.99	7.54	-1.06	+2.51
	Gas "Prices" at 15% Return (¢/MCF)					
1971	23.5	-1.5	+2.8	25.9	-3.1	+7.0
1975	27.9	-1.9	+3.5	30.6	-3.9	+8.7
1980	37.8	-2.6	+4.8	41.1	-5.2	+11.7
1985	53.0	-3.7	+6.8	58.8	-7.5	+16.9

will no doubt be heavily influenced by taxation policy.

The 1969 tax law established a minimum tax equal to 10 percent of the difference between the taxpayer's total preference items (such as statutory depletion) and his actual income tax liability. If this preference tax were either eliminated or raised to 20 percent, it would have the effect in 1985 of about a $0.17 per barrel change in the "price" of *all* oil and $0.01 per MCF for *all* gas. The impact on individual taxpayers would vary widely.

Two types of tax credits were also evaluated. One is the 7-percent job development credit now in effect, and the other is a 12.5-percent credit for investment in exploration or additional recovery which has been proposed. The impact of both of these credits is essentially the same for Cases II and III and is shown in Table 80.

TABLE 80

CHANGE OF TAX CREDITS—
50-PERCENT TAX RATE

	Case II	Change Due to Removing 7% Job Development Credits	Change Due to Implementing 12.5% Exploration and Additional Recovery Credits
	Oil "Prices" at 15% Return ($/Bbl)		
1971	3.22	+0.06	-0.17
1975	3.63	+0.08	-0.24
1980	4.73	+0.11	-0.30
1985	6.18	+0.15	-0.38
	Gas "Prices" at 15% Return (¢/MCF)		
1971	23.5	+0.3	-1.4
1975	26.2	+0.2	-1.5
1980	31.8	+0.3	-2.2
1985	39.8	+0.3	-2.6

The job development credit is of increasing importance in a growing industry; an exploration and additional recovery tax credit could provide a significant incentive to develop new oil and gas supply.

Another parametric study was made to evaluate the impact of capitalizing intangible drilling costs as depreciable investment for tax purposes. The

TABLE 81

CAPITALIZATION OF INTANGIBLE DRILLING COSTS
15-PERCENT RATE OF RETURN
(Million Dollars per Year of Increased Revenue Requirements)

	Oil		Gas		Total	
	Case II	Case III	Case II	Case III	Case II	Case III
1971	633	616	352	351	985	967
1975	620	530	279	280	899	810
1980	451	318	236	238	687	556
1985	332	227	92	92	424	319

TABLE 82

TOTAL AVAILABLE OIL
(MMB/D)

	Actual	Projected											
		Case I			Case II			Case III			Case IV		
	1970	1975	1980	1985	1975	1980	1985	1975	1980	1985	1975	1980	1985
Conventional Petroleum Liquids	11.3	10.2	13.6	15.5	10.2	12.9	13.9	9.8	11.6	11.8	9.6	8.9	10.4
Synthetic Liquids													
From Coal	–	–	0.1	0.7	–	–	0.1	–	–	–	–	–	–
From Oil Shale	–	–	0.2	0.8	–	0.1	0.4	–	0.1	0.4	–	–	0.1
Oil Imports	3.4	7.2	5.8	3.6	7.4	7.5	8.7	8.5	10.6	13.5	9.7	16.4	19.2
Total Supply*	**14.7**	**17.5**	**19.6**	**20.5**	**17.6**	**20.5**	**23.1**	**18.3**	**22.3**	**25.8**	**19.3**	**25.3**	**29.7**

* Totals may not agree due to rounding.

effect of this change would be to increase the revenue required by the industry by the amounts shown in Table 81 in order to maintain the same after-tax capital available for drilling, assuming a 50-percent tax rate for the industry. The initial impact is very significant and in effect would increase the after-tax drilling costs by about one-third. The effect upon industry earnings diminishes in later years as a depreciable base is built up. However, any new investor will always bear the full impact since he has no depreciable base with which to start.

TABLE 83

TOTAL AVAILABLE GAS (TCF/YEAR)

	Actual	Projected											
		Case I			Case II			Case III			Case IV		
	1970	1975	1980	1985	1975	1980	1985	1975	1980	1985	1975	1980	1985
Lower 48													
Onshore	22.2	18.7	17.3	17.1	18.5	16.5	15.2	17.6	14.3	12.0	17.4	13.1	9.6
Offshore		4.9	6.9	9.1	4.8	6.3	7.8	4.3	4.8	5.5	4.1	4.0	3.6
Alaska, North Slope	–	–	1.4	3.3	–	1.3	2.7	–	1.1	2.2	–	–	1.3
Alaska, South	0.1	0.2	0.2	1.1	0.2	0.2	0.9	0.2	0.2	0.6	0.2	0.2	0.4
Total Conventional* (Wellhead Production)	**22.3**	**23.7**	**25.9**	**30.6**	**23.6**	**24.3**	**26.5**	**22.0**	**20.4**	**20.4**	**21.8**	**17.3**	**15.0**
Synthetic Gas													
From Coal	–	–	0.6	2.5	–	0.4	1.3	–	0.4	1.3	–	0.2	0.5
From Liquids	–	0.6	1.3	1.3	0.6	1.3	1.3	0.6	1.3	1.3	0.6	1.3	1.3
Gas from Nuclear Stimulation	–	–	0.2	1.3	–	0.1	0.8	–	0.1	0.8	–	–	–
Imports													
LNG	†	0.2	2.3	3.2	0.2	2.3	3.4	0.2	2.3	3.7	0.2	2.3	3.9
Pipeline	0.8	1.0	1.6	2.7	1.0	1.6	2.7	1.0	1.6	2.7	1.0	1.6	2.7
Total Supply*	**23.1**	**25.5**	**31.9**	**41.6**	**25.4**	**30.0**	**36.0**	**23.8**	**26.1**	**30.2**	**23.6**	**22.7**	**23.4**

* Totals may not agree due to rounding.
† Less than 10 billion cubic feet

Chapter Five
Domestic Coal Availability

Introduction

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

With the further development and application of technologies for (1) solving the environmental problems inherent in the mining and combustion of coal and (2) transforming solid coal into synthetic gaseous and liquid fuels, U.S. coal resources can make a major contribution to the Nation's energy needs in the period to 1985. The ultimate size of this contribution will depend primarily on the outcome of government policy issues. However, even under the most favorable circumstances, it is unlikely that coal alone could completely eliminate the Nation's dependence on imported fuels in the 1971-1985 period.

Summary and Conclusions

Resource Base

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

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

Future demand for coal is treated in two distinct market segments in this chaper: (1) coal used in conventional markets and (2) coal used in gasification and liquefaction. Major markets in the conventional category are electric power generation and steelmaking. Future prospects for these markets are evaluated on the assumption that technological changes in the utility and steel industries will not greatly alter their patterns of coal use. For all the coal growth rates examined in this report, it is assumed that these conventional markets are supplied from the same type of recoverable reserves which have supplied these markets in the past.

In the case of coal-based synthetic gas and liquids production, a simplifying assumption was made that all coal supply for synthetics would come from western surface-mined reserves during the 1971-1985 period. Exceptions to this assumption might occur, but they would not materially affect the conclusions drawn in this report.

Supply

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

- The cost of coal will continue to vary by regions over an exceedingly wide range (as

TABLE 84

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

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

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

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

it has in the past) as a result of the great variances in regional mining conditions.

- The cost of underground coal will increase more slowly after the large increases in recent years, based on the assumption that productivity will return to its historical upward trend.
- The cost of eastern U.S. surface-mined coal will increase about 30 percent by 1985 due to increased reclamation costs and higher overburden ratios.

A maximum possible sustained growth for coal production in the 1971-1985 period was defined because of the important role intended for coal in future domestic energy development. The uncertainties associated with coal's future make such a growth rate difficult to forecast with confidence. A 5-percent sustained rate of growth is considered feasible, based on past industry history and using presently worked reserves as the base. This growth rate was chosen to represent the maximum growth conditions (Case I).

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

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

Totaling the coal requirements for these several categories yields the overall required tonnages shown in Table 84 during the 1971-1985 period.

Utilization

Utilization of coal as a boiler fuel in conventional markets depends on future air quality standards. At present, low-sulfur oil, most of it imported, is being used to displace coal in a wide and increasing segment of this market because viable pollution control technology is not yet available for coal-fired boilers. Over 40 percent of estimated coal resources east of the Mississippi River have a high sulfur content (over 3 percent). In Case I, where domestic energy sources are to be maximized, it is assumed that technology will be available to permit the use of all sulfur levels of coal. Cases II through IV are premised on somewhat less success in solving the problems which are retarding coal's usage. Future use of the higher sulfur content coal is likely to require (1) stack gas cleanup, (2) conversion to clean gas (high- or low-BTU) and/or (3) conversion to low-sulfur liquids. Research and development efforts in the first two of these three areas now appear adequate to solve the respective problems, but work on liquefaction is not being vigorously pursued.

Utilization of coal for synthetic pipeline gas is projected in 1985 to supply 2.48 TCF per year under Case I, 1.31 TCF per year under Cases II and III and 0.54 TCF per year under Case IV. The coal utilized to meet gasification demand for Case I would reach a maximum of 232 million tons per year by 1985. Technology for the production of low-BTU gas from coal is available today, and the technology for producing higher-BTU gas is being vigorously pursued. Conversely, technology for economically producing coal-based liquids is not available today. The Case I output of coal-based liquids is projected to be 680 MB/D (107 million tons of coal per year) in 1985. To approach such a level of production would require an immediate decision to proceed with the design and construction of a first commercial-demonstration liquefaction plant. This assumes a 30 MB/D capacity plant which could start operation by 1977. This would be a high-risk plant because technology is now only partially developed. Under current economic conditions, the incentives to develop and build such a plant do not exist. Cases II and III therefore project only a modest supply of coal-based liquids in 1985; Case IV does not provide for any.

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

An important conclusion regarding synthetic gases and liquids from coal for the 1971-1985 period is that they cannot be developed fast enough to replace the Nation's expanding imports of petroleum. However, the annual growth of capacity for production of coal synthetics in the 1971-1985 period could have a significant bearing on the U.S. energy balance in the post-1985 period.

Summary

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

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

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

Potential Future Coal Supply

The Resource Base

Sources of Supply for Conventional and Synthetics Uses

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

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

In contrast, the supply of coal for conversion to gas or liquids during the 1971-1985 period can be expected to be based largely on use of surface coal deposits in the Rocky Mountain area in view of the much lower mining cost of that coal. Therefore, the adequacy of this specific resource will be considered in connection with the future production of synthetic fuels. This does not mean that only western coals will be used for synthetic feedstocks. Coal from other areas may be used but the quantity would probably be very small as compared to western coal.

Regions of U.S. Coal Resources

An examination of future coal supply requires some manner of geographically categorizing the available resources. The categorization is most useful if the resources are grouped in such a manner that each region is fairly uniform in terms of coal deposit and mining method. The groupings, shown in Table 85, of surface and underground coal resources into mining regions were selected on the basis of these considerations. Figures 48 and 49 relate coal fields of the United States with the six underground and the six surface mining regions, respectively, given in Table 85.

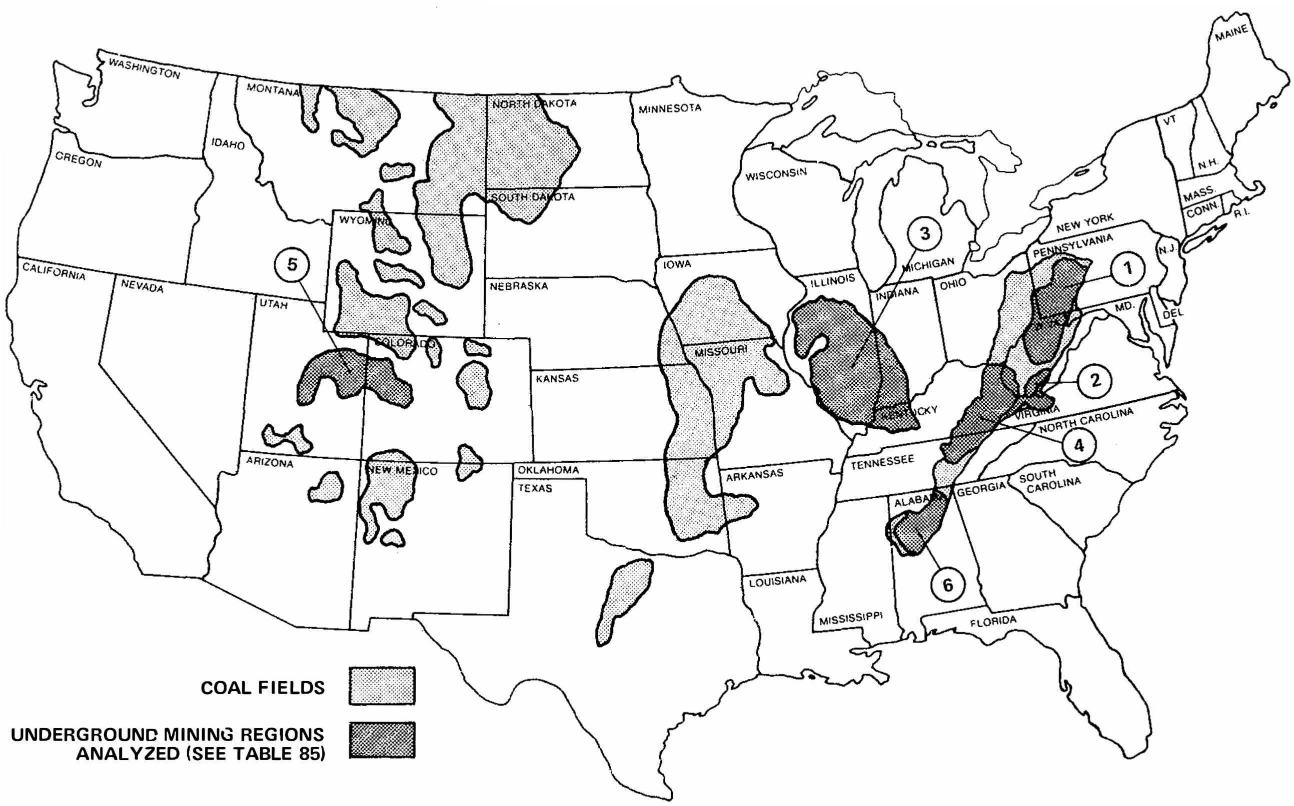


Figure 48. Coal Fields of the United States—Major Underground Mining Regions.

The total resources were first divided between underground- and surface-mined coal. These two groups were then subdivided into major coal basins where mining conditions vary only within a fairly narrow range. Cost projections were then made for each of these basins.

Magnitude of the Resource Base

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

Figure 50, taken directly from the original USGS report, gives the percentage distribution of the 1.56 trillion tons at less than a 3,000-foot depth in the mapped and explored areas. The total is subdivided by depth, by seam thickness and by three categories of certainty.

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

The block shown in Figure 50 within the dotted line, totaling 394 billion tons (25 percent of the mapped and explored resources), is termed "remaining measured and indicated reserves" and is composed of 349 billion tons of underground and 45 billion tons of surface resources.

In Tables 86 and 87, these remaining resources have been assigned to the regions defined in Table 85. In the case of underground coal, shown in Table 86, the remaining resources (349 billion tons) are further narrowed down to "economically

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

TABLE 85

COAL FIELDS OF THE UNITED STATES

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

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

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

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

The amounts shown in Table 86 are particularly sensitive to the impact of mining technology. This tabulation assumes the application of current techniques and economics and assumes a 50-percent recovery factor. A wide-scale switch to long-wall mining or any other system which yields higher recovery could add substantially to the recoverable reserves.

Similarly, the recoverable surface-mined coal reserves are grouped in Table 87 according to the regions tabulated in Table 85. In Table 87, a recovery factor is not applied since, in most cases of surface mining, it will exceed 90 percent. The life of these surface reserves is related to the 1970 production rate at 0-, 3- and 5-percent annual growth rates. This life excludes the potential use of the surface reserves in Regions 4, 5 and 6 (western United States) for synthetic fuels.

Tables 86 and 87 exclude inferred and potential coal yet to be found in unmapped and unexplored areas. Together the two tables represent only about 150 billion tons of recoverable coal reserves, or less than 5 percent of the total potential resource in place (3.21 trillion tons). The size of the additional coal reserves which may be potentially accessible should be emphasized. As Figure 50 shows, even within existing mapped and explored areas there are thick resources under less than 1,000 feet which are potentially available. These resources could represent about 215 billion tons if they were defined better. This would be over and above the 394 billion tons now regarded as the Nation's resource base.

Unmapped and unexplored coal resources could also yield significantly greater coal reserves. As noted above, resources in this category are presently estimated to amount to 1.31 trillion tons. Table 88, an excerpt of USGS data for a sample of states, gives an indication of the additional potential in unmapped and unexplored areas.

The last column in Table 88 gives an indication of the remaining potential for each state. Not unexpectedly, the greatest potential remains to be found in the Rocky Mountain region, followed by the Midwest. The East has been well explored. While the additional coal resources in the West are likely to be somewhat less accessible than the Nation's historical eastern sources, they should still include substantial amounts of coal within current economic reach.

Supply Outlook

Future Mining Cost

Two hypothetical coal mines—one surface and

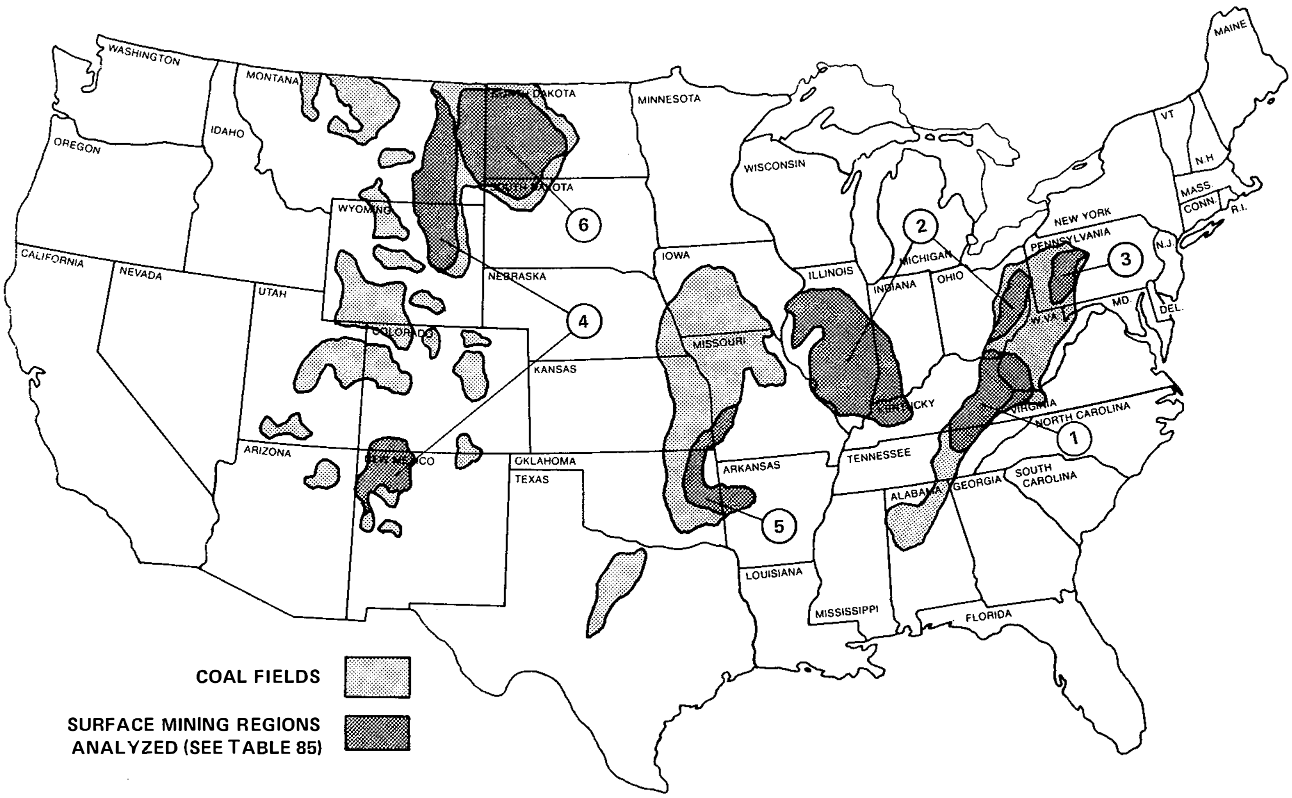


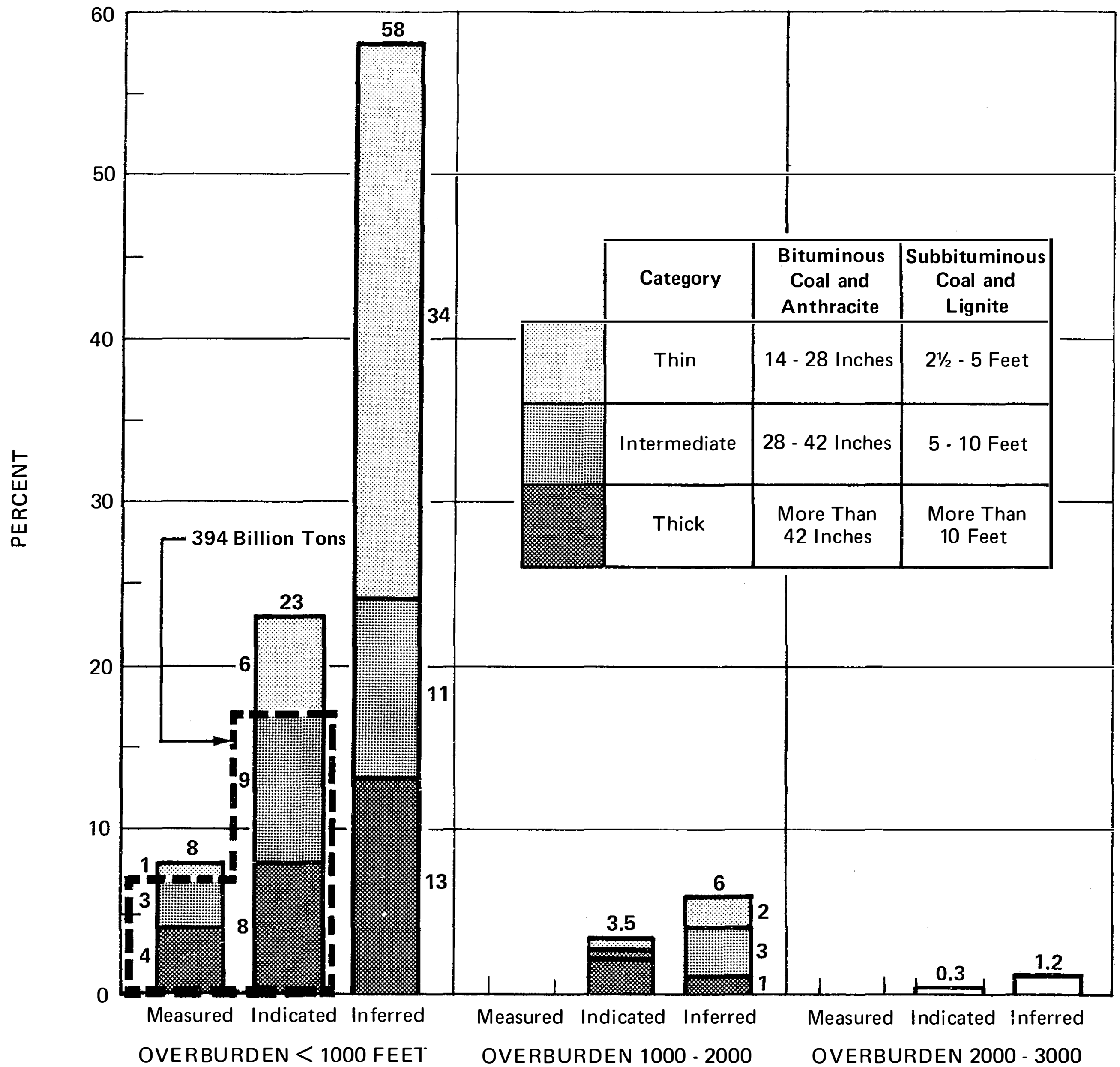
Figure 49. Coal Fields of the United States—Major Surface Mining Regions.

one underground mine—were defined to serve as the basis for an economic model to evaluate future coal costs. This economic model is described conceptually on Figure 51. The major categories of cost for these typical mines were analyzed based on historical data and were then projected for the period through 1985. This analysis was done on a regional basis (see Table 85) for each of the six underground and three surface mining regions for which historical data are available, as well as for the underground and surface mining regions, respectively, grouped together. As shown in Figure 51, the model is used to calculate the f.o.b. value of coal at three DCF rates of return (10, 15 and 20 percent) and for two growth rates of coal production (3 and 5 percent).

The model is structured so that the effect of economic, physical and technological variables as well as certain governmental policies on the cost of producing coal can be analyzed.

The purpose of the model is to assist in examining certain aspects of the conventional coal industry in the East and Midwest. The coal industry in this part of the country might best be described as a mature industry in an economic sense. For several reasons, the model cannot be used to analyze the relatively new coal industry in the West where opening or closing one or two mines might completely change the basic economic structure of the industry in that area.

A vast amount of statistical data pertaining to the various operating aspects of the coal industry have been published by the U.S. Bureau of Mines as well as a number of state agencies in the principal coal producing regions. However, little data have been published in regard to the average capital and operating costs of producing coal. Those variables of which capital and operating costs are a function were determined. Then the historical values for each of these variables were collected for the past 10 years. After analyzing each variable, the information obtained was used to design each mine in such a manner that it reflected the average operating conditions which ex-



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

Figure 50. Estimated Mapped and Explored Coal Resources—U.S.A. (Total Shown—1.56 Trillion Tons).

isted in the coal industry during the base year—1969.*

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

Shown in Table 89 are the estimated future capital requirements for mine investment—both the initial and the total capital investment over the life of the mine. These include the cost of land acquisition, exploration, initial mine investment, working capital and deferred capital costs.

The investment required to open a new mine is

TABLE 86

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

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

* Bituminous, subbituminous and lignite in seams of "intermediate" or greater thickness and less than 1,000 feet overburden (see Figure 50).

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

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

§ May not add correctly due to rounding.

TABLE 87

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

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

greater than the average capital investment for all mines currently producing coal. For example, Table 89 shows that the *average* original capital investment per annual ton of production for all underground mines operating in 1970 was $7.15, while investment per ton for a new mine was $8.00 to $20.00.

Besides adding new capacity to satisfy demand growth, the model also adds new capacity to compensate for exhausted mines—3 percent of the total production capacity per year. This replacement rate reflects the fact that the average coal mine has an expected life of approximately 30 years.

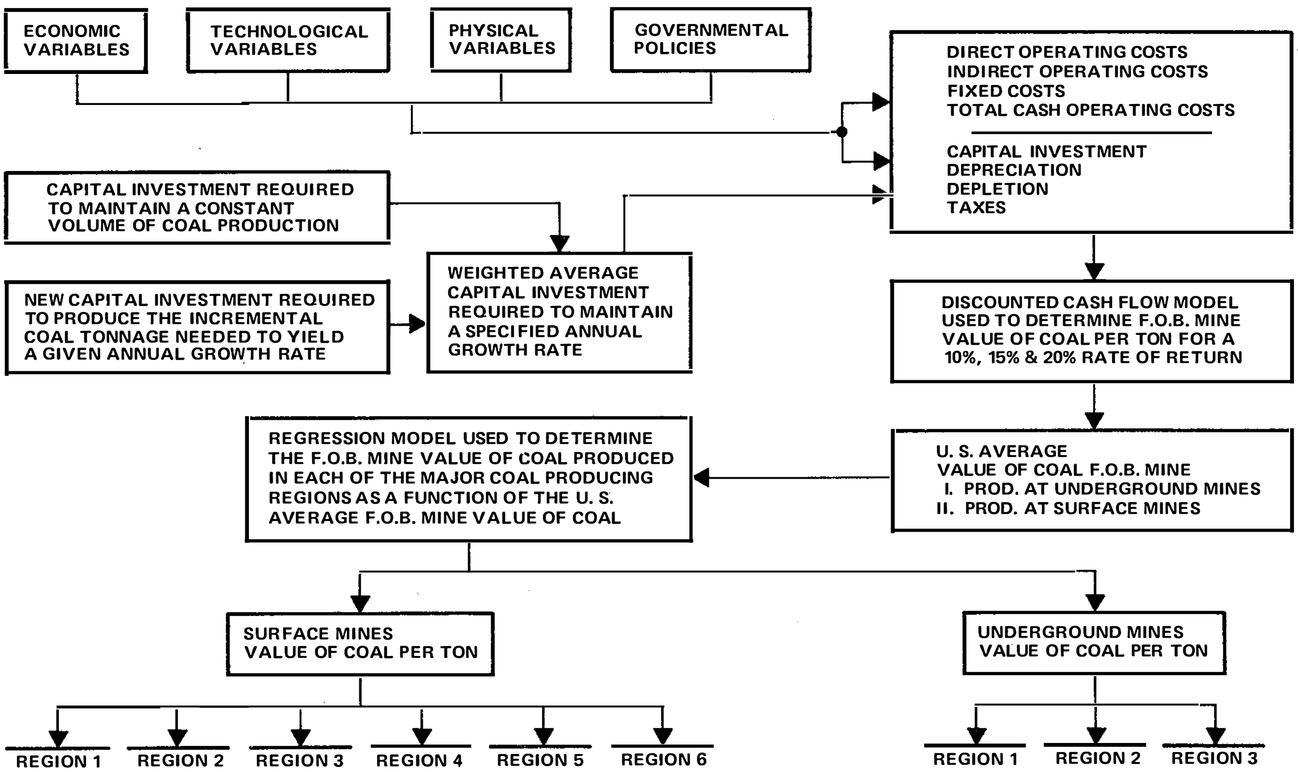


Figure 51. Method of Analysis—Coal Economic Model.

TABLE 88

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

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

The model is properly sensitive to mining productivity, particularly to that of underground mining. Productivity is defined in terms of output per man per day. U.S. average productivity for underground and surface mines is shown in Figures 52 and 53, respectively. On the historical trend line for underground mines (Figure 52), the sharp drop between 1969 and 1971 reflects the impact of the Coal Mine Health and Safety Act of 1969. As the projection for deep-mining productivity indicates, the model assumes that the decline has now reached its nadir and that productivity will again increase but at a slower pace than previously. Figure 53 covers the present surface mines in Regions 1, 2 and 3 and does not include the potential productivity in the western regions which are treated separately.

There are certain limitations inherent in the use of an economic model to predict coal mining costs. An economic model can never reflect the actual cost situation at any specific mine with perfect accuracy. The average costs of mining in different regions differ very widely depending on the spe-

TABLE 89

ESTIMATED CAPITAL INVESTMENT PER ANNUAL TON OF PRODUCTION AT U.S. COAL MINES

(30-Year Life—Constant 1970 Dollars)

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

* Less salvage value.

cific conditions (reflected in investment and operating costs) which prevail in each region. Seam thickness and depth, topography, roof conditions, underground water flow and many other items that affect cost vary from mine to mine. Some of these factors are not readily predictable.

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

Considering the wide range of coal mining conditions in the United States, it is not surprising to find a wide range of costs projected for the different regions. Figures 54 and 55 show the "price" projection determined by the economic model for all underground mining operations. Only the highest and lowest cost regions are shown together with the U.S. average. The figures are based on 3-percent and 5-percent annual growth rates and "prices" assuming three DCF rates of return.

Figures 56 and 57 cover the surface mining areas which have been active in the past. The same growth rates (3 percent and 5 percent) and rates of return (10, 15 and 20 percent) were used. This does not include the major new surface mines associated with the possible application to synthetic fuels; these are treated separately.

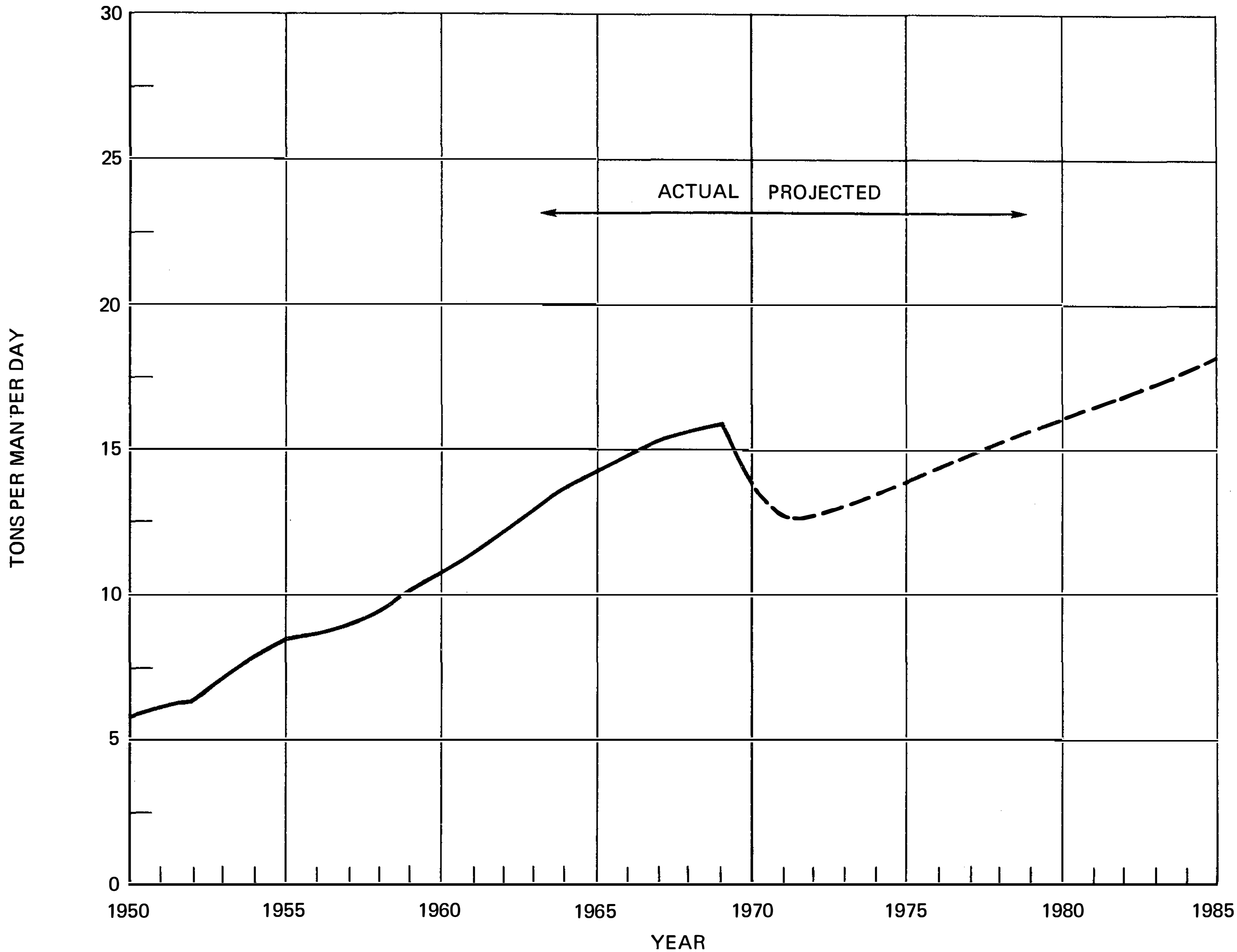
Figures 58 and 59 show the average U.S. cost of underground- and surface-mined coal, in both constant and current dollars.

Table 90 shows the projected costs for new underground-mined and new surface-mined coal and compares these with the corresponding average costs (assuming a 3-percent growth rate). The resulting differences are generally less than 10 percent. The results of the model may understate the real problem, however. It may be desirable to sell coal from an existing mine at prices associated with a low rate of return, but it would not be attractive at the same time to invest in a new mine unless a greater return were expected.

To illustrate, the 1970 average cost of underground coal, at a 10-percent rate of return, is shown in Table 90 as $7.36 per ton. To achieve a 20-percent rate of return, which might better represent the return needed to motivate investment in new production, a cost of $9.43 per ton results. The "new coal" cost is thus 28 percent above the average.

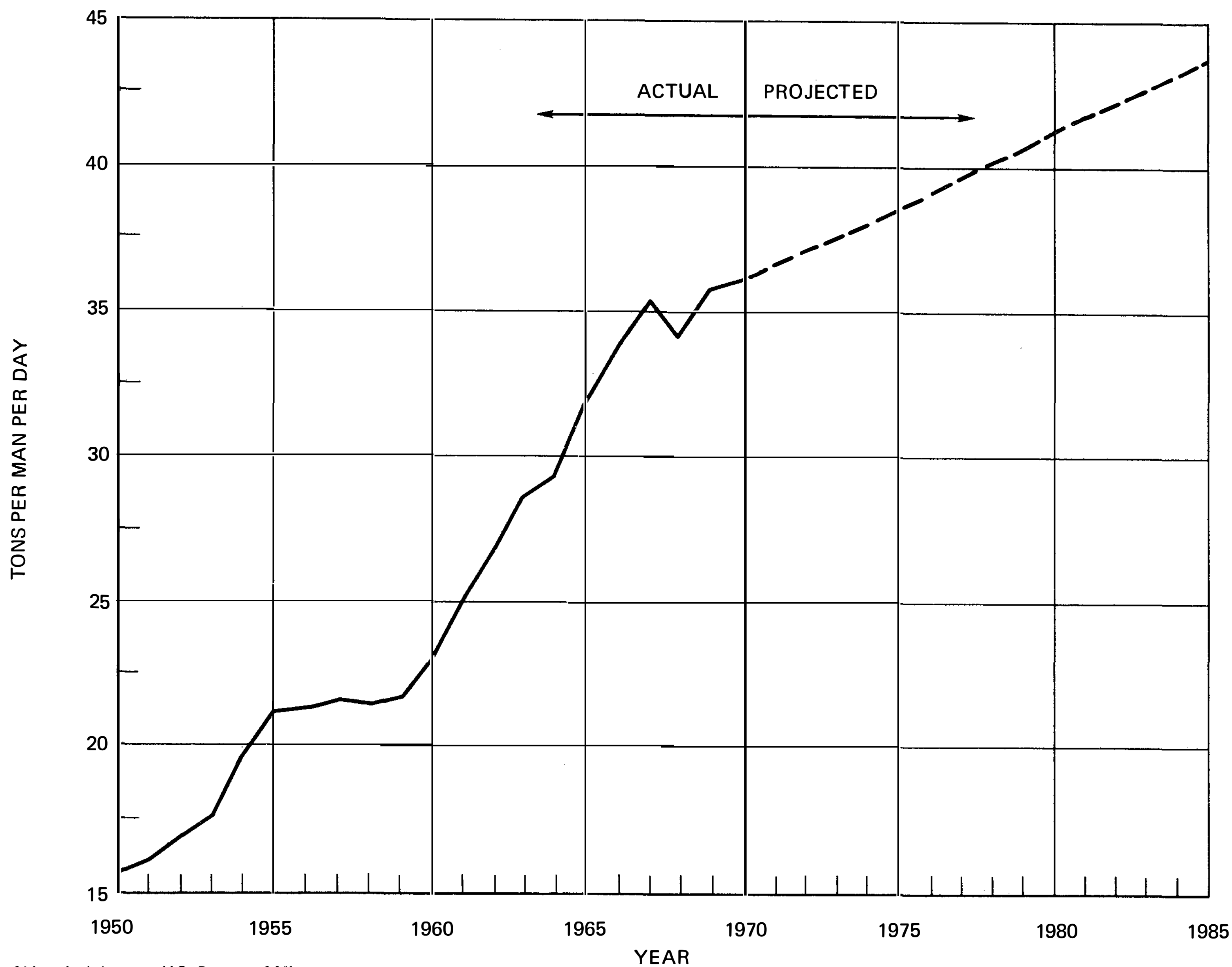
Sensitivity of Cost to Key Parameters

A number of sensitivity calculations were performed to evaluate the effect of different assumptions on some of the important input factors.



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

Figure 52. Output per Man per Day at Underground Bituminous Coal Mines.



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

Figure 53. Output per Man per Day at Surface Bituminous Coal Mines.

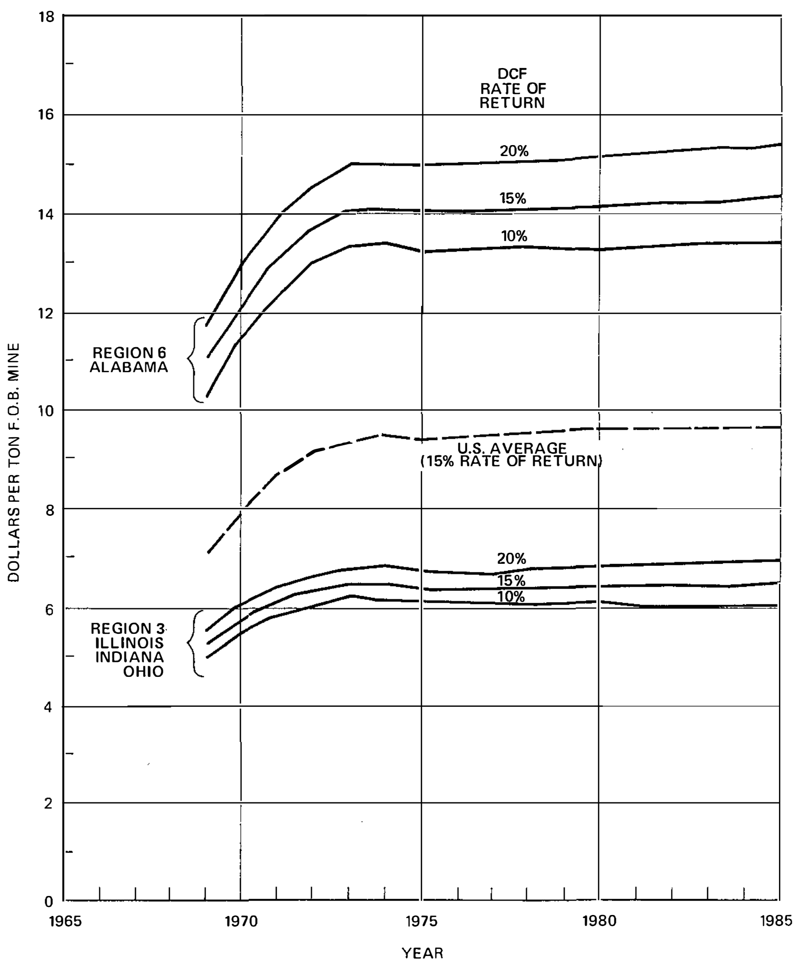


Figure 54. Range of Projected Underground Coal "Prices": Regional Extremes and U.S. Average (Years 1969 Through 1985—3-Percent Growth Rate Case—Constant 1970 Dollars).

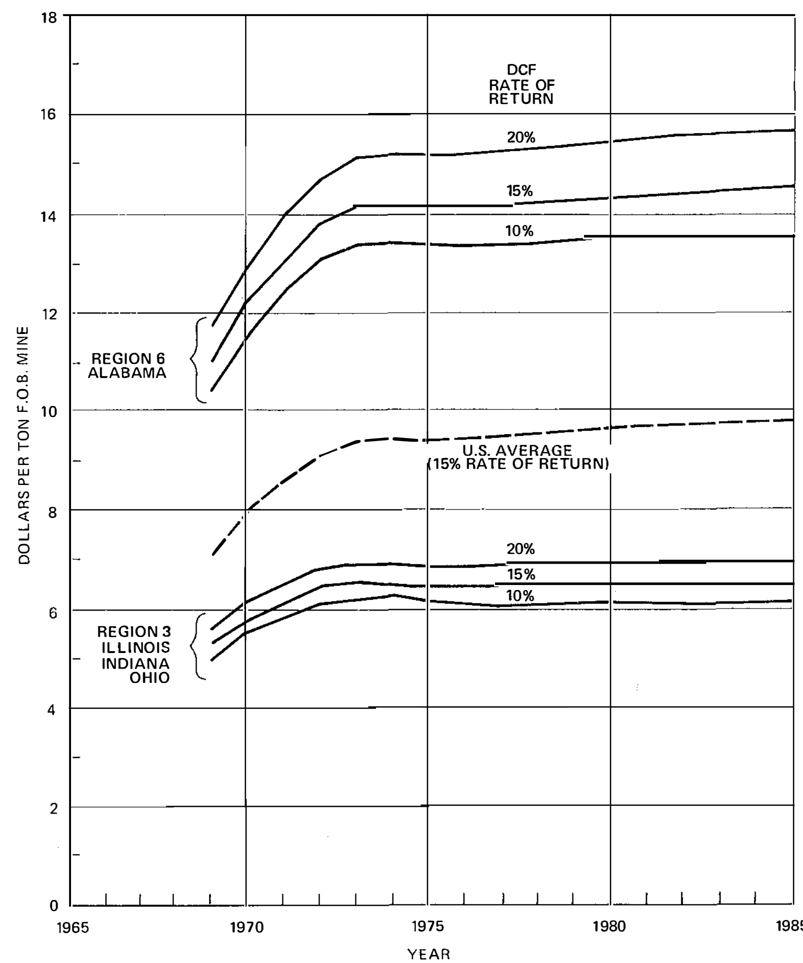


Figure 55. Range of Projected Underground Coal "Prices": Regional Extremes and U.S. Average (Years 1969 Through 1985—5-Percent Growth Rate Case—Constant 1970 Dollars).

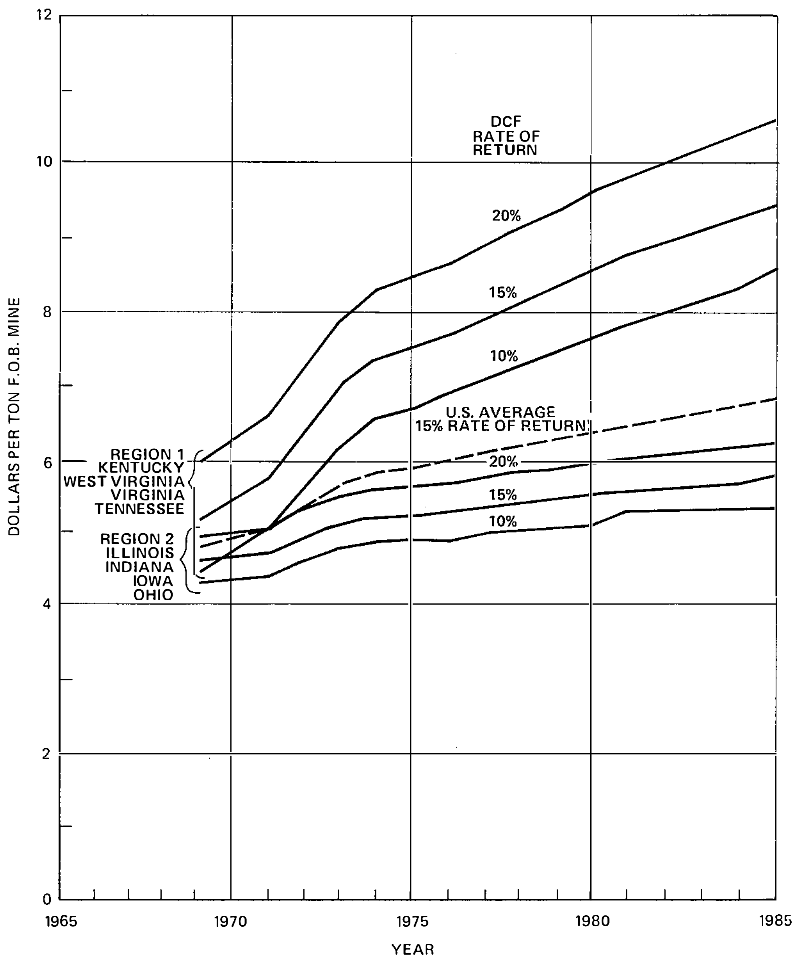


Figure 56. Range of Projected Surface Coal "Prices": Regional Extremes and U.S. Average (Years 1969 Through 1985—3-Percent Growth Rate Case—Constant 1970 Dollars).

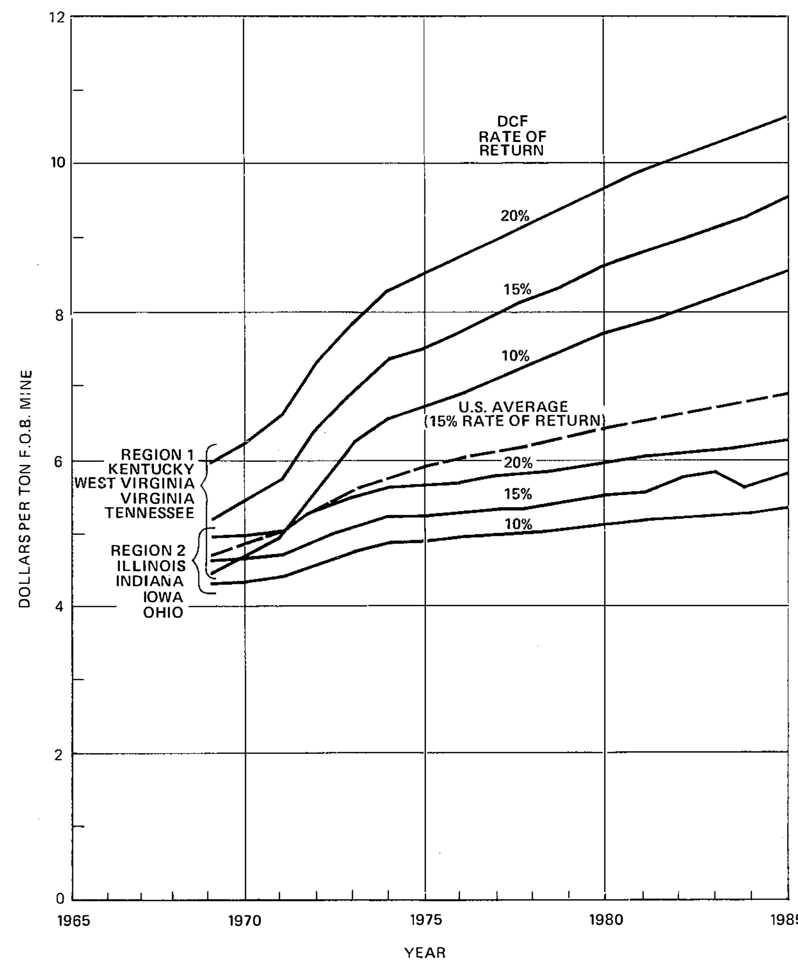


Figure 57. Range of Projected Surface Coal "Prices": Regional Extremes and U.S. Average (Years 1969 Through 1985—5-Percent Growth Rate Case—Constant 1970 Dollars).

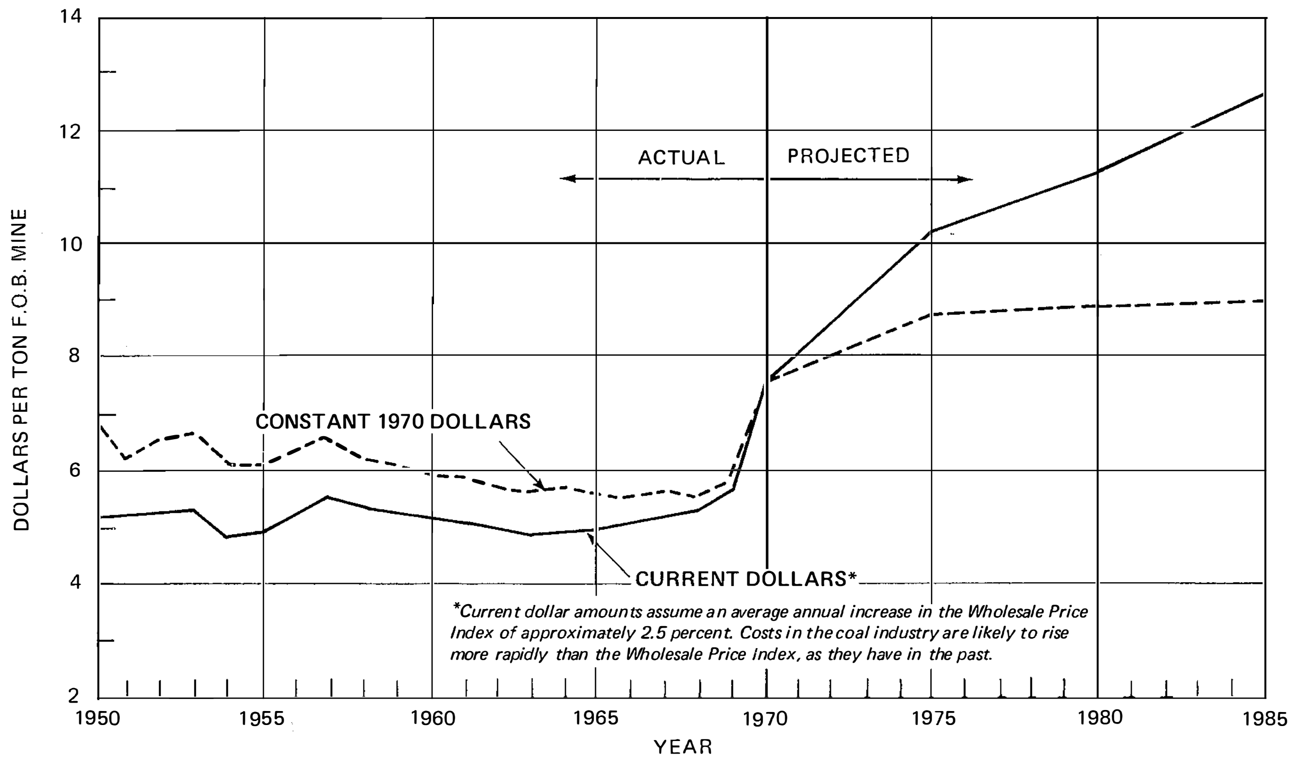


Figure 58. Average Value of Bituminous Coal from Underground Mines—Comparison of Historical and Future Values in Current and Constant 1970 Dollars (10-Percent Rate of Return—3-Percent Growth Rate).

These factors include productivity, income tax rates, capital costs and depletion.

Productivity: Productivity is of obvious importance in coal mining. A sensitivity analysis was made to determine the impact of a 10-percent change in labor productivity on the total cost of producing coal. Figures 60 and 61 illustrate the results for the "typical" underground and surface mines. For easy reference, the productivity used in the "base case" calculation of average value is shown on the bottom of each figure.

Figures 60 and 61 show that underground mining is more labor-intensive than surface mining. The rapid increase in the cost of producing coal at underground mines during the 1969-1973 period is primarily due to the decrease in the productivity of labor. This decrease results largely from the Coal Mine Health and Safety Act of 1969. It was assumed that the Coal Mine Health and Safety Act will not have a great impact on the productivity of labor at surface coal mines. However, environmental regulations governing such activities as surface reclamation could decrease surface productivity by more than 10 percent.

Income Tax Rate: A change in the income tax rate was also analyzed to determine its effect upon the cost of coal. As Table 91 indicates, the cost of producing a ton of coal is not highly sensitive to a 10-percent change in the effective tax rate. For example, in the case of an average underground mine in 1970, a 10-percent increase in the effective tax rate results in only a 1.2-percent increase in the cost of coal. This is because net profits after taxes, in this example, are only about 11.4 percent of the f.o.b. mine value of the coal.

Capital Costs: These costs vary considerably between areas, mining conditions, mining methods and even different mining companies. For these reasons, a sensitivity analysis was undertaken to illustrate the effect that a 10-percent or 20-percent increase in capital costs would have on the total cost of producing coal. The results are shown in Table 92.

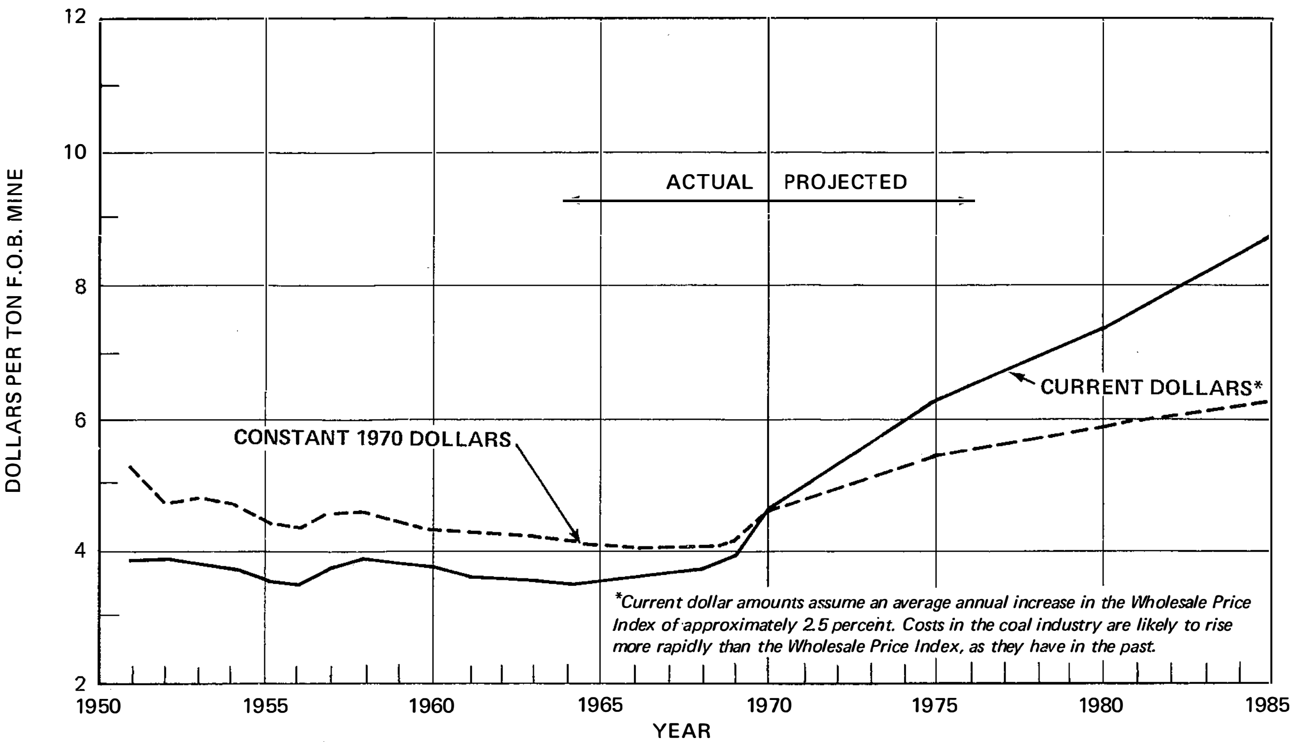


Figure 59. Average Value of Bituminous Coal from Surface Mines—Comparison of Historical and Future Values in Current and Constant 1970 Dollars (10-Percent Rate of Return—3-Percent Growth Rate).

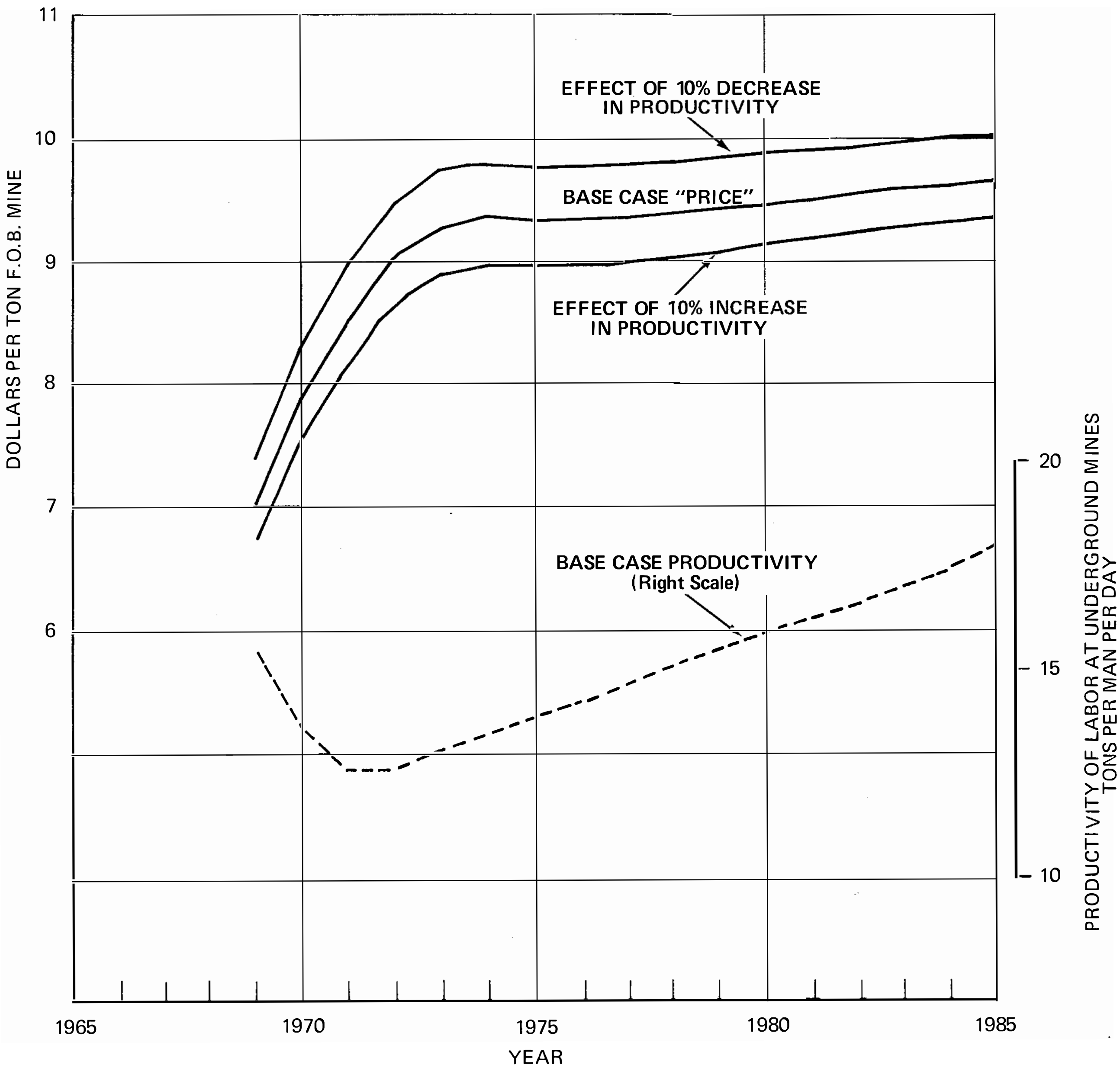
TABLE 90

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

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

* 3-percent growth rate case.

Depletion: Under the percentage method permitted by the Internal Revenue Code for depletion computation, a 10-percent statutory rate on gross income is allowed for the coal industry, unless the

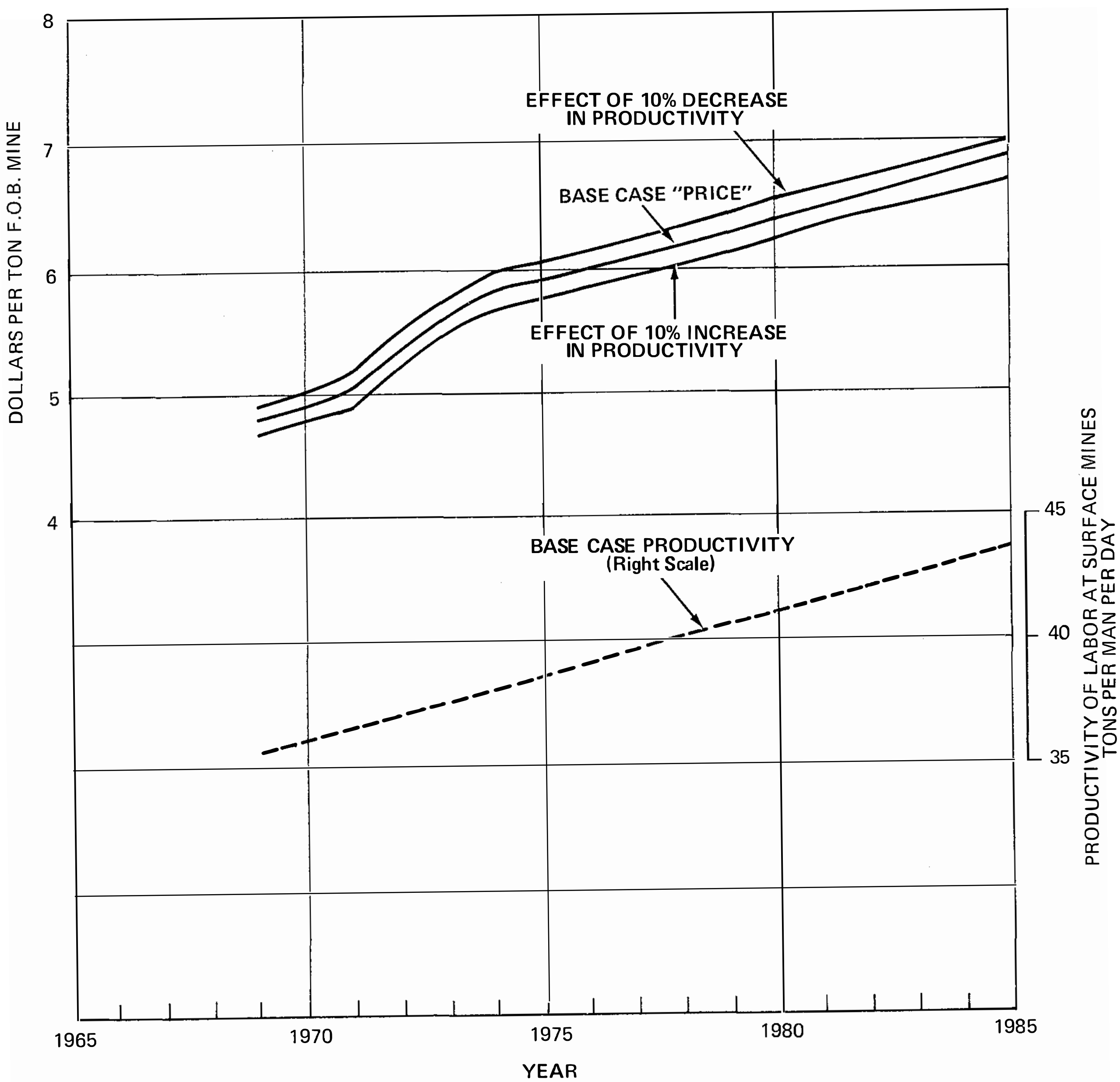


NOTE: Base case "price" ranges are shown in Figures 54 and 55.

Figure 60. Effect of Productivity on the Average Value of Coal from Underground Mines (Constant 1970 Dollars—15-Percent Rate of Return—3-Percent Growth Rate).

resulting deduction exceeds a limitation of 50 percent of net income.

Table 93 shows that eliminating the depletion allowance would raise the required "price" of coal as much as $1.00 per ton. Table 93 also shows that, at low rates of return, the 50-percent net income limitation applies. For example, for both 10-percent and 15-percent rates of return at underground mines, the 50-percent net income allowable depletion is lower than the corresponding 10-percent gross income allowable depletion. (For surface mines, the 50-percent net income allowable



NOTE: Base case "price" ranges are shown in Figures 56 and 57.

Figure 61. Effect of Productivity on the Average Value of Coal from Surface Mines (Constant 1970 Dollars—15-Percent Rate of Return—3-Percent Growth Rate).

depletion is lower for a rate of return of 10 percent. The difference is due to the fact that surface mines are more capital-intensive than underground mines.) Thus, "prices" at low rates of return are likely to be those under the "50-Percent Net Income Depletion" column in Table 93; those at high rates of return are likely to be those under the "10-Percent Gross Income Depletion" column.

Growth Capacity for the Domestic Industry

The Initial Appraisal projected a 1971-1985 sustained growth rate for coal of 3.5 percent per year

TABLE 91

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

	Effective Tax Rate		
	40%	50%	60%
	Underground Mines		
1970	7.77	7.84	7.93
1975	9.23	9.32	9.42
1980	9.36	9.45	9.55
1985	9.51	9.60	9.71
	Surface Mines		
1970	4.80	4.87	4.96
1975	5.79	5.87	5.97
1980	6.27	6.36	6.46
1985	6.70	6.79	6.90

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

from reserves presently mined. The present study indicates that a maximum rate of growth of 5 percent per year could be sustained by the coal industry. In addition to evaluating the effect of this growth rate on costs and "prices," a more moderate rate of growth of 3 percent per year was also analyzed. Coal supply resulting from these growth rates are shown in Table 94.

U.S. coal mines produce coal for export and in the future will produce coal for conversion to synthetic gas and liquids. Table 84 at the beginning of this chapter adds the coal required for these purposes to the conventional domestic demand and gives Cases I through IV projections for total coal supply and use. The expected growth of exports is the same as that projected in the Initial Appraisal. Derivations of the synthetic gas and liquids projections are given in a later section of this report.

The history of coal production for the last 35 years is shown in Figure 62, which gives total U.S. coal production and a breakdown into underground and surface bituminous coal (including lignite) and anthracite.

TABLE 92

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

DCF Rate of Return	Underground Mines 1970	1975	1980	1985	Surface Mines 1970	1975	1980	1985
	Rate of Return with Projected Capital Investment							
10%	7.36	8.76	8.85	8.97	4.44	5.38	5.82	6.21
15%	7.84	9.32	9.45	9.60	4.87	5.87	6.36	6.79
20%	8.42	9.99	10.16	10.35	5.36	6.43	6.97	7.45
	With 10% Higher Capital Investment							
10%	7.54	8.96	9.07	9.21	4.57	5.53	5.98	6.39
15%	8.06	9.58	9.73	9.90	5.04	6.07	6.57	7.03
20%	8.67	10.31	10.51	10.73	5.58	6.68	7.24	7.75
	With 20% Higher Capital Investment							
10%	7.71	9.17	9.29	9.45	4.69	5.67	6.14	6.56
15%	8.29	9.84	10.01	10.20	5.21	6.27	6.79	7.26
20%	8.97	10.64	10.87	11.11	5.80	6.93	7.52	8.05

* 3-percent growth rate.

TABLE 93

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

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

* 3-percent growth rate.

The greatest output from underground bituminous mines was reached during 1944 (518.7 million tons) and was preceded by a sustained growth in underground coal production over a 6-year period of almost 8 percent compounded annually. In the light of this, the 5-percent maximum growth assumed in this report seems reasonable for future underground production.

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

Factors Potentially Limiting Supply

Manpower

The need for trained new miners is a continuing problem. Figure 63 shows the historical relationship of total mining employment to the total U.S. labor force. The percentage of U.S. employment devoted to mining is now at a very low level—less than 0.2 percent. This suggests that manpower theoretically should not be a limiting parameter for the range of industry growth rates used in this report. However, attraction of adequate numbers of young workers into mining remains a problem, especially in view of the increasingly sophisticated equipment employed, which raises the level of worker competence and training required.

A more serious shortage of certain specifically trained supervisory and professional manpower may develop, however. Only 20 colleges and universities in the United States offer undergraduate degrees in mining engineering or related areas. In 1970, 132 mining engineers graduated from these schools; 184 were scheduled to graduate in 1971. Based on the "Engineer Manpower Bulletin" of April 1967, the maximum number of mining engineers expected to graduate (with B.S. degrees) between 1971 and 1975 is 722 (145 per year).

The percentage of total manpower which is in the technically trained category varies between regions and size of operations. A 2.0-percent to 2.5-percent range is representative now, but the percentage may have to be increased as mining technology becomes increasingly complex. On the basis of the 2.5-percent figure and a 5-percent annual turnover caused by engineers leaving the coal industry, the annual demand for engineers is now at about 310 and will grow in direct proportion to coal production. Thus, the potential imbalance between supply and demand of these specialists is a real problem. In itself, however, it need not limit the growth of the coal industry within the ranges projected by this study. Additional engineers can be supplied by transfer from other engineering disciplines (civil, electrical, etc.) .

Restrictions on Surface Mining

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

Surface minable recoverable reserves were shown earlier to approximate 45 billion tons. Essentially none of this coal can be recovered by underground methods. A federal law prohibiting all surface mining would thus result in elimination of all these recoverable reserves from our U.S. energy supply. In 1970, surface mining accounted for 264 million tons or slightly over 43 percent of the total coal produced.

Mining techniques for strippable coal reserves can be divided into two broad classes—contour and area mining. Contour mining is employed in hilly areas where topography governs pit design. Because the terrain is steep, the recoverable reserves tend to lie in a narrow band adjacent to the coal outcrops. The coal pits are usually developed in the form of long, narrow strips, each of which follows a certain contour interval around the mountain or hill. Since the coal beds are nearly flat and the terrain is quite rough, in most cases only a few cuts can be made around the hills before the maximum economic stripping ratio is reached. In some regions this method is called collar mining.

Area mining is used in flat or slightly rolling areas where the coal seams are relatively flat. The pit design is governed mainly by the equipment and desired level of production. The pits are developed in a series of long, narrow strips. As the mining progresses, the overburden from each strip

TABLE 94

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

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

* Based on preliminary Bureau of Mines estimates. See footnote, Table 84.

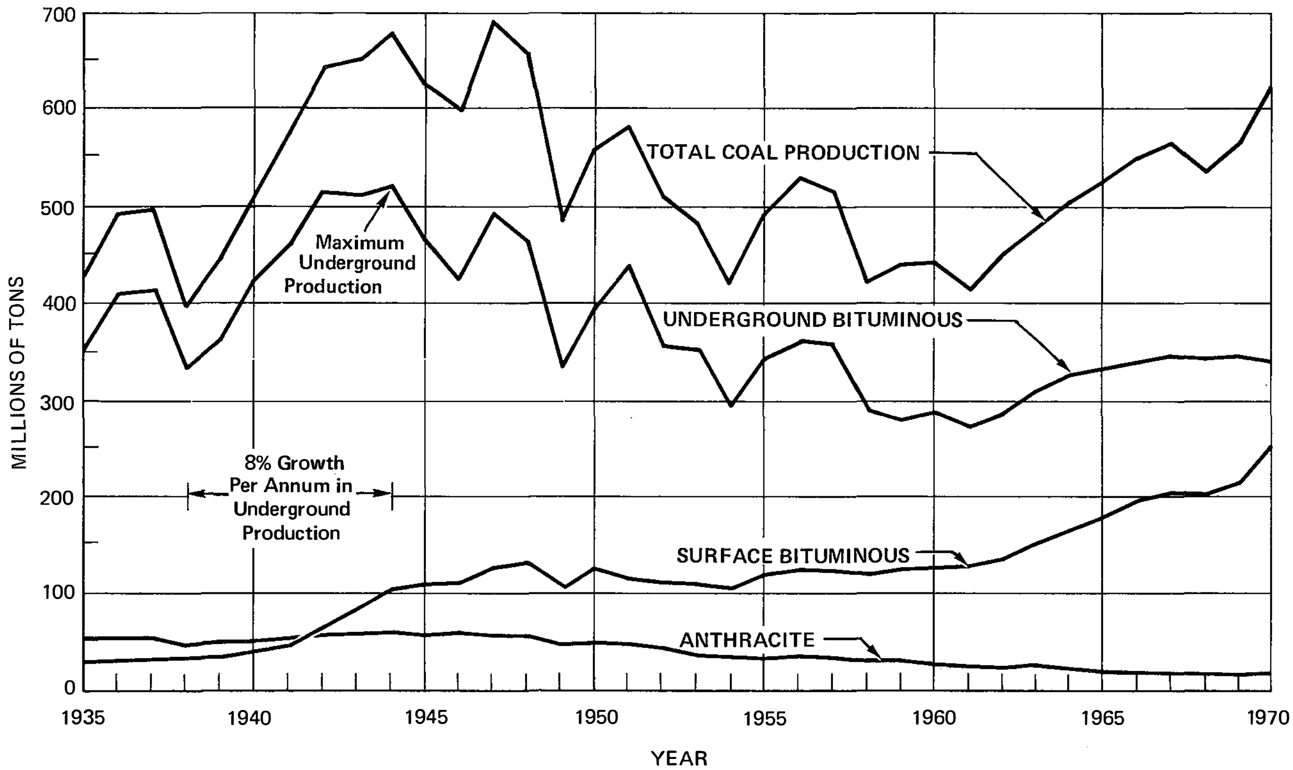


Figure 62. Production of Bituminous Coal (Including Lignite) and Anthracite—1935-1970.

is cast back into the open pit of the previous strip. Thus, a series of parallel furrows are formed in much the same manner as a farmer plowing his field. For this reason, area mining is sometimes referred to as furrow mining.

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

Given these regional differences in mining methods, the reserves in various coal fields can be grouped to evaluate the effect of proposed surface mining restrictions. If all contour mining were prohibited, for example, an estimated 4.4 billion tons of recoverable reserves would become unavailable for production. If surface mining were prohibited in counties having no previous record of surface mining, 10.4 billion tons would become unavailable. This figure can be broken down in terms of the three ranks of coal as follows:

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

The impact on actual coal output under either of these two assumptions would be major in the near-term period between now and 1985, particularly as it affects supply for conventional markets. The combined effect (total ban on surface mining) would reduce projected coal output over 40 percent in each year studied and under each case studied. Table 95 shows an estimate of contour and area mining as a percentage of total surface mining by state in surface Regions 1 through 3. Table 96 then indicates the aggregate effect of a contour mining ban in these surface regions for the entire Case I-IV range of projected production

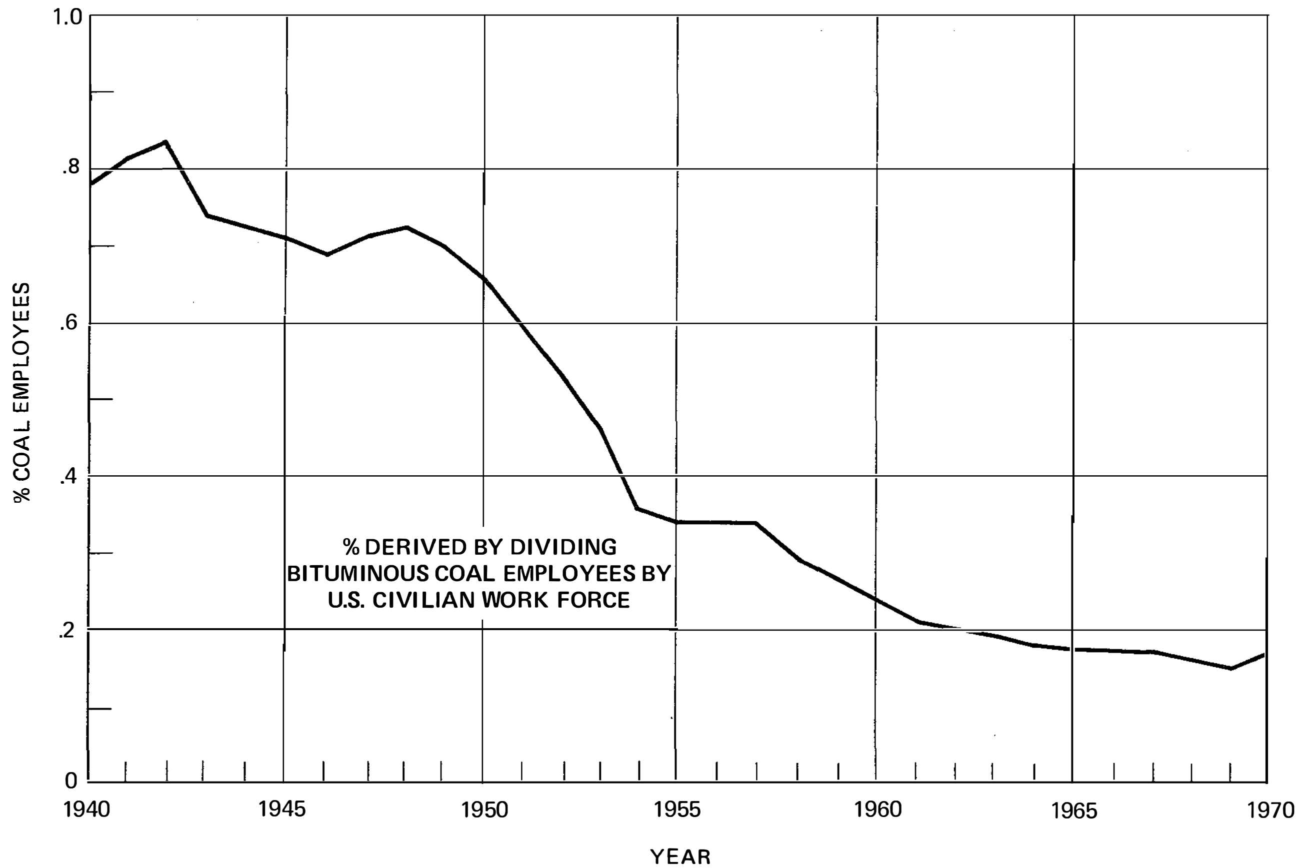


Figure 63. Coal Employees as Percent of Total U.S. Work Force.

levels. Also shown is the effect of a total strip mining ban in these regions.

Restrictions on Sulfur Content

No data are available on the sulfur characteristics of the specific 150 billion tons of presently recoverable reserves listed in Tables 86 and 87. Limited information is available on the U.S. coal resource base as a whole, however. According to the Bureau of Mines, 46 percent (720,060 million tons) of the Nation's total known coal reserves under less than 3,000 feet of cover contain 0.7-percent or less sulfur. Of this low-sulfur content coal, 93 percent is located in the states west of the Mississippi River. Thus, most of the Nation's low-sulfur coal is distant from the major demand centers in the East. In the eastern states, 43 percent of the total reserves have sulfur contents of over 3.0 percent, while only 11 percent contain 0.7-percent or less sulfur. Much of this 11 percent is low- or medium-volatile coal and is used primarily as metallurgical coal—its characteristics are such that it is not well suited for most existing power generation plants. A large part of these low-volatile coal reserves are committed to steel making.

Tables 97 through 99 indicate the sulfur content of certain coal reserves within less than 3,000 feet depth which have been mapped and explored. States with the largest coal concentrations of 0.7-percent or less sulfur content are listed in Table 99.

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

Availability of Adequate Transportation Systems

Almost two-thirds of all U.S. coal depends on rail movement, and one-fourth moves on waterways. The figures shown in Table 100 are not additive because a substantial amount of coal moves sequentially by rail and barge or lake boat.

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

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

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

TABLE 95

CONTOUR AND AREA MINING AS A PERCENTAGE OF SURFACE MINING

(Surface Regions 1 Through 3)

State	Contour (Percent)	Area (Percent)
Region 1		
Kentucky	20	80
West Virginia	90	10
Virginia	90	10
Tennessee	100	0
Region 2		
Illinois	0	100
Ohio	25	75
Indiana	0	100
Iowa	0	100
Region 3		
Pennsylvania	25	75

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

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

TABLE 96

EFFECT OF CONTOUR AND TOTAL SURFACE MINING CURTAILMENT*

(Surface Regions 1 Through 3)

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

* Production is for domestic conventional markets (see Table 84). A total ban of surface mining in 1970 would have reduced total production by 264 million tons.

During the intervening 4 years between 1965 and 1969, rail movement grew 7 percent. This growth was achieved by better utilization (longer line-haul service) of cars.

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

TABLE 97

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

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

* As of January 1, 1965.

TABLE 98

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

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

* As of January 1, 1965.

TABLE 99

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

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

TABLE 100

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

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

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

Water transport is relatively low in cost. Large-volume barge movements cost around 2.5 mills per ton mile, and the U.S. average barge cost is nearly 3.0 mills per ton mile. This compares to 5 mills per ton mile for certain unit train hauls and about 10 mills per ton mile for the average rail coal haul.

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

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

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

	1965	1970
Coal Tonnage	7.5	16.0
All Commodities	26.0	43.0

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

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

Coal Supply for Synthetic Fuels Production

Resources Available and Probable Costs

The simplifying assumption has been made in this study that all production of synthetic pipeline gas or synthetic liquid fuels in the 1971-1985 period would come from the Nation's large surface minable reserves in the West. Possible exceptions are not precluded, but it appears that the generally much lower cost of these reserves would more than offset the greater cost of transporting synthetic fuels to the centers of demand. The cost of pipelining liquids or high-BTU gas is comparatively low.

The total amount of such reserves appears adequate to support even the highest rate of production of synthetics that one could visualize for the 1971-1985 period. This is discussed in more detail later in this chapter.

The cost of these particular surface-mined coals should be significantly below other U.S. coals because a large part of this resource is known to be present in thick seams and under low overburden. Recoverable reserves in the key western states amount to approximately 28 billion tons (see Table 87, Regions 4, 5 and 6). Information on the overburden characteristics of western coal is limited, but the information which is available shows a total range of overburden/coal ratio for the three western regions of up to 14:1. In all likelihood, the coals needed to supply the projected synthetic fuel plants will not require mining at ratios above 7:1.

In order to determine the range of costs which might be incurred, a model of a surface (area) mine has been defined and the cost of coal calculated as a function of the overburden/coal ratio. Figure 64 shows the results of this evaluation for 10-percent, 15-percent and 20-percent DCF rates of return.

Figure 65 shows that the impact of any variance in three additional factors—hauling distance, seam thickness and investment—is not significant. If each of these three items were increased by 50 percent, the combined impact on cost of coal would be only about 15 percent.

The cost of the bulk of coal supplied to the initial group of synthetic fuel plants is likely to fall between \$2.75 and \$4.00 per ton. The likely range of costs can vary depending on seam thickness and cost of reclamation. Legislation concerning the latter is still in a state of flux. Table 101 illustrates the potential impact of reclamation costs on the particular reserves under consideration. Reclamation costs for eastern reserves are much higher.

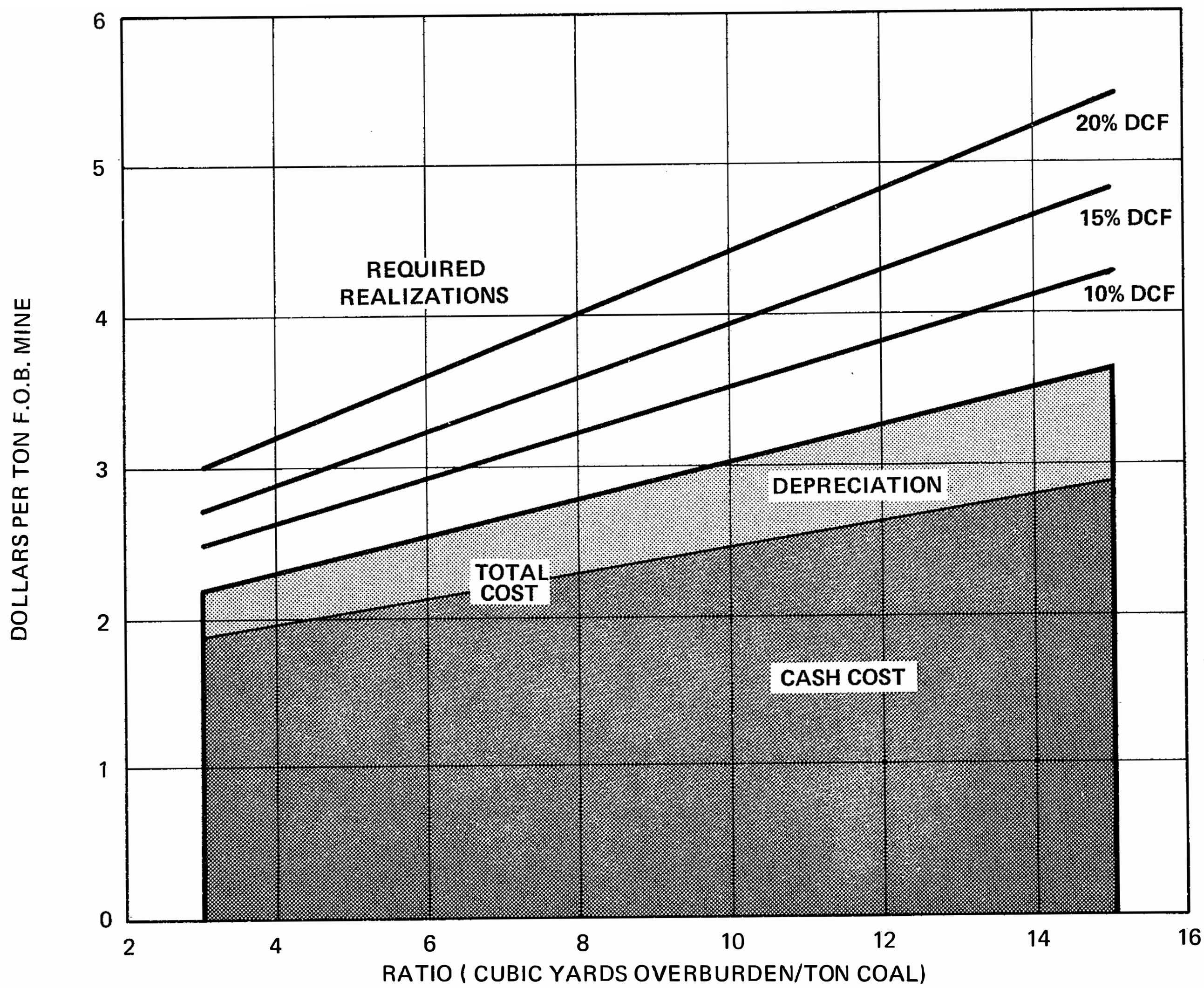


Figure 64. Western Surface Coal Value Analysis (Constant 1970 Dollars).

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

TABLE 101

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

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

Allocation of Western Surface-Mined Coal by Market

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

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

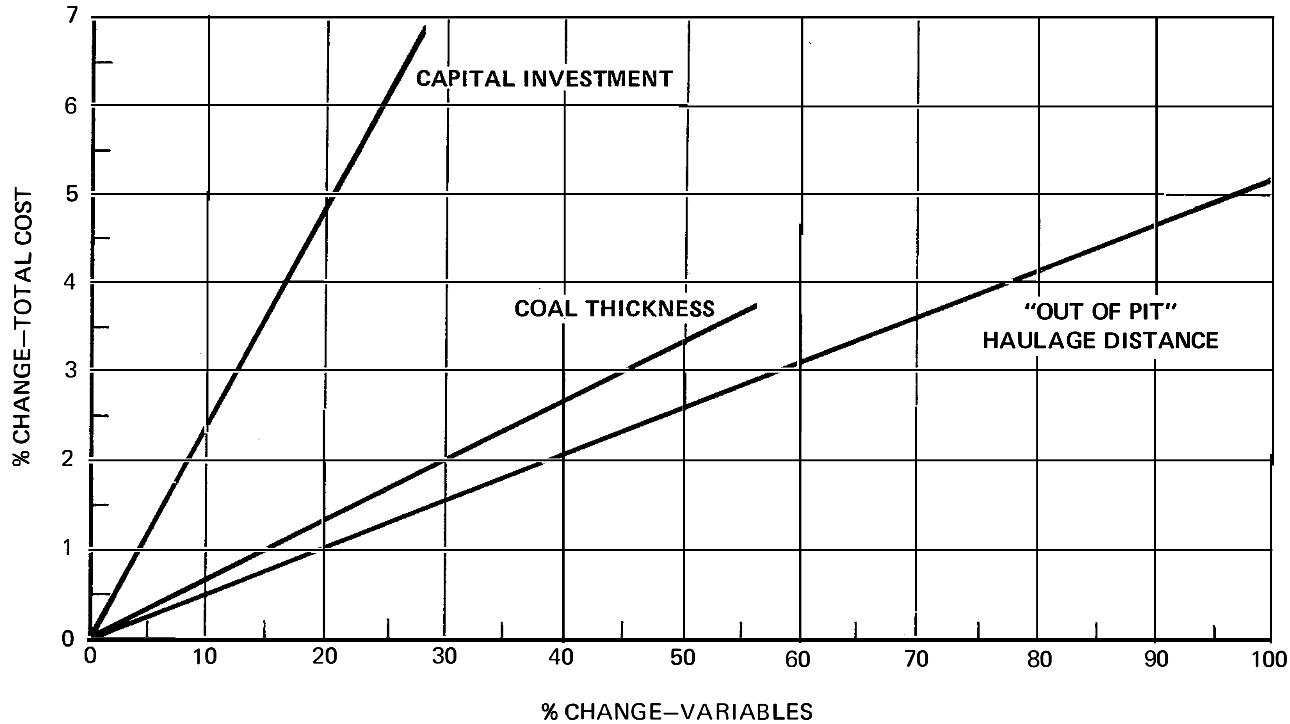


Figure 65. Western Surface Coal Analysis Sensitivity of Total Cost at Constant Overburden Ratio.

- Synthetic liquid fuel plant: 50 MB/D, 90-percent operating factor; thermal efficiency—72 percent.

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

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

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

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

The western surface minable coal recoverable reserves are arbitrarily assigned to such plants in Table 102. Western reserves would be adequate over a 30-year period to supply coal to generate 46.5 million KW (at a 70-percent average load factor) *plus* the equivalent of 4.73 TCF per year of pipeline gas (at 915 BTU's per cubic foot)* *plus* 2.64 MMB/D liquids. As will be shown, these levels of production for synthetics will not be reached by 1985. In fact, a large portion of these reserves will remain uncommitted at that time. It is likely that only the more desirable part of the reserves (thick seams and lower overburden/coal ratio) will be used during the pre-1985 period.

The 28 billion tons considered in Table 102 were only the measured and indicated part of the resource in the mapped and explored areas. The

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

TABLE 102

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

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

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

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

USGS suggests that a substantial amount of similar coal could be found by further drilling, mapping and exploration. This would uncover new resources and would move "inferred" deposits into the measured and indicated category. The USGS figures presented in Table 103 indicate the percentages of measured and indicated reserves based on the total known coal reserves in the western states. These figures suggest a good chance for success from an expanded exploration program.

Potential Future Coal Utilization

No significant change in the outlook for the technologies for use of coal in power plants and for conversion to synthetic gas and liquids has occurred since the Initial Appraisal was issued. The present report deals only with certain aspects of introducing the new technology during the 1971-1985 period.

Use of Coal for Power Generation

The use of coal in future power generation will depend on a satisfactory solution to the air pollution problem. For the near term, this implies cleanup of the existing coal-fired plants which constitute a large share of current installed capacity. For existing stations, this cleanup requires add-on stack gas cleanup systems except for those stations which can obtain low-sulfur fuels (including low-sulfur fuels made from coal itself). For newly built plants, stack gas cleanup must compete with alternate ways to convert coal to electricity in a pollution-free manner.

Stack Gas Cleanup: The present status of stack gas cleanup is best described by reference to Table 104. It lists the scrubbing systems of commercial size which have been built or which are contracted for installation in U.S. power stations at this time. As Table 104 indicates, many of the planned systems will not be on stream until late 1972 or 1973. Thus, while there is considerable promise in many of these programs, their specific potential cannot be evaluated at this time.

The cost associated with scrubbing will differ over a very wide range because the problem of retrofitting an existing plant obviously varies significantly depending on site, type of plant, and load factor (which on individual generator sets may vary all the way from 30 percent to 90 percent). The high and low extremes of possible investment size and possible load factor can lead to a tenfold difference in the capital charges of stack gas cleanup. Because some 5 million MWe have already been committed to stack gas cleanup, this technique seems likely to emerge as one possible answer to pollution control. However, plant design, location and configuration may preclude retrofitting in some instances.

The U.S. Government, through the Environmental Protection Agency, is planning to support scrubbing development with a total of $57.5 million between 1971 and 1975. To this can be added an unknown amount spent by private industry. At least 2 to 3 years will be required before operational results as well as the relevant economies become clear. At that time, a better judgment of the viability of this technology can be made.

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

Combined-Cycle Power Plant: Combined-cycle power plants are receiving increased attention. Several U.S. utilities have announced their intent to install such plants based on the desire to use clean fuel. The fuel, either gas or low-sulfur oil, must be satisfactory for combustion in a gas turbine. These plants are low in initial cost in comparison to standard coal-burning steam-electric plants. They are thus especially desirable for so-called intermediate load, or cycling power generation.

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

Combined-cycle plants can be coal fired either by converting coal to low-BTU gas (175 BTU/CF) in the power plant proper, or by conversion at mine mouth to higher-BTU gas or low-sulfur liquid

TABLE 103

MEASURED AND INDICATED RESERVES OF KNOWN COAL RESERVES IN WESTERN STATES

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

TABLE 104

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

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

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

† Now abandoned.

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

§ Partial EPA funding.

TABLE 105

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

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

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

for distribution to the plants by pipeline. The transportation of low-BTU gas by pipeline is uneconomical, except for very short-distance movements. All of these possibilities require additional R&D.

This study discusses alternate means to increase the supply of energy from domestic sources, implying an increasing demand for coal to supply a share of the energy used in electric power generation. Without speculating on the relative commercial buildup rates of the alternate methods by which coal can be used without causing pollution, it can be noted that particular requirements of individual power plants will dictate which route appears most suitable. Regardless of the route chosen—whether it involves stack gas cleanup, gasification (high- or low-BTU gas) or liquefaction, or whether it is based on conventional steam-electric or combined-cycle power plants—it will affect the overall U.S. energy balance as a result of the somewhat different overall efficiency of conversion from coal to electricity. Demand for complete freedom from pollution will cause this overall power plant efficiency to decline. The extent of this decline and the resulting additional demand for coal is not known at this time.

Use of Coal for Synthetic Pipeline Gas

The technology for converting coal to synthetic pipeline gas was discussed in the Initial Appraisal. The subject of this report is the prospective rate of buildup of synthetic gas production. The cases considered are:

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

Technology to build low-BTU synthetic gas plants is now available, at least for the noncaking or mildly caking coals of the kind available in large quantities in the western United States. The gasification technology was developed some years ago in Germany, where similar coal is mined. The demonstration of the important methanation step needed to raise the BTU content of the gas to a pipeline quality is not complete, but a project toward this goal is in progress. Thus, no delay is required due to a lack of technology. The buildup rate would be influenced primarily by economic or other considerations. Table 105 illustrates the growth of capacity for the three cases discussed above.

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

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

At the end of the period, the cumulative investment for the total period (in constant 1970 dollars) for Case I would be approximately $7.5 billion. The slower buildup indicated by Cases II and III, by comparison, suggests a total of 16 plants of the 250 MMCF/D size by 1985 with cumulative investment reaching $4.0 billion. At the end of the period, increased capacity would be added at the rate of three plants per year. Case IV is identical to the Initial Appraisal projection. The Annual tonnage required for one coal gasification plant for the three types of coal involved, based on 250 MMCF/D of pipeline gas, is as follows:

- Bituminous coal (11,500 BTU/lb)—5.3 million tons
- Subbituminous coal (8,500 BTU/lb)—7.2 million tons
- Lignite (6,750 BTU/lb)—9.1 million tons.

TABLE 106

DISTRIBUTION OF COAL GASIFICATION PLANTS IN 1985

	Case I		Cases II/III		Case IV	
	No. of Plants	TCF	No. of Plants	TCF	No. of Plants	TCF
			Bituminous Coal			
New Mexico	4.0	0.33	4.0	0.33	2.0	0.16
			Subbituminous Coal			
Wyoming	7.0	0.58	3.4	0.28	2.1	0.18
Montana	6.4	0.53	3.0	0.25	1.0	0.08
			Lignite			
Montana	8.0	0.66	3.6	0.29	0.0	0.00
North Dakota	4.6	0.38	2.0	0.16	1.5	0.12
Total	**30.0**	**2.48**	**16.0**	**1.31**	**6.6**	**0.54**

In Table 106, the potential number of plants has been assigned for the three cases to the three types of coal in the various states. The number of plants is lower in all instances than that shown in Table 102, illustrating again that coal reserves are adequate.

Table 107 indicates the annual coal requirement for synthetic gas plants for the various cases.

Western surface coals are estimated to cost between $2.75 and $4.00 per ton (in constant 1970 dollars) through 1985. The range of BTU levels involved (13.5 million BTU/ton to 23.0 million BTU/ton) indicates a possible range of $0.12 to $0.30 per million BTU's for coal feedstocks. The actual range is likely to be narrower because the low-BTU lignites are likely to fall into a lower range of costs.

The effect of this variation in coal cost on the cost of synthetic gas is likely to cause SNG cost to vary from about $0.90 to $1.10 (constant 1970 dollars) per million BTU's at a western plant site, based on an 18-percent charge against the rate base, utilizing utility-type financing. On the basis of a 15-percent DCF rate of return on investment, the lowest cost would be approximately $1.20 per million BTU's. If this gas were to be pipelined to the Midwest, the pipelining charges could add about $0.20 to $0.30 per million BTU's for a delivered city gate gas cost of about $1.10 to $1.50.

Within the quantities covered by the proposed buildup rates (Cases I to IV) there should be no significant variation in the cost of gas other than that resulting from variations in the cost of coal. There is no supply elasticity involved in building a series of essentially identical gasification plants. In the post-1985 period, when the new coal gasification processes have been operated commercially for a number of years, the cost of gas (in constant 1970 dollars) will probably decrease by roughly 2 to 5 percent per year as design and operating improvements are developed from the commercial operations and from continuing research, i.e., from the "learning curve." Potential improvements through entirely new technology may result from the continuing research efforts in gasification.

Use of Coal for Synthetic Liquid Fuels

The problem of liquefaction differs from that of gasification because an acceptable technology for

TABLE 107

ANNUAL COAL REQUIREMENT FOR SYNTHETIC GAS PLANTS IN 1985

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

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

This report describes a reasonable range of possible assumptions for rate of buildup. The buildup under Cases II/III is based upon the assumption that, after 2 years of R&D effort, a prototype, semi-commercial plant will be built. This plant will take 5 years to build and successfully operate. The initial plant will be followed by a small, commercial plant of 30 MB/D capacity 4 years later. Thus, the first plant would come on stream 11 years from the start of the R&D program. Subsequent buildup could then follow as shown in Table 108.

This buildup reflects a moderate growth, assuming a reasonable incentive for buildup of domestic liquid fuel sources. It is, of course, possible to visualize faster buildup under greater economic incentives or new government policies, but only *after* technology has been established.

TABLE 108

COMMERCIAL COAL LIQUEFACTION PLANT BUILDUP—CASES II/III

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

Table 109 portrays a range of growth rates: Case I—maximum incentive, Cases II/III—a moderate buildup, and Case IV—no incentive, i.e., no commercial liquefaction of coal during the 1971-1958 period. The maximum case differs from Cases II/III by assuming that a "high risk" 30 MB/D plant will be placed on stream in 5 years, to be followed by three 50 MB/D plants 3, 4 and 5 years later, with a buildup reaching 200 MB/D per year at the end of the period.

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

The following cost figures are the same as those given in the Initial Appraisal. Initially, at the 30 to 50 MB/D scale, investment will be $7,400 per daily barrel. At the 200 MB/D level, the figure drops to $6,500 per daily barrel. The resulting cumulative investment for Case I amounts to about $4.58 billion by 1985, and the Cases II/III total is $592 million.

The commitment of western surface coal reserves suggested in Table 102 would permit the supply of coal for 52.9 synthetic liquid plants

TABLE 109

BUILDUP OF SYNTHETIC LIQUIDS FROM COAL
(MB/D)

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

TABLE 110

ASSUMED DISTRIBUTION OF COAL LIQUEFACTION PLANTS IN 1985

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

TABLE 111

ANNUAL COAL REQUIREMENT FOR SYNTHETIC LIQUID PLANTS IN 1985

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

producing 50 MB/D each. Cases I and II indicate the equivalent of 13.6 and 1.6 plants respectively by 1985. The available supply of coal thus seems to be ample for the suggested buildup. The annual coal tonnage required for each 50 MB/D plant is as follows:

- Bituminous coal (11,500 BTU/lb)—6.0 million tons
- Subbituminous coal (8,500 BTU/lb)—8.1 million tons
- Lignite (6,750 BTU/lb)—10.1 million tons.

In Table 110 the potential number of plants is assigned for the three cases to the three types of coal in the various states.

Table 111 shows the annual coal requirements for the assumed set of synthetic liquid fuel plants for Cases I to IV.

As in synthesis of pipeline gas, coal costs for synthetic liquids will range from $2.75 to $4.00 per ton (in constant 1970 dollars) through 1985, using western surface-mined coal. The cost of synthetic crude will vary between $6.25 and $6.75 per barrel at the plant gate (constant 1970 dollars) at a 10-percent DCF rate of return for a commercial demonstration 30 MB/D plant. It will range from $7.75 to $8.25 at a 15-percent DCF rate of return. A reduction of about $0.50 per barrel would be possible for operations exceeding 100 MB/D. The cost of producing a partially desulfurized low-ash fuel would be somewhat lower.

U.S. Capability to Build Up Synthetic Fuels Industry

The total investment, on a cumulative basis, for plants and associated mines for Cases I through IV is shown in Table 112.

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

TABLE 112

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

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

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

† Basis: $7,400 per B/D first 80,000 B/D; $6,500 per B/D above initial 80,000 B/D.

‡ Basis: $6.0 per annual ton of surface mine capacity.

Chapter Six
Nuclear Energy Availability

Introduction

Nuclear power is expected to become increasingly important in meeting U.S. energy requirements. This development reflects (1) a shift of energy demand toward electrical usage and (2) the generally currently favorable economics of nuclear power plants for base-load generation of electricity over plants that utilize fossil fuels.

This chapter will examine—

- Various projected nuclear growth rates and factors which will influence these growth rates
- The adequacy of the uranium resource base
- Exploration, mining and milling activity required to supply U_3O_8 from the uranium resource base
- The calculated uranium prices corresponding to various parametric assumptions
- The nuclear fuel processing requirements
- The necessary capital expenditures for the nuclear fuel supply industry.

Summary and Conclusions

Nuclear Power Growth

Four projections of nuclear power growth were developed in order to assess the capability of the nuclear industry to contribute to U.S. energy requirements and to take account of possible changes in government policies and economic conditions. Because of uncertainties concerning technical, environmental, legal and regulatory problems, installed capacity could range from 240,000 to 450,000 megawatts electricity in 1985. This compares to a 1985 projection of 300,000 MWe of installed nuclear power capacity in the Initial Appraisal.* A comparison of the four cases of nuclear power growth of this study and the Initial Appraisal is shown in Table 113.

TABLE 113

PROJECTED GROWTH OF NUCLEAR POWER
(Thousand MW of Installed Generating Capacity)

	Initial Appraisal	Case I	Case II	Case III	Case IV
1975	59	64	64	64	28
1980	150	188	188	150	107
1985	300	450	375	300	240

Case III corresponds very closely to the Initial Appraisal projection, and it is also very nearly equal to current AEC and FPC official forecasts.† The present legal and regulatory turmoil delaying nuclear plant licensing and operation will have to be at least substantially resolved in the near future, either through legislation or procedural improvement, if even the Case III projection is to be realized.

Since 1971, when the AEC instituted the procedure to evaluate all environmental factors related to nuclear power plants in compliance with the National Environmental Policy Act, the time necessary to obtain construction permits and operating licenses has increased significantly.

Case IV projects a continuation or worsening in constraints on nuclear plant installation, including (1) technical problems of more than a routine nature, (2) delays in site acquisition and approval because of environmental considerations, and (3) delays in licensing plants because of legal and regulatory considerations.

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* NPC, *U.S. Energy Outlook: An Initial Appraisal 1971-1985*, Vols. I and II (1971).

† AEC, *Nuclear Power Growth 1971-1985*, WASH-1139—Rev. 1 (December 1971); FPC, *The 1970 National Power Survey Part I* (December 1971), p. I-1-17.

Case II projects the converse of Case IV conditions, with streamlined licensing procedures, improved construction techniques and well defined environmental standards. This should result in a 6- to 7-year order lead time which will be sufficient for the reactor manufacturers, pressure vessel suppliers, turbine generator vendors and other nuclear plant component manufacturers. It should also be sufficient for the design and construction industry to meet the increased nuclear growth rate suggested.

Case I projects that all central station base-load electric generating plants installed between 1980 and 1985 will be nuclear. This level of nuclear power growth could be achieved with an all-out effort by both government and industry to make nuclear power a high priority national goal. This effort, in the process, would reduce manufacturing and construction lead time between the date a new plant is ordered and the date it is available for power production.

All of the nuclear power capacity in 1985 is assumed to be light-water or high-temperature gas reactor plants. Fast breeder reactors, representing a new concept in nuclear technology, are not expected to be commercially available before 1985. Because of the long lead time necessary for uranium exploration, however, breeder reactor introduction in the late 1980's or early 1990's will tend to moderate the requirements prior to 1985 for uranium discovery and fuel cycle investment.

Uranium Demand

The four nuclear power growth projections will require from 400,000 to 700,000 tons of U_3O_8 through 1985. These requirements are shown in detail in Table 114.

Uranium Resources

The AEC presently estimates domestic proved and potential uranium resources at a forward cost of up to $15 per pound to be about 1.6 million tons. Reasonably assured (proved) reserves of U_3O_8 with a forward cost of less than $8 per pound presently total 273,000 tons.* The AEC has stated that "potential resources" at a cost of $8 per pound include an additional 460,000 tons. Within the United States, low cost uranium resources should be adequate to meet the total projected demand over the 15-year forecast period.

The AEC estimate of additional resources of U_3O_8 is not an attempt to measure the ultimate uranium resources of the country or the total recoverable resources at the costs indicated. The "potential" estimate is related to specific known mineralization and geological trends and, as such, is subject to change from time to time as new information is developed.

* The AEC cost levels ($8, $10 and $15 per pound of U_3O_8) cannot be directly compared with "prices" as calculated in this study since the AEC's values do not include a return on investment. Further, the AEC's "forward costs" do not include interest, income tax or amortization of past investments in exploration and mine/mill construction.

TABLE 114

ANNUAL U_3O_8 REQUIREMENTS FROM INDUSTRY*
(Thousand Tons U_3O_8)

	Initial Appraisal		Case I		Case II		Case III		Case IV	
	Annual	Cumul.	Annual	Cumul.	Annual	Cumul.	Annual	Cumul.	Annual	Cumul.
1975	18.4	66	19.1	58	19.1	58	19.1	58	11.5	30
1980	34.2	205	50.9	240	45.6	230	36.5	200	29.1	140
1985	59.3	450	108.5	700	89.2	600	70.7	500	60.4	400

* These figures do not include uranium reserves needed in 1985 for future production. Such reserves considered necessary amount to an additional 0.7 million to 1.3 million tons of U_3O_8 (Case IV-Case I; corresponds closely to a 10-year forward reserve).

Substantially, all of the proved reserves of U_3O_8 and approximately 85 percent of the potential reserves categorized by the AEC as potential resources are located in the present producing areas, yet these areas make up less than 10 percent of the total region where evidence of uranium occurs. Even the presently producing areas in many cases are not completely explored. Therefore, the uranium resource base in the United States offers the prospect of yielding significant additional reserves, providing the necessary exploratory effort is mounted.

Since about 50 percent of all proved and potential uranium resources are on federal or Indian lands in the western United States, reasonable access to these lands must be allowed to support the necessary exploration and development effort.

Thorium, which is used only in high-temperature gas reactors, is known to be available in quantities significantly beyond expected requirements.

Uranium Supply

While the uranium resource base is considered adequate, there must be sufficient economic incentives to ensure a sufficient level of exploration activity to locate these potential resources and to develop both proved and potential reserves. The long lead time involved between exploration and nuclear fuel availability for electric power generation will require a rapid buildup in uranium exploration activity over the next 5 to 6 years. Based on an average discovery rate of 4 pounds U_3O_8 per foot, surface drilling must increase from 15.5 million feet in 1971 to 45 million feet in 1977 to meet the Case III projections; under the Case I projections, surface drilling must reach 65 million feet in 1977.

Sound government policies and improved economic incentives will be required to achieve the required sharp increase in exploration activity, considering the long lead times required from exploration to production. Present market conditions have not been satisfactory to provide the necessary incentives for uranium producers to explore extensively for additional uranium deposits or to develop many known properties, let alone to explore for and develop the higher cost ore bodies. In fact, drilling rates have decreased in the last 2 years. The necessary incentives could include the following:

- Long-range uranium purchase contracts between producers and utilities
- Uranium selling prices which cover the costs of discovery, development and production, and a reasonable return on investment
- Assurance that the present government policy regarding importation of uranium will continue
- Continuation of a favorable tax environment
- Timely access to public lands for uranium exploration and development.

Uranium mining and milling capacity now in operation or under construction plus existing U_3O_8 inventory is adequate to meet U.S. requirements at least through 1975 under all demand cases considered. However, all presently discovered reserves will need to be in production by 1980, and substantial production from new discoveries will be required in the 1980-1985 time period. Commitments to construct new mine and mill facilities needed after 1975 must begin within 1 or 2 years.

For the purpose of estimating future costs of uranium, it was assumed that the average costs of uranium obtained from reserves yet to be discovered will be comparable to the estimated cost of mining uranium from presently known resources. Further, it is estimated that exploration expenditures would start 9 years prior to production and that mine/mill construction would start 4 to 5 years prior to production with the average mine life extending approximately 10 years.

Taking these costs and lead time estimates into consideration, levelized U_3O_8 "prices"* to provide a DCF rate of return on investment in new reserves were calculated and are summarized in the following tabulation.

Return on Investment (Percent)	Levelized "Price" (\$/lb of U_3O_8)
10	8.91
12.5	9.59
15	10.37
17.5	11.27
20	12.39

* The term "levelized price" as used here is the average "price" required over the assumed life of U_3O_8 production centers to provide a given DCF rate of return.

The levelized "prices" apply to U_3O_8 produced from new mines which go into production during the 1979-1985 period. The "prices" are expressed in constant 1970 dollars.

Uranium "prices" required to yield a return on investment as computed in this study are particularly sensitive to uranium discovery rates. The discovery rate is projected to remain at the present level of 4 pounds of U_3O_8 per foot of drilling at least through 1985. A decrease of 1 pound U_3O_8 per foot in the discovery rate increases the "price" of U_3O_8 required for a 15-percent return on investment by about $1 per pound.

Environmental, health and safety factors have already had significant impact on the economics of uranium mining and will undoubtedly continue to be a prime consideration. Cost increases in underground uranium mines to meet the 1971 radon exposure standards are estimated to range from $0.25 to $1.15 per pound U_3O_8, depending on ore grade and mining conditions. The cost of meeting 1971 radiation exposure standards has been taken into account in the production cost projections.

No land reclamation costs beyond the cost of current industry practice have been included in the production cost projections. The cost of meeting land reclamation requirements in open pit mining could increase the cost of uranium as calculated here from $0.10 to more than $1.00 per pound U_3O_8.

Nuclear Fuel Processing Requirements

At present, enrichment capacity exceeds current production requirements. Therefore, the three existing plants are able to preproduce and stockpile enriched uranium for future use. With the present enrichment capacity, preproduction plans, the AEC enrichment plant expansion program and the recently announced government plan to increase enrichment plant tails assay to 0.275-percent U_{235} or higher which will utilize the Government's natural uranium stockpile, the three enrichment plants will have sufficient capacity to meet the demand for enriched uranium until 1980 for Case I and 1985 for Case IV. For Case III, a new, fourth enrichment facility will be required by 1982. Because the lead times for construction of a new enrichment facility may be as much as 9 years, a decision is needed in 1973 to implement plans for construction if private industry is to build the next plant under Case III conditions. Under Case I, a new enrichment plant construction program would have to be part of the overall government/industry effort directed at emergency expansion of nuclear facilities.

Excess capacity now exists in all other fuel processing sectors, including conversion, fuel fabrication, transportation, spent fuel reprocessing and the storage of wastes. However, as with nuclear generation plants, regulatory delays could prove to be inhibiting. The orderly development of additional nuclear fuel processing capacity depends on reasonable and timely regulatory action.

Nuclear Fuel Costs

Nuclear fuel costs (in constant 1970 dollars) are expected to be in the range of $0.18 to $0.20 per million BTU's in 1985.

After allowing for the higher capital costs associated with building nuclear generating plants, the projected nuclear fuel cost places future nuclear power at a competitive break-even point with future fossil-fueled plants utilizing fuels costing $0.40 per million BTU's or higher. The lower break-even cost assumes the use of coal with stack gas desulfurization. There are substantial differences in this break-even value for comparative oil, coal and natural gas plants.

Table 115 is the breakdown of a typical 1,000 MWe pressurized water reactor (PWR) fuel cycle cost.

A significant increase in uranium costs would not materially affect the competitive position of nuclear generated electricity. For example, if the

TABLE 115

FUEL CYCLE COSTS FOR TYPICAL 1,000 MWe (BASE-LOAD) PWR

Fuel Cycle Components	Cost (Mills/KWH)
Fabrication (@ $70 /kg U)	0.40
Uranium (@ $8/lb. U_3O_8)	0.66
Conversion (@ $2.52/kg)	0.08
Enrichment (@ $32/SWU)	0.80
Reprocessing & Shipping (@ $45/kg U)	0.14
Plutonium Credit (@ $7.50/g)	(0.15)
Total Fuel Cycle Cost	**1.93**

"price" of U_3O_8 doubled from $8 to $16 per pound, the fuel cycle cost would be increased by 0.66 mills per KWH, and this amount would produce only a less than 10-percent increase in the cost of nuclear generated electricity.

Capital Expenditures

Capital expenditures for the nuclear fuel supply industry are estimated to range from $6.7 billion (Case IV) to $13.1 billion (Case I) over the 1971-1985 period.

Nuclear Power Growth

Background

The Initial Appraisal of the nuclear energy outlook for the period 1971-1985 was made under the basic assumption that the government policies and economic climate prevailing in 1971 would continue without major changes throughout the period. Installed nuclear power capacity was projected to reach 300,000 MWe in 1985.

This report examines the conditions under which an increased portion of U.S. energy requirements could be supported by domestic nuclear fuels, taking into consideration certain factors which might affect this capability. Four projections of nuclear power growth representing slow, medium, fast and maximum rates were prepared. These projections were then examined in light of the resulting (1) uranium resource availability, (2) uranium exploration and production requirements, (3) government policies, and (4) economic factors.

In projecting nuclear fuel demand, it was assumed that commercial use of nuclear fuel will be confined to the electric utility industry. While nuclear fuel may also be used to provide some process heat by 1985, this use was assumed to be negligible relative to the overall demand for nuclear fuel.

There are three types of commercial nuclear reactors available in the United States today: (1) the PWR, (2) the boiling water reactor (BWR), and (3) the high-temperature gas-cooled reactor (HTGR). The PWR and BWR use uranium fuel with water serving as the primary coolant, and as such they are called light-water reactors (LWR). The HTGR is fueled with uranium and thorium with helium serving as the primary coolant.

Commercial fast breeder reactors are projected to begin operation in the United States in the 1986-1990 period. The development of breeder reactors will allow an increase in the utilization of the energy content of natural uranium from between 1 and 2 percent (as is now achieved in non-breeder reactors) to about 60 to 70 percent.

Nuclear electric power today depends largely on fission of the uranium isotope U_{235} in a reactor to create the heat necessary to produce the steam that drives a steam turbine. The use of nuclear fuels differs substantially from fossil fuels in two important ways:

- Prior to use in an electric utility, uranium must undergo a complex series of processing steps to produce fuel elements that are used within the nuclear reactor.
- Nuclear fuels are not completely expended when used for the first time in a reactor but are removed, purified, replenished and refabricated periodically.

These unique characteristics establish a "fuel cycle," which can be described broadly as consisting of the steps of exploration, mining, milling, conversion, enrichment, fuel fabrication, fuel recovery and reprocessing, transportation and waste disposal. The fuel cycle is illustrated in Figure 66.

Uranium as it is found in nature contains about 0.7 percent of the isotope U_{235} with the remainder being the isotope U_{238}. Through the process of enrichment which is accomplished in the AEC's gaseous diffusion plants, the percentage U_{235} is increased to 2 to 3 percent which is required in the LWR's. The isotope U_{238}, which comprises 97 to 98 percent of the enriched uranium fuel, can contribute significantly to power production only after it is transformed into a fissionable isotope of plutonium (Pu) within the reactor. This plutonium then adds to the supply of heat.

HTGR's use highly enriched uranium (approximately 93-percent U_{235}) as the fissile fuel and thorium as the fertile fuel.* In the HTGR, the thorium is converted to the fissionable isotope U_{233} which adds to the supply of heat.

At approximate annual intervals, 25 to 35 per-

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* Fissile fuels such as U_{233}, U_{235} and Pu_{239} are those which undergo fission; fertile fuels such as thorium and U_{238} absorb neutrons to produce a fissile fuel (U_{233} and Pu_{239} respectively).

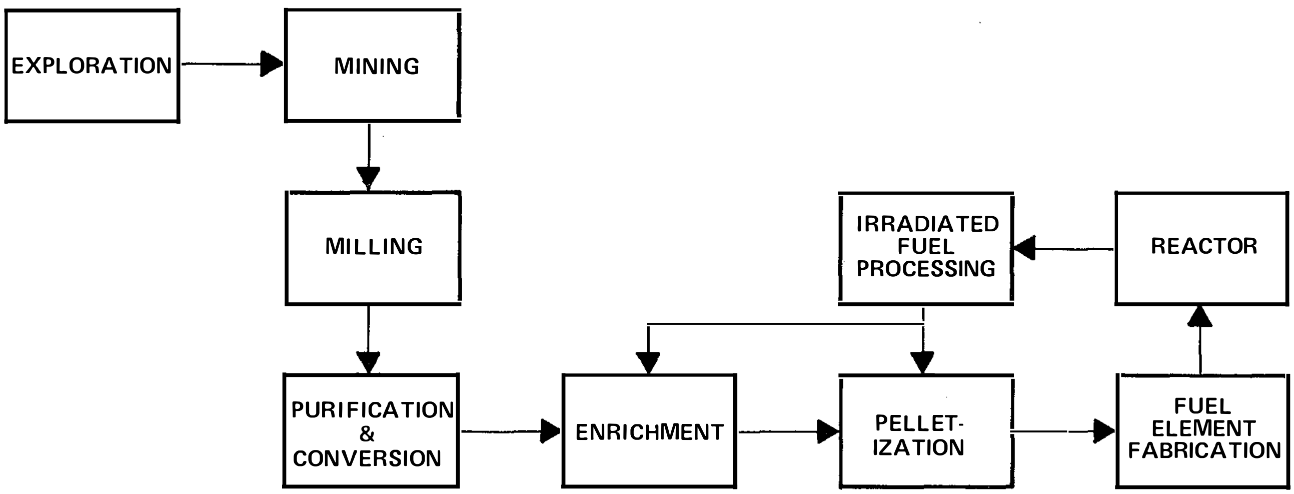


Figure 66. Nuclear Fuel Cycle.

cent of the fuel assemblies are removed from the reactor because the fuel is depleted in U_{235} content to the point that, coupled with a buildup of fission products, fuel cycle economics are adversely affected. The depleted fuel is then shipped to a reprocessing plant. There it is treated chemically either to dissolve and recover plutonium and unutilized uranium from LWR's or unutilized uranium from the HTGR. Both recovered elements have value and may be used as reactor fuel again, thus completing the fuel cycle. The recovered plutonium may be stored for future use as fuel in a breeder reactor or it may be recycled in fuel for LWR's as a substitute for U_{235}. The recovered U_{235} is recycled into fuel for LWR's, and the recovered U_{233} from the HTGR fuel is recycled into HTGR fuel in place of U_{235}.

Nuclear Power Projections

The Initial Appraisal adopted the 1971 AEC estimates of nuclear electric power growth and uranium requirements through 1985. In the present study, the nuclear power growth was reexamined with emphasis on variations in this growth as a function of alternative assumptions.

In evaluating the possibilities for greater domestic supply of nuclear energy, projections of nuclear electric power growth up to the year 1978 were based on scheduled operation dates for electric utility plants under construction and on order as of October 1971.* From this new base, three projections of electric load growth were developed to 1985: 450,000, 375,000 and 300,000 MWe of installed nuclear capacity for Cases I, II and III respectively (see Table 116). A fourth projection was made to take into account the possibility of a very substantial slowing of nuclear plant additions through 1980 and a continuing lag through 1985, resulting in limiting installed capacity to 240,000 MWe through 1985 (see Table 116, Case IV).

The four cases were then further projected to the year 2000 in order to establish the requirements for exploration and the development of forward reserves of natural uranium through 1985 and to analyze trends in demand for and supply of nuclear energy to the end of the century. Levels of installed MWe utilized to develop U_3O_8 requirements beyond 1985 are also shown in Table 116. These MWe capacity figures were converted to BTU's and KWH's and are shown in Table 117. Following is a general description of the four cases projected through 1985.

Case III assumes an orderly growth of nuclear power production tied to the projected growth of

* This projection was based on the Edison Electric Institute's (EEI) compilation of nuclear plant schedules. The AEC has subsequently published an estimate of expected nuclear power growth which shows a slightly lower rate of installation through 1978. However, the effect on nuclear fuel demand projections of using the more recent AEC data rather than the EEI data would be minor.

TABLE 116

PROJECTED NUCLEAR CAPACITY
(1,000 MWe)

	Initial Case	Case I			Case II			Case III			Case IV		
	Thermal*	Total	Thermal	FBR†	Total	Thermal	FBR	Total	Thermal	FBR	Total	Thermal	FBR
1972	19	22	22		22	22		22	22		11	11	
1973	32	38	38		38	38		38	38		16	16	
1974	46	55	55		55	55		55	55		22	22	
1975	59	64	64		64	64		64	64		28	28	
1976	73	71	71		71	71		71	71		38	38	
1977	89	89	89		89	89		89	89		51	51	
1978	108	108	108		108	108		108	108		68	68	
1979	128	140	140		140	140		128	128		87	87	
1980	150	188	188		188	188		150	150		107	107	
1981	173	227	227		216	216		173	173		128	128	
1982	199	269	269		250	250		200	200		152	152	
1983	230	320	320		288	288		230	230		179	179	
1984	263	380	380		328	328		263	263		209	209	
1985	300	450	450		375	375		300	300		240	240	
1990		750	675	75	625	560	65	500	450	50	400	395	5
1995		1,065	795	270	890	665	225	710	530	180	568	463	105
2000		1,470	900	570	1,225	750	475	980	600	380	785	495	290

* Thermal includes light-water and high-termperature gas-cooled reactors.

† FBR means fast breeder reactor. For purposes of calculation of U_3O_8 requirements, the breeder reactor was assumed to be put in commercial use as follows: Cases I and II—5,000 MWe in 1986; Case III—4,000 MWe in 1986; Case IV—5,000 MWe in 1990. Breeders were assumed to be of 1,500 MWe size and to have a fuel doubling time of 8 to 10 years. A parametric study has also been prepared assuming that the breeder will enter into commercial use more slowly, beginning at a level of 1,000 MWe in 1987 and growing to only 5,000 MWe in 1990, 44,000 in 1995 and 254,000 in the year 2000 (see text).

total electric power capacity. This is a "medium" nuclear energy demand case and closely approximates the AEC's "most likely" case. In this case nuclear plants will come on line with gradually increasing frequency resulting from improvements in manufacturing techniques and administrative procedures. The current licensing and legal problems are expected to be largely resolved during the next 2 or 3 years. The lead time required from order to plant operation drops to 6 or 7 years from the present 8 years or more. Because of their economics and general characteristics, nuclear plants comprise a majority of the large or base-load plant additions.

Case II assumes that, in addition to the situation described under Case III, a marked preference develops for nuclear plants over fossil-fueled plants because of increasingly stringent air pollution regulations and limited availability of clean fossil fuels. This case further assumes licensing procedures are streamlined and environmental problems are resolved without delays.

Case I assumes that both government and industry join in a maximum effort to increase U.S. nuclear power capacity. This could be the result of a national energy policy which makes nuclear power a first priority national goal or the existence of emergency conditions which require such an

TABLE 117

NUCLEAR ENERGY PROJECTIONS TO THE YEAR 2000

	Case I				Case II				Case III				Case IV			
	Thermal MWe (000)	FBR MWe (000)	KWH* x 10^9	BTU† x 10^{12}	Thermal MWe (000)	FBR MWe (000)	KWH x 10^9	BTU x 10^{12}	Thermal MWe (000)	FBR MWe (000)	KWH x 10^9	BTU x 10^{12}	Thermal MWe (000)	FBR MWe (000)	KWH x 10^9	BTU x 10^{12}
1972	22		96	983	22		96	983	22		96	983	11		72	736
1975	64		390	4,000	64		390	4,000	64		390	4,000	28		162	1,661
1980	188		1,107	11,349	188		1,107	11,349	150		955	9,787	107		662	6,788
1985	450		2,908	29,810	375		2,463	25,249	300		1,973	20,220	240		1,573	16,126
1990	675	75	4,981	49,348	560	65	4,147	41,059	450	50	3,323	32,902	395	5	2,674	26,726
1995	795	270	7,180	69,782	665	225	6,144	59,566	530	180	4,788	46,523	463	105	4,061	37,521
2000‡	900	570	9,986	95,356	750	475	8,322	79,461	600	380	6,657	63,569	495	290	5,330	51,046

* All nuclear units are assumed to be operated as base-load plants reaching capacity factors of 80 percent after a few years of operation. When nuclear capacity exceeds the base-load requirements (after 1990), some nuclear plants are assumed to operate at a lower capacity factor.

† Equivalent input BTU's were calculated using the following heat rates:

LWR & HTGR	1970-1985	10,250 BTU/KWH
	1985-2000	10,000 BTU/KWH
FBR	1985-2000	8,800 BTU/KWH

‡ Case I includes the MWe (000) equivalent of about 5-percent utilization of nuclear energy for process heat. If this is used as process heat, electrical output would have to be reduced accordingly.

effort. Such a policy might result from both very stringent air pollution standards and a need to limit the use of oil and gas for electrical power production in order to minimize the U.S. dependence on imported fuels.

Case IV assumes that environmental constraints, manufacturing and technical problems of more than a routine nature, and regulatory difficulties all continue to cause planning and construction delays such that only the plants already on order in 1971 will go into operation by 1980. Under Case IV, nuclear plant completions pick up after 1980, but the installed capacity by 1985 falls 20 percent short of Case III.

Factors Bearing on Nuclear Power Growth

The growth rate for installation of nuclear power plants will be influenced by a number of factors over the next 15 years. Many of these factors—such as site selection, availability of construction labor, and certain environmental factors—are common to all electric power plants and are discussed in Chapter Eleven of this report. There are, however, several key factors that will bear uniquely on the growth of nuclear power generating capacity.

Plant Site Requirements

The AEC regulates the location, design and operation of the nuclear power plants. AEC guidelines have been issued which specify the criteria for plant location and land requirements. Natural characteristics important to the integrity of the plant are taken into consideration and, therefore, certain factors at the proposed site such as seismology, geology, hydrology and meteorology are evaluated by the AEC before the site is approved. The maximum foreseeable sites required for plants completed by 1985 would be 300. This assumes an average station size of only 1,500 MWe in 1985. The magnitude of this requirement is not to be minimized but it should be considered in perspective by noting that the existing U.S. electric generating capacity of about 350,000 MWe for plants of all types (fossil and nuclear) is located on more than 3,000 separate sites. Some of these existing sites will be able to accommodate new nuclear units. Furthermore, the concept of preassembled, platform-mounted, large nuclear plants located on water has been introduced by several manufacturers. This technique has promise of expanding the number of available sites.

Nuclear Plant Licensing

AEC regulations require that a utility obtain a construction permit prior to starting construction of a nuclear plant and an operating license before beginning commercial operation. These regulations have been recently revised to require a full environmental review to meet the requirements of the National Environmental Policy Act of 1969. In addition, utilities must obtain as many as 60 clearances or permits from the local, state and national government agencies that have asserted jurisdiction over various aspects of siting, construction and operation of major electric power facilities. Regulatory delays in obtaining the necessary clearances and permits as well as court challenges involving the revised environmental requirements have recently become a major obstacle to the growth of nuclear power. Such factors have delayed the planned operating date of most of the nuclear plants that have been announced, are presently under construction or, in some cases, are actually ready for full power operation. Primarily as a result of such delays, the lead time from order to completion of a new nuclear plant has increased to 8 years or more. The degree to which nuclear growth rates might increase in the latter part of the 1971-1985 period will depend substantially on the ability of industry and government to develop effective plant siting and licensing procedures.

Environmental Considerations

While nuclear plants do not have particulate or gaseous pollutants from combustion, there are several potential environmental problems that are either unique to or are more accentuated for nuclear plants. These include—

- Radioactivity release to the environment in the form of radiation, airborne radioactivity and radioactive liquids: Potential exposure from these sources has been calculated to be well below the normal medical and diagnostic X-ray exposures and even below exposure from the natural background. While the amounts of radioactivity released are very small, special systems and procedures and continuous monitoring are required to limit environmental exposure.
- Heat dissipation from cooling water: Light-water type nuclear power plants in use today require larger amounts of cooling water and discharge greater amounts of waste heat to the water than comparably sized fossil-fueled plants because (1) they are less efficient in the conversion of thermal energy to electricity and (2) they discharge all of their waste heat through the cooling water system whereas about 25 percent of the waste heat from a fossil-fueled plant is discharged through the stack. However, thermal discharges are not necessarily harmful to the environment. The effects of thermal discharges are dependent upon the specific location, natural water-body conditions and natural temperature ranges. In areas where increased temperature of the natural waters is potentially harmful, cooling facilities such as cooling ponds or cooling towers can be installed to minimize or completely eliminate these heat effects.
- Potential release of radioactivity as a result of accident conditions such as a malfunction of the emergency core cooling system (ECCS): Rule-making hearings are presently being conducted by the AEC regarding the adequacy of present ECCS design criteria. Further, a loss of fluid test will be conducted in the near future by the AEC to gather experimental data on reactor conditions affecting ECCS design in order to ensure adequate regulatory requirements.
- Low-level radioactive waste products resulting from normal operation of a nuclear plant: These wastes, collected by a radioactive waste treatment system, are placed in protective containers at the power plant for shipment to an AEC approved facility, where the container is buried. High-level wastes are also created within the fuel elements as a result of fission of the nuclear fuel. However, these wastes remain sealed within the fuel elements until the spent fuel is reprocessed at a separate location (discussed more fully in later sections, "Fuel Reprocessing" and "Waste Disposition").

Nuclear Fuel Costs

Within reasonable ranges, increases in nuclear fuel costs will not retard the growth of nuclear power as nuclear fuel represents only about 25 percent of the cost of generating electricity in a nuclear power plant. As shown in Table 118, for a typical base-load PWR, nuclear fuel amounts to about 1.9 mills per KWH out of a total electricity generating cost of 9 to 11 mills per KWH.

TABLE 118

COST OF ELECTRIC POWER FROM 1,000 MWe (BASE-LOAD) PWR

Fuel Cycle Components	Cost (Mills/KWH)
Fabrication (@ $70/kg U)	0.40
Uranium (@ $8/lb. U_3O_8)	0.66
Conversion (@ $2.52/kg)	0.08
Enrichment (@ $32/SWU)	0.80
Reprocessing & Shipping (@ $45/kg U)	0.14
Plutonium Credit (@ $7.50/g)	(0.15)
Total Fuel Cycle Cost	**1.93**
All Other Costs (New Plants)	7.00-9.00
Total Electric Power Cost	**9.00-11.00**

As a result of nuclear fuel's relatively small contribution, total power costs are not very sensitive to a relatively large change in fuel costs. For example, if uranium prices were to double from $8 to $16 per pound U_3O_8, power costs would increase less than 10 percent. A 20-percent increase in the cost of enrichment services would increase power costs only about 2 percent. The total fuel cost of about 1.9 mills per KWH shown in Table 118 is equivalent to about $0.18 per million BTU's. It is expected that fuel costs will remain in the range of $0.18 to $0.20 per million BTU's through 1985.

Capital Costs of Nuclear Power Plant

As long as licensing procedures are prolonged and safety and environmental requirements continually change and become more stringent, the capital cost of nuclear power plants will very likely increase, even on a constant dollar basis. When the influence of these factors and basic engineering design stabilize, the major cause of future cost increases will be inflation and wage escalation. Many of these same factors will, of course, cause increases in the capital cost of all electric power generation plants to some degree.

On a comparative basis, nuclear power plants are expected to be more expensive to build than comparable fossil-fueled plants during the time period under consideration in this study.* However, the high capital cost of nuclear power can be more than offset, over the long term, by the relatively low cost of nuclear fuel, and therefore, it is not necessarily the controlling factor in a decision to expand nuclear power. Caution must be exercised in applying this general observation because conditions affecting both capital costs and fuel costs can vary considerably in different areas of the United States.

Industry's Ability to Supply Necessary Equipment and Construction Capability

A 6- to 7-year order lead time is adequate to adjust manufacturing capacity to meet demand in all areas of nuclear plant equipment supply. Generally, the items with the longest lead times—requiring as much as 5 to 6 years each—are the turbine generator and the pressure vessel. For the long term, the construction industry's capability to build nuclear power plants is dependent upon its having highly qualified personnel both to design and to staff field construction activities. Recent experience indicates that this should not be a major obstacle in the path of nuclear power growth. Design difficulties have diminished as the industry has gained experience, and the quality of construction required by the exacting specifications has proved to be well within the skills of good craftsmen. Therefore, the problem of the availability of

* Electric utility capital investment requirements for the period through 1985 shown in this report were developed by the Electricity Task Group, which utilized a capital cost factor for nuclear plants of $300/KW for committed capacity and $400/KW for uncommitted capacity. Capital cost factors for fossil-fueled plants range from $200/KW to $300/KW.

TABLE 119

REQUIREMENTS FROM INDUSTRY FOR URANIUM CONCENTRATE*
(1,000's Short Tons U_3O_8)

	Case I		Case II		Case III		Case IV	
	Annual	Cumul.	Annual	Cumul.	Annual	Cumul.	Annual	Cumul.
1972	12.3	12.3	12.3	12.3	12.3	12.3	5.1	5.1
1973	12.6	24.9	12.6	24.9	12.6	24.9	5.9	11.0
1974	13.7	38.6	13.7	38.6	13.7	38.6	8.2	19.2
1975	19.1	57.7	19.1	57.7	19.1	57.7	11.5	30.7
1976	22.0	79.7	22.0	79.7	21.7	79.4	14.6	45.3
1977	28.0	107.7	28.0	107.7	23.5	102.9	18.1	63.4
1978	39.2	146.9	38.9	146.6	27.7	130.6	21.8	85.2
1979	44.4	191.3	40.9	187.5	31.6	162.2	24.9	110.1
1980	50.9	242.2	45.6	233.1	36.5	198.7	29.1	139.2
1981	71.7	313.9	62.9	296.0	48.4	247.1	39.3	178.5
1982	84.2	398.1	69.4	365.4	54.4	301.5	44.8	223.3
1983	96.3	494.4	76.7	442.1	61.2	362.7	50.2	273.5
1984	100.0	594.4	82.3	524.4	66.2	428.9	54.9	328.4
1985	108.5	702.9	89.2	613.6	70.7	499.6	60.4	388.8

* The Initial Appraisal U_3O_8 demand estimates were based on a tails assay of 0.20-percent U_{235} with plutonium recycle starting in 1974. The corresponding assumptions for Cases I through IV are: 0.20-percent U_{235} tails assay through 1981 and 0.275-percent tails thereafter; 60 percent of the Pu produced in LWR's recycled beginning in 1978. These quantities exclude U_3O_8 supplied from the government stockpile in accordance with the government plan announced March 7, 1972. For further discussion see "Analytical Method and Assumptions," "Uranium Production" and "Nuclear Fuel Processing" sections of this chapter. For comparative purposes U_3O_8 production for the year 1970 was 12.9 thousand tons.

qualified construction labor can be considered in the broader context of the requirements for all power plants rather than solely for nuclear power plants.

Nuclear Resources

While domestic uranium resources are expected to be adequate to supply the U.S. requirements to meet demands beyond 1980, additional uranium discoveries will be needed. In view of the long lead times required from exploration to production, converting these resources to economically recoverable reserves will require that the recent decrease in uranium exploration activity be reversed in the near future. A growing, aggressive exploration program can be achieved only with sound government policy and improved economic incentives, such as long-range uranium purchase contracts and uranium prices which cover the costs of discovery, development and production, and a reasonable rate of return on investment.

Uranium Resource Requirements—1971-1985

The Initial Appraisal accepted the AEC estimates of proved uranium reserves plus potential uranium resources as a basis for evaluating their adequacy to supply the growth in domestic nuclear electric power to 300,000 installed MWe in 1985. Given appropriate economic incentives, the uranium resource position of the United States appeared adequate with respect to low cost uranium to supply the related cumulative U.S. requirement for 450,000 tons of U_3O_8.

The current study evaluates the requirements for nuclear fuels needed to support increased growth rates of nuclear power over and above the rate projected in the Initial Appraisal. It also addresses the possibility of a reduced growth rate for nuclear

TABLE 120

DOMESTIC RESOURCES OF URANIUM AS ESTIMATED BY AEC—JANUARY 1, 1972

Cost of Production* ($ per Pound)	Tons of U_3O_8 (Cumulative) Reasonably Assured (Proved Reserves)	Estimated Additional (Potential Reserves)	Total
$ 8 (or less)	273,000	460,000	733,000
$10 (or less)	423,000†	650,000	1,073,000
$15 (or less)	625,000†	1,000,000	1,625,000

* Based on the forward cost of production, not including amortization of past investments, interest or income taxes; also, no provision is made for return on investment; does not necessarily represent the market price.

† Includes 90,000 tons potentially recoverable as a byproduct of phosphate and copper mining at a cost of $10 per pound or less.

power. Estimated ranges of nuclear growth indicate cumulative uranium production requirements through 1985 ranging from 400,000 tons of U_3O_8 in Case IV (low case) to 700,000 tons in Case I (maximum case). The production requirement for Case II (high case) is estimated at 600,000 tons, and for Case III (medium case), it is near 500,000 tons. Table 119 illustrates U_3O_8 demand on an annual basis for each of the four cases.

Uranium Resources Available—1971-1985

The AEC estimates uranium reserves in the United States as of January 1, 1972, available at a cost of production not to exceed $15 per pound of U_3O_8, to be 625,000 tons of reasonably assured (proved) resources plus 1 million tons of estimated additional (potential) resources (see Table 120).* The potential resources are located primarily in and around the known uranium producing districts. The AEC estimates of resources available at $15 per pound of U_3O_8 are thus in excess of all the projected demands through 1985 and are sufficient to provide substantial forward reserves in all demand cases. However, it should be recognized that well over half of this material remains to be found and that, at current costs of $8 per pound or less for U_3O_8, existing underground mining operations are not recovering low-grade ores which have been adjudged to be capable of yielding U_3O_8 at costs in the range of $8 to $15 per pound. Once these ores have been bypassed during the initial mining operation, the likelihood of recovering the remaining U_3O_8 for $15 per pound or less, in many mines, is very small.

The comparison of AEC estimates of available uranium resources at various cost levels to the uranium requirements for power plants is misleading for several reasons:

- The AEC selection of cost levels ($8, $10 and $15 per pound of U_3O_8) cannot be directly compared with "prices" as calculated in this study since the AEC does not include a return on investment or certain other costs such as interest, income tax or amortization of past investment in exploration and mine/mill construction.
- Present facilities do not have the capacity to produce the uranium required. Additional facilities must be constructed.

* *Reasonably assured resources* refers to uranium which occurs in known ore deposits of such grade, quantity and configuration that it can, within the given cost range, be recovered with currently proved mining and processing technology. Estimates of tonnage and grade are based on specific sample data and measurements of the deposits and on knowledge of ore-body habit.

Estimated additional resources refers to uranium surmised to occur in unexplored extensions of known deposits or in undiscovered deposits in known uranium districts, and which is expected to be discoverable and exploitable in the given AEC cost range. The tonnage and grade of estimated additional resources are based primarily on knowledge of the characteristics of deposits within the same districts.

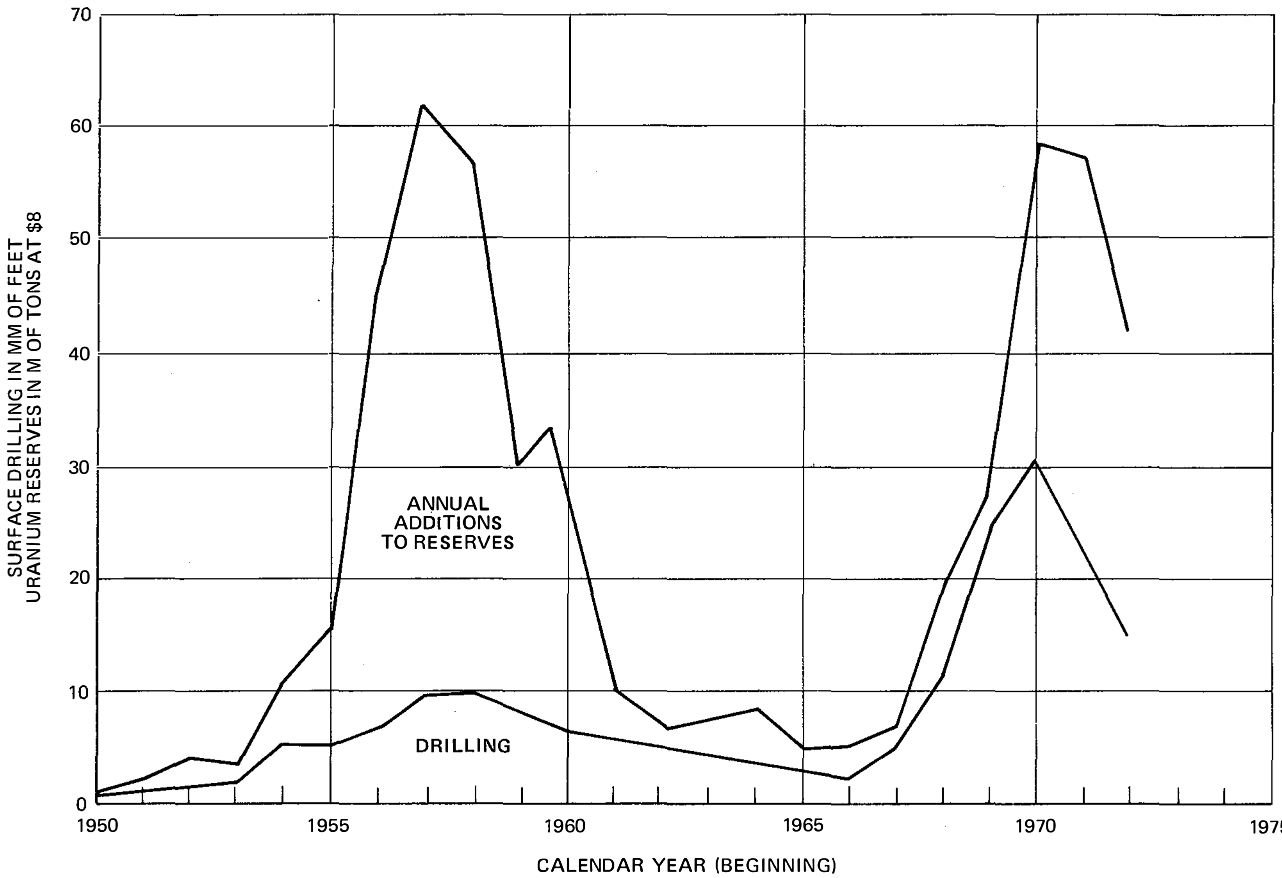


Figure 67. Annual Surface Drilling and Reserve Additions (Based on AEC Data).

- Extensive exploration and development drilling are necessary to bring the estimated additional reserves into the reasonably assured category.

Due to the lead times (8 to 10 years) required from initiation of the exploration program until the first production of uranium, exploration for new deposits must be under way in the near future if it is to have any impact on uranium supply during the 1980-1985 period. With a prevailing market price of less than $8 per pound of U_3O_8, major efforts have not been made recently to do extensive exploration for or to develop low-grade uranium deposits. "Price" projections shown in this report indicate that a range of roughly $9.00 to $12.50 per pound—based on average production costs—is necessary to provide a rate of return on investment of 10 to 20 percent. However, the risk inherent in exploration ventures makes the higher rate of return essential if the necessary drilling effort is to be undertaken.

Uranium Exploration Activity

Historically, the uranium industry has twice demonstrated the capability to add substantially to reserves of uranium ore through an increased exploration effort (see Figure 67). Over the last 10 years—during which total footage drilled rose from 2.1 million feet per year to 30 million feet per year in a 4-year period—the discovery rate averaged about 4 pounds of U_3O_8 per foot drilled. Exploration effort declined sharply after 1969 as market incentive decreased. However, this past industry performance and the potential of partially explored areas alone support the conclusion that adequate reserves can be developed to meet production requirements through 1985 if appro-

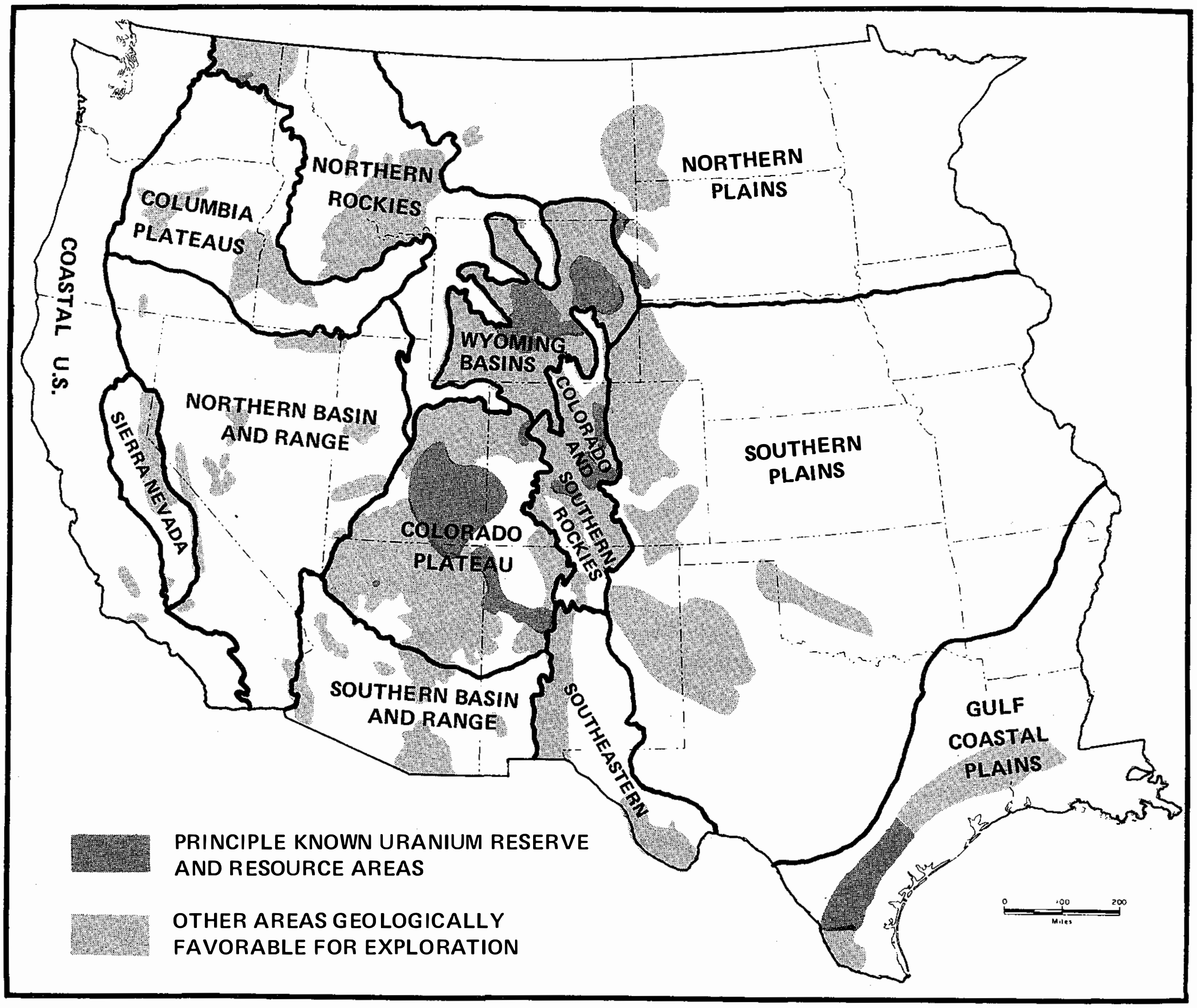


Figure 68. Uranium Resources—Western United States.

priate incentives to step up exploration activity exist.

Potential Uranium Resources

In the Future Petroleum Provinces report of the National Petroleum Council, quantitative estimates of speculative potential resources have been made as a result of a comprehensive assessment of the petroleum potential of the entire United States, including its offshore regions. No such extensive assessment has yet been made of the potential for uranium, and such a study was considered beyond the scope of this report. Nevertheless, such potential resources must be taken into account in assessing the capability of U.S. industry to discover such reserves and to produce additional domestic uranium from them at costs of production less than $15 per pound.

The published AEC estimate of "additional resources" of U_3O_8 is not an attempt to measure either the ultimate uranium resources in this country or the total recoverable resources at the costs indicated and should not be so interpreted. The AEC additional resource estimate is related to specific known uranium mineralization and geological trends and, as such, is subject to change from time to time as new information is developed.

Ninety-five percent of the uranium discovered in the United States is in sedimentary rocks, principally sandstone. While new types of deposits are expected, the sandstone type will probably provide the basis for the U.S. uranium industry in the future, at least in the lower price range. Most of the uranium occurrences in sedimentary rocks in the United States have been found in a 450,000 square mile region of the western United States (see Figure 68).

Substantially all of the reasonably assured reserves and approximately 85 percent of the estimated additional resources are located in the present producing areas. Much of the recent drilling (85 to 90 percent) has been concentrated in and around these producing areas. These areas, which make up less than 10 percent of the total region in which uranium occurrences are found, are still not completely explored. Exploration drilling in other regions has been limited because there has been little reason to conduct wildcat exploration while adequate opportunities for the discovery of new reserves still exist in the known districts.

In the future, it will become necessary to explore outside the present producing areas. There is every reason to assume that significant additional deposits of uranium will be discovered.

Nearly 50 percent of the estimated proved and potential resources are located on the public domain. Exploration for uranium on the public domain, and production therefrom, is accomplished under the federal mining laws. If access to the public domain were to be substantially restricted, the availability of uranium resources would be reduced proportionally.

Thorium

Available thorium resources in the United States are more than adequate to meet projected demands for thorium oxide, and thus there is little incentive or need for exploration for new deposits. Production capabilities for commercial and nuclear grade thorium oxide are more than adequate for today's demand. However, in order to meet requirements for nuclear grade thorium oxide from domestic resources through the year 2000, production capacity must be added.

Utilization of thorium as a nuclear fuel in HTGR's could result in a lowering of demand for U_3O_8 by 5 to 10 percent after 1985.

Uranium Supply Analysis

Analytical Methods and Assumptions

The basic approach used in analyzing the uranium supply requirements involved the following steps:

- Establishing a range of nuclear power growth projections
- Computing the resulting nuclear fuel demand
- Determining the ability of the industry to satisfy nuclear fuel demand.

Two computer programs were used in projecting the key elements of nuclear power supply. The "uranium demand program" used in projecting uranium demand and separative work requirements was provided to the Nuclear Task Group by the AEC's Office of Planning and Analysis. This program was used to "test" the effect on demand utilizing various assumptions regarding nuclear generating capacity growth and a wide range of nuclear power plant and fuel cycle operating parameters.

The calculation of uranium demand started with a projection of the annual additions to the nuclear capacity of each reactor type through the year 2000. Initial fuel core characteristics of these reactors were combined with specified lead times for various fuel cycle services to project annual requirements for initial core fuel processing and supply. Operating characteristics were used with uranium and plutonium recycle projections and reprocessing lead times to calculate the various fuel cycle requirements for replacement fuel. These were then added to the projection of the initial core requirements to provide annual schedules of requirements for natural uranium and separative work. The calculations were repeated with various key parameters being assigned different values in order to test the sensitivity of the projected demand schedules to these parameters.

The second program, the "uranium supply program," was constructed by the Nuclear Task Group to study the variables affecting uranium supply. This program was designed to be used in conjunction with the demand program and to utilize data derived from detailed information on uranium production capability maintained by the AEC. It provided three types of data:

- Estimates of operating requirements for the uranium raw materials industry
- Projections of capital expenditures and operating costs in the uranium raw materials industry
- Uranium "prices" calculated to provide a specified DCF rate of return on projected investments. The levelized U_3O_8 "prices" with a given return on investment calculated in the program are based on average production costs. Therefore, the lower cost production centers will earn greater than average returns when selling at the levelized "price" while the higher cost production centers will be earning much lower than average returns.

In order to analyze the U.S. uranium supply capability, including both ore reserves and required facilities, five reserves/facility classifications of production (mining and milling) were utilized:

- Class 1: Existing production centers* and associated reserves
- Class 2: Production centers under construction and associated reserves
- Class 3: Possible future production centers justified by defined reserves
- Class 4: Possible future production centers justified by partially explored and potential reserves
- Class 5: Production from future discoveries (no production center identified).

The uranium supply program contains numerous assumptions concerning lead times, investment requirements and operating costs for future uranium supplies. These assumptions were based on detailed estimates of present domestic uranium resources and production costs that are maintained by the AEC. The major cost and lead time assump-

* Exploration and cost data maintained by the AEC on U.S. uranium reserves and production capability were considered in designing the supply model. The AEC utilized the concept of a "production center" to develop data for Classes 1-4. A production center consists of a mill and its supporting mines and available resources.

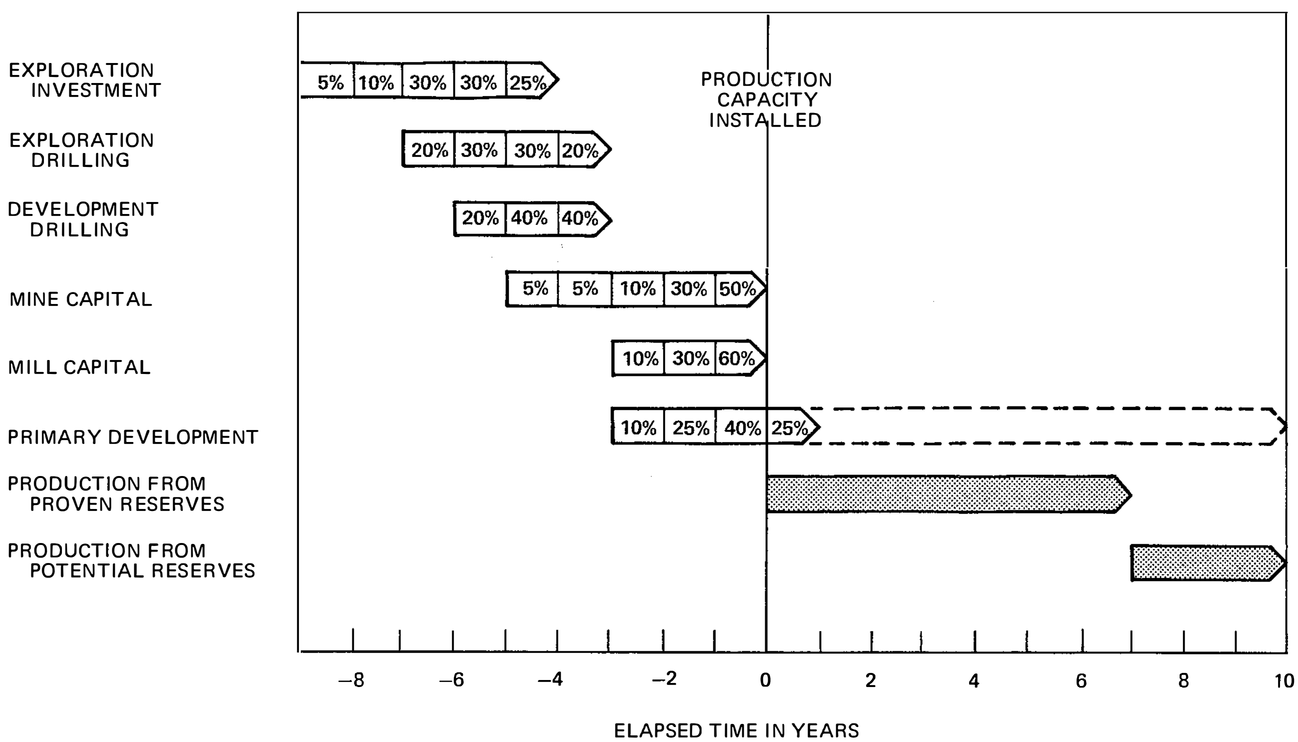


Figure 69. Uranium Exploration and Development Lead Times and Expenditures.

TABLE 121

NEW URANIUM PROPERTY INVESTMENT AND OPERATING EXPENSE

Exploration	Reserve Additions $/lb. U_3O_8 Indicated and Inferred Resources	
Land Costs	0.10	
Exploration Drilling	0.60	
Development Drilling	0.20	
Total	**0.90**	
Capital	**$/lb. U_3O_8 Annual Production Capacity**	**$/lb. U_3O_8 Produced**
Mine Construction	1.10	0.110
Mill Construction	4.25	0.425
Mine Development	—	0.900
Operating Expense	**$/lb. U_3O_8 Produced**	
Equipment Replacement	0.15	
Total Direct and Indirect	4.35	

tions used are shown in Figure 69 and Table 121.

In addition the following assumptions were used in the supply analysis:

- Discovery Rate: In calculating each of the four basic cases, a discovery rate of 4 pounds U_3O_8 per foot of total surface drilling was assumed. However, the sensitivity of exploration requirements and calculated "prices" to discovery rates ranging from 2 to 6 pounds U_3O_8 per foot was also tested in various parametric studies.
- Reserves/Production Ratio: For each of the basic cases, it was assumed that prior to placing a Class 5 property into production an R/P of 7.0 would be required. It was also assumed that additional reserves would be found during the first year of mine operation, thereby increasing the overall R/P to 10.0. In addition, a parametric study was utilized which investigated the effect on uranium reserve requirements and prices by changing the initial R/P from 7.0 to 5.0 and 9.0.
- Taxes: It was assumed in the basic cases that the present tax treatment for uranium exploration and production would continue. However, various tax alternatives were also investigated through parametric analysis.

Limitations

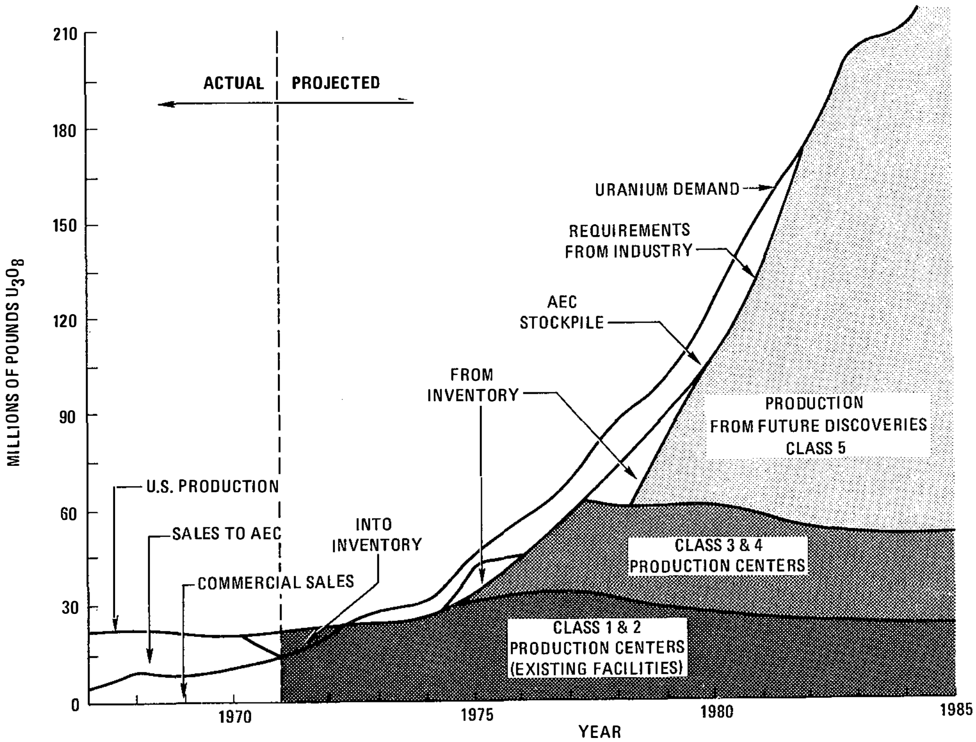
The supply program allows a fixed set of basic analytical projections to be made by simulation of the uranium raw material supply industry and provides for sensitivity testing of a wide range of influencing assumptions. It is not an econometric or price forecasting program.

Utilizing the standard DCF rate of return on investment procedure, the program simply computed a levelized "price" required over the assumed life of production centers in each production class which would provide a given return on investment. The calculated "price" had no influence on the projected level of production activity which was determined solely by the demand in the specific case considered.

Results

Uranium Production

For each of the four demand cases, estimates of annual U_3O_8 supply were calculated, as shown in Figures 70 through 73. Total U_3O_8 production from existing and new facilities through the year 1985 is shown in Table 119 and summarized in the following schedule.



NOTE: "Uranium Demand" quantities reflect an enrichment plant tails assay of 0.275 percent. "Requirements from Industry" reflect an enrichment tails assay of 0.20 percent through 1981 and 0.275 percent thereafter. See Table 119. Variations in supply from inventory are due to the utilization of a fixed pattern of future production from Class 3 and 4 production centers for all supply cases (I—IV).

Figure 70. Estimated Annual U_3O_8 Supply—Case I.

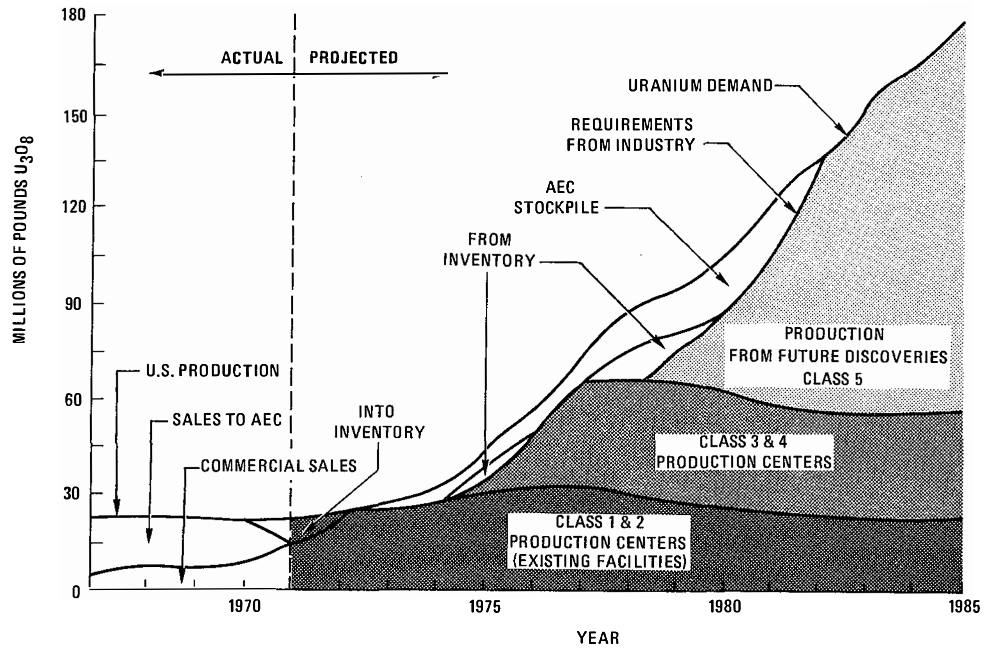
	Thousand Pounds U_3O_8			
	Case I	Case II	Case III	Case IV
U_3O_8 Production (1971-1985)	700	600	500	400

In Cases I and II, production from Class 3 facilities is required in 1975, from Class 4 facilities in 1976, and from yet undiscovered reserves in 1979. For Case III, which is characteristic of the most common nuclear growth forecast, production from Class 3 properties is needed in 1976 and from Class 4 in 1977, while production from new discoveries would not be needed until 1980. For Case IV, the low demand case, Class 3 production is not needed until 1979, Class 4 in 1980, and Class 5 would not be required until 1982.

Drilling and Discovery Requirements

Figure 74 shows the annual U_3O_8 reserve additions required in Case III. It is important to note that in this case, new discoveries must account for only 30 percent of reserve additions in 1972 but that this proportion increases to 80 percent by 1985. Figure 75 shows the supply program projection of surface drilling required per year for each case. It is obvious that a reversal of the recent downward trend in drilling activity is necessary even in the most pessimistic case. To achieve the Case I projection, the level of surface drilling experienced in 1971 must be doubled by 1973 while for Case II it must be doubled by 1974.

The significant increase in surface drilling during the second half of the 1970's is needed to locate new production centers that will be required to meet the substantial increases in U_3O_8 production projected for the 1980's. This peak in exploration and discovery requirements during the late 1970's is brought on by several factors affecting demand in the early 1980's: (1) the need to replace government stockpile deliveries with new production, (2) the retirement of existing production centers (Class 1) which must be replaced, and (3) the rapid market growth projected for the



NOTE: "Uranium Demand" quantities reflect an enrichment plant tails assay of 0.275 percent. "Requirements from Industry" reflect an enrichment tails assay of 0.20 percent through 1981 and 0.275 percent thereafter. See Table 119. Variations in supply from inventory are due to the utilization of a fixed pattern of future production from Class 3 and 4 production centers for all supply cases (I–IV).

Figure 71. Estimated Annual U_3O_8 Supply—Case II.

1980's. The subsequent decline in annual drilling is due to the leveling out in demand for uranium during the late 1980's as a result of fast breeder reactor introduction.

Investment Requirements

Between 1972 and 1985, cumulative uranium raw material investment is projected to range from \$3.7 to \$6.0 billion. A capital investment summary for Cases I through IV for the years 1972, 1975, 1980 and 1985 is shown in Figure 76. The pattern is cyclical with the emphasis being on exploration investment in the early period and mine/mill investment in the later period.

The decline in investment requirements after 1980 reflects (1) completion of the large buildup in production capacity which is needed to meet market requirements in the 1980-1985 period and (2) reduction in post-1985 uranium demand caused by the introduction of the breeder reactor.

Calculated Uranium "Price"

Using the detailed cost and lead time assumptions, a levelized uranium "price" was calculated to yield a specified return on invested capital. The "prices" for Cases I through IV are the same and are shown for future discoveries (Class 5) as follows:

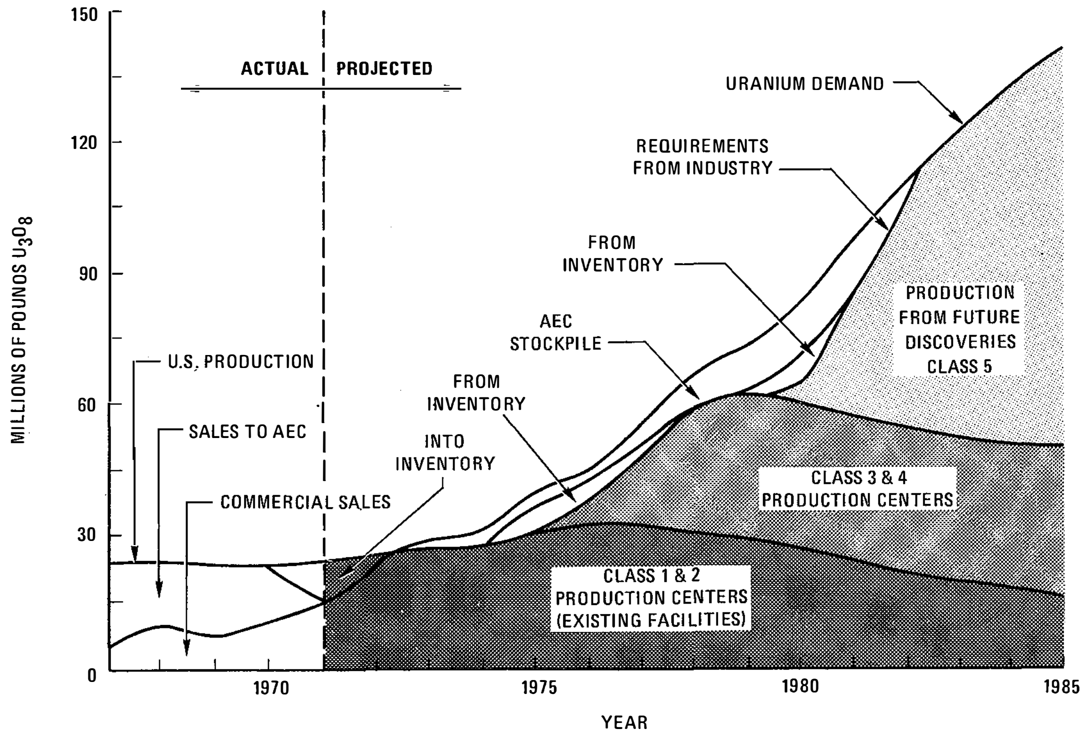
Return on Investment (Percent)	Levelized "Price" (\$/lb of U_3O_8)
10	8.91
12.5	9.59
15	10.37
17.5	11.27
20	12.39

Parametric Studies

A number of parameter variations were studied with the aid of the uranium supply program in order to identify those variables which have the most significant effect on the uranium supply and "price" calculations. The following are the most significant parametric studies.

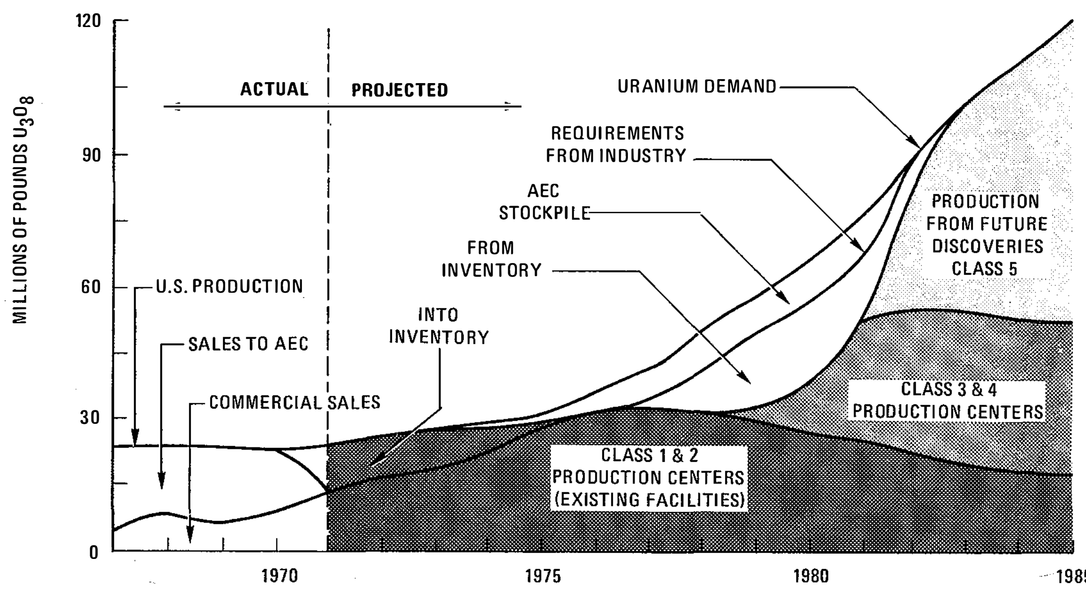
Discovery Rate

The magnitude of the exploration effort required to provide a given level of uranium supply is inversely proportional to the discovery rate. It



NOTE: "Uranium Demand" quantities reflect an enrichment plant tails assay of 0.275 percent. "Requirements from Industry" reflect an enrichment tails assay of 0.20 percent through 1981 and 0.275 percent thereafter. See Table 119. Variations in supply from industry are due to the utilization of a fixed pattern of future production from Class 3 and 4 production centers for all supply cases (I–IV).

Figure 72. Estimated Annual U_3O_8 Supply—Case III.



NOTE: "Uranium Demand" quantities reflect an enrichment plant tails assay of 0.275 percent. "Requirements from Industry" reflect an enrichment tails assay of 0.20 percent through 1981 and 0.275 percent thereafter. See Table 119. Variations in supply from industry are due to the utilization of a fixed pattern of future production from Class 3 and 4 production centers for all supply cases (I–IV).

Figure 73. Estimated Annual U_3O_8 Supply—Case IV.

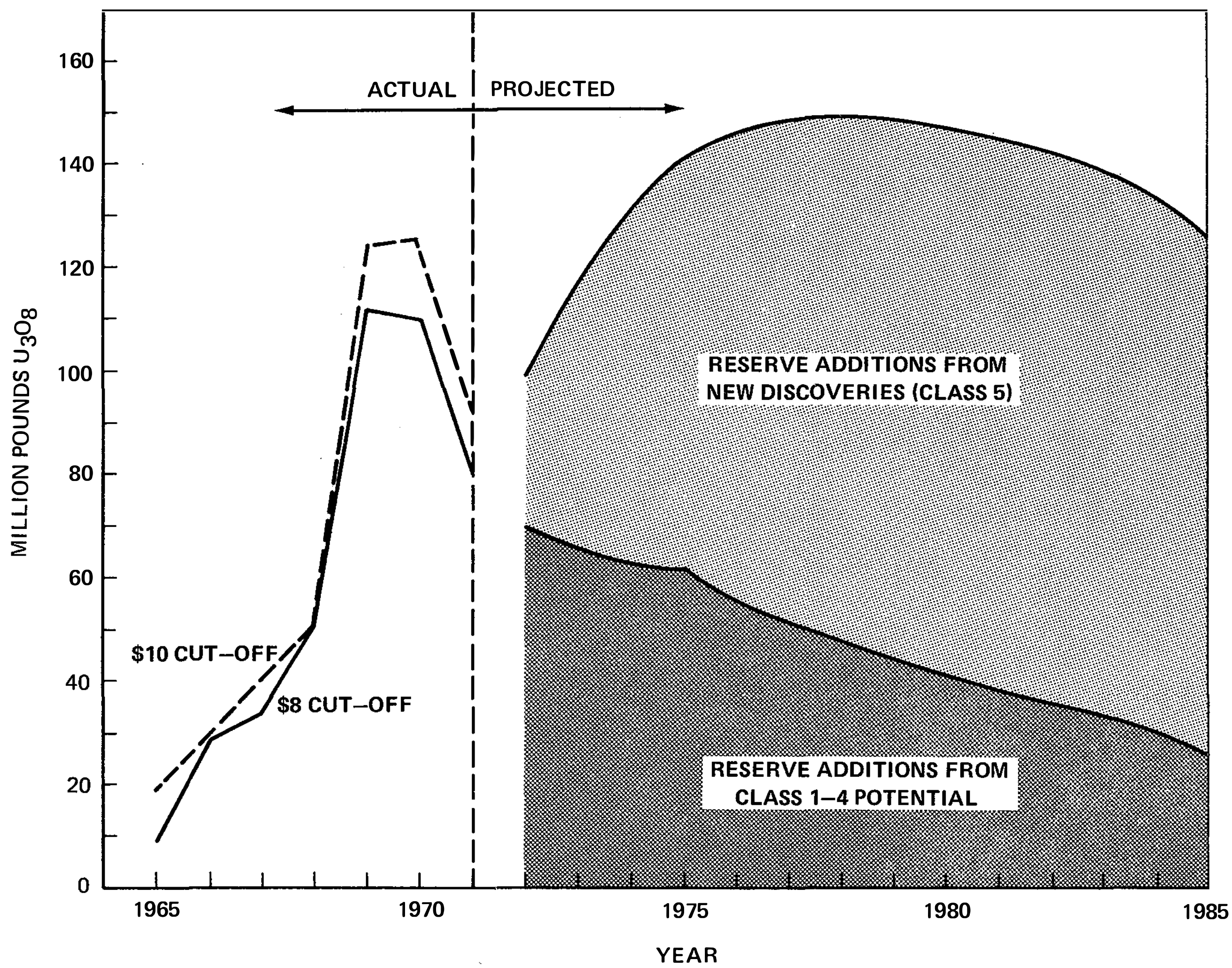


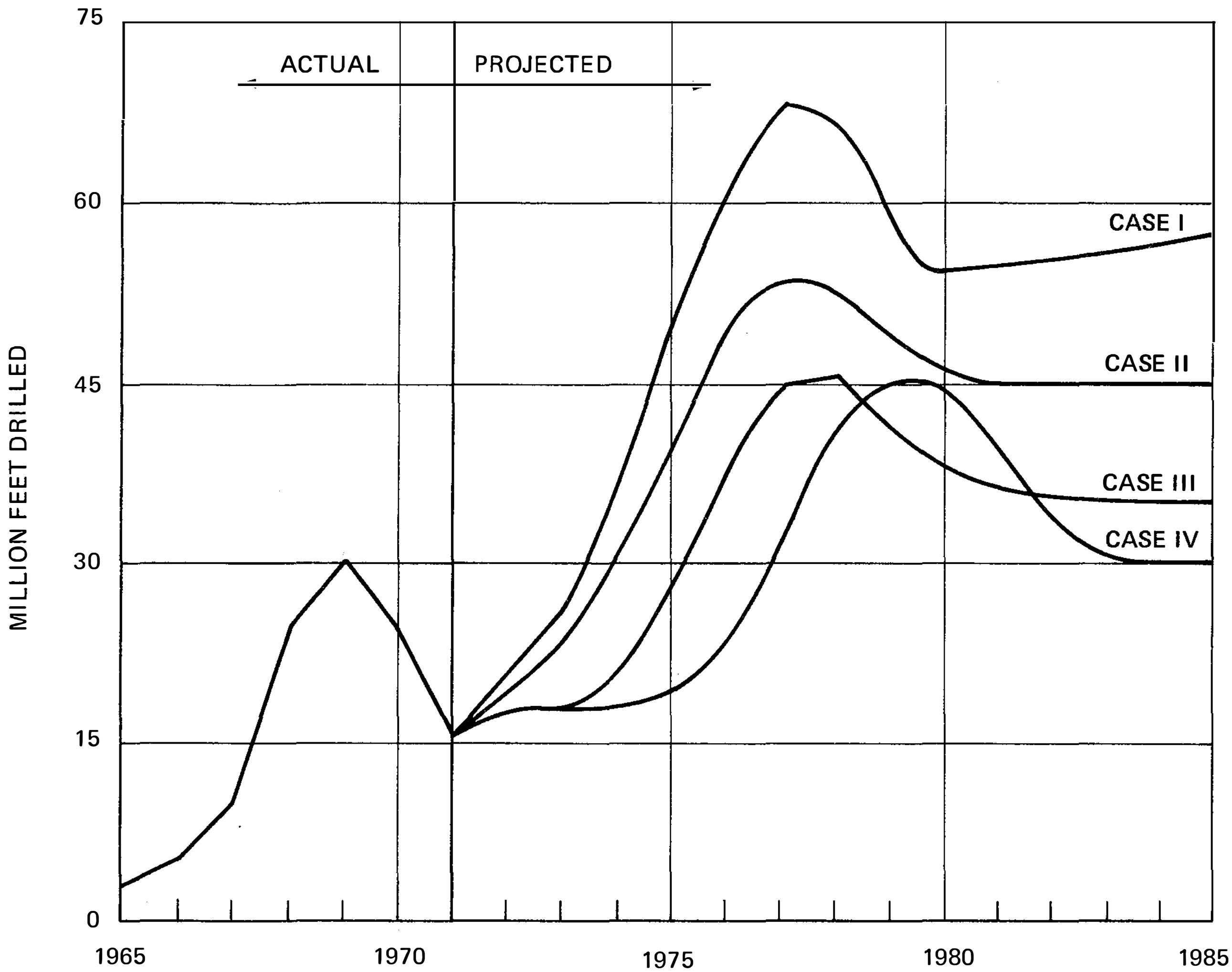
Figure 74. Annual U_3O_8 Discovery Requirements—Case III.

should also be noted that the effect of changes in the discovery rate on uranium "prices" is very significant. Figure 77 shows the variation in the calculated Class 5 U_3O_8 "prices" required for returns between 10 percent and 20 percent over a range of discovery rates. A reduction in the discovery rate from 4 pounds per foot, as used in the four basic cases, to 2 pounds per foot increases the calculated "price" of U_3O_8 to about $14 per pound. This represents a 40-percent increase.

Reserve/Production Ratio

The amount of exploration effort needed to support a given level of uranium demand is affected significantly by the quantity of known reserves deemed necessary to be "in-hand" before production can commence. The standard assumption used in all four of the basic cases was that an initial R/P of 7.0 would be representative of future uranium production operations. Relative to these basic cases, an increase in the R/P to 9.0 would increase annual surface drilling requirements by about 25 percent. Alternatively, a ratio of 5.0 would decrease these requirements by 25 percent (see Figure 78). Furthermore, an increase in the R/P from 7.0 to 9.0 would increase the calculated "price" of U_3O_8 at a 15-percent return by about $0.50 per pound (see Figure 79).

Since the basic cases were calculated on the basis of a 10-year mine life, the initial 7.0 R/P



Note: Levelized to drilling rate required to support a 10 year minimum forward reserve at the 1985 demand level.

Figure 75. History and Forecast of Surface Drilling—Annual (Assumptions—Production Classes 1-5—Discovery Rate—4 lb./ft. U_3O_8).

would not be sufficient to sustain production over the full period. Therefore, the additional 3 years of ore reserves were considered to have been proved during the time of the first production from a new mining facility. Because of the long lead times between exploration investment and first production, it is evident that there is an economic tradeoff between (1) expenditures in the early years to prove up reserves guaranteeing an increased mine life and (2) keeping the exploration investment to the minimum required for an economically viable production operation.

Mine/Mill Investment

Although the investment in mining and milling facilities is probably more certain for any specific project than are exploration costs, there may be a considerable range of capital costs because of differences in ore grade and in annual tonnage capability of mills associated with specific production centers. The effect of increased mine/mill investment on calculated uranium "price" is, however, relatively small as shown in Table 122.

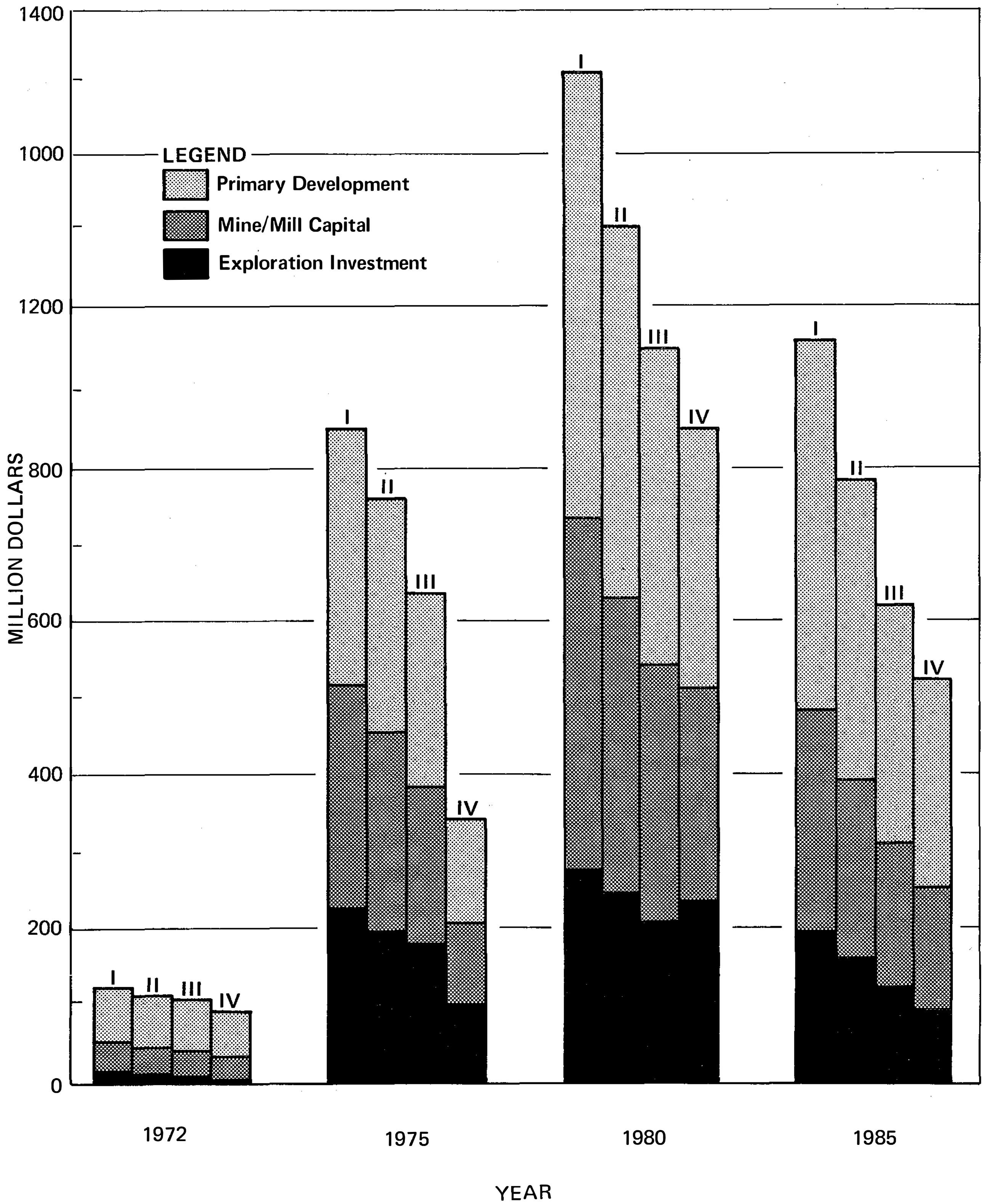


Figure 76. Uranium Raw Materials Capital Investment Summary.

TABLE 122

EFFECT OF INCREASED MINE/MILL INVESTMENT ON CALCULATED URANIUM "PRICE"

Return on Investment (Percent)	"Price"/lb. U_3O_8 for Basic Cases	"Price" Increase Due to an Increased Investment of: 20%	50%
10	$ 8.91	$ 9.09	$ 9.39
15	10.37	10.60	10.99
20	12.39	12.74	13.25

Tax Alternatives

Possible variations in the tax laws affecting uranium were studied. However, the range of tax alternatives studied should not be interpreted either as a recommendation for specific tax law changes or as evidence of special knowledge concerning pending tax proposals. What was attempted was to use the supply program to evaluate the importance of various tax parameters such as depletion allowance, investment tax credits and preference taxes.

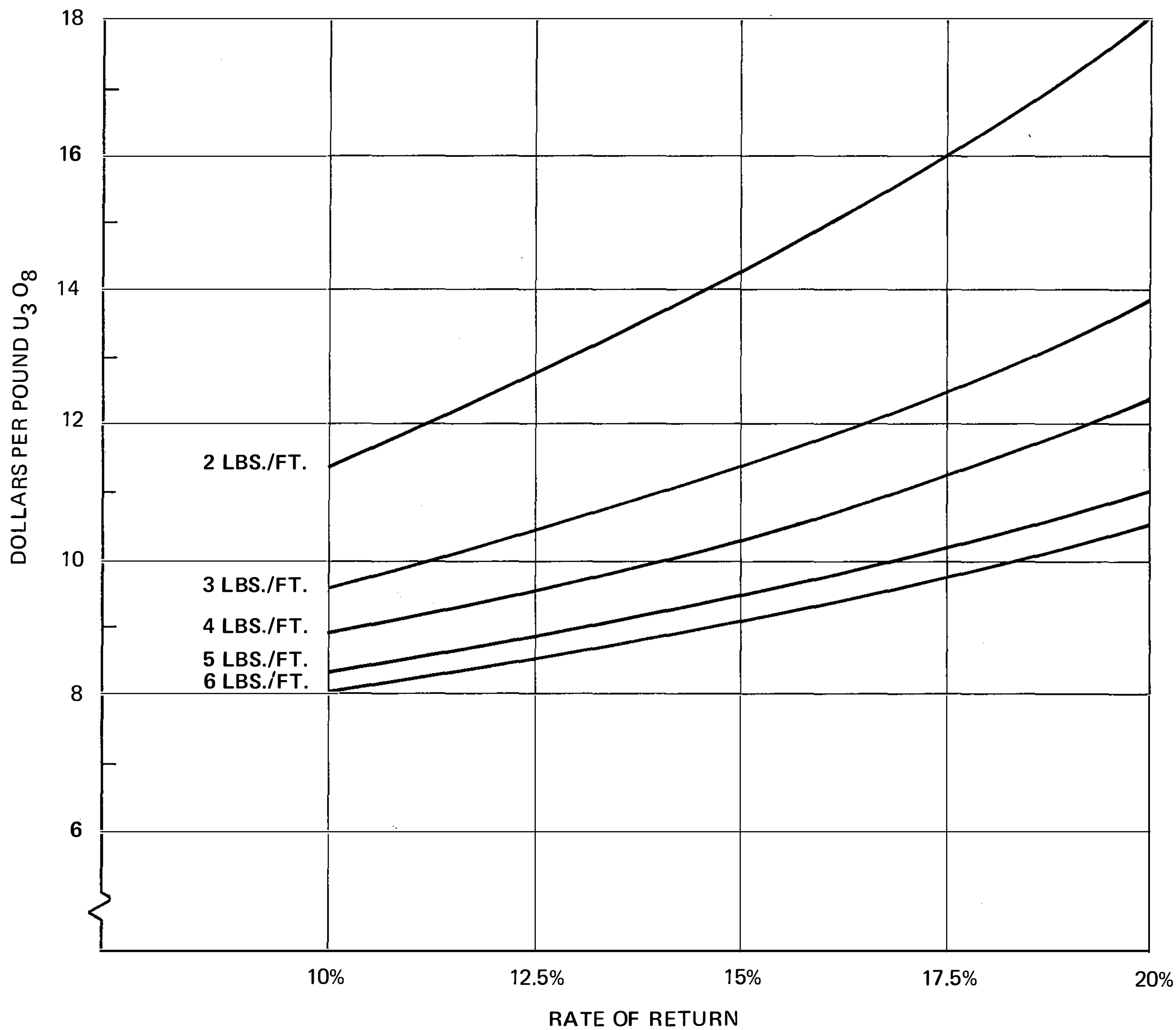


Figure 77. Parametric Study—Case III (Future Discoveries) Class 5 "Price"/Pound U_3O_8 *vs.* Discovery Rate.

Of the various tax parameters considered, depletion allowance was perhaps most significant. It was noted that a complete elimination of the depletion allowance would have the greatest impact on uranium "prices" as calculated in the basic cases.* This alternative would increase the calculated "price" of U_3O_8 from $10.37 to $12.23 per pound or $1.86 at a 15-percent DCF rate of return. This represents nearly a 20-percent increase.

* The following tax assumptions were used in the basic cases: (1) a 50-percent income tax rate, (2) a 22-percent depletion rate with a 50-percent net income limitation, (3) a preference tax equal to 8 percent of depletion minus income tax, and (4) an investment tax credit equal to 7 percent on 80 percent of mine/mill investment.

On the other hand, even a substantial increase in the current depletion allowance would not be advantageous from a price standpoint except in a relatively small way at higher rates of return. Since present tax laws limit depletion allowance to 50 percent of net income, the full benefit of the statutory depletion rate is not received. Therefore, if the current depletion rate is increased to 27.5 percent, no reduction in the calculated "price" of uranium is realized even at a 15-percent DCF rate of return, unless the 50 percent of net income limitation is also removed. With the simultaneous removal of this limitation, the "price" per pound U_3O_8 decreases by some $0.48 down from $10.37 to $9.89 per pound. This, however, only represents a 5-percent reduction in "price."

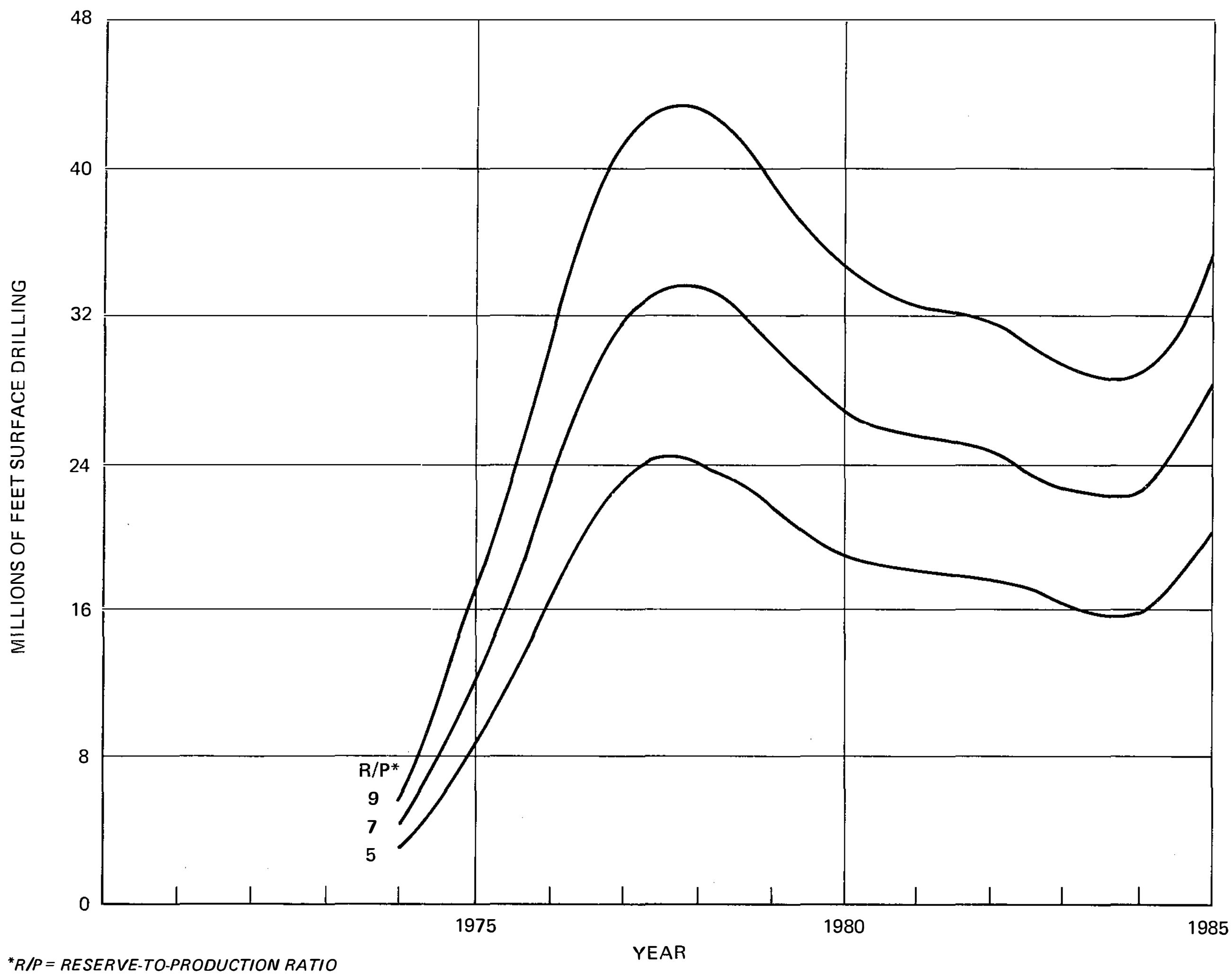


Figure 78. Parametric Study—Case III—Drilling to Prove (Future Discoveries) Class 5 Reserves *vs.* R/P.

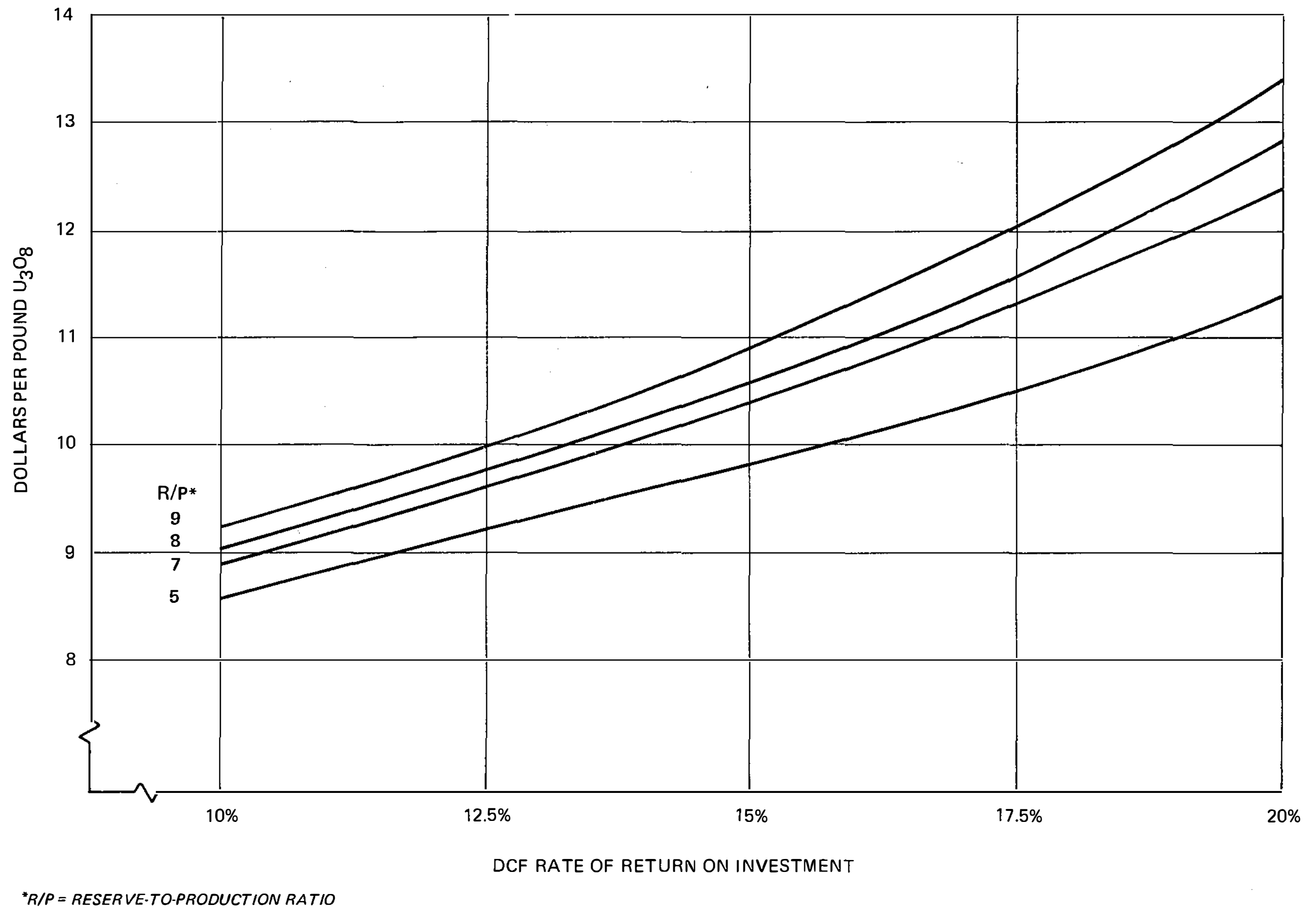


Figure 79. Parametric Study—Case III (Future Discoveries) Class 5 "Price" *vs.* R/P.

Rate of Fast Breeder Reactor Introduction

The timing and rate of breeder reactor introduction is an extremely important factor in projecting uranium requirements. Figure 80 illustrates the impact on uranium demand if breeder reactors are introduced at a slower rate than assumed in reference Case III. Even though there is no divergence in the assumed light-water reactor *vs.* breeder reactor additions until 1986, the U_3O_8 demand curves begin to separate in 1984 due to the lead times involved. The annual U_3O_8 demand when breeder reactors are introduced at a slower rate is approximately 20 percent greater than in reference Case III by 1990 with the differential increasing thereafter.

Although this parameter variation does not cause significantly increased U_3O_8 demand prior to 1985, it substantially increases the drilling requirements (over and above the Case III projection) that will be needed by at least 1980 (see Figure 81).

Mining Regulations

The health and safety standards set forth under the Federal Metal and Nonmetallic Mine Safety Act of 1966 and surface reclamation requirements established by state agencies have had in the past and will continue to have major economic effects on mining operations. The impact has been particularly severe for the uranium mining industry where underground mines must comply with strict radiation exposure limits. The cost of complying with these standards will vary from mine to mine, and the limited experience under the new requirements does not provide sufficient data for firm determination of the incremental cost for

TABLE 123			
ESTIMATED INCREMENTAL COSTS TO MEET NEW RADIATION AND SAFETY STANDARDS			
	Mine Conditions		
	Favorable	Average	Severe
Cost/Ton Ore	$1.03	$1.65	$2.90
Cost/lb. U_3O_8			
@ 2.6 lb. Recovered	0.40	0.63	1.12
@ 3.0 lb. Recovered	0.34	0.55	0.97
@ 4.0 lb. Recovered	0.26	0.41	0.73

meeting the new standards. However, reasonable estimates can be made. The relationship of U_3O_8 "prices," as calculated in the supply program, to increased capital costs was discussed in the parametric analysis section. However, increases in operating costs, unlike increases in capital costs, would require a before-tax dollar for dollar increase in "price" since the cash flows occur in the same year and therefore are not subject to a discounting effect.

Underground Mines

The incremental costs of meeting the new radiation and safety standards have been estimated based on current operating experience and the Arthur D. Little report.* Those incremental increases under differing conditions are shown in Table 123. All costs include the required additional capital expenditures and operating and indirect costs.

The majority of underground uranium mines now in operation (Classes 1 and 2) would be clas-

* "The Economic Effects of Radiation Exposure Standards for Uranium Mines," prepared by Arthur D. Little, Inc., for the Federal Radiation Council, September 1970.

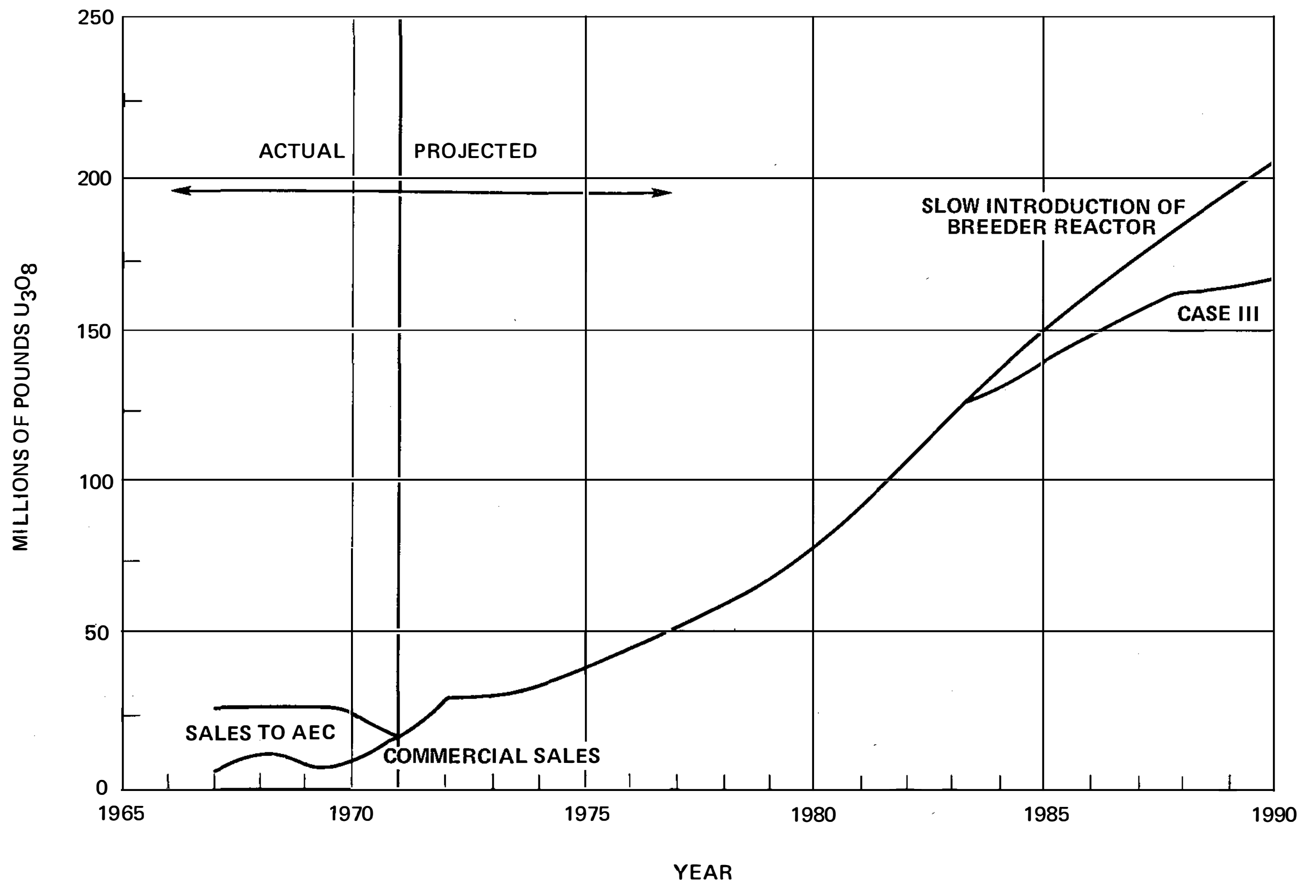


Figure 80. Parametric Study—Annual U_3O_8 Demand Assuming Slow Introduction of Breeder Reactors.

sified as having favorable or average mine conditions while most new underground developments (Classes 3, 4 and 5) will be deeper and probably produce more water. Conditions in the latter type mines would probably be considered to be severe.

Any further reduction in the radiation exposure standard would be costly and extremely difficult, if not impossible, to meet by further refinements of standard ventilation practices. A completely new approach to the problem would have to be developed with the cost and results being speculative.

Open Pit Mines

Open pit mines are generally not affected by radiation limitations; however, other new health and safety standards will increase equipment costs. When related to cost per ton of ore, these requirements should not exceed $0.02 per ton. However, the major concern in open pit mining is the land reclamation requirements enacted by the states. Requirements vary from state to state, and complete restoration of the land to its original condition may eventually be required in some areas.

Based on cost estimates by the Stanford Research Institute (SRI) for coal mines, the cost of surface reclamation for a typical uranium open pit mine will range from $0.07 per ton of ore to $2.90 per ton as shown in Table 124.

Nuclear Fuel Processing

As has been illustrated in Figure 66, the nuclear fuel cycle includes many operations both before and after fuel usage. This section includes a discussion of the requirements and capabilities of the major segments of the uranium fuel cycle other than the raw material acquisition segments (exploration, mining and milling) which were discussed in detail earlier in this chapter.

Uranium Enrichment

The three government-owned enrichment plants have a present total capability of 17,230,000 units of separative work (SWU) per year. The plants are not now operating at full capacity, but they are processing more uranium than is required and thereby providing a stockpile of enriched material that can be drawn upon in the future. With the completion of the AEC's expansion programs, namely the Cascade Improvement Program and Cascade Uprating Program, the total capacity of the three plants will be increased by about 60 percent to 27,900,000 SWU per year.

The cumulative separative work requirements for the four cases are shown in Figure 82. Included in these requirements are the expected foreign and U.S. government requirements for separative work. Hence, Figure 82 is a representation of the cumulative total demand on the U.S. uranium enrichment plants. Also shown is the

TABLE 124

ESTIMATED INCREMENTAL COSTS TO MEET OPEN PIT RECLAMATION REQUIREMENTS

	Requirements*		
	Mild	Moderate	Severe
Cost/Ton Ore	7.0¢ - 11.5¢	11.0¢ - 17.0¢	$2.10 - $2.90
Cost/lb. U_3O_8			
@ 2.6 lb. Recovered	2.7¢ - 4.4¢	4.2¢ - 6.5¢	$0.81 - $1.12
@ 3.0 lb. Recovered	2.3¢ - 3.8¢	3.7¢ - 5.7¢	$0.70 - $0.97
@ 4.0 lb. Recovered	1.8¢ - 2.9¢	2.8¢ - 4.3¢	$0.53 - $0.73

* Reclamation requirements are as follows:

Mild requirements: Regrade dumps, cover with top soil and reseed.
Moderate requirements: Regrade dumps, slope pit walls, cover with top soil and reseed.
Severe requirements: Backfill all pits and return surface to near original.

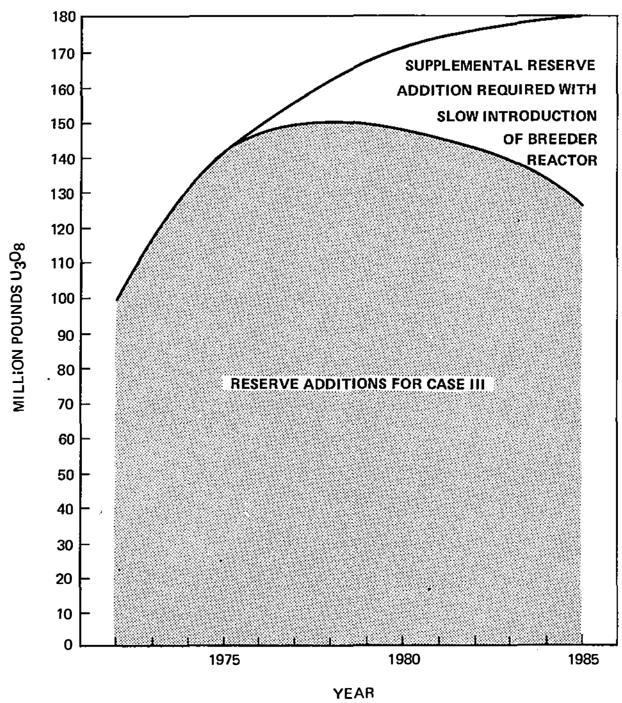


Figure 81. Parametric Study—Annual U_3O_8 Discovery Requirements Assuming Slow Introduction of Breeder Reactors.

cumulative separative work production as planned by the AEC. On the basis of these data, additional uranium enrichment capacity beyond the expansion programs will be required for Case I by 1980, for Case II by 1981 and for Case III by 1982. Capacity is adequate for Case IV through 1985.

There is some flexibility in the capacity of an enrichment plant to supply enriched uranium which is accomplished primarily by adjusting the assay of the plant tailings. By operating at a tails assay of 0.30-percent U_{235}, the production of enriched uranium can be increased by more than 20 percent above the capacity of the same plant operated at a tails assay of 0.20-percent U_{235}. However, this increase must be accompanied by an increase in the uranium feed requirements of about 20 percent. Thus, changes in uranium enrichment operations cannot be made without causing significant changes in the uranium requirements.

Government and industry must closely scrutinize enrichment requirements because of the long lead times associated with building new enrichment facilities. It is estimated that the lead time for industry to plan and construct new enrichment facilities will be 9 years, while for the government it will be 6 to 7 years. Construction of additional capacity at an existing plant could reduce this lead time by 1 to 2 years and reduce capital costs by 25 percent. In any event, if additional power generating capacity is required, the limiting factor may be the 6- to 8-year lead time associated with building a new power plant.

Before additional enrichment capacity can be committed, decisions will have to be made concerning whether the new capacity will be built by government or by private industry, who will own it, where it will be located, who will supply the power, what technology will be used, and how much capacity will be added at one time. If private industry is to provide new capacity by 1982, prompt action must be taken with respect to: (1) acceleration of the transfer of technology to private industry; (2) energetic action by government and industry to carry out the technology sharing program presently underway; and (3) recognition by government and industry that decision dates are near at hand on the many issues relating to ownership, location, technology and size.

The cost of new enrichment capacity is about \$125 to \$150 per SWU capacity per year. Based on these costs, the capital requirements through 1985 for additional enrichment capacity would vary from about \$2 billion in Case IV to over \$6 billion in Case I. This estimate does not include the cost of the electric power plants needed to supply power to the enrichment plants.

Fuel Reprocessing

Three privately owned plants designed to reprocess irradiated fuel elements removed from power reactors are operating or are being built in the United States. Their combined capacity has been announced to be 2,700 metric tons uranium (MTU) per year. This is estimated to be sufficient to process the irradiated fuel discharged from power reactors through 1981 for Case I. However, additional capacity will be required prior to 1985 in all four demand cases.

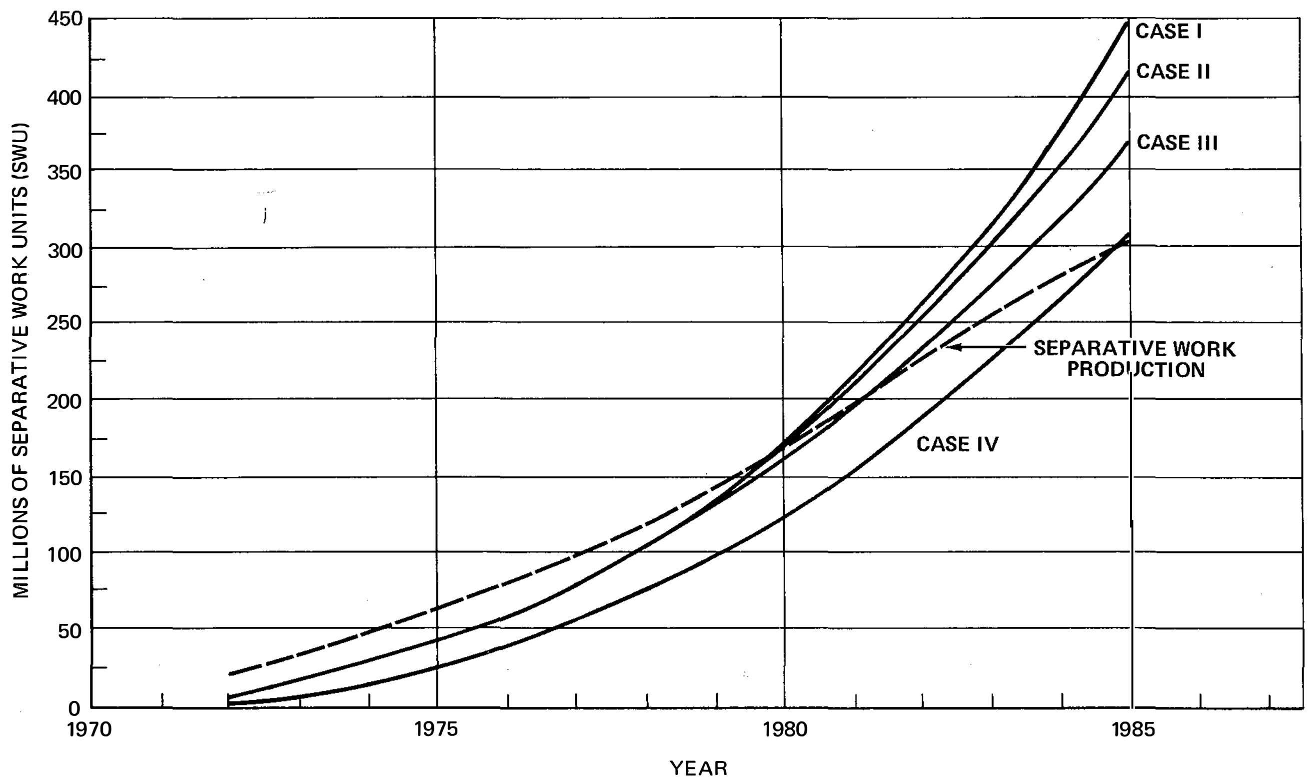
Difficulties are being encountered in obtaining operating licenses for plants now being built, and similar difficulties may be anticipated with any new plants. Since reprocessing is a necessary step in the fuel cycle, licensing problems must be resolved. A total lead time of about 8 years may be necessary because of this difficulty. This includes 3 years for obtaining a license and 5 years for construction.

Estimates of the capital cost of reprocssing plants range between $50,000 and $100,000 or even higher per annual metric ton of throughput, depending upon the size of the plant, the nature and extent of the facility, and regulating requirements to process or recover solid, liquid and gaseous wastes. For the purpose of estimating total capital investment requirements, an average cost of $65,000 per annual metric ton of throughput capacity was assumed.

Waste Disposition

The fuel cycle generates radioactive wastes of various intensities. Low-level wastes are generally buried in storage tracts licensed by the AEC. High-level wastes are currently disposed of by storage either in liquid form in large buried tanks or conversion to solid form such as glass or ceramic and storage on the surface at the reprocessing plant. The AEC is studying other storage possibilities for high-level wastes. These include storage in abandoned mines or in rooms excavated in salt beds. The quantity of high-level wastes is modest, estimated at 125,000 cubic feet (about 3,000 tons) for the period 1972-1985 and 770,000 cubic feet (about 20,000 tons) by the year 2000. Such waste storage costs are expected to contribute only about 0.03 to 0.05 mills per KWH to the cost of power generation.

Storage of gaseous radioactive wastes (Krypton 85 and Tritium) released during the dissolution of spent fuel will impose additional cost, the magnitude of which will depend on recovery technology now under development and upon government regulatory policy.



NOTE: Demand includes foreign and U.S. Goverment requirements at 0.275 tails assay.

Figure 82. Cumulative Separative Work Requirements.

Conversion and Fabrication

The remaining major steps in the fuel cycle are (1) conversion of uranium concentrates from U_3O_8 to UF_6 and (2) reduction of the enriched UF_6 to UO_2 and subsequent fabrication of the UO_2 into reactor cores. The former is called conversion; the latter is fabrication.

There is adequate capacity today in these fields to provide additional capacity, and lead time to construct plants is not considered a limiting factor. For both types of plants, the lead time between start of design and operation is about 3 years. Capital costs for the conversion and fabrication plants are estimated to be $4,000 and $25,000 per annual MTU capacity respectively.

Plutonium Supply

Plutonium is recovered from spent fuel removed from light-water reactors. It has two important uses in the nuclear power economy—as a fuel in non-breeder reactors to replace U_{235} and as the primary fuel in fast breeder reactors. The former use is known as plutonium recycle.

Decisions made during the next 5 to 10 years regarding the use of plutonium will be important to the nuclear industry. Plutonium recycle, for example, reduces both natural uranium and enrichment requirements. However, if too much plutonium is recycled, there will be an insufficient stockpile to provide fuel for breeder reactors when they are ready for commercial operation in the latter 1980's. In this study, it was determined that 60 percent of the recovered plutonium could be recycled without detriment to the projected breeder program.

The capital cost of a fabrication plant to produce mixed plutonium and uranium oxide fuel elements is estimated at $100,000 to $135,000 per annual metric ton of capacity.

Transportation of Nuclear Materials

The transportation of nuclear fuel materials is regulated by the Department of Transportation and requires specific types of containers and shipment control. Until the nuclear fuel materials have been irradiated in a reactor, their transportation from point to point does not present any major problems.

Transport of recovered plutonium and U_{233} requires additional precautions, however. Shipment of irradiated fuel materials requires the use of containers which are heavily shielded and so constructed to withstand damage in the event of accidents during transit. With the increasing volume of irradiated fuel elements from power reactors, a substantial number of containers will be required, and their transportation to and from reprocessing plants will present potential logistical problems. Adequate planning for the manufacture of the required containers as well as for the movement of these containers in interstate commerce is essential to avoid unnecessary economic penalties for the resulting delays.

Capital Expenditures

A summary of capital expenditures for the nuclear fuel cycle over the period 1972-1985 is shown in Table 125.

TABLE 125

CAPITAL EXPENDITURES FOR THE NUCLEAR FUEL CYCLE—1972-1985
(Billion Dollars)

Fuel Cycle Sector	Case I	Case II	Case III	Case IV
Uranium Raw Materials	6.0	5.0	4.3	3.7
Conversion	0.3	0.2	0.2	0.1
Enrichment	6.0	5.0	3.5	2.5
Fabrication	0.4	0.3	0.2	0.2
Transportation, Reprocessing and Waste Storage	0.4	0.4	0.3	0.2
Total Fuel Cycle	**13.1**	**11.0**	**8.5**	**6.7**

Chapter Seven
Oil Shale Availability

Introduction

The Initial Appraisal presented a projection of shale oil production from high potential regions for the 1971-1985 period, assuming a continuation of present government policies and present technology. The report discussed in detail the energy reserve potential in U.S. oil shale and described a method of development that might utilize these reserves. It also discussed the various technologies of mining and crushing oil shale, retorting the shale to produce crude shale oil, and upgrading the crude shale oil to a pipeline quality syncrude. The syncrude product is a 46° API, hydrotreated distillate essentially free of sulfur and low in nitrogen, thus constituting a premium refinery feedstock. Capital investment and operating cost estimates for the various parts of a commercial syncrude venture based on the method of development assumed in the Initial Appraisal also were given.

This additional analysis considers changes in industry and government policies and economic conditions that could affect the production of syncrude. Among other things, this chapter discusses the effects of certain changes in government policies, legislation and technology on the availability and required "prices" of syncrude. In addition, the direct regional support required by an oil shale industry is evaluated. The basic engineering and economic data from the Initial Appraisal were used in this study.

Summary and Conclusions

Reserves and Production

Oil shale reserves, equivalent to 54 billion barrels of syncrude, in the Piceance Basin of Colorado and the Uinta Basin of Utah are considered to be the most economically recoverable portion of the Green River Formation oil shale resources. However, maximum projected development (Case I) through 1985 would commit less than 6 billion barrels of these reserves, all located in the Mahogany Zone of the Piceance Basin.

The Case I projection of 750 MB/D in 1985 (see Table 126) reflects the maximum feasible syncrude production capacity under non-emergency conditions and assumes that syncrude prices are adequate to encourage commercial development. This output would require an estimated capital investment in plants of $4.0 billion. Lower projections (Cases II-IV) reflect slower rates of investment because of either the lack of investment incentive or the need for time to demonstrate process feasibility.

TABLE 126

PRODUCTION OF SYNCRUDE FROM OIL SHALE (MB/D)

	1975	1980	1985
Case I	0	150	750
Case II/III	0	100	400
Case IV	0	0	100

Required "Prices"

The calculated "prices" applicable to the initial venture in shale oil will depend on the assay of the oil shale present in the individual leasehold. To these "prices" must also be added a cost of about $0.50 to $0.75 per barrel for transportation to refining centers. Government and private oil shale reserves are all assumed to be available for commercial development, with payment of royalty on the oil shale mined. No leasing costs or bonus payments are included in the economic studies.

Required "prices" are calculated on invested capital required to build and equip two mines, two retorts and one upgrading plant in order to produce 100 MB/D of syncrude. The capital requirements do not reflect pioneer plant risks or unusual costs. The "prices" calculated for three DCF rates of return for 30- and 35-gallon per ton oil shale are shown in Table 127. The lower figures in the ranges given in Table 127 are for adit mines; the higher figures assume shaft mines.

TABLE 127

REQUIRED SHALE OIL "PRICES"
(Dollars per Barrel)

DCF Rate of Return (Percent)	30 Gal/Ton	35 Gal/Ton
10	4.32-4.47	3.97-4.09
15	5.58-5.79	5.10-5.29
20	7.03-7.29	6.45-6.72

Federal Policies

Federal leasing policies will influence the level of production because about 80 percent of the oil shale resources of the Green River Formation in Colorado, Utah and Wyoming are federal holdings. Present law restricts individual leasing to a total of 5,120 acres. A change in this legal restriction to make adequate reserves available and permit individual company holdings of at least 10,000 to 20,000 acres of federal oil shale leases would be essential for a sufficiently large and long-term commercial enterprise. This size range of leasehold is needed to provide adequate minable shale in the Mahogany or other rich zones; leaner shales in other zones would require proportionally larger leases.

Tax and royalty policies were evaluated to determine their influence on required syncrude "price." Assuming a 15-percent DCF rate of return on 35-gallon per ton shale, each of the following changes will reduce calculated syncrude prices by $0.19 to $0.35 per barrel: (1) changing the depletion allowance from 15 percent on the crude shale oil value to 22 percent on the syncrude value, (2) continuing investment tax credit, (3) reducing depreciation life to 5 years, and (4) suspending royalty payments. (These are discussed in further detail in the later section, "Government Tax and Royalty Policies.") The combined effect of increasing the depletion allowance, continuing the investment tax credit and shortening depreciation life would be to decrease the calculated syncrude "price" by $0.70 per barrel.

Environmental Costs

The investment and cost assumptions in the Initial Appraisal are sufficient to meet present-day environmental standards. Environmental control costs will increase if regulation becomes more restrictive than assumed. For example, it has been assumed that spent shale will be disposed of above ground. The sensitivity of syncrude price to such factors shows that a 10-percent increase in the total initial mine and plant investment would increase the required syncrude "price" $0.40 per barrel at a 15-percent DCF rate of return or would reduce the rate of return 1.5 percentage points at a constant syncrude price. However, the same total additional investment, made in equal increments over a 15-year period, would require an increase in syncrude "price" of only $0.15 per barrel.

New Technology

The effect of new technology is difficult to evaluate quantitatively. For example, *in situ* retorting of fractured strata appears to have potential but will require considerably more development to become commercially significant. However, modifications of presently available retorting processes could make possible the production of syngas from oil shale.

Oil Shale Resources

Oil shale deposits of potential commercial interest exist in the Green River Formation of Eocene

Age, which ranges in thickness from a few hundred feet to about 7,000 feet, underlying 10 million acres of several basin areas in Colorado, Utah and Wyoming. The location of thick deposits, mainly dolomitic shales and marlstones, is shown in Figure 83. In general, the central parts of the Piceance Basin in Colorado and the Uinta Basin in Utah and Colorado contain thick, rich oil shale sequences which grade to thinner and leaner oil shale at the basin margins. Somewhat thinner and generally lower grade deposits in the Green River and Washakie Basins of Wyoming also show a decrease in grade toward the basin margins.

Oil shale resources of the Green River Formation have been classified in four groupings to reflect the degree of commercial attractiveness, as explained below:

Class	Description
1, 2	These are the resources satisfying the basic assumption limiting resources to deposits at least 30 feet thick and averaging 30 gallons of oil per ton of shale, by assay. Only the most accessible and better defined deposits are included. Class 1 is a more restrictive cut of these reserves and indicates that portion which would average 35 gallons per ton over a continuous interval of at least 30 feet.

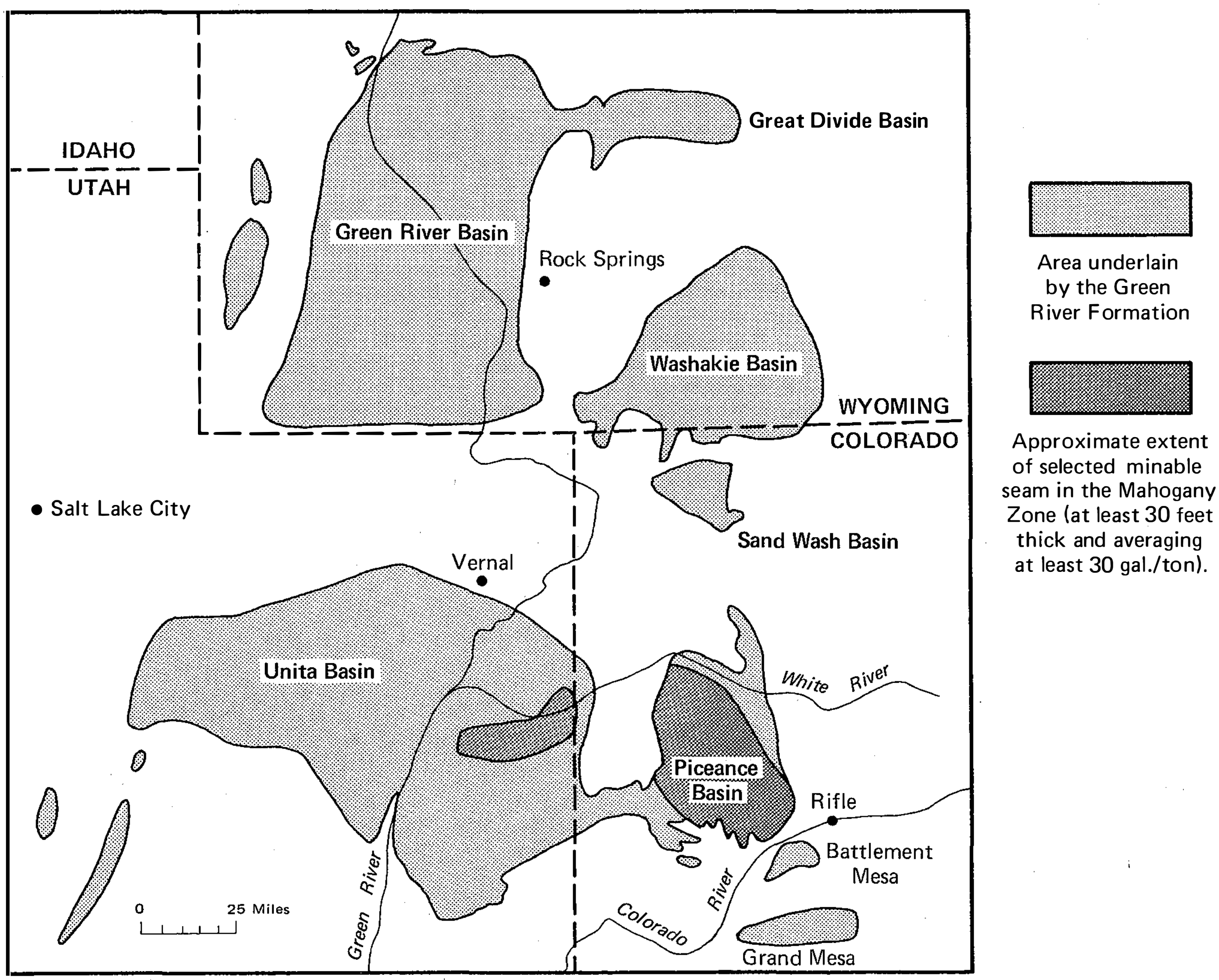


Figure 83. Mahogany Zone Reserves Used in This Study for Calculation of Required "Prices" for Various Levels of Production.

3 Class 3 resources, although matching Classes 1 and 2 in richness, are more poorly defined and not as favorably located. These may be considered potential resources and would be exploitation targets at the exhaustion of Class 1 and Class 2 resources.

4 These are lower grade, poorly defined deposits ranging down to 15 gallons per ton which, although not of current commercial interest, represent a target in the event that their recovery becomes feasible. These may be considered speculative resources.

A summary of the quantity of potential shale oil in the four classes of resources is given in Table 128. A total of 1,781 billion barrels is indicated for all classes, but only 129 billion barrels is shown for the more accessible and better defined Classes 1 and 2.

TABLE 128

SUMMARY OF OIL SHALE RESOURCES–
GREEN RIVER FORMATION
(Billions of Barrels)

	Resources				
Location	Class 1	Class 2	Class 3	Class 4	Total
Piceance Basin Colorado	34	83	167	916	1,200
Uinta Basin Colorado and Utah	–	12	15	294	321
Wyoming	–	–	4	256	260
Total	**34**	**95**	**186**	**1,466**	**1,781**

Oil shales occurring in other sections of the United States are much lower in grade and quality than the Green River shales, generally assaying below 15 gallons per ton, and are not considered to be commercially significant.

Oil Shale Reserves for Commercial Production

It is apparent from the resource estimate given in Table 128 that an immense quantity of potential shale oil exists in the Green River Formation. However, the amount of shale oil in the Class 1 and 2 categories that can be recovered by a proved technology, which starts with extraction of a minable seam, will be considerably less than the gross resource estimate. To estimate these recoverable reserves, a comprehensive survey was undertaken of the minable seam in the Mahogany Zone, which is the richest, most continuous and shallowest oil shale section in the Green River Formation. The assumptions were made that all of the resources, both government and private, would be available for commercialization and that development would be by underground, room-and-pillar mining, according to the method described in the Initial Appraisal. It was further assumed that the minable seam in the Mahogany Zone would be delineated by the lean strata of shale above and below the main rich seam. By utilizing available core hole data from the Piceance and Uinta Basins of Colorado and Utah, a minable seam in the Mahogany Zone was mapped which averaged about 60 feet in thickness and assayed at least 30 gallons per ton.

Working first with the Piceance Basin, the minable seam was blocked out in 130 tracts, each containing 634 million assay barrels of reserves in place. This reserve requirement is based on a 20-year supply of oil shale, 60-percent recovery of shale in the minable seam, 96 volume percent of Fischer assay as syncrude yield, and production from each tract of sufficient crude shale oil to yield 50 MB/D of syncrude. Thus, each tract represents sufficient reserve for production of 365 million barrels of syncrude. In the Uinta Basin, because there is less information on the reserves, the tracts were subdivided into larger blocks of 730 million barrels of potential syncrude to yield 100 MB/D production rate.

The depth of the seam was catalogued, and the method of entry for mining, whether by adit or shaft, was specified. Using these classifications, the tracts were totaled for each category (see Table 129). The total reserves amount to 54.2 billion barrels but, as discussed later, development of less than 6 billion barrels—or barely 10 percent—of these reserves is anticipated through 1985.

Required "Price"

Required "prices" were calculated for various levels of production of syncrude from the oil shale reserves described above. These "prices" were obtained by calculating the "price" required to yield

TABLE 129

POTENTIAL SYNCRUDE RESERVES FROM A SELECTED MINABLE SEAM IN THE MAHOGANY ZONE OF THE PICEANCE AND UINTA BASINS*

Shale Assay (Gal/Ton)	Recoverable Oil Shale Reserves as Syncrude (Billion Barrels)			
	Piceance Basin		Uinta Basin	
	Adit Mine	Shaft Mine	Adit Mine	Shaft Mine
30	2.9	6.9	2.9	3.7
31	2.6	2.2	–	–
32	1.1	4.7	–	–
33	2.5	4.4	–	–
34	1.5	4.4	–	–
35	1.5	7.7	–	–
36	0.4	3.7	–	–
37	–	1.1	–	–
Total	**12.5**	**35.1**	**2.9**	**3.7**
Total Reserves	**54.2 billion barrels as syncrude.**			

* Bases for estimate: (1) Wyoming deposits are not well defined but are believed to be too lean and thin or too deep for including in these reserves; (2) continuous minable section at least 30 feet thick and averaging at least 30 gallons per ton; (3) 60-percent recovery of the oil shale; and (4) 96 volume percent of Fischer assay as syncrude yield.

a given rate of return for the syncrude that would be produced from each tract, based on the economic data developed in the Initial Appraisal.

Syncrude "prices" in constant 1970 dollars, f.o.b. the syncrude plant, were calculated at three DCF rates of return to bracket the range of major interest. Figure 84 shows the relationship of these "prices" to potential production. Table 130 and Figure 85 show that required "price" is very sensitive to rate of return and shale assay. The difference between adit and shaft mining is less pronounced.

Initial production was assumed to be from the lowest cost syncrude production, *i.e.*, from 36 gallons per ton shale recovered by adit mining. As shown in Table 130, these per barrel "prices" are $3.91, $5.02 and $6.34 for 10-, 15- and 20-percent DCF rates of return, respectively.*

* In reality, these "prices" are not attainable because the particular tract on which they are calculated can only support a 50 MB/D operation. Implicit in all required "price" calculations are the cost reductions realizable with a 100 MB/D operation. Therefore, these "prices" only serve to identify the origin of the supply curve in Figure 84.

As shale quality decreases, costs and resulting calculated "prices" rise. The reserves were cumulated at increasing syncrude "prices" to calculate the total supply that may be obtained at a given syncrude "price." To obtain the first 10 billion barrels of potential production, the average shale quality decreases to 33 gallons per ton, and the required syncrude price at a 15-percent DCF rate of return is $5.28 per barrel, or $0.26 above the "price" for producing the highest quality reserves. For additional increments of 10 billion barrels of production, "price" increases are smaller, as shown in Figure 84. The increase in "price" averages only $0.12 per barrel for each additional 10 billion barrels of production.

Calculated required "prices" are at the mine. To deliver the syncrude by pipeline to a refinery center, for example, in the Chicago area, would cost an additional $0.50 to $0.75 per barrel.

The following additional assumptions for the syncrude "price" calculations should be noted:

- A royalty charge based on the U.S. Department of the Interior's proposed Prototype Oil

TABLE 130

ESTIMATED SYNCRUDE VOLUMES AND ECONOMICS

Oil Shale Assay (Gal/Ton)	Recoverable Reserves as Syncrude (Billion bbl)	Syncrude Production Capacity (MB/D)	Required Syncrude "Price" ($/bbl) f.o.b. Syncrude Plant (DCF Rate of Return) 10%	15%	20%
Piceance Basin—Private Adit Mines					
31	2.2	300	4.24	5.48	6.91
32	0.7	100	4.17	5.38	6.79
33	2.5	350	4.10	5.28	6.67
34	1.5	200	4.03	5.19	6.56
35	1.5	200	3.97	5.10	6.45
36	0.4	50	3.91	5.02	6.34
Total	8.8	**1,200**			
Piceance Basin—Private Shaft Mines					
33	1.5	200	4.23	5.48	6.94
35	0.4	50	4.09	5.29	6.72
Total	**1.9**	**250**			
Piceance Basin—Public Adit Mines					
30	2.9	400	4.32	5.58	7.03
31	0.4	50	4.24	5.48	6.91
32	0.4	50	4.17	5.38	6.79
Total	**3.7**	**500**			
Piceance Basin—Public Shaft Mines					
30	6.9	950	4.47	5.79	7.29
31	2.2	300	4.38	5.68	7.17
32	4.7	650	4.30	5.58	7.05
33	2.9	400	4.23	5.48	6.94
34	4.4	600	4.16	5.38	6.83
35	7.3	1,000	4.09	5.29	6.72
36	3.7	500	4.02	5.20	6.62
37	1.1	150	3.95	5.12	6.52
Total	**33.2**	**4,550**			
Unita Basin—Public Adit Mines					
30	2.9	400	4.32	5.58	7.03
Unita Basin—Public Shaft Mines					
30	3.7	500	4.47	5.79	7.29

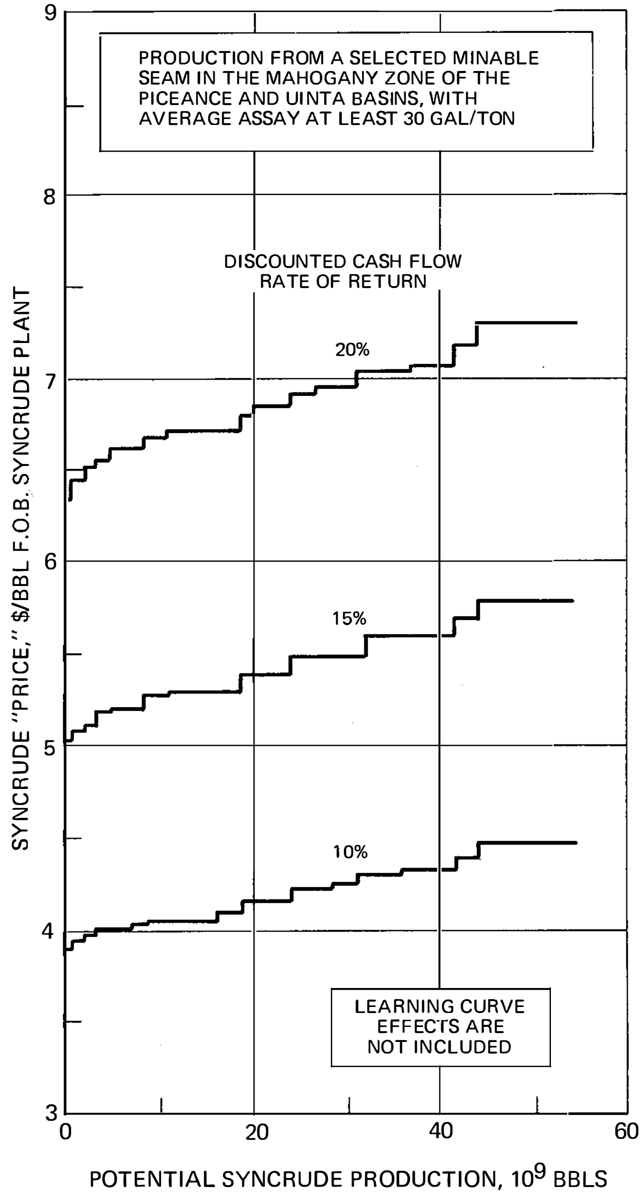


Figure 84. Required "Prices" for Syncrude from Oil Shale (Constant 1970 Dollars).

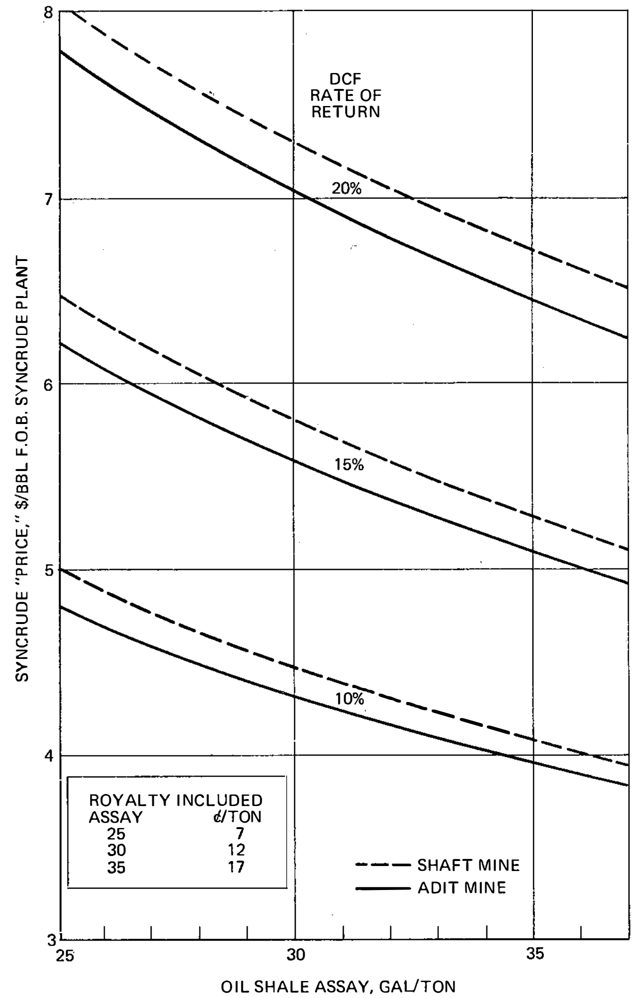


Figure 85. Value of Syncrude from Oil Shale with Adit or Shaft Mining and First-Generation Technology (Constant 1970 Dollars).

Shale Leasing Program of 1971 is assumed for oil shale mined on both state and federal holdings, and an equivalent charge is applied to private holdings.

- No leasing costs or bonus payments were included.
- The present 15-percent depletion allowance based on the value of crude shale oil and 1971 income tax rates were used.
- Commercial plant size, as a basis for the economic calculations, was selected to produce 100 MB/D of syncrude by operation of two mines, two retorting plants and one crude shale oil upgrading facility. A 3-year construction period and a 20-year operating period were assumed for each installation.
- Investment and operating costs, in constant 1970 dollars, are the same as those used in the Initial Appraisal. These are listed in Table 131 and are based on first-generation shale oil syncrude production technology, described in some detail in the Initial Appraisal. Compliance with the environmental control

TABLE 131

ESTIMATED COSTS FOR PRODUCING 100 MB/D SYNCRUDE FROM OIL SHALE*
(At Mid-Year 1970)

	25 Gal/Ton Shale	30 Gal/Ton Shale	35 Gal/Ton Shale
Oil Shale Mined & Retorted (Tons/D)	174,800	145,600	124,800
Crude Shale Oil Produced (B/D)	104,000	104,000	104,000

	25 Gal/Ton Shale				30 Gal/Ton Shale				35 Gal/Ton Shale			
	Surface		Underground		Surface		Underground		Surface		Underground	
Mining Method	Pit	Strip	Adit	Shaft	Pit	Strip	Adit	Shaft	Pit	Strip	Adit	Shaft
	Capital ($ Million)											
Mining, Crushing, Ash Disposal												
Initial	176.8	95.4	105.0	130.8	147.2	79.4	87.6	109.0	126.2	68.2	75.0	93.4
Deferred	94.2	79.4	71.4	74.0	78.4	66.0	59.4	61.6	67.2	56.6	51.0	52.8
Retorting	248.2	248.2	248.2	248.2	206.8	206.8	206.8	206.8	177.2	177.2	177.2	177.2
Upgrading	192.8	192.8	192.8	192.8	192.8	192.8	192.8	192.8	192.8	192.8	192.8	192.8
Water System	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
Total Investment	719.0	622.8	624.4	652.8	632.2	552.0	553.6	577.2	570.4	501.8	503.0	523.2
Working Capital	27.6	27.6	27.6	28.8	23.6	23.6	23.6	24.8	20.8	20.8	20.8	21.8
Total Capital (Not Incl. Land)	**746.6**	**650.4**	**652.0**	**681.6**	**655.8**	**575.6**	**577.2**	**602.0**	**591.2**	**522.6**	**523.8**	**545.0**
	Operating Costs ($ Million/Year)†											
Mining, Crushing, Ash Disposal	39.6	39.6	39.6	42.8	33.0	33.0	33.0	35.6	28.2	28.2	28.2	30.6
Retorting	20.4/25.6				17.0/21.2				14.6/18.2			
Upgrading	16.8/19.4				16.8/19.4				16.8/19.4			
Water System	0.4				0.4				0.4			
Total Operating Costs												
First 15 Years	**77.2**	**77.2**	**77.2**	**80.4**	**67.2**	**67.2**	**67.2**	**69.8**	**60.0**	**60.0**	**60.0**	**62.4**
After 15 Years	**85.0**	**85.0**	**85.0**	**88.2**	**74.0**	**74.0**	**74.0**	**76.6**	**66.2**	**66.2**	**66.2**	**68.6**

Unit Costs

	Mining, Crushing, Ash Disposal				Retorting Oil Shale	Upgrading Crude Shale Oil	
	Pit	Strip	Adit	Shaft			
Capital ($ per Ton/D)—Initial	1,011	546	601	748	1,420	($ per B/D)	1,854
—Deferred	539	454	409	424	—		—
Operating Cost (¢ per Ton)							
First 15 Years	62	62	62	67	32	(¢ per Bbl.)	44
After 15 Years	62	62	62	67	40	(¢ per Bbl.)	51

* Taken from the Initial Appraisal.

† Operating costs do not include depreciation.

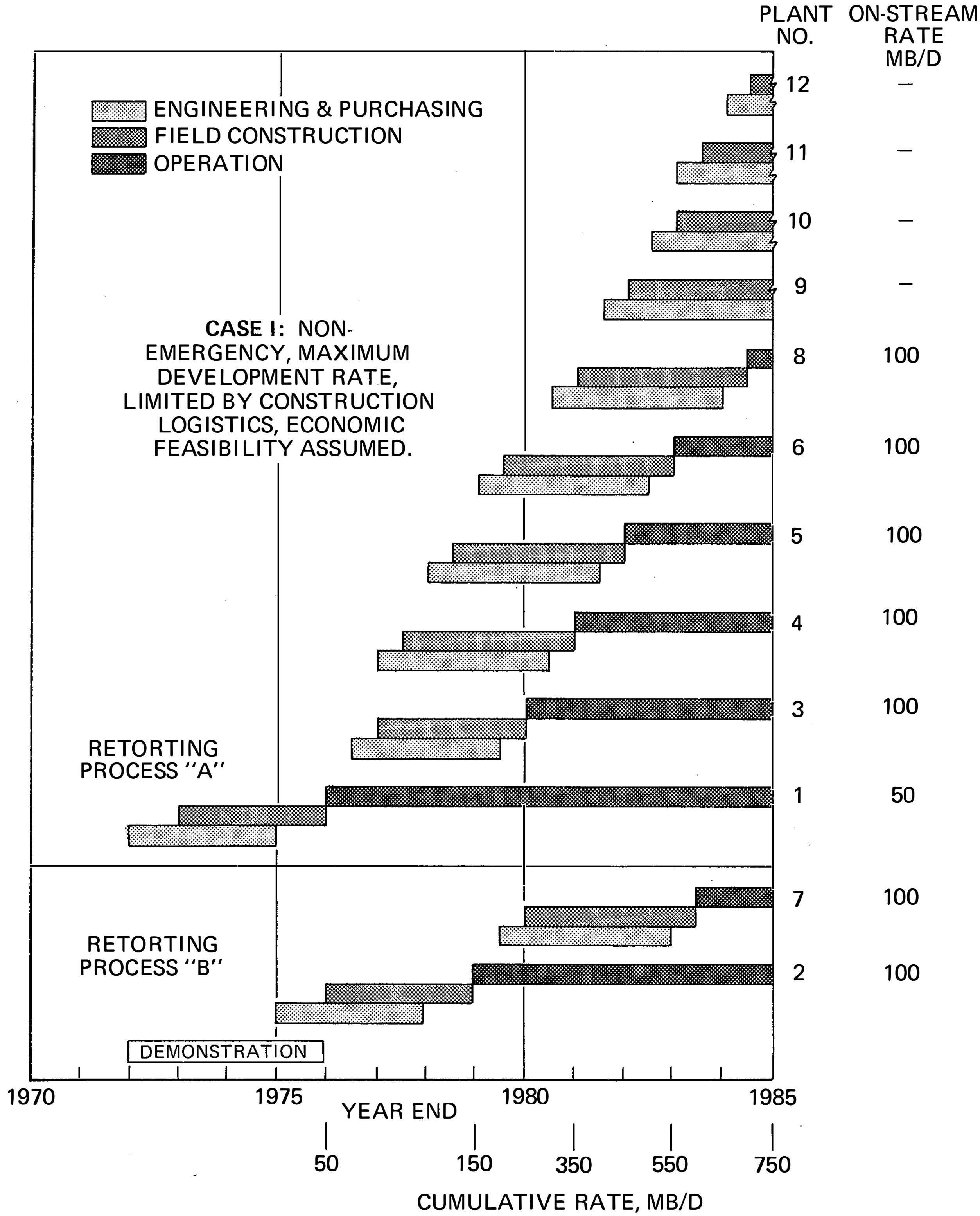


Figure 86. Development Schedule for Production of Syncrude from Oil Shale—Case I.

regulations in effect in Colorado in 1970 was provided for in these investment and operating costs. Many of the main items of equipment and operating procedures used for environmental control purposes have been in use for some time and are considered standard design and operating practice.

- Alumina and soda ash were not considered potential byproducts from the spent shale.

Development Schedule

Shale oil production schedules were developed to correspond to each of the four cases outlined earlier.

Assuming that syncrude "price" will be adequate to encourage commercial development, the factors that would limit the rate of growth of production capacity are (1) the logistics of plant design, (2) engineering and construction, and (3) industry's capability to supply heavy mine and plant equipment.

In considering the Case I maximum production rate, some of the factors which are expected to limit the rate of development of syncrude production are construction logistics, availability of operating personnel, restrictive environmental criteria, and lack of employee housing and supporting commerce and industry. Over the long term, water availability may be a limiting factor, but sufficient water for mine and plant use is available for the anticipated scale of production up to 1985. The financing of a large, new capital-intensive industrial activity is a subject that requires special consideration.

Methodology for structuring the Case I development schedule is based on a number of factors. Two retorting processes are assumed subject to commercialization, the first being ready for engineering and purchasing the early part of 1973, and the second requiring a demonstration period. Construction logistics are assumed to limit simultaneous construction capacity to 400 MB/D, encompassing 8 mines, 8 retorting plants and 4 upgrading plants under various stages of construction at one time and with no interference from other activities. Time required for (1) engineering and purchasing and (2) field construction is estimated to be 3 to 3.5 years each. Considerable overlapping was assumed for each project, and thus the total time required would be 3.5 to 4 years.

Assuming that the above constraints would apply, the commercial development schedule shown in Figure 86 was developed. The result is a non-emergency, maximum snycrude production rate of 750 MB/D for Case I by 1985. The yearly buildup of production capacity is shown in Figure 87.

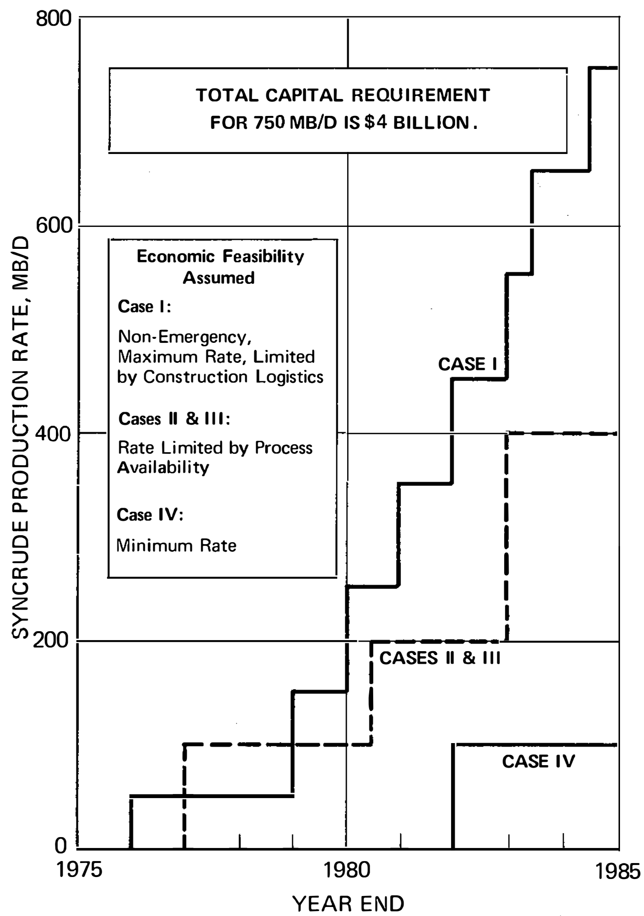


Figure 87. Production Schedule of Syncrude from Oil Shale—Cases I-IV.

An investment schedule in constant 1970 dollars was estimated from the Case I development schedule (Figure 86) and plotted as Figure 88. Both annual and cumulative investments are given. The cumulative investment ranges up to a maximum of nearly $5.2 billion through 1985 for the 12 scheduled plants shown in Figure 86. Capital for only those 8 plants projected to be in operation by the end of 1985 and producing 750 MB/D of syncrude amounts to \$4.0 billion.

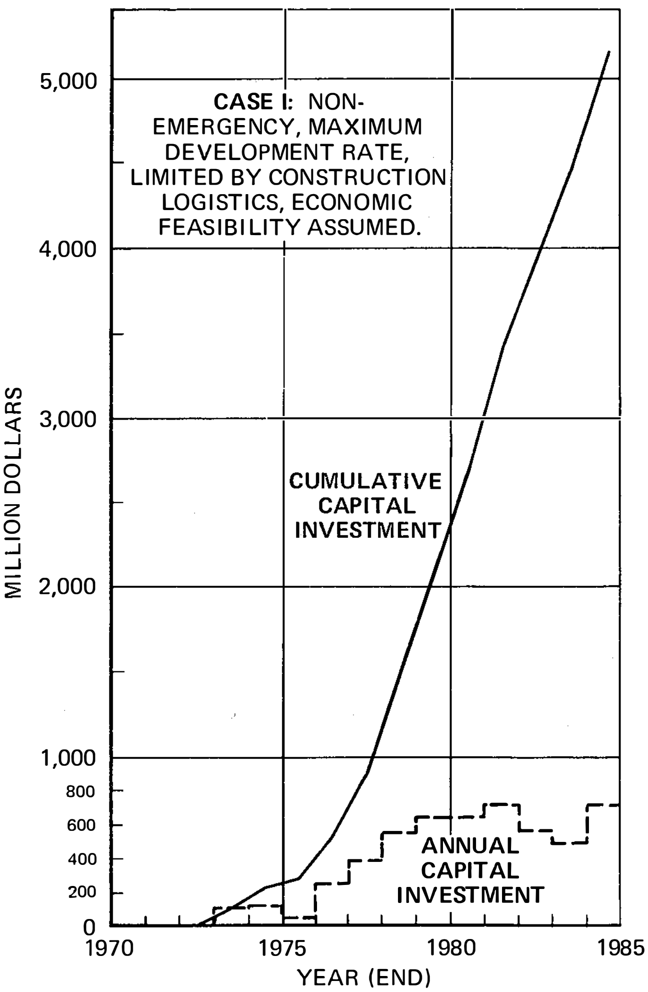


Figure 88. Investment for Syncrude from Oil Shale (Constant 1970 Dollars).

After syncrude production has been initiated, moderate increases in syncrude "price" would be required to achieve the Case I, 750 MB/D rate. This increase would compensate for the somewhat poorer quality of the oil shale deposits which would be exploited as the production rate is increased. Assuming constant technology and 1970 dollars, the syncrude price increase would be \$0.10, \$0.20 and \$0.25 per barrel at 10-, 15- and 20-percent DCF rates of return, respectively, for a 750 MB/D rate by 1985 (see Figure 89). These small increases may well be overshadowed by changes due to experience, technological improvements, inflation and shifts in rate of return required by investors.

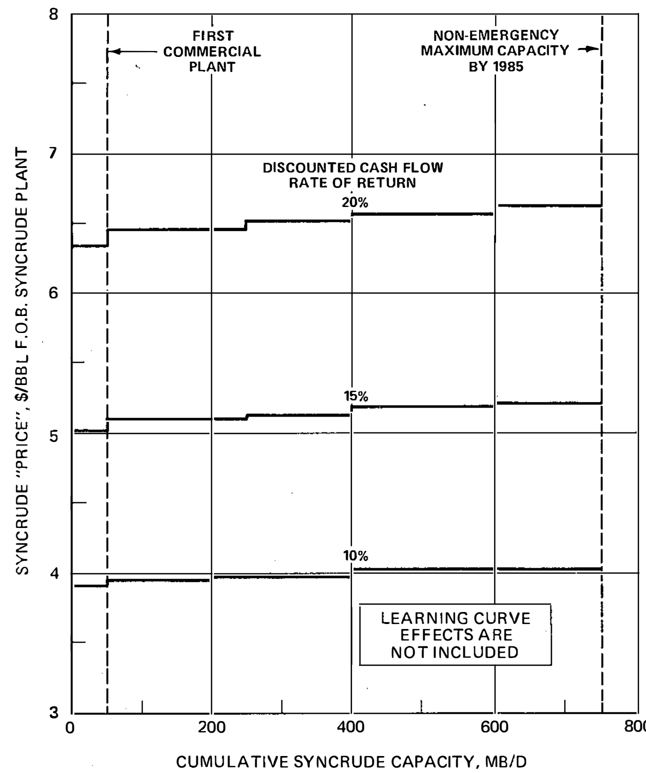


Figure 89. Required "Prices" for Syncrude Production from Oil Shale Through 1985 (Constant 1970 Dollars).

In the Initial Appraisal, shale oil production was not expected to exceed the capacity of the first 100 MB/D plant. This report considers this to be a relatively low production level—consistent with the premises of Case IV supply development. The Initial Appraisal also discussed a higher buildup rate (400 MB/D). The basis was that the "price" of syncrude would be adequate to give the required rate of return but that no process would be ready for immediate commercialization, and therefore additional time would be required to demonstrate the technical and economic feasibility of the first process in a prototype unit before constructing an initial 100 MB/D plant. A conservative development schedule was then followed, which involved delaying start of the second plant until the initial plant had demonstrated the feasibility of commercial operation.

Cases II and III in this report reflect the 400

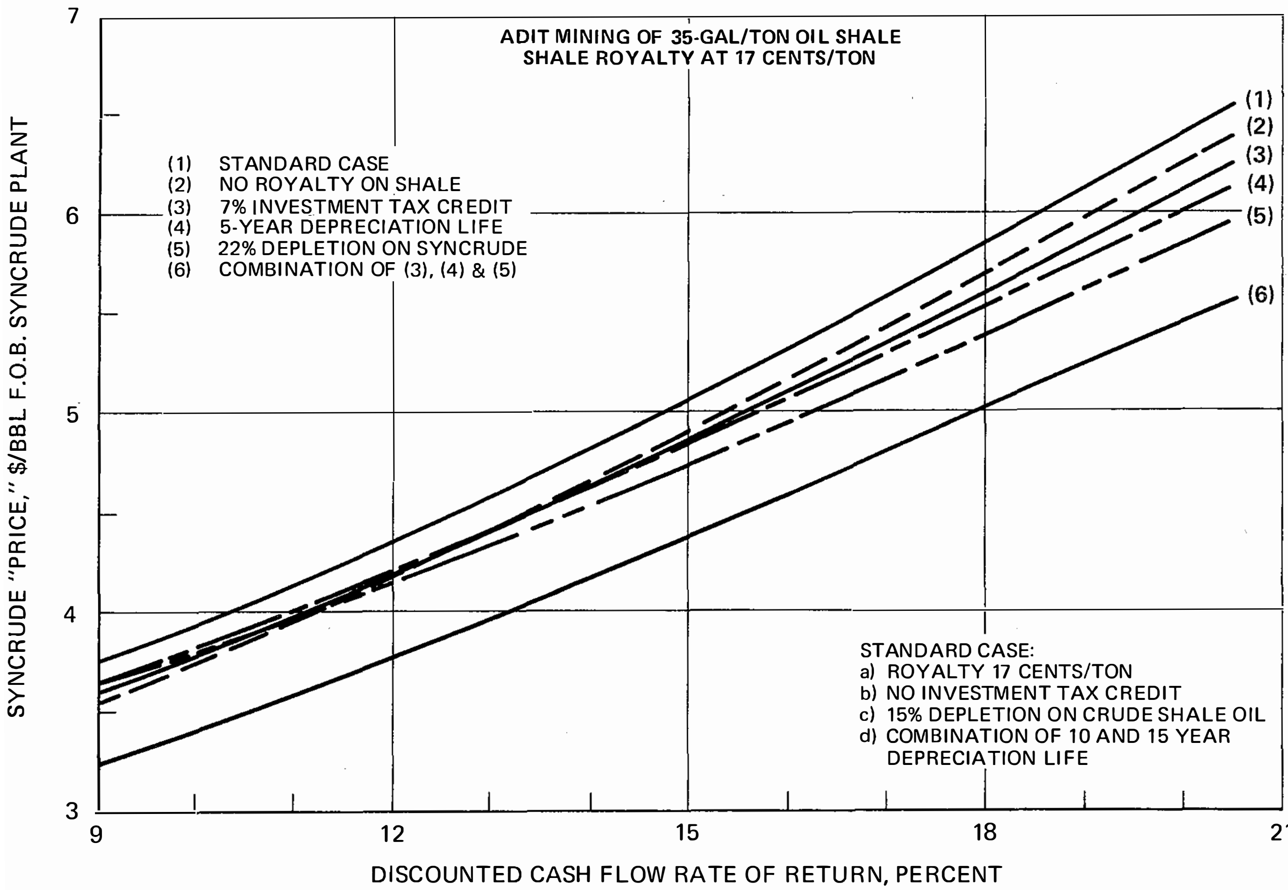


Figure 90. Changes in Government Tax and Royalty Policies (Constant 1970 Dollars).

MB/D buildup schedule. Figure 87 shows this schedule, along with the Case I and Case IV schedules mentioned earlier.

Financing is not a subject of this present study. Each company entering into this activity probably will utilize different ratios of debt to equity and will evaluate the project by its own rate of return standards.

Parametric Studies

A number of parameters were evaluated to quantify as much as possible their effect on syncrude "price" and potential supply. The specific areas considered were government policies in leasing, taxing and environmental controls, and technology improvements resulting from research and development and from improved efficiency as plants are constructed and operated. The base investment and operating costs evaluated in the parametric studies are shown in Table 131.

Government Leasing Policy

Federal leasing policies are an important parameter because about 80 percent of the oil shale resources of the Green River Formation in Colorado, Utah and Wyoming are in federal holdings. As indicated in Table 130, sufficient higher grade oil shale is in private ownership in the Piceance Basin to allow realization of the production level in Cases II and III, but public lands would be required to exceed that level.

The present law permits leases totaling not more than 5,120 acres for each owner. This is not sufficient to encourage industry development because (1) it does not provide adequate higher quality shale for continued long-term operation with second-generation plants by the same party and (2) it does not allow a single operator sufficient reserves to sustain a 100 MB/D operation. Minimum holdings of 10,000 to 20,000 acres per state are needed to provide adequate minable shale in the Mahog-

TABLE 132

ECONOMIC EFFECT OF GOVERNMENT TAX AND ROYALTY POLICIES*

Syncrude "Price" ($/bbl) f.o.b. Plant	(1) Standard Case†	(2) No Royalty on Shale	(3) 5-Year Depreciation Life	(4) 7% Investment Tax Credit	(5) 22% Depletion on Syncrude	(6) Combination of (3), (4) & (5)
			DCF Rate of Return (Percent)			
3.50	7.7	8.7	8.5	8.5	8.1	10.5
4.00	10.2	11.1	11.0	11.2	11.1	13.0
4.50	12.5	13.2	13.3	13.5	13.7	15.4
5.00	14.6	15.3	15.6	15.6	16.1	17.9
5.50	16.5	17.2	17.8	17.6	18.4	20.2
6.00	18.4	19.0	19.9	19.5	20.4	22.5
			Increase in DCF Rate of Return (Percent)			
3.50		1.0	0.8	0.8	0.4	2.8
4.00		0.9	0.8	1.0	0.9	2.8
4.50		0.7	0.8	1.0	1.2	2.9
5.00		0.7	1.0	1.0	1.5	3.3
5.50		0.7	1.3	1.1	1.9	3.7
6.00		0.6	1.5	1.1	2.0	4.1

* For all of these cases, the application of depletion allowance is restricted to not more than 50 percent of taxable income for any given year.

† Based on adit mining of 35-gallon per ton oil shale with royalty on shale at $0.17 per ton; constant 1970 dollars.

any or other rich zones for a long-term commercial operation. A policy which makes government reserves available in adequate quantities and permits an individual company to hold, per state, at least double the present limit of 5,120 acres would therefore be essential. Further, any acreage limitation should not be applied to reserves actually under commercial development. Development will thus be encouraged by permitting additional acreage to be obtained as commercial operation proceeds in response to demand for more oil.

Government Tax and Royalty Policies

Table 132 and Figure 90 show the effect of various tax and royalty policies on syncrude "price" for 35-gallon per ton shale at a 15-percent DCF rate of return. These analyses indicate that:

- Increasing the depletion allowance from the present 15 percent on crude shale oil to 22 percent on syncrude will permit reduction in the calculated syncrude "price" of $0.35 per barrel.
- Continuing the recently instituted investment tax credit of 7 percent reduces the calculated syncrude "price" $0.26 per barrel.
- Decreasing present depreciation life of 10 years on mining capital and 15 years on plant capital to 5 years on all capital, as proposed in current legislation, will reduce the calculated syncrude "price" $0.23 per barrel.
- Suspending the present Federal Government royalty on oil shale, graduating up to $0.17 per ton for 35-gallon per ton shale, will reduce calculated syncrude "price" $0.19 per barrel.
- The combined effect of increased depletion allowance, investment tax credit and shorter depreciation life reduces required syncrude "price" by $0.70 per barrel. Applying this reduction to the first plant would give a required

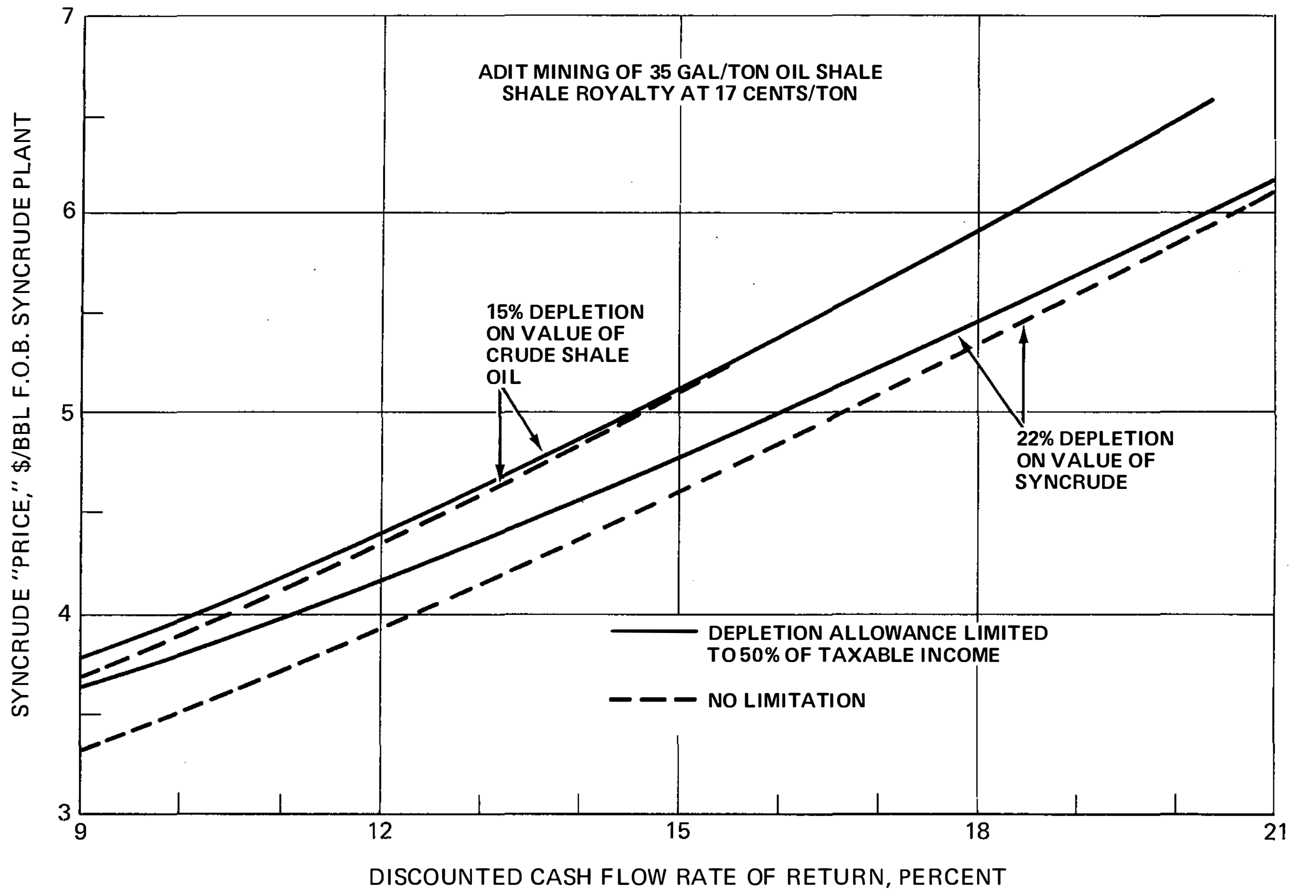


Figure 91. Removal of Taxable Income Limitation in Calculation of Depletion Allowance (Constant 1970 Dollars).

syncrude "price" in the range of $4.40 to $4.60 per barrel.

Present law limits the application of depletion allowance to not more than 50 percent of the taxable income. Removal of this limitation would have a negligible effect under the present law which provides only 15-percent depletion allowance on the crude shale oil value (see Table 133 and Figure 91).

Government Health and Safety Laws and Environmental Controls

Based on a survey of the mining and plant construction industries, capital and operating costs given in Table 131 provide sufficient allowance to meet present-day environmental standards and mine health and safety laws.

Additionally, Table 131 includes capital and operating costs for the disposal of spent shale. If above ground disposal is not allowed or if reclamation requirements change, the disposal allocation will be insufficient. Other environmental control costs will also increase if legislation becomes more restrictive. The sensitivity of syncrude "price" to these factors was analyzed by two cases in which investment was increased in response to the need for additional environmental controls. In one case, shown in Table 134 and Figure 92, the investment was made during the normal construction period. In the other case (Table 135 and Figure 93), the investment was made in equal increments over the first 15-year operating period of the project. Annual operating costs related to the new equipment were assumed to be 5 percent of the additional investment.

The effect of the above factors can best be seen by considering the following specific example. A

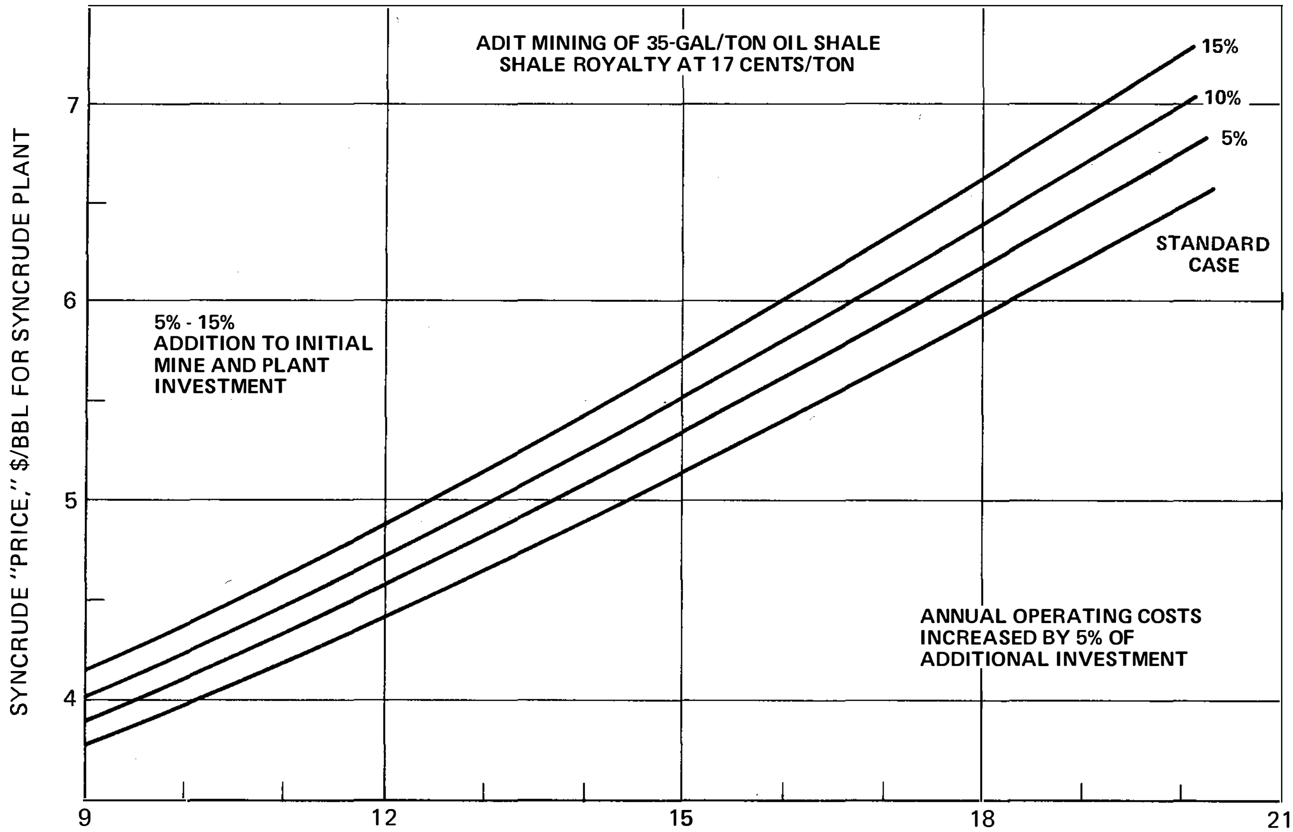


Figure 92. Effect on Required "Price" of Increased Initial Investment and Resultant Operating Costs for Environmental Control (Constant 1970 Dollars).

10-percent increase in the total initial mine and plant investment would amount to $450 B/D of syncrude capacity. At a 15-percent DCF rate of return, this investment, plus an attendant increase in operating costs of $0.06 per barrel, would increase the required syncrude "price" $0.40 per barrel. This same additional investment, only made in equal increments over a 15-year period and with comparable increases in operating costs, would increase required syncrude "price" by only $0.15 per barrel.

Environmental control problems which cause a prolonged delay in normal project startup after completion of construction could be another important parameter. A delay of this kind could result from unanticipated and more restrictive changes in regulations requiring that additional equipment be purchased and installed prior to startup. Aside from the effect of the added investment and operating costs, which have already been evaluated, the economic effects of such a delay are substantially shown in Table 136 and Figure 94. For example, at 15-percent DCF rate of return, a 12-month delay would increase the required syncrude "price" by $0.55 per barrel.

Technological Changes

Technological improvements in producing and upgrading shale oil, resulting in reduced syncrude cost, may be anticipated to occur as the industry develops. Some of the improvements will come about as designers and operators become more experienced and familiar with the processes and equipment. Removal of bottlenecks in mine and plant operation, construction of larger and more efficient process units, increased automation and technological innovation will also assist in cost reduction.

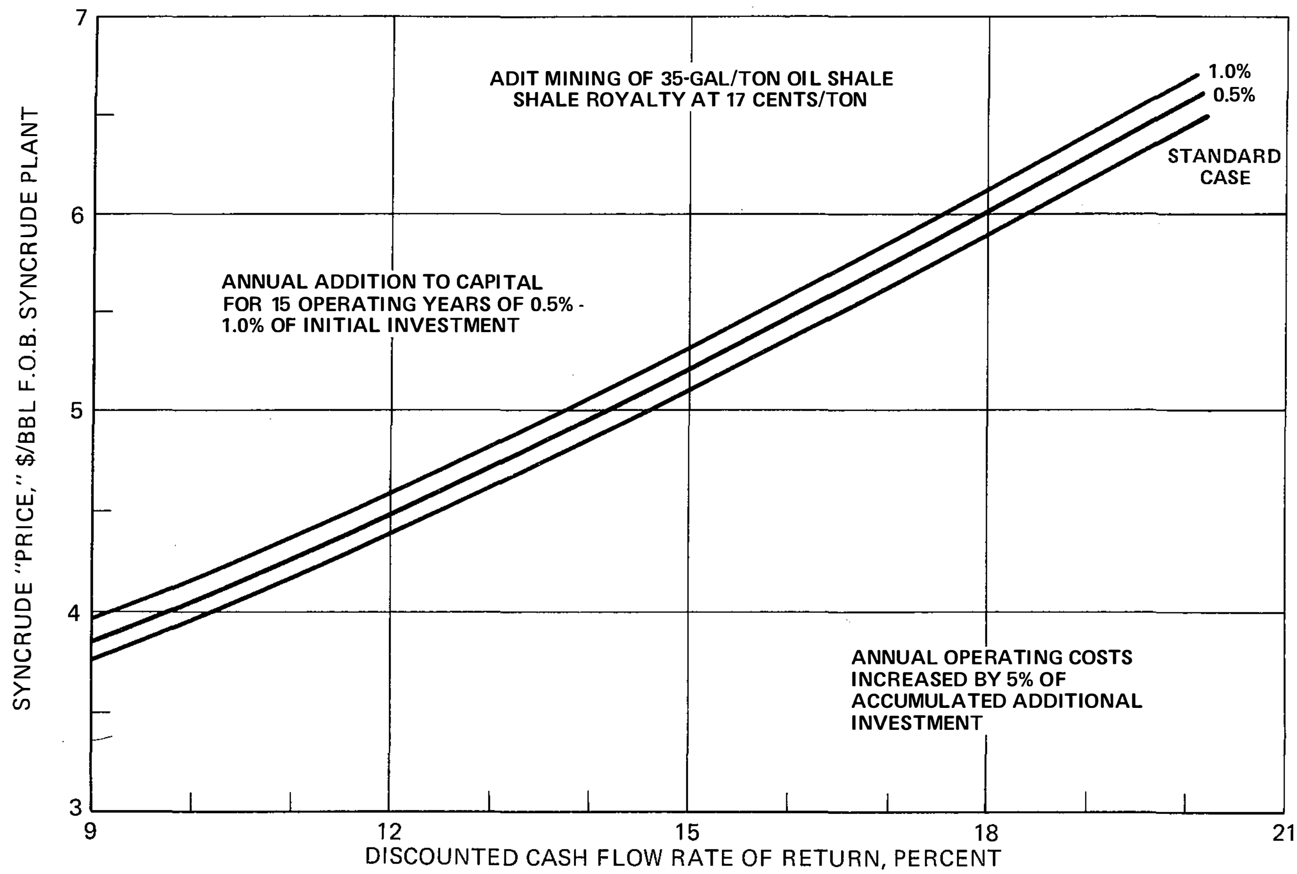


Figure 93. Effect on Required "Price" of Equal Annual Additions to Investment and Resultant Operating Costs for Environmental Control (Constant 1970 Dollars).

No attempt is made in this study to quantify these effects. However, Figure 95 was prepared to provide a measure of the sensitivity of syncrude "price," required for a stated DCF rate of return, to an across-the-board reduction or increase in capital or operating costs. The effects shown are reasonably accurate for a range of 80 to 120 percent of the costs shown in Figure 86. The effects on syncrude "price" from changes in capital and operating costs are additive.

Improvements in mining equipment and methods that may be anticipated include making room-and-pillar mining less costly by use of large, mobile crushers and conveyor systems. More radical changes might be postulated, such as the development of continuous mining machines for oil shale.

Modifications and further improvement in the efficiency and operability range of present-day oil shale retorting processes may be expected. The recycled hot solids type of retort was used in the Initial Appraisal cost estimates because it can handle 35-gallon per ton shale satisfactorily. Potential improvements appear mainly to be an increase in size and capacity of individual units. Modifications to design and operation of the hot-gas retort to permit it to be used for 35-gallon per ton shale, with good yield, would also contribute important retorting advances.

Improvements in shale oil upgrading catalyst and modification of the processing scheme may reduce both capital and operating costs.

Development of feasible and economic *in situ* methods are important for eventual recovery of the deeply buried oil shale resources in the Green River Formation. At present, *in situ* retorting appears to have a potential for producing shale oil from these strata. It is assumed, however, that no

TABLE 133

ECONOMIC EFFECT OF REMOVING TAXABLE INCOME LIMITATION FROM DEPLETION ALLOWANCE CALCULATION

Syncrude Price ($/bbl) f.o.b. Plant	15% Depletion on Value of Crude Shale Oil: 50% Limit*	15% Depletion on Value of Crude Shale Oil: No Limit	22% Depletion on Value of Syncrude: 50% Limit	22% Depletion on Value of Syncrude: No Limit
	DCF Rate of Return (Percent)			
3.50	7.7	8.1	8.1	9.9
4.00	10.2	10.5	11.1	12.3
4.50	12.5	12.6	13.7	14.6
5.00	14.6	14.7	16.1	16.7
5.50	16.5	16.6	18.4	18.8
6.00	18.4	18.4	20.4	20.7
		Increase in DCF Rate of Return (Percent)		
3.50		0.4	0.4	2.2
4.00		0.3	0.9	2.1
4.50		0.1	1.2	2.1
5.00		0.1	1.5	2.0
5.50		0.1	1.9	2.3
6.00		0.0	2.0	2.3

* Standard Case: Adit mining of 35-gallon per ton oil shale; royalty on shale at $0.17 per ton; constant 1970 dollars.

TABLE 134

ECONOMIC EFFECT OF INCREASED INITIAL INVESTMENT FOR ENVIRONMENTAL CONTROL

Syncrude Price ($/bbl) f.o.b. Plant	Return on Base Investment*	Increase in Total Initial Investment†: 5%	10%	15%
	DCF Rate of Return (Percent)			
3.50	7.7	7.0	6.4	5.9
4.00	10.2	9.6	9.0	8.4
4.50	12.5	11.8	11.2	10.6
5.00	14.6	13.8	13.1	12.5
5.50	16.5	15.7	15.0	14.3
6.00	18.4	17.5	16.8	16.0
		Reduction in DCF Rate of Return (Percent)		
3.50		0.7	1.3	1.8
4.00		0.6	1.2	1.8
4.50		0.7	1.3	1.9
5.00		0.8	1.5	2.1
5.50		0.8	1.5	2.2
6.00		0.9	1.6	2.4

* Based on adit mining of 35-gallon per ton oil shale with royalty on shale at $0.17 per ton; constant 1970 dollars.

† Effect shown on DCF rate of return includes the effect of increased annual operating costs related to increased initial investment in equipment and assumed to equal 5 percent of the additional investment. A 20-year operating period is assumed for each installation.

TABLE 135

ECONOMIC EFFECT OF EQUAL ANNUAL ADDITIONS TO INVESTMENT OVER 15 YEARS FOR ENVIRONMENTAL CONTROL

Syncrude Price ($/bbl) f.o.b. Plant	Return on Base Investment*	Annual Addition to Initial Capital Investment†: 0.5%	1.0%
	DCF Rate of Return (Percent)		
3.50	7.7	7.1	6.6
4.00	10.2	9.8	9.3
4.50	12.5	12.1	11.6
5.00	14.6	14.2	13.7
5.50	16.5	16.1	15.7
6.00	18.4	18.0	17.6
		Reduction in DCF Rate of Return (Percent)	
3.50		0.6	1.1
4.00		0.4	0.9
4.50		0.4	0.9
5.00		0.4	0.9
5.50		0.4	0.8
6.00		0.4	0.8

* Based on adit mining of 35-gallon per ton oil shale with royalty on shale at $0.17 per ton; constant 1970 dollars.

† Investment assumed to be made in equal increments over the first 15 years of a 20-year operating period. Resultant decrease in DCF rate of return includes the effect of incremental additions to annual operating costs related to the increased investment in equipment and assumed to be 5 percent of the accumulated incremental investment.

TABLE 136

ECONOMIC EFFECT OF PROLONGED START-UP DELAY

Syncrude Price ($/bbl) f.o.b. Plant	Standard Case*	Delay in Initiating Start-Up†: 12 Months	24 Months
	DCF Rate of Return (Percent)		
3.50	7.7	7.0	6.4
4.00	10.2	9.2	8.4
4.50	12.5	11.1	10.1
5.00	14.6	12.9	11.6
5.50	16.5	14.5	13.0
6.00	18.4	16.1	14.3
		Reduction in DCF Rate of Return (Percent)	
3.50		0.7	1.3
4.00		1.0	1.8
4.50		1.4	2.4
5.00		1.7	3.0
5.50		2.0	3.5
6.00		2.3	4.1

* Based on adit mining of 35-gallon per ton oil shale with royalty on shale at $0.17 per ton; constant 1970 dollars.

† Operating costs during delay were charged at 25 percent of normal costs. No income during delay; project life extended by length of delay.

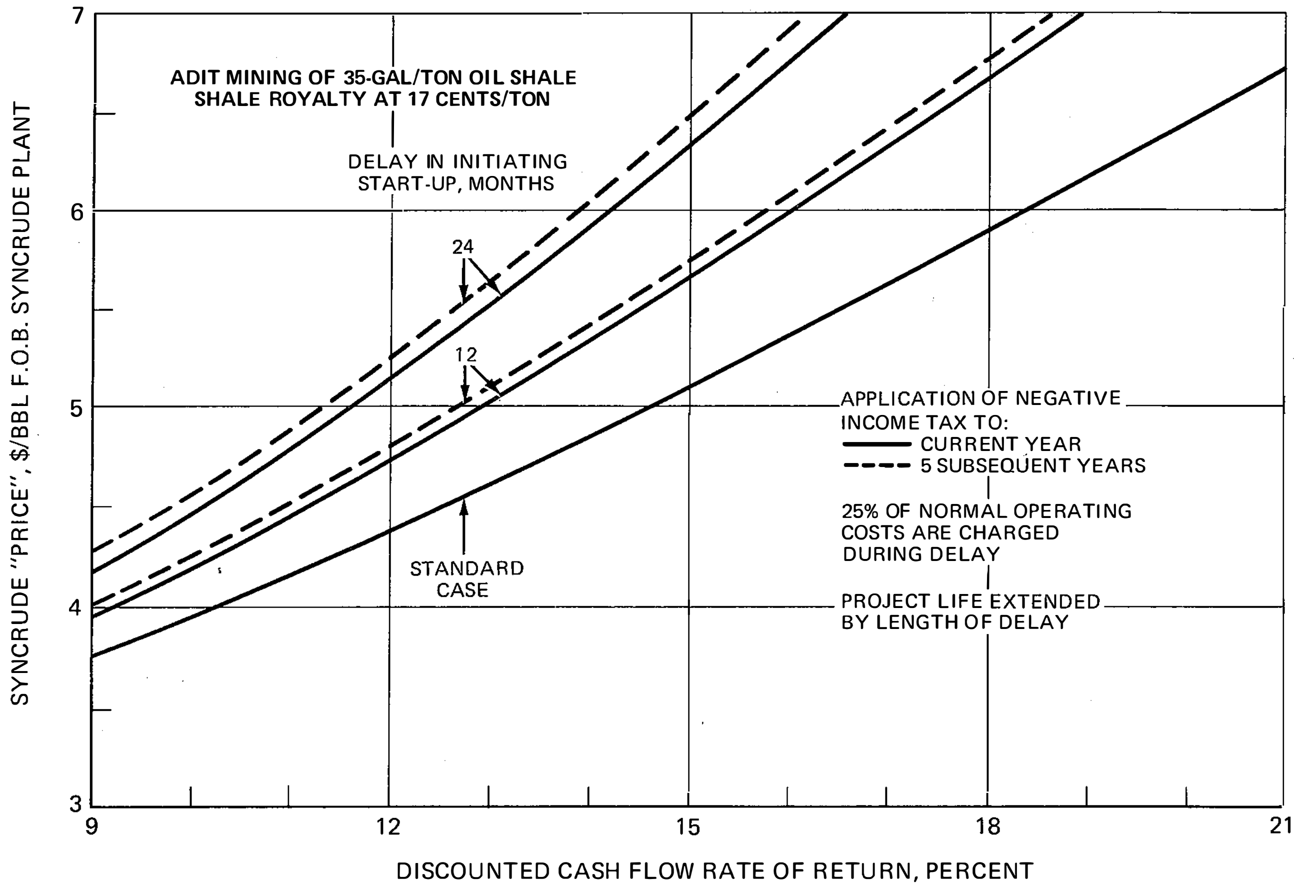


Figure 94. Prolonged Delay in Initiating Startup (Constant 1970 Dollars).

significant commercialization will occur before 1985 because of the considerable amount of development work that is necessary.

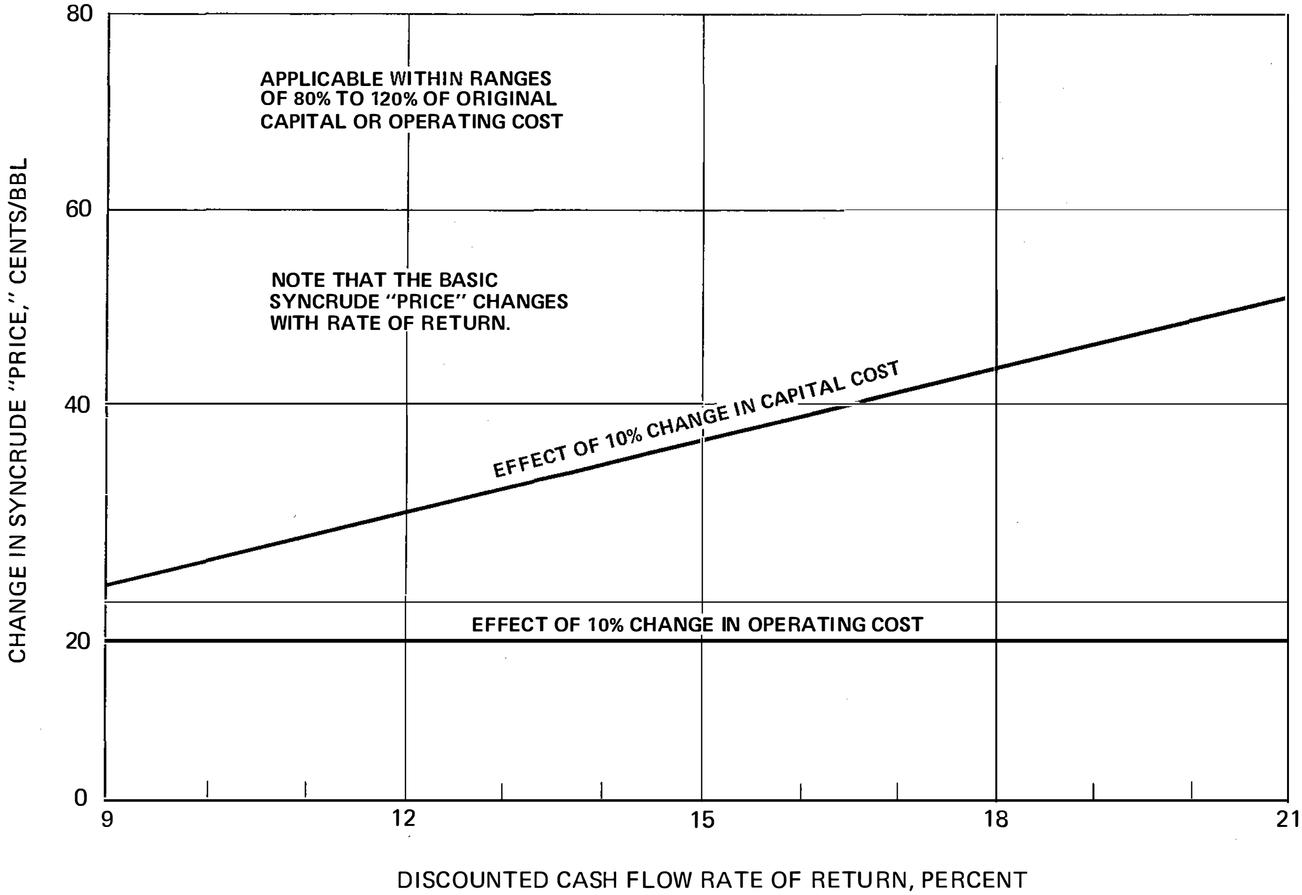
Direct Regional Support

Resources from the surrounding region, which will provide direct support of a shale oil industry, include manpower, water, electric power, secondary roads, pipelines and community services. Estimates of these needs have been made to provide guidance as to the external demands occasioned by development of commercial syncrude production.

A total of 1,700 permanent employees is estimated for a first-generation 100 MB/D syncrude installation including mines, retorting plants and upgrading facilities. The number of construction personnel for this installation may average 1,800 over the 3-year construction period, peaking at 3,800 during the final year. By 1985, direct resource needs anticipated for the Case I, 750 MB/D development rate, are—

- Permanent employees—12,750
- Temporary construction personnel—7,200
- Mine and plant water requirement (acre-feet per year)—124,000
- Electric power generation (KW)—825,000
- Power plant water requirements (acre-feet per year)—6,000
- Cost of constructing secondary roads—$20,000,000.

Primary roads, pipelines and community services would need expansion to fully provide for the above level of syncrude production.



Note: Effects on "price" from changes in capital and operating costs are additive.

Figure 95. Sensitivity of Syncrude "Price" to Change in Capital and Operating Costs (Constant 1970 Dollars).

Chapter Eight
Tar Sands Availability

Introduction

This chapter discusses the possibilities that exist in North America for commercial development of tar sands and heavy oils deposits. The terms "tar sands," "oil sands" and "bituminous sands" are all used to describe hydrocarbon-bearing deposits distinguished from more conventional oil and gas reservoirs by the high viscosity of the hydrocarbon, which is not recoverable in its natural state through a well by ordinary oil production methods. Reservoir energy is typically nonexistent or minimal so that for production to be initiated and sustained, some form of energy (heat, fluid pressure, mechanical work by mining machinery, etc.), must be applied. Large tar sands deposits are located in Canada, Venezuela and, probably, Colombia. Much smaller deposits are known in the United States and in the Eastern Hemisphere. Heavy oils, also discussed in this chapter, are defined as those oils requiring thermal stimulation for primary recovery of reserves. Canada has large deposits of such heavy oils.

Summary and Conclusions

The Canadian tar sands and heavy oils deposits, located in Alberta, will probably be the only source of commercial production of this material for the North American market through 1985. However, production from this source is projected to make only a minor contribution to the satisfaction of total North American energy needs during this period. The Initial Appraisal estimates of likely production volumes from deposits in Canada are summarized as follows:

1975	50— 75	MB/D
1980	275— 500	MB/D
1985	500—1,250	MB/D

For this report, the conclusions of the Initial Appraisal are unchanged.

Domestic Tar Sands

A review of the information on the extent and quality of domestic tar sands resources and of current, very preliminary knowledge about the technology and likely costs of exploiting these resources, reaffirms the conclusion reached in the Initial Appraisal that the total possible rate of output attainable from *domestic* tar sands would be minimal in the total U.S. energy supply/demand balance, even to the year 2000.

The Initial Appraisal cited only five deposits in Utah as being potentially large enough, based on existing information, to possibly support some eventual commercial exploitation. These deposits and their estimated in-place resources are listed in Table 137.

These estimates of in-place resources are based on very sketchy data and may be overstatements. Even if the volumes are realistic, physical limitations, the absence of a developed exploitation technology, uncertainties associated with federal and state leasing policies and ecological questions as

TABLE 137

ESTIMATED IN-PLACE RESOURCES OF UTAH TAR SANDS DEPOSITS
(Billion Barrels)

Tar Sand Triangle	10.0 – 18.1
P. R. Spring	3.7 – 4.0
Sunnyside	2.0 – 3.0
Circle Cliffs	1.0 – 1.3
Asphalt Ridge	1.0 – 1.2
Total	**17.7 – 27.6**

yet undefined will curtail the extent of reserves available for production and will delay or inhibit exploitation of some areas.

It is very questionable as to whether the Athabasca technology is transferable directly to the Utah deposits because the Utah sands are believed to be much harder and therefore more difficult to produce. When the quantity of reserves which must be dedicated to an individual producing operation under any reasonable assumptions about venture economics is considered, it becomes clear that the number of such operations would have to be small, and their aggregate output would be insignificant in the total U.S. energy supply picture. Thus, physical and other limitations to development make it apparent that total production from Utah reserves could never be much greater than 500 MB/D. Production is unlikely by 1985, and it is also doubtful that any but token "demonstration" production could be in service by the year 2000.

It is believed that any reasonable changes in existing government policies in land use, parks requirements, minerals and hydrocarbons leasing, or water rights would not materially affect the importance of the U.S. tar sands deposits to the U.S. energy picture by 1985. Industry interest in these deposits is minimal as there are other, more promising sources of supplemental domestic energy.

Canadian Tar Sands

The outlook for development of Canadian tar sands is more promising. One commercial plant is in operation, and others are in various stages of planning. The reserves in Alberta, estimated at about 400 billion barrels of bitumen (equivalent to 174 billion barrels of syncrude) in the Initial Appraisal, are much larger than those in the United States, and the sands seem better suited to extraction than the more consolidated Utah deposits. Despite the large total size of the tar sands and heavy oil reserves in Canada, it is believed that the rate of production by 1985 will not exceed about 1.25 MMB/D regardless of possible rises in competitive energy values. This is because technological development and construction lead time, and possibly construction industry saturation and capital availability, will limit the rate of installation of new plants.

In developing estimates of potential Canadian petroleum exports to the United States, tar sand oil was considered along with conventional crude oil. No attempt was made to identify the relative proportions of these materials that would ultimately be consumed in Canadian and U.S. markets.

Chapter Nine
Hydroelectric, Geothermal and New Energy Forms

Introduction

This chapter discusses the contribution to the Nation's energy requirements that can be made by (1) energy resources which are projected to provide a relatively small amount of usable energy during the 1981-1985 period or (2) processes which can increase the efficiency of present fossil-fuel energy utilization for the generation of electric power. Hydropower represents a form of primary energy, the full potential of which has largely been developed. Geothermal energy is largely undeveloped at present but make a larger (though still relatively insignificant) contribution by 1985. Potentially available solar energy is not likely to be exploited significantly within the time frame of this study.

The combined-cycle process for generating electric power is the technological innovation most likely to make a significant impact on the efficiency of fossil-fuel utilization. In the order of their potential significance by 1985, other processes likely to boost electric power generation from the same amount of fuel are: (1) gasification of coal for combined-cycle use and (2) fuel cells. Magnetohydrodynamics (MHD) and thermionic topping of fossil-fuel power plants if successful are more likely to appear after 1985.

Hydroelectric Energy

Summary and Conclusions

Good sites for hydropower dam construction in the United States have largely been developed, and only scattered small sites remain. Therefore, the use of hydropower will grow more slowly than use of other energy sources, declining to a 3-percent share of national energy requirements by 1985.

Hydroelectric Energy Supply

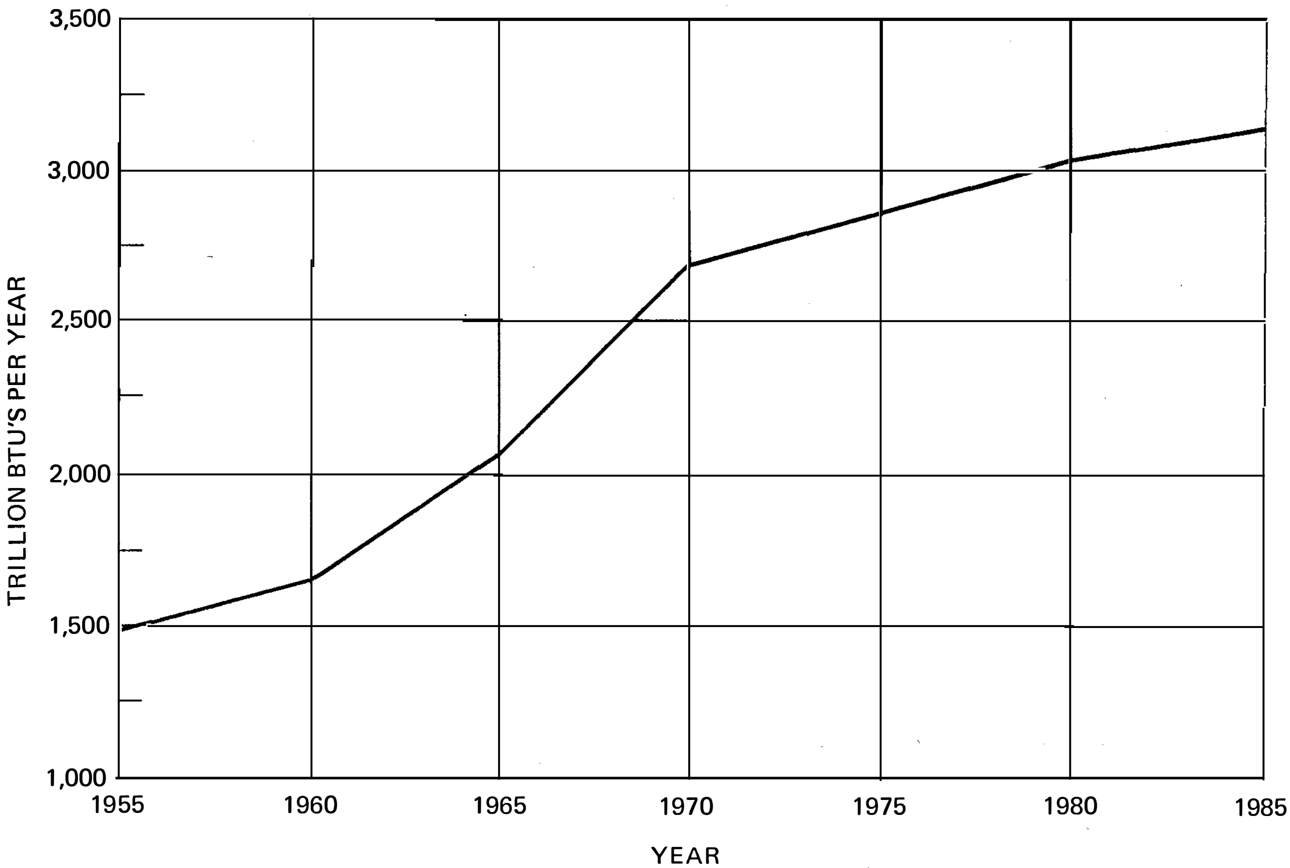
In 1971, conventional hydroelectric energy supplied approximately 16 percent (249 billion KWH) of the U.S. energy requirements for electric power generation, or 4 percent of total U.S. energy production. This share is expected to decline to 3 percent in 1985 because few usable sites remain for significant development of hydroelectric energy in the United States. Energy from hydroelectric sources is projected to grow only 1.6 percent per year in the period until 1985, primarily through development of small sites of less than 200 MWe capacity located in the western areas of the country (see Figure 96). If this projection proves reliable, about 60 percent of the U.S. potential conventional hydroelectric energy will have been harnessed in 1985, with the undeveloped potential consisting of widely scattered small sites that may never be developed for economic reasons. The somewhat doubtful economic feasibility of small sites, as well as the impact of environmental regulations, may make even the projection of 60 percent optimistic.

Pumped-storage hydroelectric plants will find increasing use by 1985 as an economical way of *storing* energy (not as a primary energy source). Nuclear power plants will serve as the primary energy source and in off-peak hours will pump water into storage reservoirs. Since they will be used for peak-load power generation, the pumped-storage plants will compete with the gas turbine generators which are now largely used for that purpose.

Geothermal Energy

Summary and Conclusions

Where hot portions of the earth's crust are in close enough proximity to underground water



SOURCE: NPC, U.S. Energy Outlook: An Initial Appraisal 1971-1985, *Vol. I and II (1971).*

Figure 96. Total U.S. Energy from Conventional Hydroelectric Sources.

sources, the resulting steam can be utilized to drive conventional steam turbine generators. Efforts are also being made to use hot geothermal water with a heat exchange system. However, even if geothermal energy sources (steam wells, hot water) are developed at a relatively optimistic rate, they probably will supply only 1 percent of U.S. energy requirements in 1985. Projection of energy to be derived from geothermal sources is subject to great uncertainty.

Geothermal Energy Supply

Cases I through III assume that large areas will be available for prospecting, including the recently opened federal lands, to encourage exploration in the next 4- to 5-year period. Case III is identical to the Initial Appraisal estimate, and Case IV is a 50-percent reduction of Case III.

The success ratio in exploration and drilling during the next 4 to 5 years will have a vital bearing on future exploration and, accordingly, total energy from localized geothermal resources. No experience presently exists with respect to a finding rate as a function of total area explored or the number of feet drilled. Variations in the success ratio for dry-steam reservoirs, similar to the Geysers area in northern California, are reflected in the curves in Figure 97 which show energy projections for geothermal energy. The Case III curve, which shows 7,000 MWe being developed by 1985, could be reduced as much as 50 percent with poor success in exploration and drilling in new areas. This possibility results in the Case IV projection of 3,500 MWe by 1985. If the success ratio is particularly good, increases could be about 25 percent above the Case III pro-

TABLE 138

IN SITU* HEAT RESOURCES
(Quadrillion BTU's)

Geothermal Target	Reserve Target for 1985	Resource Base
Localized Hydrothermal Systems, down to 2 Miles Deep	5.6	560
Localized Hydrothermal Systems, down to 6 Miles Deep	2.8	2,800
High-Enthalpy Waters, Sedimentary Basins	119	64,000
Magma Chambers, Within Depths of a Few Miles	119	120,000 – 400,000
Low-Enthalpy Waters, Sedimentary Basins	635	640,000
Cratonic and Platform Areas, down to 6 Miles	2,000	20,000,000

* For comparison, heat of combustion of 1 barrel of oil is 5.8 million BTU's. The *recoverable* amounts of heat are one to two orders of magnitude lower than the *in situ* figures shown in this table.

TABLE 139

CONSTRAINTS TO GEOTHERMAL RESOURCE DEVELOPMENT

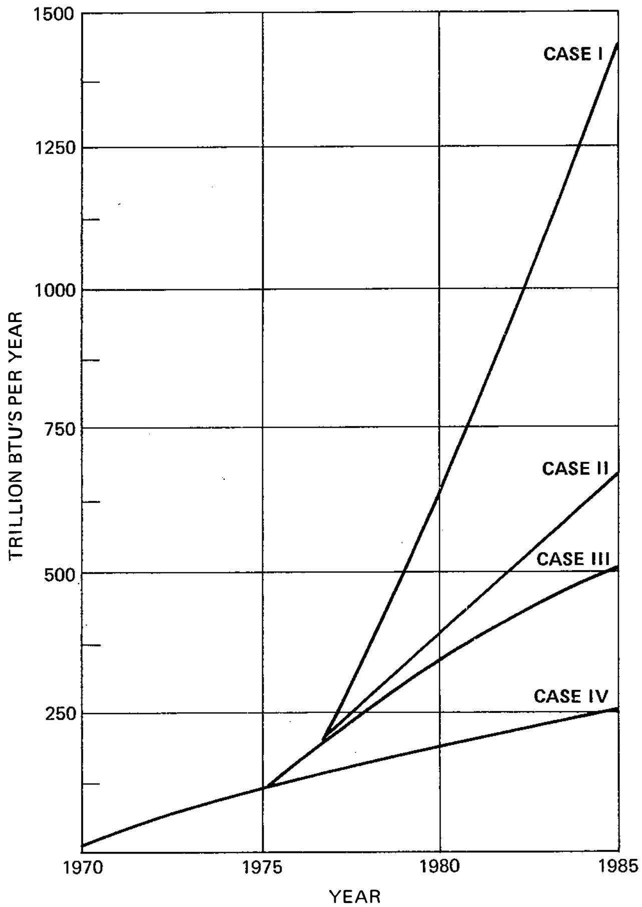
Geothermal Target	Current Constraints	Subsequent Constraints	Outer Contingency
Localized Hydrothermal Systems down to 2 Miles Deep	Leasing, Exploration Economics	Small Resource Base	Air and Water Pollution
Localized Hydrothermal Systems down to 6 Miles Deep	Economics	Leasing, Exploration	Air and Water Pollution
High-Enthalpy Waters Sedimentary Basins	Exploration, Deep Drilling	Economics	Brine Disposal and Utilization
Magma Chambers Within a Depth of a Few Miles	Exploration R&D Magmas	Economics	Unknown
Low-Enthalpy Waters Sedimentary Basins	R&D, Power Generation	Exploration, Economics	
Cratanic and Platform Areas, down to 6 Miles	R&D, Plowshare	Economics	Radioactive Pollution

jection. This is shown in Case II which indicates a level of 9,000 MWe by 1985. The top curve (Case I) assumes that technology for hot water systems will be available in 1977.

Parameters Affecting Geothermal Energy Supply

By 1985, a level of proved *recoverable* heat reserves could be established, ranging from 29 to 290 quadrillion BTU's (see Table 138). This is providing that existing constraints as identified in Table 139 are resolved.

The potentially more important geothermal targets are deep sedimentary basins, cratons and platforms, and shallow magma chambers. The main constraining factors, which vary with the type of target, are (1) uncertainty about the magnitudes of the recoverable reserves and resource bases and



NOTE: In 1985, Case I represents 19,000 MWe of installed capacity; Case II, 9,000 MWe; Case III, 7,000 MWe; Case IV, 3,000 MWe.

Figure 97. Total U.S. Energy from Geothermal Sources.

(2) insufficient or absence of research and development on certain technical questions.

Lease Costs

At present, lease costs and landowner royalties are below those currently paid by the petroleum industry. However, success in developing geothermal resources will stimulate competition for leases and will likely cause these costs to increase.

Exploration Technology

At the present time there is no exploratory tool for locating geothermal deposits such as the reflection seismograph used for locating oil and gas structures. There are several geophysical methods being used at the present time, but with limited success. Progress depends primarily on the ability to drill deeper exploratory holes.

Depletion Allowance

Estimates which have been made for the development rate of geothermal energy are based on the assumption that the depletion allowance of 22 percent will continue to be in effect. If the depletion allowance were abolished, the average cost of steam will increase from 2.75 to 3.10 mills per KWH. Although this would not affect power costs significantly, it would discourage the development of some geothermal areas.

Environmental Impact

It is expected that geothermal energy development will have few environmental effects. However, the time required to develop environmental impact statements and handle possible lawsuits and the threat of court injunctions would significantly slow the pace of geothermal exploration and development.

Productivity

In most of the future fields, condensed steam and hot water will have to be injected into the ground and, in many cases, directly back into the reservoir. Although this has been accomplished experimentally in both dry-steam and hot-water fields, the effects on reservoir pressures and temperatures are not yet known. If the productivity of a field is adversely affected by injection, it may be offset by increased longevity of production.

New Energy Forms

Summary and Conclusions

In order to affect significantly the national average efficiency of electric power generation in 1985, new innovations would have to be technologically proved already. This is because existing electric generating plants have a life span of several decades, and new plants have long construction lead times. Only one such technological innovation—the gas turbine and steam turbine combined-cycle plant—is currently available. This plant utilizes waste heat from large gas turbines to generate steam for conventional steam turbines. Its advantage is that it generates more electricity from the same amount of fuel than does a gas turbine powered generating unit. The best combined-cycle plants that might be built in 1985 are projected as using almost 30 percent less fuel per KWH generated than conventional plants being built in 1972. Nevertheless, due to the large number of existing plants, the national "heat rate" (BTU requirement per KWH generated) is projected to decline only 8 percent from 10,666 BTU's per KWH in 1972 to 9,800 BTU's per KWH in 1985.

Gasification of coal to low-BTU gas for most existing steam-electric utilities and large industrial plants is not likely to be economical. However, when compared to the cost of stack gas scrubbing processes or the burning of clean fossil fuels, gasification of coal for use in new combined-cycle plants looks attractive.

Fuel cells might find widespread commercial application by 1985. However, fuel cells are no more efficient than other means of generating electric power, and they are unlikely to have a major effect on total energy requirements. Total energy plants have a high system fuel efficiency but their economics are expected to keep their contribution small during the period.

Other devices for increasing the efficiency of energy utilization include MHD and thermionic devices for topping of fossil-fuel plants. None of these devices is expected to reach the stage of widespread commercial development by 1985.

Other energy sources, including solar energy and energy from agricultural products, are unlikely to make a significant contribution prior to 1985.

Energy Conversion to Electric Power

The utilization of gas turbines in combination with steam turbines is the technological innovation most likely to promote efficient use of fossil fuels in the generation of electricity. Combined-cycle (Brayton-Rankine) plants utilize the presently wasted hot exhaust from gas turbines to generate steam for conventional steam-electric generators. An additional increment of electricity is thus obtained with the same level of fuel consumption. This improvement in the efficiency of energy utilization in steam-electric plants is commonly expressed in terms of the heat rate. Changes in the national average of the heat rate will be slow due to the fact that so much installed capacity exists and the ultimate replacement of current power plants and those on order through 1980 will not occur until well beyond the year 2000.

Combined-cycle plant capacity is likely to grow rapidly from zero in 1972 to about 90,000 MWe in 1985 (see Table 140). By 1985 the combined-cycle could account for over one-third of the new fossil-fuel plant capacity.

Heat rate improvement in the gas turbine from 9,200 BTU's per KWH in 1972 to 7,000 BTU's per KWH in 1985 appears reasonable. A more rapid improvement in efficiency is assumed in the 1975-1980 period, presumably as new alloys, ceramics and cooling techniques are applied to gas turbines. Improvements would be slower in the 1980-1990 period, approaching a materials limit of about 7,000 BTU's per KWH in 1985.

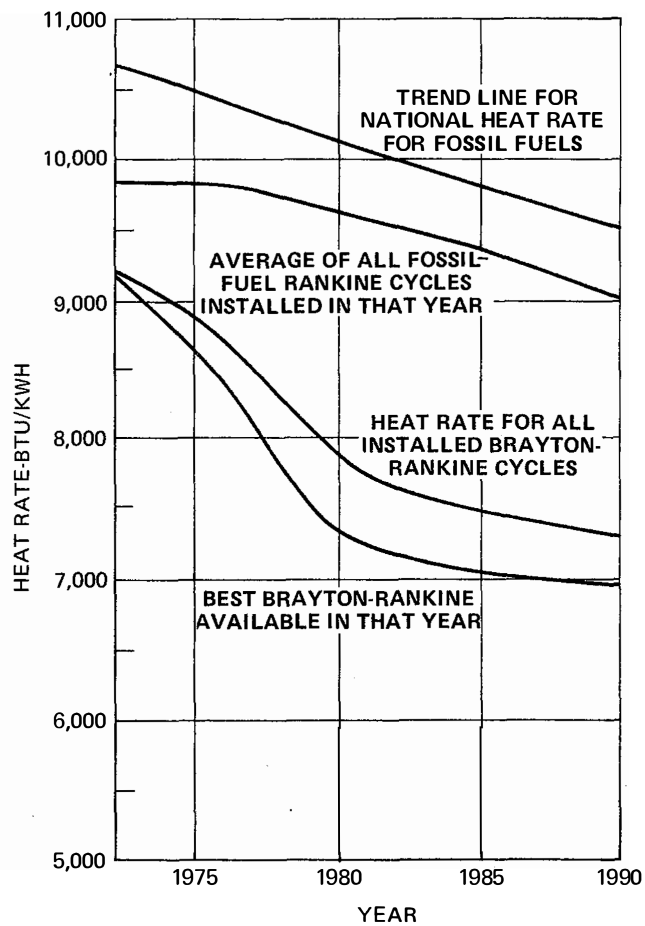


Figure 98. Estimated Trends for Efficiency of Electric Power Generation from Fossil Fuels—1972-1990 (Based on Plant Installation Rates Shown in Table 141).

TABLE 140

HEAT RATE TREND FOR CONVENTIONAL AND COMBINED-CYCLE FOSSIL-FUEL, STEAM-ELECTRIC PLANTS

	Annual Rankine Cycle Plant Additions* (MWe)	Heat Rate Rankine Cycle (BTU/KWH)	Annual Brayton-Rankine Cycle Plant Additions* (MWe)	Heat Rate Brayton-Rankine Cycle (BTU/KWH)	Annual New Fossil Plant Additions* (MWe)
1972	22,000	9,800	0	9,200	22,000
1975	20,000	9,800	2,000	8,600	22,000
1980	15,000	9,600	8,000	7,300	23,000
1985	15,000	9,300	9,000	7,050	24,000
1990	15,000	9,000	10,000	7,000	25,000

* Annual new plant addition rates shown were assumed for the purpose of projecting limits of reduction in the national average heat rate for fossil-fuel steam plants.

The average heat rate of all fossil-fuel plants installed in 1972 was assumed to be 9,800 BTU's per KWH (based upon 50 percent for coal at 9,000 BTU's per KWH, 30 percent for residual oil at 11,000 BTU's per KWH, and 20 percent for gas at 10,000 BTU's per KWH) and was assumed to stay constant for installed steam plants through 1977. The use of cooling towers and stack gas scrubbing for environmental protection purposes will tend to perpetuate relatively high heat rates.

After 1978, the heat rate of conventional Rankine cycle steam plants should begin to improve due to the introduction of higher pressure steam (about 1975) and the use of fluid-bed combustion for residual oil and coal boilers (about 1980). However, the use of residual oil containing sodium and vanadium will tend to keep the overall efficiency of the steam cycle low unless residual oil is gasified or used in fluid-bed boilers. Gasification technology could lead to more rapid improvements in the Rankine cycle.

Heat rate trends are shown in Figure 98. It has been assumed that fossil-fuel plant capacity of 300,000 MWe existed in 1971 with a heat rate of 10,666 BTU's per KWH. The annual operating factor for this capacity was assumed to be 60 percent in 1972, decreasing to 40 percent in 1990 due to increased utilization of the newer, more efficient fossil-fuel and nuclear plants. The conventional Rankine cycle capacity added after 1972 was assumed to have an annual operating factor of 70 percent, as opposed to 50 percent for the combined cycle.

Based on these assumptions, the national heat rate will decrease from 10,666 BTU's per KWH in 1972 to 9,798 BTU's per KWH in 1985 and 9,507 BTU's per KWH in 1990. This represents an improvement in the overall efficiency of fossil-fuel plants of about 8 percent over the 13-year period.

The rate of installation of new fossil-fueled power plants shown in Table 140 and reflected in the trends in heat rates in Figure 98 was selected as a maximum rate for the purpose of analyzing the effect of improved energy conversion on the national average heat rate. The number of fossil plants may be less than that assumed, depending on such factors as the relative costs of fuels, required capital investment, and the lead times for construction and regulatory approval by government of various types of plants.

As shown in Figure 98, the average heat rate for the combined-cycle plants in 1990 would be about 7,300 BTU's per KWH. This is an optimistic schedule for the installed capacity and efficiency trends for combined-cycle plants. Despite the optimism, it is readily seen that the change in the national heat rate over an 18-year period is relatively small.

Technology for gasification of coal to low-BTU gas is available but is not widely used. As shown in Table 141, fixed-bed gasification to low-BTU gas prior to the combined cycle would result in an overall thermal efficiency of 45 percent by 1978. Capital costs of coal gasification plants will be $75 to $85 per KW using the available Lurgi technology. Development of fluid-bed processing for coal gasification to low-BTU gas is about 10 years behind the Lurgi fixed-bed technology. If successful, these R&D programs might reduce costs to $60 to $70 per KW for large plants (500 to 1,000 MWe range). There is some probability that costs will be higher and may even exceed the costs of the Lurgi process which has some latitude for cost reduction.

Stack gas scrubbing processes have been estimated to add an additional $80 per KW (see Chapter Eleven) to the cost of conventional steam plants. Gasification and cleanup costs in the range of $60 to $100 per KW indicate that low-BTU gas from coal will be an attractive alternative for electric utilities. Cleanup costs represent about 25 percent of the total costs. The relatively lower cost for making a low-BTU gas is due to the fact that gasification and sulfur removal occur under pressurized conditions. Sulfur removal uses well-known technology for hydrogen sulfide (H_2S) removal under concentrated pressure conditions.

In general, gasification of coal to low-BTU gas for existing boilers and large industrial users of energy is not likely to be economical prior to 1985. Some large power plants which have relatively efficient cycles (8,500 to 9,500 BTU's per KWH) may find that retrofitting of coal gasification is economically feasible after 1985. The economics would vary for each installation depending on load factor, size of plant, availability of land and the local cost of coal. Capital costs to make low-BTU gas from coal for small users of energy will likely be at least $100 per KW. Considering these costs, the use of refined petroleum fuels or even synthetic fuels from coal will tend to be preferred energy forms.

It is likely that coal gasification can be used economically in conjunction with newly constructed combined-cycle plants. Figure 99 provides several power cost curves for combined-cycle plants, given five different assumptions about plant capital costs and operating costs. As with most fossil-fuel plants, it can be seen that power costs are closely related to fuel costs.

TABLE 141

ESTIMATES ON AVAILABILITY OF COMMERCIAL TECHNOLOGY FOR ENERGY CONVERSION

	Electrical Thermal Efficiency (Percent)	When Available
Stand-Alone MHD	20-25	1980
MHD-Topped Power Plant	50-52	1985
MHD-Topped Power Plant	55-60	1995
Fuel Cells Using Reformed Methane	40-45	1976
Combined Cycle* Using Clean Fossil Fuels	40	1972
Combined Cycle* Using Clean Fossil Fuels	45	1978
Combined Cycle* Using Clean Fossil Fuels	48	1985
Fixed-Bed Gasification of Coal and Combined Cycle*	40	1975
Fixed-Bed Gasification of Coal and Combined Cycle*	45	1978
Fluid-Bed Gasification of Coal and Combined Cycle*	40	1982
Fluid-Bed Gasification of Coal and Combined Cycle*	45	1988
Fluid-Bed Gasification of Coal and Combined Cycle*	48	1992
Fluid-Bed Combustion Coal or Residual Oil—Rankine Cycle	38-41	1980
Thermionic Topping Fossil-Fuel Power Plants	45	1985
Gas Turbine-Brayton Cycle (Clean Fossil Fuels)	28	1972
Gas Turbine-Brayton Cycle (Clean Fossil Fuels)	34	1978
Gas Turbine-Brayton Cycle (Clean Fossil Fuels)	38	1985
Fixed-Bed Gasification of Coal to Low-BTU Gas	80-85†	1972
Fluid-Bed Gasification of Coal to Low-BTU Gas	90-95†	1980

* Brayton—Rankine.

† Chemical energy efficiency.

Research and Development Trends

Fuel Cells

Fuel cells save on transmission costs but incur

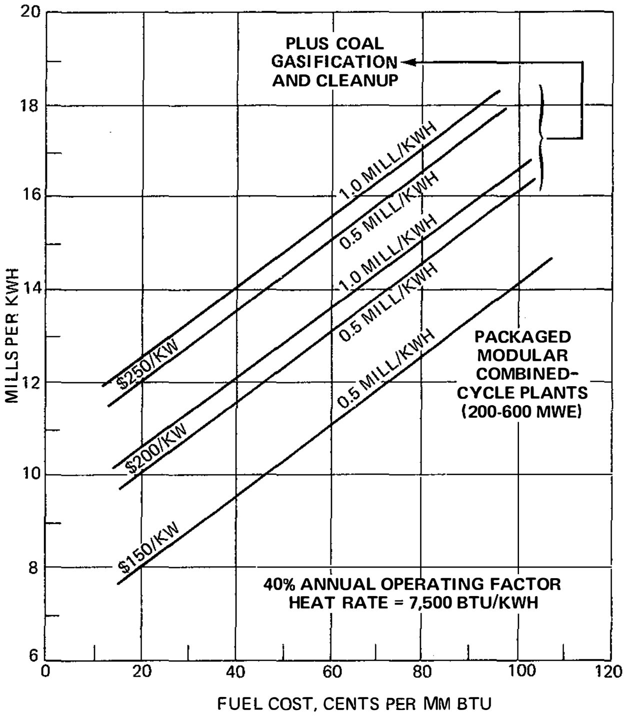


Figure 99. Power Costs of Intermediate-Type Power Plants—1975-1985.

transportation and handling costs by shifting the point of electricity generation from central stations to the point of consumption. However, as mentioned before, the fuel cell will be no more efficient than other means of generating electric power, and it is therefore unlikely to have a major effect on total energy requirements. Commercial testing of fuel cells should be completed by 1975, but their broad application will have to wait until a technical breakthrough is made in the development of cheap catalysts.

Total Energy Plants

Total energy plants utilize hydrocarbon fuels to drive electric generators to meet electrical needs in a relatively small area (small industrial establishments, etc.) and utilize heat recovery to meet the additional energy needs of the same area. The plant has a high system fuel efficiency, but its economics are favorable only in areas of low fuel costs. No significant contribution is expected prior to 1985.

Magnetohydrodynamics

MHD involves the generation of electricity from a moving stream of hot ionized gas, rather than from a moving mechanical dynamo. This concept is unlikely to be developed prior to 1985 due to the difficulty of technological problems involved.

Thermionic Devices

Thermionic devices represent another way of increasing the efficiency of energy utilization in fossil-fuel steam-electric plants. It is hoped that such devices can extract some of the energy from the hot stack gases presently exhausted from steam-electric plants and convert that energy to electric power. Due to the severe heat conditions that thermionic devices would have to withstand and the resultant materials problems which must be solved, practical applications of this concept are not expected before 1985.

Other Energy Sources

Solar Energy

Utilization of the sun's tremendous energy is complicated by the very high capital cost of the devices presently used to convert solar energy to electric energy. Advances are needed in developing the solar spectrum more efficiently. Barring a major R&D effort, little progress is expected in developing the required major technological breakthroughs in this area by 1985.

Agricultural Energy

In agricultural energy, a steady improvement in yield per acre of cereal grains is likely to continue. Little R&D work is now underway on specific production of grains for industrial alcohol or specific crops grown for high energy productivity per acre. Even if these programs are successful, the impact from this R&D is not likely to be significant before 1985.

Chapter Ten
Water Availability

Introduction

Electric power plants require large volumes of water for cooling purposes. Plants that produce synthetic oil and gas also need large volumes of water, both for processing and cooling. For example, a shale oil plant requires 3.4 barrels of water and a coal liquefaction plant requires 5.3 barrels of water for each barrel of oil produced. Some of the water requirement could potentially be reduced, but this would increase the cost of oil produced. Many such plants to be constructed by 1985 will have to be built in relatively arid regions of the western states. The situation can be stated quite simply. There is sufficient surface water in the overall western states area to supply the amounts required for these plants, but it is often locally insufficient within the areas containing oil shale and coal. Also, legal restrictions will impede its geographic redeployment.

Summary and Conclusions

Demand for water was based on the projections of shale oil production and production of synthetic gas, synthetic liquids and electric power from coal formulated by the fuel supply task groups. Estimates of water availability were those of federal, state and local agencies. Consideration was given to both physical and legal constraints. Only surface water supplies were considered since data on underground water resources are limited.

A billion-dollar program to construct dams and aqueducts would have to be initiated almost immediately to assure sufficient water availability to meet the high energy supply projections set forth in Case I. Case IV would permit a delay of 2 years in beginning such a construction project. Other needs of the area make this project necessary in the near future regardless of the development of the synthetic fuels industries.

TABLE 142

WATER REQUIREMENTS FOR PROJECTED NEW ENERGY PLANTS IN MONTANA AND WYOMING

Type of Plant	Water Requirement* (Case I—1985)	Percent of Total
Synthetic Gas	215,000 acre-feet per year	32
Synthetic Oil	150,000 acre-feet per year	22
Coal-Electric	310,000 acre-feet per year	46
Total	**675,000 acre-feet per year**	**100**

* These numbers were rounded off to the nearest thousand.

The most critical states with regard to water availability for new energy plants are Montana and Wyoming. A breakdown of water requirements for projected new plants in these states to support the Case I supply projections follows in Table 142.

The water requirements of these new plants could be largely met by the Montana-Wyoming Aqueduct as preliminarily planned by the U.S. Bureau of Reclamation. This aqueduct would transport water from the Bighorn and Yellowstone Rivers into the coal-bearing regions of Montana and Wyoming. In order to be in service by 1981—as required by the projections in Case I—the engineering planning work would have to begin in 1972. Even for Case IV, work would have to begin in 1974. The project, estimated to cost $750 million, will require federal funding for construction. The cost of the project could be repaid by those companies utilizing the water or mining the coal on federal lands.

Aside from the need to begin work immediately

TABLE 143

WATER SUPPY/DEMAND SUMMARY IN 1985—UPPER COLORADO RIVER*
(1,000's of Acre-Feet per Year)

	Arizona	New Mexico	Utah	Colorado	Total
			Projected Water Requirement†		
Electricity from Coal	62	120	24	–	206
Coal Synthetics	–	60	–	–	60
Shale Oil‡	–	–	18	112	130
Total	**62**	**180**	**42**	**112**	**396**
			Apparent Water Potential §		
Electric Power	34.1	90.0	261.8	108.2	494.1
Minerals	0.3	17.4	10.3	128.3	156.3
Subtotal	**34.4**	**107.4**	**272.1**	**236.5**	**650.4**
Agriculture	7.6	329.0	660.6	1,778.2	2,775.4
Other	8.0	141.3	314.0	1,004.7	1,468.0
Total	**50.0**	**577.7**	**1,246.7**	**3,019.4**	**4,893.8**

* Wyoming's Colorado River entitlement is discussed elsewhere in this study.

† Case I.

‡ Total shale oil requirement includes 124,000 acre-feet per year for mine and plant use and 6,000 acre-feet per year for generation of necessary electric power. The apparent water potential in Colorado is sufficient to provide the total projected requirement of 130,000 acre-feet per year if the buildup of syncrude production capacity occurs in the Piceance Basin of Colorado (see Chapter Seven).

§ From Upper Colorado River Framework Study—States' Alternatives at the 6.5 million acre-feet level to year 2000.

on this major construction project if the Case I supply levels are to be realized, the other problem area is the need to settle disputes over water rights or over water allocations. In the southwestern states of Arizona and New Mexico in particular, the present allocation of water to the energy sector is insufficient. Fortunately, alternatives exist for changing water use and for moving coal to areas of water availability.

Water requirements for potential development of nuclear generation of electricity were not considered in detail. However, they will accentuate problems in areas where water availability limitations are already projected.

Sustained energy development, at rates higher than those projected in Case I for 1985, will require very large investments for water resource projects with long lead times and may ultimately require major governmental decisions regarding the allocation of water resources among competitive users.

Scope of the Report

A large portion of the potential energy resources to meet future demand for energy production from oil shale and coal is located in the western states. The review of water availability for energy development was therefore directed primarily to the water supply and associated water quality problems of this region. In addition to the specific states listed in Tables 143 and 144, the states of Washington, Texas and Arkansas were also considered in some detail. Further, where water

TABLE 144

WATER SUPPLY/DEMAND SUMMARY IN 1985—UPPER MISSOURI RIVER
(1,000's of Acre-Feet per Year)

	Montana	North Dakota	South Dakota	Wyoming	Total
	Projected Water Requirement*				
Electricity from Coal	148	98	20	160	426
Coal Synthetics	170	46	—	195	411
Oil Shale	—	—	—	—	—
Total	**318**	**144**	**20**	**355**	**437**
	Apparent Water Potential†				
Existing Projects					
Yellowstone River Tributaries	244	—	—	976	1,220
Wind-Bighorn River					
Yellowtail & Boysen Reservoirs					
Missouri River	500	500	—	—	1,000
Fort Peck & Garrison Reservoirs					
Subtotal	**744**	**500**	**—**	**976**	**2,220**
Projects to Be Developed					
Little Missouri	—	60	20	—	80
Yellowstone Surplus	450	—	—	—	450
Other	120	—	—	230	350
Subtotal	**570**	**60**	**20**	**230**	**880**
Total	**1,314**	**560**	**20**	**1,206**	**3,100**

* Case I.

† Modified from *North Central Power Study*, Vol. I (October 1971), Table III.

availability proved to be a limitation on energy production, such limitations were identified and alternatives, if available, were examined. While nuclear power generating plants are projected to lie within these states, it seems likely that they will not compete significantly for the same water supplies needed to develop the coal and oil shale energy sources.

The eastern states were also considered. No serious water availability problems are expected to be encountered in this area, so a detailed analysis was not attempted.

Physical Limitations on Water Availability

The finite character of the Nation's water resources has only recently begun to gain widespread recognition. The programs and efforts of the Water Resources Council, the National Water Commission, the U.S. Geological Survey and the U.S. Bureau of Reclamation, as well as numerous other federal, regional, state and local agencies, both public and private, are directed toward a better assessment of this vital resource.

All estimates of future surface water supplies are based on historical stream flow records. A substantial body of such records is available; however, the time interval represented by most specific records is relatively short, covering a historical period of less than 30 years.

Since most available water is committed to such fundamental uses as municipal and industrial supply, agriculture, electric power and energy resource development, the risk of an unpredictable dry cycle becomes a serious matter. As the point is approached when all of the apparently available water in any one area is committed to use, a decision to invest capital in additional plant capacity becomes more risky.

Water requirements for electrical generation, synthetic pipeline gas and oil from coal, and synthetic oil from oil shale projected for Case I through Case IV were considered. The maximum requirements (consumptive use) in the critical areas of the Upper Colorado and Upper Missouri River Basins are shown by state in Tables 143 and 144, where the apparent availability is also shown to facilitate direct comparison. It should be noted that improved technology, such as air cooling of plants, may decrease the water required.

An accurate and generally acceptable estimate of water availability in the states considered proved somewhat difficult to determine. With the exception of parts of Washington, Texas and Arkansas, the states which were the subject of detailed consideration in this study are arid, and their water availability is physically limited and legally complex. The estimates and projections of the individual states were used with respect to water supply and allocations to various uses. The division of water usage among municipal and industrial supply, agriculture, electric power and energy resource development will be more or less in accord with the projections of the state agencies. But, as noted, such predicted allocations are, in most cases, subject to variation in response to economic factors, inasmuch as water uses in all these states are transferable.

Legal Background on Water Availability

In regard to legal aspects of water availability, three factors must be noted:

- Most of the western states involved here are "appropriation" states.* Water rights are acquired initially by filing a notice of appropriation in accordance with procedure established by the state statutes, followed by construction of works and application of water to use with reasonable diligence. A second type of appropriation is that for a right to store water for ultimate use. The date of filing notice establishes the priority of the right and determines the right to the quantity of water put to use up to the originally appropriated quantity by "relating back" to the filing date. Shortages are borne by appropriators in the inverse order of priorities. In all of these states, water rights are transferable from one right owner to another. A water supply for a particular coal conversion plant may thus be obtained either by an initial appropriation of unappropriated water (if any) or by purchase of an existing appropriation. Thus, the fact that the water in a particular stream may be fully appropriated does not necessarily mean that water cannot be made available. The right of transfer is limited by the condition that other appropriators must not be adversely affected by a change of the place of diversion.

- In most of the states considered, the Federal Government has constructed large projects to store and convey water under the Reclamation Act or statutes authorizing construction of works by the Corps of Engineers. In addition, Congress has authorized large projects which have not yet been constructed. The Federal Government in some cases has acquired water rights for those projects under state laws; in others it initially established water rights in its own name in the exercise of federal constitutional power (e.g., the Boulder Canyon Project Act). In all cases, availability of water stored by federal projects is dependent on the execution of contracts with the U.S. Government or its designated contracting agencies.

- All of the river basins involved here are subject to interstate compacts which impose restrictions on use of water. In the Colorado River Basin, the Mexican Water Treaty imposes an added constraint in that it guarantees delivery to Mexico of 1.5 million acre-feet annually.

* Texas and Arkansas are exceptions.

Water Availability in the Missouri River Basin

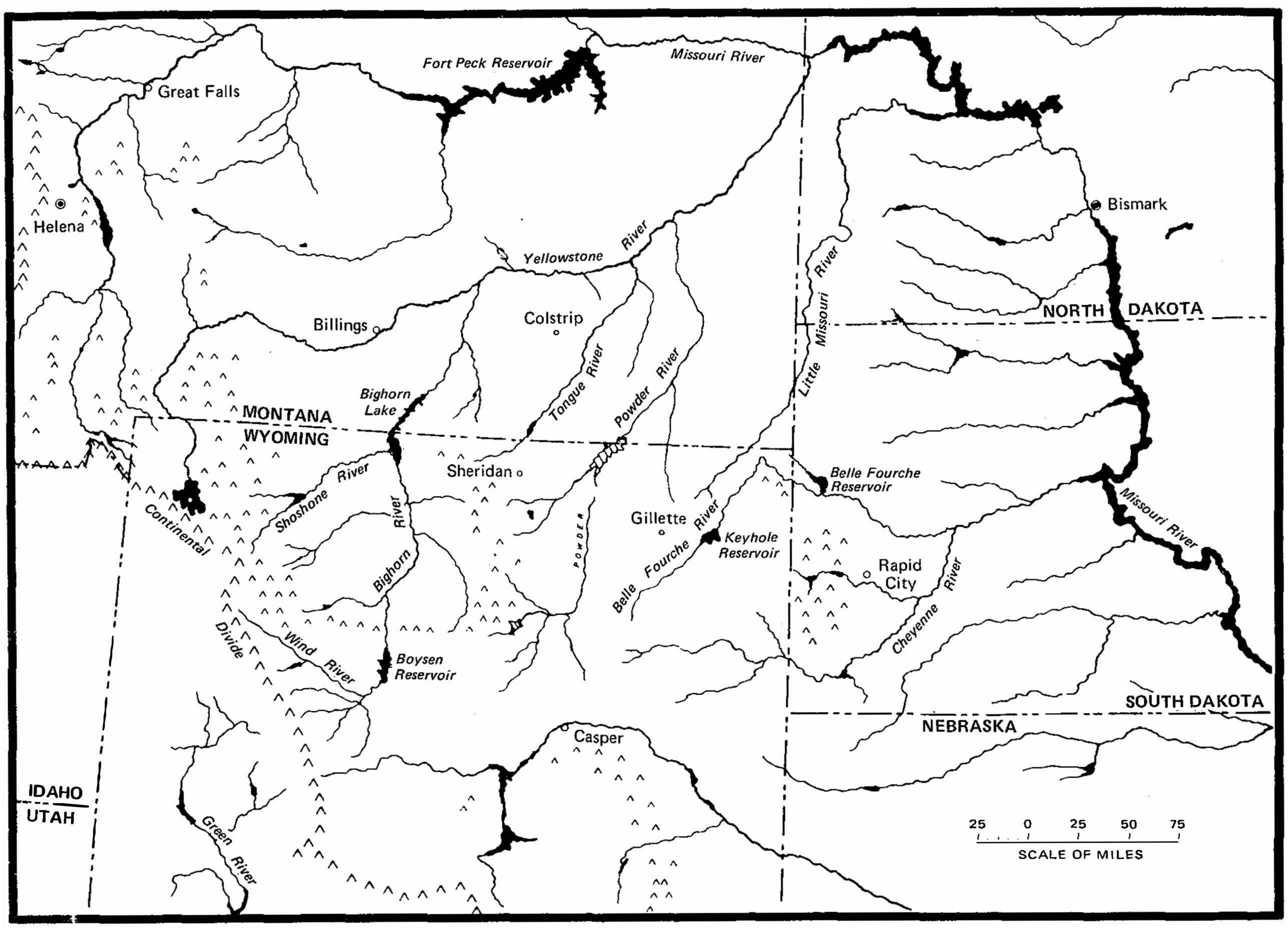
Energy resource development in Montana, Wyoming, North Dakota and South Dakota is dependent on the availability of water from the Missouri River Basin (see Figure 100).

Montana

Projected water requirements in Montana are 318,000 acre-feet per year to provide 148,000 acre-feet for electrical generation, 145,000 for synthetic gas from coal and 25,000 for synthetic oil from coal (see Figure 101).

The apparent potential water supply is as much as 1.3 million acre-feet per year. This could probably be materially increased by larger diversions from the Missouri River than have been contemplated in this assessment. Some 244,000 acre-feet are available from existing reservoirs on the Bighorn River and 120,000 acre-feet from streams near the coal deposits identified in this study but which will require new dam construction for development. Full development of the Yellowstone River should yield an additional 450,000 acre-feet per year, and more than 500,000 acre-feet per year are available from existing reservoirs on the Missouri River. However, this water must be transported to coal fields.

Water availability could be a potentially limiting factor in energy development in Montana—particularly when there is a requirement to utilize the water that is not in streams near the identified coal deposits—due to the requirements for capital and construction time. Montana's water demand for projected 1985 energy requirements could be met through development of local water supplies and use of water from the Bighorn Reservoir (by



SOURCE: North Central Power Study, Vol. II (October 1971).

Figure 100. Water Availability in the Upper Missouri River Basin.

permitting it to flow down the Yellowstone River and diverting it in a series of small aqueduct systems serving individual coal deposits), without the need for a large, single-water transmission facility requiring years for engineering, financing and construction. However, many considerations argue against this approach, particularly the inefficiency of using a series of small systems and the danger of increased damage to the environment. A major transmission facility, logically originating in Montana and crossing near much of Montana's coal, will be required to serve energy requirements in Wyoming. A single, integrated water distribution system such as the Montana-Wyoming Aqueduct System proposed by the U.S. Bureau of Reclamation is the indicated logical alternative.

To meet the projected water requirements for Case I, such an aqueduct will need to be in service by 1981. Even should the water requirements be at the Case IV level, the aqueduct will be needed before 1985, but could be developed on a slightly smaller scale depending upon the economics and timing of future coal development.

Such an aqueduct system will require large capital investment (the U.S. Bureau of Reclamation indicates capital requirements of $750 million), rapid evaluation of environmental impact, and a minimum lead time of 8 years. However, it must

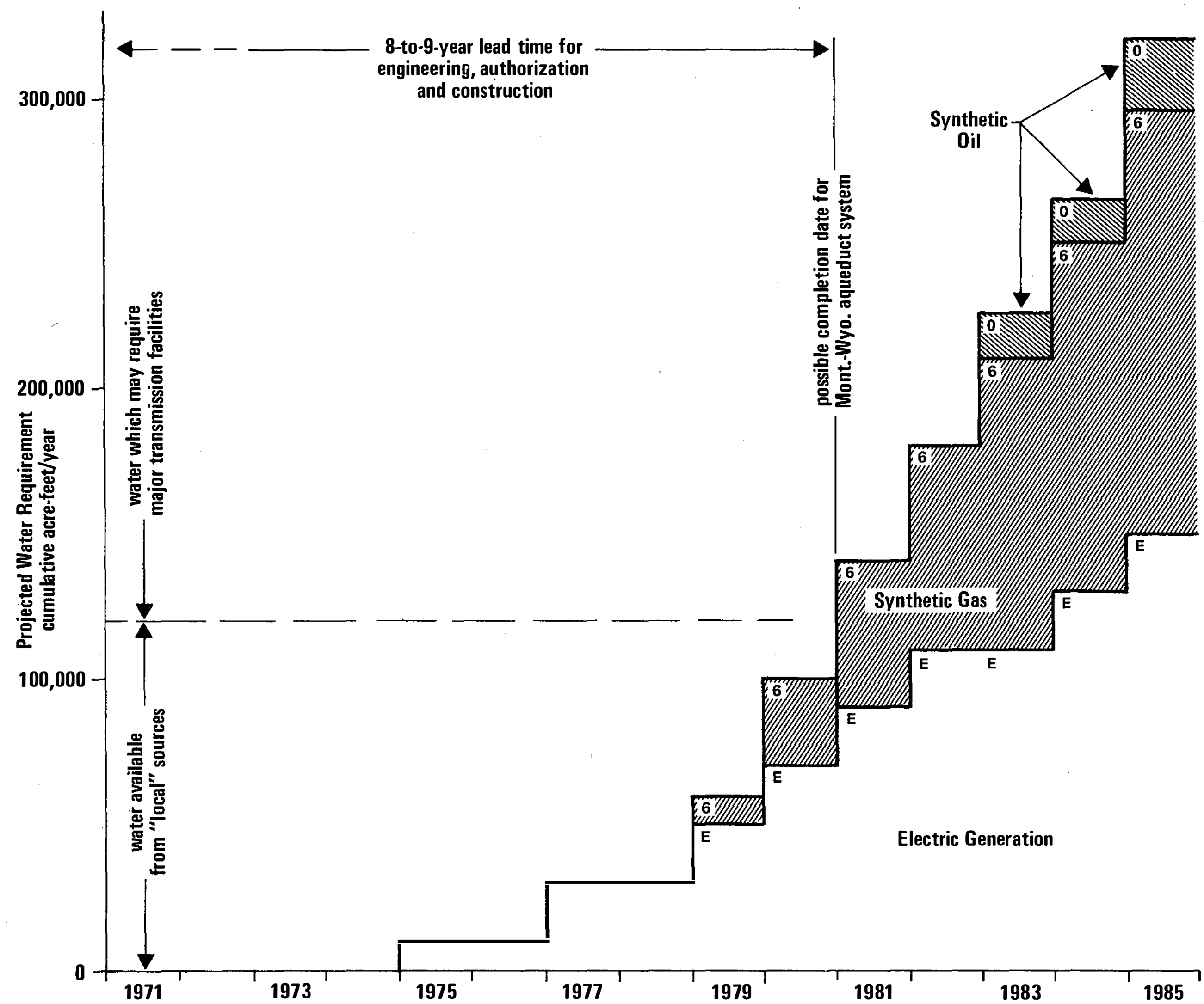


Figure 101. Projected Water Requirements in Montana—Case I Energy Development.

be recognized that the 8-year lead time allows no delays in study authorization, planning, consideration of the environmental impact, congressional authorization and funding for construction, and, of course, the construction of a near billion-dollar aqueduct.

Due to the magnitude of this project, it is assumed that federal funds will be required. Various methods have been suggested to finance this substantial project. One is that a lessor of federal lands for extraction of coal pay a sufficiently high rental to amortize the capital costs as well as the operating and maintenance costs of the necessary facilities. Another is to provide for water service charges sufficient to cover amortization as well as delivery costs.

Wyoming

Projected water requirements for Wyoming are 355,000 acre-feet per year to provide 160,000 acre-feet for electrical generation, 70,000 for synthetic gas and 125,000 for synthetic oil production (see Figure 102).

Apparent supply is approximately 1,206,000 acre-feet per year, subject to the legal considerations set forth elsewhere in this report. Availability consists of (1) about 130,000 acre-feet from "local" sources (i.e., streams reasonably close to the major coal deposits), (2) 100,000 acre-feet from the Green River in southwestern Wyoming (under the state's Compact entitlement to Colorado River water), and (3) some 1 million acre-feet from the Wind-Bighorn tributary to the Yellowstone River. Most of the water from the Wind-Bighorn tributary is from the existing Bighorn and Boysen Reservoirs and would not require new dam construction. However, availability would depend on resolution of the Yellowstone River Compact.

The 130,000 acre-feet supply from local sources can be developed with relatively modest requirements for capital and construction time. No problem is foreseen in developing this supply to meet Case I projected requirements through 1980 (see Figure 102). Requirements beyond that time impose a need for the construction of large-scale long-distance aqueduct facilities. The movement of the 100,000 acre-feet of Green River water from southwestern Wyoming to the coal fields in the northeastern part of the state would be a large undertaking and would not meet the projected 1985 requirements. It appears that the construction of a single integrated aqueduct system to move Bighorn-Yellowstone River water to the northeastern Wyoming coal fields offers a more practical approach to development of a water supply to meet the projected requirements of the 1980's. (Such a project is discussed in the section on Montana.) Figure 102 shows the critical time relationships.

Use of the waters of the Yellowstone River system is controlled by the Yellowstone River Compact between Montana, North Dakota and Wyoming, approved by Congress October 30, 1951 (65 Stat. 663). The Compact (Art. V) recognizes existing appropriative rights in each state as of January 1, 1950, and allocates the remainder of the unused and unappropriated water by percentages to Wyoming and Montana. With respect to the Powder River, the allocation is 42 percent to Wyoming and 58 percent to Montana. The allocation in the case of the Bighorn River (exclusive of the Little Bighorn, which is not allocated) is 80 percent to Wyoming and 20 percent to Montana. As between Montana and South Dakota, other provisions apply, the general effect being to recognize existing appropriations, to allocate to each of those two states all water flowing in a tributary lying wholly in that state, and to divide the beneficial use of the flow below a designated point in Montana on a proportional basis of acreage irrigated.

Further, Article X of the Compact provides:

> No water shall be diverted from the Yellowstone River Basin without the unanimous consent of all the signatory States. In the event water from another river basin shall be imported into the Yellowstone River Basin or transferred from one tributary basin to another by the United States of America, Montana, North Dakota, or Wyoming, or any of them jointly, the State having the right to the use of such water shall be given proper credit therefore in determining its share of the water apportioned in accordance with Article V herein.

Unless this condition can be met, or relief obtained from its restrictions, some of Wyoming's water apparently could not be exported from the Bighorn (Yellowstone) Basin without the consent

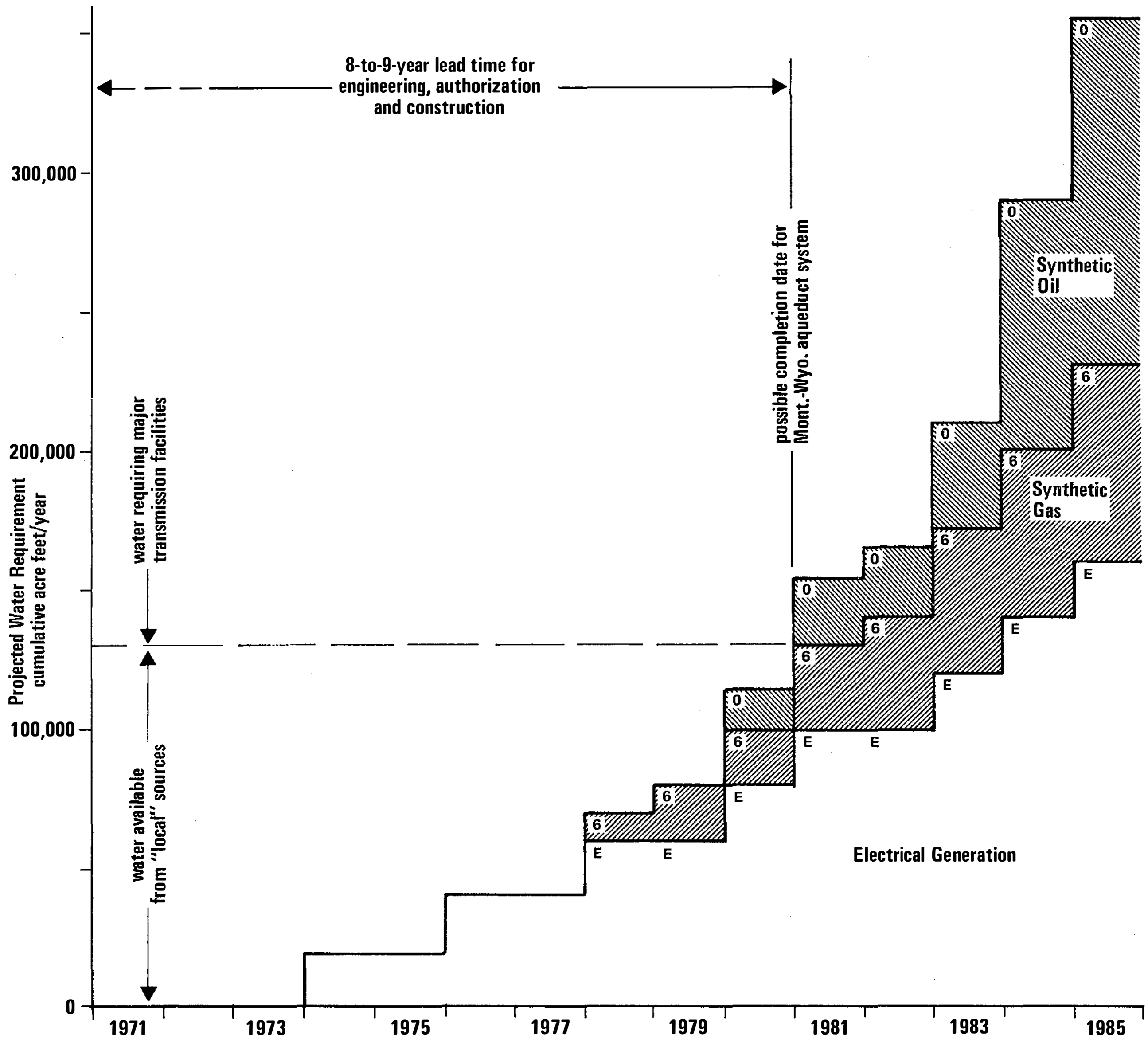


Figure 102. Projected Water Requirements in Wyoming—Case I Energy Development.

of Montana and North Dakota. Because a significant percentage of Wyoming's most attractive coal reserves are located in the Belle Fourche and Cheyenne River Basins, this provision becomes significant. This restriction would not prevent importation from the Bighorn into the Powder River Basin, since both are elements of the Yellowstone River Basin.

If it proves legally impossible to import water from the Bighorn River, three alternatives can be considered.

- One alternative would be to import water from the Green River in southwestern Wyoming. This river is a part of the Colorado River Basin. Its use is controlled by the Colorado River Compact and the Upper Colorado River Compact. Under these compacts, it is estimated by the state of Wyoming that more than 100,000 acre-feet of Green River water would be available for diversion into the Yellowstone River watershed. The Colorado River Compact and Upper Colorado

River Compact, unlike the Yellowstone River Compact, do not prohibit the exportation of water to another watershed in a state party to the Compact.

As shown earlier, the Yellowstone River Compact, Article X, provides that, in the event of importation of water into the Yellowstone, the state having the right to use such water shall be given proper credit in determining its share of the water apportioned by the Compact. The application of this provision is not clear. Presumably all water so imported could be used anywhere in Wyoming, i.e., routed into the Belle Fourche Basin.

- A second alternative to importation of water from the Bighorn River would be to move coal to plants located in the Yellowstone Basin, i.e., in either the Bighorn or Powder River sub-basins.
- A third alternative would be to purchase water rights in the Belle Fourche and Cheyenne River Basins, now used for agriculture, and apply such water to industrial use, a course which is legally possible but which would probably produce minor quantities.

North Dakota

In North Dakota, projected water requirements are 144,000 acre-feet per year to provide 98,000 acre-feet for electrical generation and 46,000 acre-feet for synthetic gas production.

Apparent supply is large, including more than 500,000 acre-feet from the Missouri River (including the existing Garrison Reservoir) and 60,000 acre-feet from the Little Missouri River.

The indicated requirements can be met with little or no new dam construction and modest aqueduct development. Much of the state's lignite is reasonably close to one of the streams, and water for each plant may reasonably be developed on an individual basis. No limiting capital or construction time demands are anticipated.

South Dakota

Projected water requirement in South Dakota is 20,000 acre-feet per year to provide a supply for electrical generation.

Apparent supply is probably adequate to meet the modest requirement.

No capital or construction time limitation should be encountered in developing a water supply for this requirement.

Water Availability in the Colorado River Basin

The use of water in the Colorado River Basin is controlled by the Colorado River Compact,* and to some extent by the Mexican Water Treaty; in the Upper Basin by the Upper Colorado River Basin Compact † and in the Lower Basin ‡ by the Supreme Court decree in Arizona *vs.* California.§

The Colorado River Compact, in effect, allocates the annual beneficial consumptive use of 7.5 million acre-feet annually to the Upper Basin (the area above Lee Ferry) and 8.5 million acre-feet annually to the Lower Basin (the area below Lee Ferry). However, it obligates the four states of the "Upper Division" (Colorado, New Mexico, Utah and Wyoming) not to deplete the flow of the Colorado River at Lee Ferry below an aggregate of 75 million acre-feet in each period of 10 years, reckoned in continuing progressive series. In addition, it also obligates these states to furnish one-half of the quantity of any international obligation to Mexico undertaken by the United States, to the extent that such obligation cannot be supplied from the whole basin's supply "surplus" to the foregoing allocations of 8.5 plus 7.5 million acre-feet annually. There is an unresolved legal question as to whether the Lower Basin tributaries should be included in the apportionment of the Mexican burden.

The quantity available for consumptive use in the Upper Basin is thus the residue after meeting the Upper Division's share of obligations at Lee Ferry. Planning of these states and of the U.S. Bureau of Reclamation is proceeding on the calculation of this residue as about 5.9 million acre-feet annually available at site of use.

The Upper Colorado River Basin Compact, ap-

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* Compact among Arizona, California, Colorado, Nevada, New Mexico, Utah and Wyoming.

† Compact among Arizona, Colorado, New Mexico, Utah and Wyoming.

‡ Arizona, California and Nevada.

§ Portions of New Mexico and Utah are in the Lower Basin but are not affected by the decree.

proved by Congress April 6, 1949 (63 Stat. 31), apportions the consumptive use of 50,000 acre-feet annually to Arizona. The remainder is apportioned as follows:

- Colorado—51.75 percent
- New Mexico—11.25 percent
- Utah—23 percent
- Wyoming—14 percent.

This analysis has not taken into account possible increases in available quantities which might result from augmentation of the Colorado River by importations from another basin, weather modification, installation of desalination plants, etc., or diminutions which might result from deliveries to Mexico to ameliorate complaints by Mexico over the quality of water reaching the boundary. The possibility of augmentation is provided for in the Colorado River Storage Project Act (82 Stat. 896). The first increase in supply so occasioned is earmarked to meet a portion of the Mexican Treaty obligations. Currently, water is being delivered to Mexico in excess of the 1.5 million acre-feet guaranteed by the treaty, in recognition of Mexico's water quality problem.*

Colorado

Projected water requirements for Colorado are 112,000 acre-feet per year to support oil shale development.†

Of its apparent supply, Colorado has allocated more than 235,000 acre-feet of its Colorado River entitlement to electrical generation and mineral development. In addition, large supplies allocated to agriculture could be transferred to industrial use if needed and if economically justifiable.

The projected water requirement can possibly be served from existing reservoirs (Green Mountain and Reudi) and direct stream diversions, in which case there would not be a need for new dam construction. Diversion facilities and short aqueducts to the nearby oil shale deposits will impose minimal capital and construction time demands.

No legal constraint is foreseen in making available the quantities of water shown above. Future increases in supplies might be made available by sale and transfer of irrigation rights to industrial use, which is permitted under Colorado water law.

New Mexico

In New Mexico, projected water requirements are 180,000 acre-feet per year to provide 120,000 acre-feet for electrical generation and 60,000 for coal gasification.

Of its apparent supply, the state has allocated 90,000 acre-feet per year to electrical generation and 17,400 to minerals in accordance with the Upper Colorado Region Comprehensive Framework Study. More than 300,000 acre-feet are allocated to agriculture, which if not used for that purpose might be used for energy.

Most, if not all, of the apparently available supply would come from the existing Navajo Reservoir, and no new dam construction would be required. While much of the coal resource is relatively near the river, some energy plants may be located on coal deposits as far as 100 miles from the river. Significant capital and construction time will be required to develop a water supply for these distant coal deposits.

A large amount of water is allocated to Indian reservations, and a part of this might be contracted for through the tribal council. Such a contract would require approval by Congress, as do contracts for existing available water from the Navajo Reservoir.

Utah

Projected water requirements for Utah are 42,000 acre-feet per year to provide 24,000 acre-feet for assumed electrical generation and 18,000 acre-feet for assumed oil shale development.

Utah has allocated more than 250,000 acre-feet of its Colorado River entitlement (including the Green and White Rivers) to electric power generation and mineral development. No problem of water availability is indicated at energy demand levels projected for 1985.

Utah's oil shale is near the White River, and a dam and short aqueduct system would be required to develop a water supply. An alternative to dam construction might be to divert the necessary water from the Green River and move it through a longer aqueduct. Since coal for electrical genera-

* Minute 218, International Boundary and Water Commission, United States and Mexico.

† Colorado oil shale development may require 130,000 acre-feet per year (see ‡, Table 144 and Chapter Seven), but the apparent water supply is still adequate.

tion is reasonably close to the Green River and to an existing reservoir on the Colorado River, only minor diversion structures and short aqueduct systems would be required, and capital and construction time demands also would be minor.

There appear to be no legal constraints on the use of the water which is indicated above to be available.

Wyoming

Wyoming forecasts that, out of the 817,000 acre-feet that it plans on using from the Green River, eventually 158,000 acre-feet might be used in the Colorado River Basin for electric (thermal) power generation, and up to 185,000 acre-feet would be available for export to the Missouri River Basin. The Coal and Oil Shale Task Groups did not project development of coal and oil shale reserves in the Green River Basin in the pre-1985 period.

The Lower Basin

Water supplies on the main stream in Arizona and Nevada might be made available for conversion of local coal or coal transported from the Four Corners area (Arizona, New Mexico, Utah and Colorado). Either the main railroad which traverses the Four Corners area or a slurry pipeline could be utilized to transport the coal. (Coal is presently moved by slurry pipeline from northeastern Arizona to the Mojave steam power plant in southern Nevada, and a planned project will move other coal by a new rail line to a power plant on the river.)

Water Availability in Other Basins

Washington

Projected water requirements are 20,000 acre-feet per year for electrical generation, and apparent supply is large as compared to the projected requirement. No problem of availability, capital or construction time is anticipated.

Texas and Arkansas

Projected water requirements for Texas and Arkansas are 44,000 acre-feet per year for electrical generation. Compared to the projected requirement, the apparent supply is large. No problem of availability, capital or construction time is anticipated.

Capital and Time Requirements to Develop Water Supplies for Energy Conversion

The development of firm supplies of water for energy conversion plants will require various levels of capital and construction time, depending upon the size and location of impounding or diversion structures which may be required and the capacity and length of aqueducts. Specific plant siting projections are not available, and their development is beyond the scope of this NPC energy study. General estimates of new capital requirements are shown in Tables 145 and 146 indicating their order of magnitude. They are not sufficiently precise to be used as a substitute for specific engineering studies regarding any one project.

The estimates relating to dam construction have been taken from two sources: (1) published information on dams which have been planned for the development of the identified water source and (2) extrapolations from estimates for other comparable dams. Capital cost estimates for pipelines are derived from even less specific data, except in the case of the Montana-Wyoming Aqueduct where the source of water and the coal deposits to be developed are readily apparent and where the U.S. Bureau of Reclamation has completed an appraisal report on the project.

Colorado River Basin

Capital requirements for dams and aqueducts to serve Case I energy plants in the Colorado River Basin were projected only for the Upper Basin (see Table 145).

The expenditures given in Table 145 will develop water supplies for about 15 shale oil "unit" plants (50 MB/D), 6 coal-based synthetic fuel plants and 3 coal-fired electric power plants through 1985 for the Upper Colorado River Basin.* The new capital investment will be about $6 million for each plant. This low capital requirement reflects the existence of a number of major dams and reservoirs on the Colorado River and its trib-

* A greater buildup in coal-fired electric plants would require water presently allocated to agriculture use, but the capital required would not be significantly higher than the figures quoted in Table 145.

TABLE 145

UPPER COLORADO RIVER BASIN

State/Water Demand—Source/Yield	New Capital Required (Million Dollars) Dam	Aqueducts	Total
Arizona—62,000 Acre-Feet/Yr			15 – 30
Glen Canyon	Existing	15 – 30	
(About 35,000 Acre-Feet Available)			
New Mexico—180,000 Acre-Feet/Yr			50 – 75
Navajo Reservoir	Existing	50 – 75	
(About 100,000 Acre-Feet Available)			
Utah—42,000 Acre-Feet/Yr			15
Oil Shale Supply—18,000 Acre-Feet/Yr (White River)	5	5	
Coal Supply—24,000 Acre-Feet/Yr	Existing	5	
(Green & Colorado Rivers)			
Colorado—112,000 Acre-Feet/Yr			20 – 25
Green Mountain & Reudi Reservoirs	Existing	20 – 25	
(Plus Direct Flow Diversions)			
Total—Upper Colorado States	**5**	**95 – 140**	**100 – 145**

utaries, as well as the proximity of the oil shale and coal deposits to these reservoirs or to the river below such reservoirs. Hence, only limited dam construction and short aqueduct facilities will be required to develop these supplies.

Since the dam and aqueduct requirements for water supply facilities for energy development in the Upper Colorado River Basin are minimal, time problems associated with project construction are not critical. A potential time problem does appear imminent, however, in that the necessary dam and pipeline construction will, in most cases, involve federally owned land. The legal requirements for approval and permits may occasion far greater time delays than will the actual construction. Recent experience indicates that the possibility of delays occasioned by the requirements of public, administrative and judicial bodies can seriously slow construction and operation of these types of facilities. Laws and regulations which will spell out, in detail, the obligations and rights of entities which engage in the development of these water resources will necessarily need to be adopted.

Upper Missouri River Basin

Capital requirements for dams and aqueducts to serve Case I energy plants in the Upper Missouri River Basin are given in Table 146.

In addition to the costs reflected in the foregoing tables, there will be additional capital requirements for distribution facilities from pipeline terminals or turn-outs to supply individual plants. Again, in the absence of specific siting projections, it is only possible to suggest that these facilities for individual plants should require investments of less than $5 million.

These estimates indicate that new capital requirements for the development of water supplies for energy production plants (shown in Table 144) in the Upper Missouri River Basin could require $960 million for major aqeduct facilities, plus up to $300 million for distribution lines or an average of just over $20 million per plant. It should be noted that the development of "local" sources for the first plants will probably require less than this average. The investment for the Montana-Wyoming Aqueduct will provide a capacity above

TABLE 146

UPPER MISSOURI RIVER BASIN

State/Water Demand—Source/Yield	New Capital Required (Million Dollars) Dam	Aqueducts	Total
Montana—317,000 Acre-Feet/Yr			
Tongue River (60,000 Acre-Feet/Yr)	40	5	45
Powder River (20,000 Acre-Feet/Yr)	10	5	15*
Bighorn River (244,000 Acre-Feet/Yr) (Montana-Wyoming Aqueduct)	Existing	400	400†
Subtotal—Montana	**50**	**410**	**460**
Wyoming—355,000 Acre-Feet/Yr			
Powder River (100,000 Acre-Feet/Yr)	30	30	60*
Tongue River (30,000 Acre-Feet/Yr)	15	5	20
Bighorn River (382,000 Acre-Feet/Yr) (Montana-Wyoming Aqueduct)	Existing	310	310†
Subtotal—Wyoming	**45**	**345**	**390**
North Dakota—144,000 Acre-Feet/Yr			
Missouri River (144,000 Acre-Feet/Yr)	Existing	100	100
South Dakota—20,000 Acre-Feet/Yr			
Little Missouri (20,000 Acre-Feet/Yr)	5	5	10
Total—Upper Missouri Basin	**100**	**860**	**960**

* Includes Moorhead Reservoir and related aqueduct facilities which have been incorporated by the U.S. Bureau of Reclamation in the Montana-Wyoming Aqueduct Studies, resulting in a total of $750 million overall cost for that project.

† Assumes that an integrated aqueduct system to serve the requirements of both Montana and Wyoming (for example, the U.S. Bureau of Reclamation Montana-Wyoming Aqueduct) will be constructed. The division of costs here shown is based on physical location of system elements and does not attempt to allocate costs on a service-rendered basis.

the projected pre-1985 requirements of some 50,000 acre-feet in Wyoming. Therefore, there would be substantial carry-in water capacity to the post-1985 period if the system were built as now conceived by the U.S. Bureau of Reclamation. Optimization of the scale and timing of such a project will be required if it is to make its maximum contribution to energy development.

The capital requirements for water development are large, but are only a minor element in the total capital which will be required for mine, plant and product transmission facilities. Of greater significance may be the potential limitation imposed by planning, engineering and construction time requirements. The "local" water supplies, which can be expected to serve the earliest plants, are estimated to require engineering and construction times of 3 to 4 years—comparable to the engineering and construction time for the plants to be served. The time requirement becomes more alarming when major aqueduct facilities are considered. The U.S. Bureau of Reclamation has estimated that the Montana-Wyoming Aqueduct could be in service by 1981 provided (1) planning, engineering and construction are pursued in an aggressive manner from 1972 forward, (2) Congress authorizes the Bureau to proceed on that timetable, (3) industry indicates support for the project, and

TABLE 147

PROJECTED SCHEDULE OF ENERGY DEVELOPMENT AND WATER CONSUMPTIVE USE REQUIREMENTS
CASE I—MONTANA

	1970	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
Synthetic Gas													
Plant (250 MMCF/D) Units													
Incremental		–	–	–	–	–	1	2	2	2	3	2	2.4
Cumulative		–	–	–	–	–	1	3	5	7	10	12	14.4
Water Requirements (MAF/Y)*													
Cumulative							10	30	50	70	100	120	145
Synthetic Oil													
Plant (50 MB/D) Units													
Incremental		–	–	–	–	–	–	–	–	–	1	–	1
Cumulative		–	–	–	–	–	–	–	–	–	1	1	2
Water Requirements (MAF/Y)													
Cumulative		–	–	–	–	–	–	–	–	–	15	15	25
Electric Generation													
Plant (1,000 MW) Units													
Incremental		–	.4	–	1	–	1	–	1	1	–	1	1
Cumulative		–	.4	.4	1.4	1.4	2.4	3.4	4.4	5.4	5.4	6.4	7.4
Water Requirements (MAF/Y)													
Cumulative		–	10	10	30	30	50	70	90	110	110	130	150
Total Water Requirement (MAF/Y)		–	**10**	**10**	**30**	**30**	**60**	**100**	**140**	**180**	**225**	**265**	**320**

* Thousand acre-feet per year.

(4) industry is willing to enter into water service contracts as early as 1976. Completion of the Montana-Wyoming Aqueduct, or other projects of comparable magnitude will be required if the large energy developments projected in Wyoming are to be satisfied. Smaller projects requiring less time for completion could serve the projected requirements in Montana, North Dakota and South Dakota. Tables 147 and 148 show details of the projected Case I growth of production of synthetic gas and oil from coal resources in Montana and Wyoming, the assumed utilization of these resources for electric power generation, and related water consumption. The critical relationship between the energy industry water requirements in these states and the time requirements for development of the necessary water supply was previously shown in Figure 101.

It is apparent that completion of the Montana-Wyoming Aqueduct by 1981 will be necessary if the projected schedule of maximum energy-supply growth (Case I) is to be met. Even under the minimum projection, the "local" water supply will require supplement from distant water sources by 1983. Moreover, support is required from the public, industry and government for continuation of the Montana-Wyoming Aqueduct study and possible alternatives.

TABLE 148

PROJECTED SCHEDULE OF ENERGY DEVELOPMENT AND WATER CONSUMPTIVE USE REQUIREMENTS CASE I–WYOMING

	1970	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
Synthetic Gas													
Plant (250 MMCF/D) Units													
Incremental		–	–	–	–	1	1	–	1	1	1	1	1
Cumulative		–	–	–	–	1	2	2	3	4	5	6	7
Water Requirements (MAF/Y)*													
Cumulative		–	–	–	–	10	20	20	30	40	50	60	70
Synthetic Oil													
Plant (50 MB/D) Units													
Incremental		–	–	–	–	–	–	1	1	–	1	4	3
Cumulative		–	–	–	–	–	–	1	2	2	3	7	10
Water Requirements (MAF/Y)													
Cumulative		–	–	–	–	–	–	15	25	25	40	90	125
Electric Generation													
Plant (1,000 MW) Units													
Incremental		1	–	1	–	1	–	1	1	–	1	1	1
Cumulative		1	1	2	2	3	3	4	5	5	6	7	8
Water Requirements (MAF/Y)													
Cumulative		20	20	40	40	60	60	80	100	100	120	140	160
Total Water Requirement (MAF/Y)		**20**	**20**	**40**	**40**	**70**	**80**	**115**	**155**	**165**	**210**	**290**	**355**

* Thousand acre-feet per year.

Chapter Eleven
Fuels for Electricity

Introduction

The Electricity Task Group was established to examine future fuel requirements of the electric utility industry and to identify the major problem areas involved. It was requested to study reasonable ranges of alternatives for meeting the fuel needs of utilities and to consider the implications of these alternatives.

TABLE 149

1985 ELECTRIC UTILITY FUEL MIX

Fuel	Energy Requirements (Quadrillion BTU's)	Percent of Total
Oil	4.5	10
Gas	3.9	9
Coal	13.9	32
Nuclear	18.7	42
Hydroelectric	3.3	7
Total	**44.4**	**100**

Summary and Conclusions

During the 1971-1985 period, annual utility primary energy requirements are expected to increase from 16.7 quadrillion BTU's to 44.4 quadrillion BTU's, an average annual increase of 6.7 percent estimated in the Initial Appraisal. Meeting these requirements will require the installation of approximately 560,000 MWe of new generation facilities during the years 1973 through 1985. Steam generation plants will comprise 475,000 MWe of this new capacity, installed at a range of capital costs of \$130 billion to \$163 billion, depending on the fuel mix.

The conclusions of the Electricity Task Group as to the "most feasible" fuel mix for utilities in 1985 are shown in Table 149. The Electricity Task Group also postulated five other feasible, although less probable, fuel mixes.

Fuel Mix Possibilities for Generation of Electricity

The Electricity Task Group has reviewed the projections of electricity consumption and utility primary energy requirements as outlined in the Initial Appraisal and concluded that these represent reasonable estimates for the period to 1985. To supply the total requirements, several alternative fuel mixes were considered. Four of these were selected as being reasonably possible. Two others were deemed possible but not probable. All six fuel conditions are portrayed in Table 150.

Condition 1 is considered by the task group as *most feasible* from the point of view of electric utilities. It represents the *mix* which would probably evolve if the utility industry were not subjected to any severe constraints on its decisions and reflects essentially the same mix as projected by the FPC's 1970 National Power Survey.

Condition 2 is essentially the same as Condition 1, except for the conversion of half of all natural gas-fired steam generating capacity to oil.

Condition 3 is premised on a greater reliance on nuclear plants than the first two conditions, but the nuclear requirements can still be easily covered by the nuclear supply Case III. Coal requirements are reduced as compared to Conditions 1 and 2. As in Condition 2, half of all natural gas-fired capacity is converted to oil.

Condition 4 is considered the least feasible of the four *reasonable* conditions. It assumes severe limitations on the production and use of coal with the result that coal consumption does not exceed the 1970 level. Nuclear development is also limited and falls below the level projected by the nuclear supply Case IV. Natural gas is completely withdrawn for power generation purposes. The result

TABLE 150

PROJECTED FUELS MIX FOR ELECTRIC UTILITIES*
(Trillion BTU/Year)

	Condition 1				Condition 2			
Resources	1975	1980	1985	1985 Relation to 1970 Level	1975	1980	1985	1985 Relation to 1970 Level
Oil	3,460	4,050	4,530	220%	4,110	5,350	6,480	316%
Gas	3,900	3,900	3,900	100%	3,250	2,600	1,950	50%
Coal	8,905	14,306	13,900	180%	8,905	14,306	13,900	180%
Nuclear	4,270	7,500	18,713	7,800%	4,270	7,500	18,713	7,800%
Hydroelectric	2,990	3,240	3,320	116%	2,990	3,240	3,320	116%
Total	**23,525**	**32,996**	**44,363**		**23,525**	**32,996**	**44,363**	

	Condition 3				Condition 4			
Resources	1975	1980	1985	1985 Relation to 1970 Level	1975	1980	1985	1985 Relation to 1970 Level
Oil	3,000	4,050	6,150	300%	6,515	13,481	16,043	783%
Gas	3,250	2,600	1,950	50%	1,950	975	0	–
Coal	10,013	15,606	12,500	160%	7,800	7,800	7,800	100%
Nuclear	4,270	7,500	20,443	8,520%	4,270	7,500	17,200	7,167%
Hydroelectric	2,990	3,240	3,320	116%	2,990	3,240	3,320	116%
Total	**23,525**	**32,996**	**44,363**		**23,525**	**32,996**	**44,363**	

	Condition 5				Condition 6			
Resources	1975	1980	1985	1985 Relation to 1970 Level	1975	1980	1985	1985 Relation to 1970 Level
Oil	5,215	11,856	2,050	100%	3,000	4,050	10,136	495%
Gas	3,250	2,600	1,950	50%	3,250	2,600	1,950	50%
Coal	7,800	7,800	7,800	100%	10,015	15,606	21,457	275%
Nuclear	4,270	7,500	29,243	12,200%	4,270	7,500	7,500	3,125%
Hydroelectric	2,990	3,240	3,320	116%	2,990	3,240	3,320	116%
Total	**23,525**	**32,996**	**44,363**		**23,525**	**32,996**	**44,363**	

* Included in total supply is an estimated 500 trillion BTU's of geothermal energy for the year 1985. No attempt has been made to deduct this quantity from any of the identified fuel supplies.

of these constraints is to drive oil consumption to 780 percent of the 1970 level.

Conditions 5 and 6 are the two mixes considered possible, but highly unlikely, by the task group. Condition 5 assumes that coal use will be held to the 1970 level for the same reasons cited in Condition 4. Half of all natural gas-fired capacity is deprived of fuel, and oil is obliged to fill a large gap in 1975 and 1980, but will fall back to its 1970 level in 1985, which would be highly improbable for both technical and commercial reasons. As a consequence, nuclear is required to shoulder virtually all net growth in utility requirements between 1972 and 1985. This would entail a construction program resulting in nuclear capacity approaching that projected by the nuclear supply Case I. Condition 6 is considered least feasible of all the conditions covered. It is predicated on a nuclear "moratorium" in effect after 1980 and the conversion of half of all gas-fired capacity to oil. While oil absorbs a considerable portion of the resulting fuel deficit, coal serves as the main "swing fuel" and rises to 275 percent of the 1970 level. To realize this degree of reliance on coal, output from the mining industry would have to approximate the coal supply Case I. Also implied is near total success in solving the SO_2 problem, plus a marked relaxation of environmental constraints on surface mining.

TABLE 151

PROJECTED CAPITAL INVESTMENT—1973-1985*
(Billions of Constant 1970 Dollars)

	Expenditure
Reasonably Feasible	
Condition 1	148
Condition 2	150
Condition 3	153
Condition 4	136
Extremely Improbable but Feasible	
Condition 5	163
Condition 6	130

* Factors used were:
Nuclear—committed capacity @ \$300/KW, uncommitted capacity @ \$400/KW
Coal—committed capacity @ \$220/KW, uncommitted capacity with SO_2 scrubbing or low-BTU gasification @ \$300/KW
Oil—all capacity @ \$200/KW
Natural Gas—conversion to oil @ \$50/KW

Cumulative Investment Requirements (1971-1985)

For each of the six fuel mix conditions, estimates were derived for total steam plant capital expenditures (see Table 151).

Investments for steam power plants for the years 1971 and 1972 were approximately \$7 billion each year (\$8 billion including non-steam plants).

While Condition 6 carries the lowest power plant investment figure, it is the least feasible of the six conditions discussed, and the total cost to the economy and to the electricity consumer would probably be the greatest. Investment in mining facilities would be maximized, and the delivered price of power to the user would include high fuel costs resulting from a minimum contribution by nuclear energy.

Only the first four fuel mix conditions shown in Table 151 are considered probable. Capital requirements of these conditions range from \$136 to \$153 billion.

In addition to expenditures on steam plants, the utility industry will build approximately 15 percent of its new capacity requirement in forms such as internal combustion engine installations (principally gas turbines), some hydro capacity including pumped storage, and a small amount of geothermal capacity. Unit investment costs for these can vary widely—from less than \$100 per KW for gas turbine peaking units to several hundred dollars per KW for certain natural storage hydro plants. To estimate capital investment in these facilities, an average weighted unit cost of \$200 per KW has been assumed, implying a total investment of \$17 billion.

The cost of transmission facilities necessary to deliver the output of all new generation plants has been estimated to be equivalent to about 30 percent of the investment in all production plants, a ratio which has held reasonably stable in recent years. For Condition 1 this would mean a capital cost of approximately \$50 billion for transmission facilities, and this amount can be assumed to be reasonably correct for order-of-magnitude estimates for Conditions 2 through 6 for the period 1973-1985. Investments were approximately \$2

TABLE 152

CUMULATIVE 1971-1985 CAPITAL INVESTMENT
ELECTRIC UTILITY INDUSTRY
(Billions of Constant 1970 Dollars)

Condition	1	2	3	4	5	6
Steam Power Plant Investment						
1971-1972	14	14	14	14	14	14
1973-1985	148	150	153	136	163	130
Subtotal—Steam Plants	162	164	167	150	177	144
Non-Steam Power Plant Investment						
1971-1972	2	2	2	2	2	2
1973-1985	17	17	17	17	17	17
Subtotal—Non-Steam Plants	19	19	19	19	19	19
Total Power Plant Construction	**181**	**183**	**186**	**169**	**196**	**163**
Transmission Facilities						
1971-1972	4	4	4	4	4	4
1973-1985*	50	50	50	50	50	50
Total Transmission	54	54	54	54	54	54
Total Electric Utility Investment (1971-1985)	235	237	240	223	250	217

* Estimated at 30 percent of Condition 1 cumulative power plant investment.

billion per year in 1971 and 1972. Total electric utility capital requirements for the period 1971-1985 are shown in Table 152.

All of the fuel mix conditions previously discussed used the Energy Demand Task Group's projection of total electric utility primary energy demand. Under most all cases discussed in Chapter Two, energy imports are required while potential supplies of coal and nuclear fuels go unutilized. Under the Case I energy balance assumptions, an increase in electric utility growth from 6.7 to 8.8 percent per year would be required to eliminate all energy imports in 1985. An increase in the electric utility industry's annual growth rate of 2.1 percentage points above the 6.7 percent projected by the Energy Demand Task Group in order to provide more electricity to substitute for foreign fuels used in other energy consuming sectors would be difficult but not impossible.*

If there were no change in system load factors, additional capital expenditures for generating and transmission facilities could range as high as $130 billion to $150 billion (in constant 1970 dollars) over the 15-year period 1971-1985. If, as is more likely, much of the incremental electricity consumption were due to increased electric space and process heating, there would be a tendency toward improved load factors, and the incremental capital requirements for power plants and transmission lines would be correspondingly less. Considerable additional expenditures on distribution systems would be necessary in either case.

* Consuming sectors are residential/commercial, industrial and transportation.

Relative Capabilities of the Electric Utility Industry to Build and Operate Nuclear Versus Fossil-Fuel Steam-Electric Plants

In order to supply the expected increase in electric peak loads, build and maintain adequate reserve margins of generating capacity, and replace obsolete production units, the electric utility industry in the United States must install approximately 560,000 MWe of new generation facilities of all types between the end of 1972 and 1985.* It is reasonable to estimate that about 85 percent (475,000 MWe) of these gross additions will be in the form of nuclear or fossil steam plants. As of the end of March 1972, some 101,000 MWe of nuclear plants and 90,000 MWe of fossil-fuel installation were already on firm order for 1973 and later operation. Thus 40 percent of the new steam capacity needed during the coming 13 years has been put under contract. The balance of 284,000 MWe will be apportioned to nuclear and fossil fuel in part as a function of the possibilities of getting delivery of the respective plant types.

During the first half of 1971, lead times for the construction of steam power plants were estimated at 4.5 to 5.5 years for fossil-fuel installations and at 7 to 7.5 years for nuclear units in the 800 MWe to 1,100 MWe range.† In the future, streamlined licensing procedures and improved construction techniques may tend to shorten these lead times, but other factors seem likely to lengthen them. As a result of the Calvert Cliffs court decision, additional requirements for environmental protection statements under the National Environmental Policy Act have added at least a year to construction lead times for nuclear plants. Greater public participation in the planning process may also add to future delays.

As a consequence, utilities planning on in-service dates of 1985 for nuclear capacity will probably be obliged to commit themselves by 1977. For fossil-fuel units, on the other hand, commitment decisions could be delayed until 1980. In both cases, of course, particular conditions could advance or postpone the deadline as compared to these dates.

Given the lead times indicated above, and assuming no greater public instigated delays in planning and construction, the earliest possibility of commissioning a nuclear unit ordered in mid-1972 would be late 1980. Thus the electric utility industry may not be in the position to cover its remaining requirements of 284,000 MWe of steam capacity entirely with nuclear plants because it would have to accept delivery of virtually all of the new capacity in the years 1980 to 1985. This situation would not be acceptable if adequate reserve margins are to be maintained over the peak loads forecasted for the latter part of the 1970's. In any case, the relative delays for construction of the two types of plants are premised on both types being built.

If fossil-fuel plants were all but excluded from new ordering plans, the resulting additional burden placed on the manufacturers of components unique to nuclear stations would further extend already lengthy lead times. Fabrication of reactor vessels could prove a particularly acute bottleneck, and the larger turbines which may still be required by low-temperature/pressure, light-water reactors could impose heavy strains on the facilities making these machines.

In view of the reduced flexibility associated with long lead times for nuclear plants, utilities are likely to reserve at least 40 percent of their projected steam plant orders for fossil fuel.‡ Such a strategy provides a hedge against a marked decline in the medium-term growth rate of peak demand. This latter factor may be of particular importance since a near total dependence on long lead time plants could aggravate a possible future over-capacity situation created by several years of lower than average peak load growth rates.

In addition to the key element of lead times, certain other considerations will have an influence on the electric utility industry's freedom to opt for either of the two plant types. During the 3 years 1972-1974, the electric utilities have scheduled for commercial service 50 nuclear generating units totaling some 43,000 MWe. These units will provide the industry with a substantial additional input of operating experience for large scale nuclear plants. Results of this additional experience will determine in some cases the degree of

* This assumes retirements equivalent to 10 percent of gross plant additions. Net additions should total about 503,000 MWe, raising installed capacity from 412,000 MWe in 1972 to almost 915,000 MWe in 1985. The 1985 total is based on the FPC 1970 National Power Survey estimate of 665,000 MWe in 1980 and 6.6 percent per year growth in capacity during the years 1980 to 1985.

† Robert W. Patterson, "The Stretch-Out in Power Plant Schedules," *Power Engineering* (September 1971), pp. 40-41.

‡ This assumption would imply a maximum of 295,000 MWe of nuclear plants in service at the end of 1985 (taking into account the estimated 22,000 MWe to be in commercial operation by December 31, 1972). It should be noted that this total falls between NPC Case III for nuclear power (300,000 MWe) and Case IV (240,000 MWe). The AEC's "most likely" projection, adjusted to a calendar year basis, is 300,000 MWe.

further commitment to nuclear generation in the subsequent 2 or 3 years. One can safely assume, however, that any negative influence stemming from the initial operation of these plants will be marginal, as the feasibility of atomic power production has already been adequately demonstrated. Each utility will merely be obliged, in light of its own particular situation, to decide to what extent it can live with start-up problems during the immediate future.

In addition to the technical problems which may affect ordering plans for the balance of the 1970's, the administrative, regulative and legal requirements for licensing both nuclear and fossil-fuel plants can be expected to become even more complex until a "one stop" agency approval is established. As of mid-1972, there is hope that these procedures will be simplified in the future, making possible a commensurate reduction of the time delays involved. However, it should not be assumed that lead times currently envisioned have accounted for all of the impossible additional steps that might be imposed on the electric utility industry in the coming years.

Finally, the industry's freedom to rely on fossil-fuel installations for additional capacity through 1985 will depend heavily on policy decisions affecting the supply of fuels with sulfur contents low enough to satisfy existing air pollution control standards and any changes in these standards which may be made in the coming decade. If present long-term prices for low-sulfur fuels (less than 0.5-percent sulfur by weight) still prevail in 1985, the fossil-fuel premiums due to sulfur regulations would total, for the Condition 1 fuel mix, $1.5 to $3.0 billion. These costs would have to be borne by the ultimate consumers of electricity.

Environmental Policy Factors Bearing on Utility Fuel and Plant Decisions

Possible delays in ordering and constructing power plants because of environmental, health and safety rules can be only partially estimated at this time, since political and policy decisions can have a substantial effect on these delays.

Siting of Power Plants

Siting delays encountered by utilities are aggravated by the trend to allow public participation in all hearings even though the thrust of the public's complaint may be generalized and inapplicable to the specific site. The effects of new regulations are unknown. The Calvert Cliffs decision has been estimated to cause delays of 1 year or more in each nuclear plant. The problem is further compounded by the great number of governmental agencies which claim jurisdiction. There are 70 such agencies, including 25 federal agencies, many of which must be satisfied independently.

The institution of these new regulatory requirements concerning the environmental impact of nuclear plants has added as much as 1 year to the installation schedules of most plants planned for operation in the early and mid-1970's. These delays, of course, have their attendant costs. The total carrying charge alone on the nuclear plant investment involved is in the neighborhood of $3 billion for a 1-year delay. The incremental increase in the cost of replacement power generated with less efficient equipment is estimated at almost $2 billion. The substitute bloc of fossil steam and gas turbine capacity necessary represents a commitment of about $6 billion by the utility industry at least 1 year earlier than would have been the case if nuclear schedules had been maintained. This is equivalent to an additional carrying charge of almost $1 billion.

In summary, it is estimated, based on a 1-year average delay in nuclear plant schedules, that the total cost to the utility industry could amount to $5 to $6 billion. This figure compares to the total 1970 capital expenditure by electric utilities of $12.5 billion covering generation, transmission systems and distribution networks.

Status of Technology

Stack gas sulfur removal processes are still in the development stage, and there is a possibility that no process proposed today will reach satisfactory service. Capital costs have escalated, and the limestone slurry scrubbing projects once considered low cost are now costing up to $80 per KW. Disposal problems for limestone sludge appear formidable, and commercial application seems to be most probable in the later years of this decade.

Synthetic-gas-from-coal projects producing low-BTU gas should be available in the latter part of the 1970's. The commercial application in the early

1980's of these low-BTU gasification processes and the combined gas turbine/steam turbine plant with an overall efficiency of 50 percent will provide one major outlet for the high-sulfur coals.

Fuel Supply and Utilization Problems

The electric utility industry's ability to meet U.S. electric requirements during both the near and the long term is being seriously impaired by a combination of (1) long nuclear plant lead times including construction and licensing delays, (2) dwindling natural gas supplies, (3) increasingly restrictive environmental regulations, and (4) uncertainties about the oil import program.

Nuclear lead time at best is about 8 years, and, with the extended period required for greater public participation in planning and regulatory approval, there is little foreseeable hope that lead times will be reduced.

Natural gas supplies are declining, and electric utilities in most areas of the United States can no longer depend on supplies, even for existing gas-burning units. Virtually no new steam-electric generating units which will burn natural gas exclusively are now being ordered.

Environmental regulations in many areas of the country have practically eliminated most types of coal as a fuel. Current technology on stack gas desulfurization systems, coal gasification, electrostatic precipitators and combustion control is not at the stage of development to permit compliance with the sulfur, nitrogen oxides and particulate restrictions currently in effect or proposed. Consequently, many electric utilities have only nuclear and oil-fired alternatives remaining to them. As indicated, the nuclear alternative is available, but only after a longer time period relative to fossil-fueled plants.

Thus, in many parts of the United States, oil may be the only fuel which will permit electric utilities to meet customer requirements in an environmentally acceptable manner in the next few years. Very little low-sulfur domestic residual fuel oil is available with the present refining pattern of

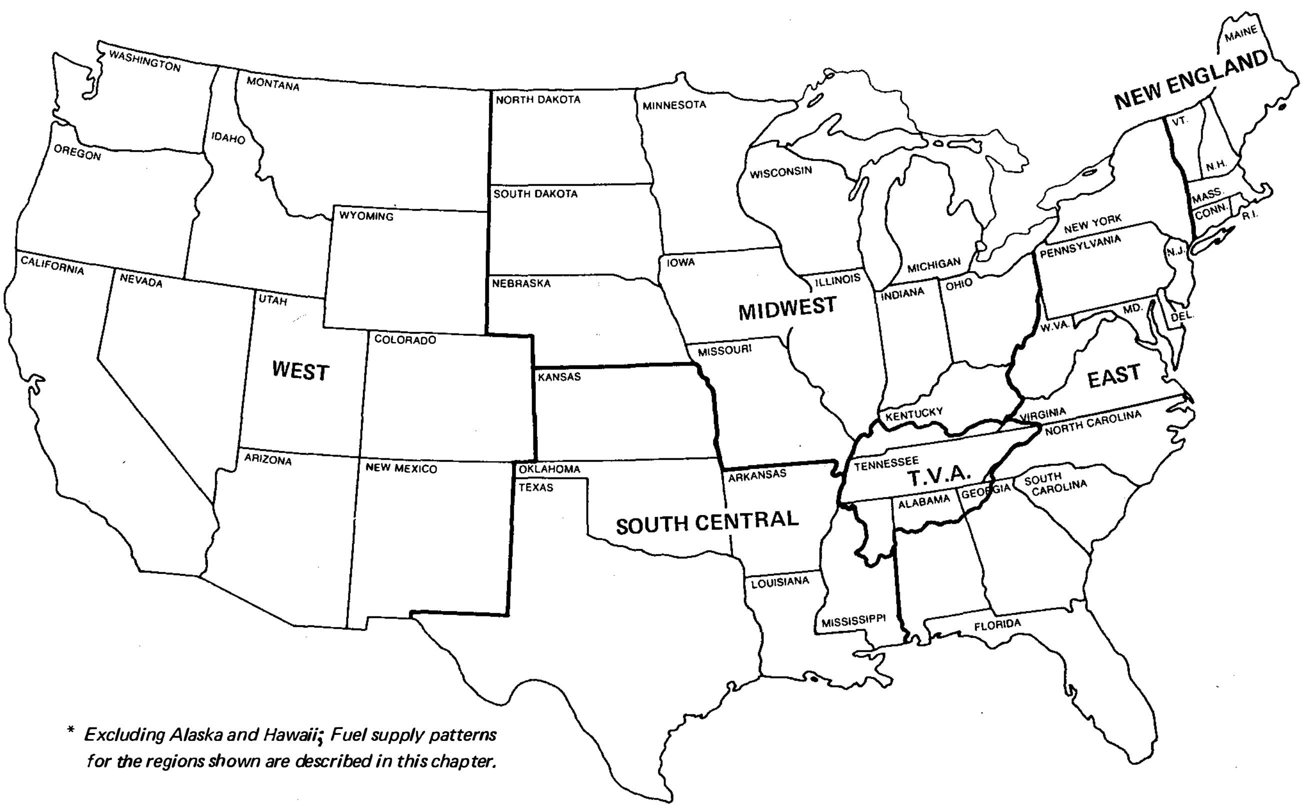

Figure 103. Fuel Supply Regions for Electric Utilities.*

the domestic petroleum industry. This leaves imported oil as the only available supply. Uncertainties about the oil import control program complicate planning for long-term use of imported oil.

Future Regional Fuel Supply Patterns

The fuel mix for electric utilities will vary in different regions of the United States, depending in large part on the regional supply of fuels and government regulation. General fuel supply patterns for six regions shown in Figure 103 are summarized in the following paragraphs.

The fuel mix for electric utilities in the western region encompasses all major energy forms. Although the region's coal reserves are abundant, environmental and water constraints will require increased dependency upon extra-regional sources of fuel, particularly oil.

In the midwest region, former reliance on coal is now declining, due to strict environmental regulations and to a gradual switch to nuclear power plants for long-term load growth. As an alternative, oil is being sought, but oil supply is hampered by major logistical problems.

The primary fuel in the south central region has traditionally been natural gas. Many plants could burn oil, but at a 20-percent decrease in capacity. Nuclear plants are planned for most new base-load capacity additions, while coal will likely play a minor role.

Coal dominates the generation capacity of the Tennessee Valley Authority (TVA) area, followed by hydroelectric capacity. New capacity is expected to be nearly all nuclear fueled. Gas and oil are relatively insignificant fuel sources in this area.

Air quality regulations have essentially outlawed coal as a boiler fuel in the New England area. Thus, this area is heavily dependent on oil, most of which is imported. Growth of capacity is expected to be in the form of nuclear power plants which are presently hindered by environmental and licensing delays.

Increasingly stringent regulations restricting sulfur dioxide emissions have forced electric utilities in the east region to switch from heavy reliance on coal mined in that area to imported low-sulfur fuels. This trend will continue for the next several years if new air quality regulations become effective as scheduled. Large commitments have already been made to nuclear power as an alternative for later years.

Chapter Twelve
Foreign Oil and Gas Availability

Foreign Oil Availability

In order to put U.S. needs into proper perspective, energy and oil requirements and supplies outside the United States must be considered. Accordingly, a projection of non-Communist foreign energy and oil consumption was made for the 1971-1985 period. This projection is summarized in Table 153.

A range for estimated non-Communist foreign energy and oil consumption was used to show the difference in individual assessments. It is significant that only minor differences in opinion exist concerning the non-Communist foreign energy outlook. A substantial difference exists, however, as to the outlook for oil. In essence, the range shown in Table 153 reflects two fundamentally different outlooks. One projects that oil's role in the energy mix will decline in the non-Communist foreign area over the next 15 years, with nuclear, natural gas, low-sulfur coal and coal gasification fuels expected to make substantial progress in the energy fuels market, particularly after 1975. The other outlook is quite pessimistic regarding prospects for nuclear fuel because of higher costs and construction and environmental delays. The outlook is also pessimistic for low-sulfur coal because of higher delivered cost, and for coal gasification because commercially feasible processes are unlikely until after 1980. These latter factors result in much higher requirements for oil being projected —largely on the basis that oil is the only available energy fuel with sufficient supply flexibility to meet the expected energy demand. The difference in the two projected energy mix outlooks is fundamental, and thus it is appropriate to show the projected possible range.

Based on the above projection, the non-Communist foreign area will consume between 257 and 277 billion barrels of crude oil during the 1971-1985 period. The United States will consume 94 to 115 billion barrels during the same period. Thus, total non-Communist World oil consumption will range from about 351 to 392 billion barrels, with the United States accounting for 27 to 29 percent of the total.

TABLE 153

NON-COMMUNIST FOREIGN POPULATION AND ENERGY AND OIL CONSUMPTION

	Population (Millions)	Energy (Oil Equiv.) (MMB/D)	Oil (MMB/D)	% Oil to Total Energy (%)	Per Capita Consumption (Bbls./Capita/Year)	
					Energy	Oil
1970	2,266	43	25	60	6.8	4.1
1975	2,517	58	37 – 38	64 – 66	8.4	5.4 – 5.6
1980	2,827	79 – 80	50 – 53	63 – 66	10.2 – 10.4	6.4 – 6.9
1985	3,179	106 – 111	64 – 74	61 – 67	12.2 – 12.7	7.4 – 8.5
Percent Annual Growth 1985 versus 1970	2.3	6.3 – 6.6	6.4 – 7.4	(0.1) – 0.9	4.0 – 4.4	4.0 – 5.0

Non-Communist Foreign Oil Supply

Competition among energy fuels is strongly affected by supply availability as well as economic, logistical, political and technological factors. These factors, in combination with the increasing demand for energy, have an important influence on the utilization of energy and oil supplies. International oil supply patterns will be influenced by many factors, including (1) the geographical distribution of oil reserves, (2) political and economic conditions, (3) the rate and ultimate amount of reserve additions, (4) price competition, (5) quality and relative refining values of alternative crude supplies, (6) security considerations, (7) the need for diversified energy and crude sources, (8) changes in geographic patterns of demand, (9) environmental considerations, and (10) the rate of development of alternative energy sources and technology.

Taking these factors into account, it is concluded that—

- Existing reserves coupled with the non-Communist World resource base remaining to be discovered, as it is presently appraised, are sufficient to meet requirements up to 1985.
- Assuming that political and economic conditions throughout the non-Communist World will continue to provide rewarding investment opportunities, it is well within the geological and technical capability of the international oil industry to add in the range of 450 to 550 billion barrels of oil to proved non-Communist World crude oil reserves during the 15-year period 1971-1985. Any events or conditions that adversely affect the political or economic climate will have a negative impact on future oil finding and development.
- Finding and developing this range of gross additions to proved non-Communist World crude oil reserves in the period through 1985 will depend, to a large extent, on the oil industry's ability to attract or generate large amounts of capital. This situation will be complicated by a variety of uncertainties in both domestic and foreign government energy policies with regard to increased taxation, nationalistic foreign government policies and actions, and the ultimate impact of current demands for participation in oil operations by governments of foreign producing countries. Also, restraints on capital recovery and possible future currency exchange adjustments may add to the already large risks and adversely affect long-term profitability and, ultimately, the oil industry's ability to provide the required supplies during this period.
- Non-Communist World oil supplies will gradually tighten during the 1970-1985 period as the ready availability of low cost oil declines. This conclusion takes into account and is based on (1) an estimate of non-Communist World proved crude oil reserves of 463.4 billion barrels as of January 1, 1972,* (2) the estimated range of gross additions to proved non-Communist World crude oil reserves of 450 to 550 billion barrels, and (3) the non-Communist World oil demand projection set forth at the outset of this section. Together, these factors combine to show a decline in the non-Communist World R/P from 27 years remaining life (based on 1972 production) to between 14 to 19 years remaining life (based on estimated 1985 proved reserves and production). Productive capacity in the non-Communist World could grow faster than demand, so that production capability could exceed requirements in 1985 by about 10 MMB/D (see Table 154).
- The cost of finding, developing and supplying the volume of oil required through 1985 will likely increase sharply over the intervening years. There is not an endless supply of so-called "low cost" oil—even in the Middle East. New increments of crude oil producing capacity will be more and more costly as much of the new producing capacity will have to come from offshore and Arctic regions. New supplies from these areas will be more expensive than existing reserves because of the high costs associated with exploring and producing oil in these harsh environments and with meeting their more stringent environmental standards. Even in Middle East countries, future new production will likely come from smaller, less productive—and therefore higher cost—reserves than those now

* *Oil & Gas Journal* (December 27, 1971), issue estimate of 533.4 billion barrels adjusted by Oil Supply Task Group to eliminate optimistic estimates in selected areas.

TABLE 154

POTENTIAL DEVELOPABLE U. S. AND NON-COMMUNIST FOREIGN LIQUID HYDROCARBON CAPACITY*
(MMB/D)

	Actual 1970	1975	1980	1985
U. S. Case III	11.3	9.8	11.7	12.3
Canada	1.6	2.3	3.7	4.7
Latin America	5.3	5.8	7.0	7.8
Subtotal Western Hemisphere	**18.2**	**17.9**	**22.4**	**24.8**
Western Europe	0	1.5	3.0	4.0
North Africa	4.5	5.2	6.0	7.0
West Africa	2.5	3.8	5.0	6.5
Subtotal Africa	**7.0**	**9.0**	**11.0**	**13.5**
Middle East	17.0	30.0	40.5	50.5
Far East/Oceania	2.0	3.0	4.0	5.5
Subtotal Eastern Hemisphere	**26.5**	**43.5**	**58.5**	**73.5**
Total Non-Communist World Supply	**44.7**	**61.4**	**80.9**	**98.3**
Total Non-Communist World Demand	**40.0**	**55.56**	**72.75**	**87.93**

* Includes synthetics from coal and shale in the United States and from tar sands in Canada. More detailed discussions of these synthetic sources are contained in Chapter Seven, "Oil Shale Availability," and Chapter Eight, "Tar Sands Availability."

supplying much of the present production. As costs increase, so must the price of crude oil and products processed.

- In the absence of substantive changes in current U.S. federal government policies and regulations to strengthen and accelerate domestic oil exploration and development activity, the U.S. oil consumer will become increasingly dependent on Eastern Hemisphere crude supplies, on higher cost alternative energy fuels, or on some combination of both. This conclusion is based on the Western Hemisphere liquid hydrocarbon supply/oil consumption balance to 1985 shown in Table 155.

  A particularly significant implication of this projected Western Hemisphere liquid hydrocarbon balance is that Canadian and Latin American crude resources cannot meet the projected increase in U.S. oil import requirements. If foreign crude imports continue to increase, both comparative costs and balance of payment considerations will create added incentives for the United States to develop new supplies of domestic oil and other energy forms.

Organization of Petroleum Exporting Countries (OPEC) Considerations

Contracted Increases in OPEC Country Tax Take

The long-term effect of the contracted increases in the OPEC countries' tax take through 1975 will probably be seen largely in terms of the competitive position of oil *vs.* other energy fuels. Prices of competing forms of energy have also been increasing at a fairly rapid rate over this period of time, and the cost factors responsible for these increases will tend to persist and escalate into the future. Nevertheless, the OPEC tax take increases have already reduced the competitiveness of OPEC

TABLE 155

WESTERN HEMISPHERE LIQUID HYDROCARBON SUPPLY—OIL CONSUMPTION BALANCE (1960-1985)*
(MMB/D)

	1960	1965	1970	1975	1980	1985 Low	1985 High
Local Oil Consumption (Excluding Exports)							
United States	9.8	11.5	14.7	18.3	22.3	25.8	
Canada	0.9	1.1	1.5	1.9	2.3	2.7	3.0
Latin America	1.7	2.1	2.8	3.9	5.1	6.5	7.0
Total Western Hemisphere	**12.4**	**14.7**	**19.0**	**24.1**	**29.7**	**35.0**	**35.8**
Conventional Liquid Hydrocarbon Production							
United States	8.0	9.0	11.3	9.8	11.6	11.8	
Canada	0.5	0.9	1.5	2.2	3.0	3.7	
Latin America	3.8	4.7	5.3	5.8	6.7	7.0	
Total Western Hemisphere	**12.3**	**14.6**	**18.1**	**17.8**	**21.3**	**22.5**	
Synthetic Liquid Production							
United States	–	–	–	–	0.1	0.5	
Canada	–	–	–	–	0.4	1.0	
Latin America	–	–	–	–	0.3	0.8	
Total Western Hemisphere	**–**	**–**	**–**	**–**	**0.8**	**2.3**	
Total Liquid Hydrocarbon Production (Conventional Plus Synthetic) Available for Net Export or (Imports Required)							
United States	(1.8)	(2.5)	(3.4)	(8.5)	(10.6)	(13.5)	(13.5)
Canada	(0.3)	(0.2)	–	0.4	1.1	2.0	1.7
Latin America	2.1	2.6	2.5	1.9	1.9	1.3	0.8
Total Western Hemisphere	**–**	**(0.1)**	**(0.9)**	**(6.2)**	**(7.6)**	**(10.2)**	**(11.0)**

* All estimates are on a Case III supply basis.

oil in a number of markets, and this trend can be expected to continue.

Current Participation Demands

A number of oil companies agreed in principle to the OPEC request for a participation interest in producing company operations. The concept of "participation" is not new. Joint ventures in which private companies operate in conjunction with national concerns have been in effect for some time in a number of areas. Hopefully, producing country government ownership or participation in foreign oil operations will work to strengthen existing relationships between oil companies and foreign governments. It will thereby contribute needed stability to these operations as well as moderate widely different current political attitudes. Whether this will be the outcome is dependent on the motives of these governments and the outcome of negotiations still underway in mid-1972.

As of late 1972, the major issues remaining to be negotiated have to do with the form and amount of compensation the foreign producing governments will agree to in order to acquire (1) their share of the oil operations, (2) ultimate participation percentage and timing thereof, and (3) the matter involving the disposition of the foreign producing governments' share of oil when acquired. Settlement of these issues must occur before other questions such as foreign producing governments' operations can even be considered, much less agreed to.

Currently there are differences on the above major issues as between the negotiating parties, and it would be premature to speculate too much at this time as to the impact of current demands for participation on foreign crude supplies or downstream operations.

Over the longer term it seems inevitable that the higher the costs of oil from the OPEC countries rise due to increased government "take," the greater the incentive will become to explore for and develop crude oil reserves or synthetic oil from shale and tar sands in the United States and Canada.

Communist Bloc Considerations

Projected Impact of U.S.S.R. and Eastern Europe Oil Imports/Exports on Non-Communist World Oil Supplies

Total U.S.S.R. oil exports to the non-Communist World could increase to 1.6 MMB/D in 1976, and to 1.9 to 2.0 MMB/D in 1980 through 1985 if the proposed pipeline system to Japan is in operation by mid-1976. Excluding these shipments to Japan, Russian oil exports to the non-Communist World —mostly Western Europe—will likely remain at about the current level of 1.1 MMB/D until 1976, at which time they may decline slightly to about 900 MB/D and remain at approximately this level through 1985. Thus, the outlook to 1985 is for little, if any, additional competitive impact from Russian oil supplies except for the possible expansion of exports to Japan. Russian oil imports from non-Communist World sources are expected to remain relatively small throughout the period.

Eastern Europe's limited oil exports to the non-Communist World, which consist mainly of products from Rumania, are expected to decline from the current 120 MB/D level to between 70 and 80 MB/D by 1985. Meanwhile, oil imports from the non-Communist World by Eastern Europe will likely increase from the current level of 160 MB/D to 300 MB/D in 1976, 800 MB/D in 1980 and 1 MMB/D in 1985. Most of the imports from the non-Communist World up to 1976 appear to be covered by arrangements already made with host governments of the Middle East and North Africa.

Mainland China, North Korea, North Vietnam and Mongolia Energy Outlook

Total energy consumption of these countries is substantial, amounting to about 6.2 MMB/D oil equivalent in 1971—nearly half again as large as Latin America's consumption and about 6 percent of the world's total. In 1971, locally produced coal supplied about 90 percent of total energy requirements. Hydroelectric power supplied about 3 percent. The remaining 7 percent was supplied by about 400 MB/D of local oil production, augmented by 50 MB/D of oil imports—30 MB/D from the U.S.S.R. and 20 MB/D from non-Communist World sources. Estimated energy consumption for the years 1975, 1980 and 1985 is summarized in Table 156.

Conjecturally, the potential for oil imports by these countries, based on their need, is very large. By 1980, this potential could exceed 1 MMB/D and by 1985 1.5 MMB/D. The realization of this potential, however, will depend upon the amount of international purchasing power they (particularly China) are able to develop in world markets. New political arrangements are required to make such a level of trading possible.

Other Considerations

No account has been made in this study of the potential impact of recent changes in U.S. relationships with the U.S.S.R. or Peoples Republic of China.

TABLE 156

ESTIMATED ENERGY CONSUMPTION FOR MAINLAND CHINA, NORTH KOREA, NORTH VIETNAM AND MONGOLIA (1975, 1980 AND 1985)

	MB/D Oil Equivalent		
	1975	1980	1985
Oil			
Domestic	550	700	700
Imports			
U.S.S.R.	40	50	50
Non-Communist World	60	100	150
Total Oil	**650**	**850**	**900**
Natural Gas	–	100	200
Coal	6,400	7,550	8,550
Hydro and Nuclear	250	500	600
Total	**7,300**	**9,000**	**10,250**

Foreign Gas Availability

As of January 1, 1972, total proved non-Communist natural gas reserves were estimated at 1,033 TCF, consisting of production to that date of 138 TCF and remaining reserves of 895 TCF. The estimate of future discoverable reserves is 6,167 TCF, while the projected growth rate of non-Communist foreign energy demand is expected to be about 6.5 percent per year. Therefore, it appears that the volume of ultimate recoverable reserves in the non-Communist areas of the world is large enough to project that an adequate potential supply of natural gas reserves is available for import into the United States.

While the potential supply is very large, considerable effort will be needed to achieve its availability. In the past, exploration efforts have apparently focused primarily on oil. This conclusion is based on the observation that natural gas proved reserves represent less than 15 percent of the estimated ultimate potential. In the Western Hemisphere, excluding the United States, less than 8 percent (190 TCF) of the estimated ultimate recoverable reserves of 2,570 TCF have been found. Furthermore, physical availability of foreign natural gas supplies to the United States must be accompanied by viable domestic regulatory and economic conditions, in addition to stable foreign relations, if import projects are to be planned and initiated with confidence.

Total non-Communist natural gas production outside the United States was 16.3 TCF in 1971, excluding injection volumes. Reserves/production ratios ranged from almost 30 in the Western Hemisphere (excluding the United States) to 121 for Africa. Resource estimates, proved reserves and production data are presented in Table 157 by geographic area.

Communist World reserves of 558 TCF, as estimated by the *Oil & Gas Journal*, include 546 TCF in Russia which is the official Russian Oil Ministry estimate as of January 1, 1971. Natural gas production in 1970 amounted to approximately 7 TCF, as reported by the Soviet's Central Statistical Board, which was less than one-third of the total produced in the United States. Remaining Russian potential gas is considered enormous—some estimates exceed 2,500 TCF, 60 percent of which is thought to be located in western Siberia.

LNG Import Project Requirements

For the Initial Appraisal, adequate reserves were assumed available to support the level of LNG imports estimated through 1985, on the basis of availability for a 20-year project life at a level of 12.5 billion cubic feet of reserves for each MMCF per day of imported LNG. The current study analysis indicates that available reserves are already more than adequate for anticipated LNG imports without considering additional reserves that will undoubtedly be added in the years prior to 1985. LNG imports face such problems as availability of specialized tankers, adequate port facilities and domestic and foreign political considerations. Table 158 shows that non-Communist proved reserves are not a constraint, even for the maximum projected 1985 LNG import volumes. At the present time, foreign demand is competitive only in Algeria and the Pacific, where current gas reserves are two times or more the calculated reserve backup.

In addition to the potential supply show in Table 158, discussions concerning imports from Russia suggest that LNG projects based on that source of supply should be considered a possibility.

TABLE 157
FREE WORLD GAS RESERVES AND PRODUCTION DATA—HISTORICAL—EXCLUDING U.S.A.

	Units	North America and Caribbean	South America	Western Europe	Africa	Middle East	Far East and Oceania	Total
Total Gas in Place*	TCF	3,500	2,500	1,300	5,400	3,600	1,100	17,490
Discoverable Gas in Place*	TCF	2,200	1,600	800	3,400	2,200	700	10,900
Economic Recoverable Gas	TCF	1,545	1,025	500	2,260	1,415	455	7,200
1/1/72 Booked Reserves†	TCF	71	56	161	193	344	70	895
1/1/72 Cumulative Production—Net ‡	TCF	35	28	22	10	35	8	138
1/1/72 Booked Ultimate	TCF	106	84	183	203	279	78	1,033
1/1/72 Unbooked Ultimate	TCF	1,439	941	317	2,057	1,036	377	6,167
1971 Estimated Gross Production	TCF (Canada Injection Out)	3.4	2.5	4.8	1.6	4.5	0.8	17.6
1971 Estimated Gas Injection	TCF (Mexico Only in N. America)	0.1	0.9	—	—	0.3	—	1.3
1971 Estimated Net Production	TCF	3.3	1.6	4.8	1.6	4.2	0.8	16.3
1970 Estimated Gas/Oil Ratio	Cubic Feet per Barrel (Gross)	4,645	1,511	26,000	711	693	1,349	1,413
1/1/72 Reserves/Production Ratios								
Net Production Basis	Years	22	35	34	121	82	88	55
Annual Reserve Additions§								
1970	TCF	4.5	4.5	20.3	2.5	9.3	3.5	44.6
1968-1970 Inclusive	TCF	5.5	1.5	14.4	22.4	19.7	4.5	68.0
1962-1970 Inclusive	TCF	4.7	2.0	16.4	14.7	13.4	3.7	54.9
1971	TCF	0.2	(1.8)	19.8	3.1	(6.2)	14.3	29.4
Production Growth Rates								
1970	% per Year	12	2.3	46	20	17	37	19
1967-1970	% per Year	11	2.6	40	23	15	21	—
1962-1970	% per Year	10	4.2	22	30	13	13	—
Booked Ultimate/Economic Recoverable Gas	Percent	6.9	8.2	36.6	9.0	26.8	17.1	14.3

Basis for Economic Recoverable Reserve Estimates

Utilizing discoverable gas in place listed and discoverable oil-in-place from same source broke discoverable gas in place down into associated-dissolved and non-associated. Recovery factors of 40 percent for associated-dissolved gas and 75 percent for non-associated gas were utilized across the board. Solution gas GOR's were used as follows to calculate associated-dissolved gas in place:

	North America and Caribbean	South America	Western Europe	Africa	Middle East	Far East and Oceania
GOR's	1,000	1,000	1,000	750	750	1,000

* T. A. Hendricks, *Resources of Oil, Gas and Natural-Gas Liquids in the United States and the World*, U.S. Geological Survey, Circular 522 (1965).

† "Price, Nationalization Jitters Plague International Oil World," *Oil & Gas Journal* (December 27, 1971), pp. 72-73.

‡ U.S. Bureau of Mines, *Minerals Yearbook* (1914-1969 inclusive), with estimated data in all years where gross gas production not reported.

§ *World Oil* data, except for 1971 which is from the *Oil & Gas Journal.*

TABLE 158

1985 LNG IMPORT PROJECT SUPPLY

Country	LNG Projects (MMCF/Day)	Calculated Reserve Backup (TCF)	1/3/71 Reserve Estimate
Algeria	4,350	54.4	106.5
Nigeria	3,500	43.8	40.0
Venezuela	1,000	12.5	25.4
Trinidad	300	3.8	5.0
Ecuador	500	6.3	6.0
Pacific	1,000	12.5	42.9

Canadian Gas Reserves, Production and Export Availability—General

Evidence of a limitation in Canadian gas supply available to the United States was recorded on November 19, 1971, when the Canadian National Energy Board (NEB) dismissed three applications for licenses to export nearly 2.7 TCF of gas to the United States. This was also indicated in August 1970, when applications for 2.5 TCF were rejected out of a total of 8.9 TCF in requests. The NEB's 1971 Annual Report gave the following reason for the 1971 rejections: ". . . the Board decided that there was no surplus of gas remaining after due allowance had been made for the reasonably foreseeable requirements for use in Canada having regard to the trends in the discovery of gas in Canada." *

As a result of the NEB's action, the import volume from Canada to the United States is expected to stabilize at the current maximum permissible volume of about 1 TCF per year over the short term. This results in a reduction, through 1978, of the Initial Appraisal's constant rate projection of 1.15 TCF per year. Thereafter, it is likely that gas from Canada's frontier areas should become available for export to the United States.

Several factors influence the long-term expectation of increased Canadian exports. First, the NEB excludes from consideration known gas reserves inaccessible to transportation as well as unproved or merely potential reserves. The Canadian frontier areas are indicated to have great potential, and several oil and gas discoveries already have been made. When pipelines are built, these gas reserves from frontier areas will be considered in the NEB's calculations and should result in a reserve surplus. Secondly, the 1971 NEB decision was based on a shortfall in current surplus as a result of a recent sharp upturn in Canadian demand. This surge of demand, caused principally by new pollution controls and recent price increases of alternate fuels, should decline from the 11-percent increase in 1971. Thirdly, the Canadian Petroleum Association (CPA) supports the general conclusion that future Canadian gas exports will increase. The CPA estimates a total export availability of 132 TCF over the next 20 years, including the 17 TCF already committed. Of the remainder, 15 TCF more is to come from western Canada, 50 TCF from the Arctic Isles and 50 TCF from offshore.†

Projections

Canadian gas reserve additions, production and market demand were projected as shown on Table 159 to determine the availability of gas for possible export to the United States. To arrive at this Canadian supply/demand balance, the country was divided into the following four areas: (1) western Canada, (2) eastern Canada offshore, (3) northwest Arctic Islands, and (4) northwest onshore. These areas are shown on Figure 104. The methodology for western Canada was based on extrapolation of historical data. The other areas were patterned after the domestic gas supply projections for similar areas with consideration of current activity.

The historical reserve data of western Canada were obtained from the CPA Annual Reserve Report. These data differ slightly from the NEB estimates, but are available on a yearly and continuous basis. The NEB estimates are made at irregular intervals. The ultimate gas resources were determined from T. A. Hendricks' estimate of North American gas in place after deducting U.S. totals.‡ This left for Canada, Mexico and the

* Canadian National Energy Board's Annual Report (December 31, 1971).

† "132 TCF Export Gas—at a Price," *Oilweek*, a summary of D. B. Furlong's (Managing Director CPA) November 18, 1972, speech at ICT Chicago meeting (November 22, 1971), p. 8.

‡ T. A. Hendricks, *Resources of Oil, Gas and Natural-Gas Liquids in the United States and the World*, U.S. Geological Survey, Circular 522 (1965).

TABLE 159

CANADA–NATURAL GAS SUPPLY AND DEMAND
(TCF)

	Atlantic Offshore		Northwest Territory – Onshore		Northwest Territory – Islands		Western Canada		Total Canada						
	Reserve Additions	Annual Production	Reserve Additions	Annual Production	Reserve Additions	Annual Production	Reserve Additions	Annual Production	Reserve Additions	Annual Production	Shrinkage, Field Use, Flared, etc.	Canadian Demand	Available for Export	December 31 Reserves	R/P
1971	N	–	–	–	0.3	–	3.7	2.7	4.0	2.7	0.8	1.0	0.9	54.7	20.3
1972	1.0	–	0.5	–	1.1	–	4.8	2.9	7.4	2.9	0.8	1.1	1.0	59.2	20.4
1973	1.5	–	1.0	–	1.0	–	4.4	3.0	7.9	3.0	0.8	1.2	1.0	64.1	21.4
1974	2.0	–	1.5	–	2.0	–	5.8	3.3	11.3	3.3	0.9	1.4	1.0	72.1	21.8
1975	2.5	–	2.5	–	3.0	–	4.5	3.4	12.5	3.4	0.9	1.5	1.0	81.2	23.9
1976	3.0	0.1	3.0	–	2.0	–	4.5	3.5	12.5	3.6	0.9	1.7	1.0	90.1	25.0
1977	3.5	0.4	4.5	–	2.0	–	4.5	3.5	14.5	3.9	1.0	1.9	1.0	100.7	25.8
1978	4.0	0.7	5.0	0.1	2.0	–	4.5	3.5	15.5	4.3	1.1	2.1	1.1	111.9	26.0
1979	4.0	0.9	5.0	0.4	2.0	–	4.5	3.5	15.5	4.8	1.1	2.3	1.4	122.6	25.5
1980	4.0	1.1	5.0	0.7	3.0	–	4.5	3.5	16.5	5.3	1.2	2.5	1.6	133.8	25.2
1981	4.0	1.2	5.0	1.0	5.0	–	4.5	3.5	18.5	5.7	1.3	2.6	1.8	146.6	25.7
1982	4.0	1.4	5.0	1.2	5.0	–	4.5	3.4	18.5	6.0	1.4	2.8	1.8	159.1	26.5
1983	4.0	1.4	5.0	1.4	5.0	0.6	4.5	3.4	18.5	6.8	1.5	2.9	2.4	170.8	25.1
1984	4.0	1.4	5.0	1.4	5.0	1.0	4.5	3.4	18.5	7.2	1.5	3.0	2.7	182.1	25.3
1985	4.0	1.6	5.0	1.6	5.0	1.0	4.5	3.3	18.5	7.5	1.6	3.2	2.7	193.1	25.7
Total	**45.5**	**10.2**	**53.0**	**7.8**	**43.4**	**2.6**	**68.2**	**49.8**	**210.1**	**70.4**	**16.8**	**31.2**	**22.4**	–	–

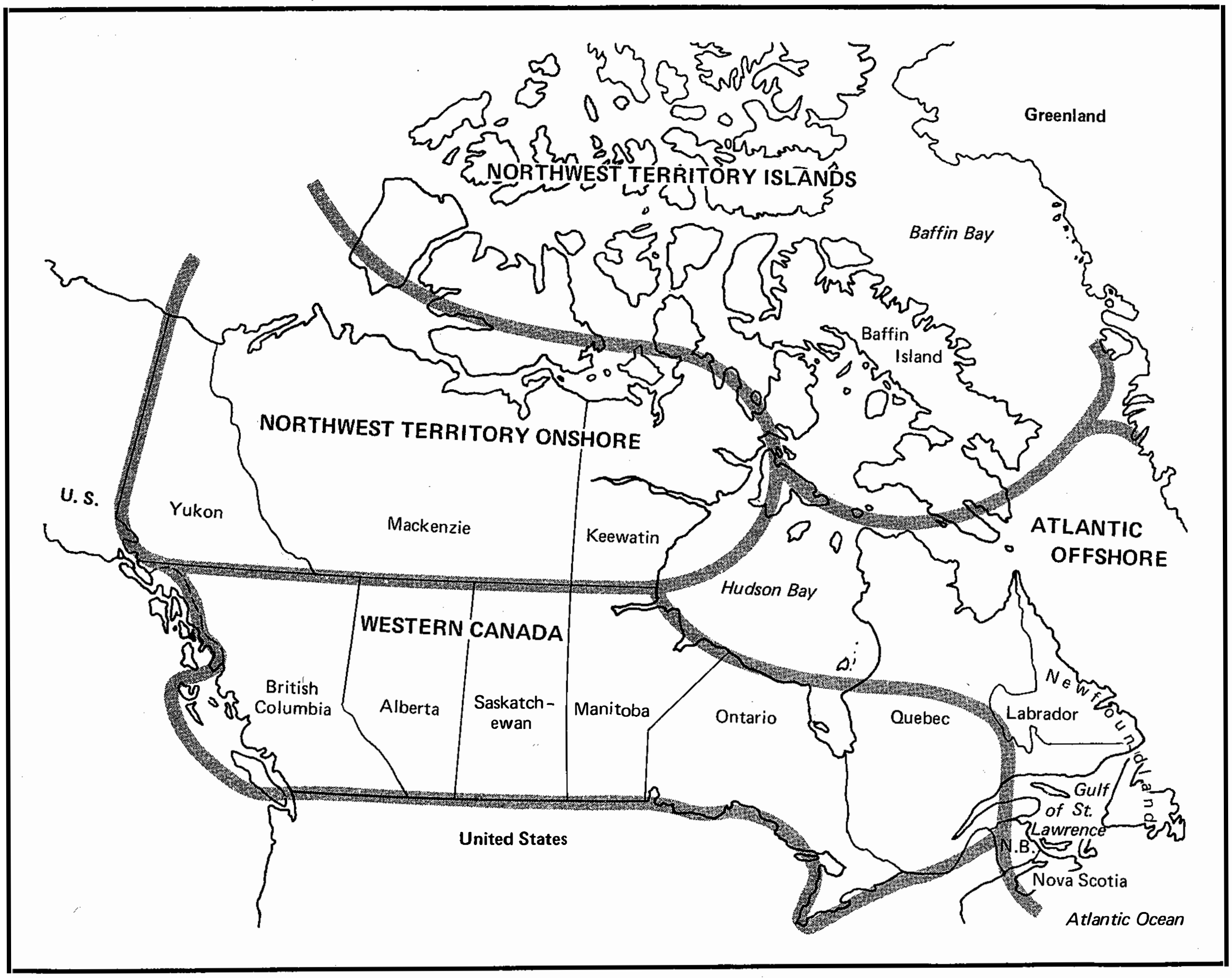

Figure 104. Area Map of Canada.

Caribbean a remaining discoverable ultimate gas recovery of 1,439 TCF as of January 1, 1972. The *Oil & Gas Journal* allocates more than 80 percent of this ultimate recovery (1,165 TCF) to Canada. Conservatively assuming Canadian potential and proved discoverable gas at 800 TCF, a reasonable breakdown by areas within Canada would be: (1) western Canada—150 TCF, (2) eastern Canada offshore—150 TCF, (3) northwest Arctic Isles—300 TCF, and (4) northwest onshore—200 TCF.

An R/P of 25 was assumed necessary to permit the exportation of any additional western Canada gas. On this basis, no additional exports from western Canada beyond volumes already authorized were forecast. The eastern Canada offshore area was estimated to be the first of the frontier areas to deliver gas to market as it is the most accessible frontier area to market. Proved reserves of 15 TCF should ensure pipeline construction while an ultimate of 25 to 30 TCF would probably be needed to justify a 48-inch diameter pipeline. Initial production is estimated in late 1976 to satisfy Canadian demand. Reserve additions are estimated to total 45.5 TCF by the end of 1985, and by 1977 the R/P for Canada's total proved reserves is estimated to rise higher than 25 years, permitting a modest export increase in 1978.

The northwest Arctic onshore region, or MacKenzie Delta/Beaufort Sea area, has highly attractive gas and oil exploration prospects. Giant oil or gas fields are not normally found in delta areas, but numerous prolific smaller fields are anticipated. In this area, gas reserves for the Taglu structure have been estimated as high as 10 TCF and for the Mallik structure in excess of 10 TCF.* Discoverable ultimate gas is estimated in excess of 200 TCF.

Drilling activity is high in the Northwest Territories, and plans are being formulated for both oil and gas pipelines. The projection anticipates completion of a gas pipeline by 1978. Reserve additions to that time are 13 TCF and are estimated to continue from that year at a rate of 5 TCF per year throughout the projection period. By the end of 1985, a total of 53 TCF of reserve additions should have accumulated.

Energy Minister MacDonald stated that the ecological and economic studies for a MacKenzie pipeline should be completed by the end of 1972.† Meanwhile, the Gas Arctic Systems Group ‡ and Northwest Project Study Group have combined and are jointly continuing their investigations of pipeline design, economics, financing and environmental and operating conditions. This project will most likely involve the transportation of both Alaskan and Canadian gas.

In the projection for the Arctic Islands, the reserve additions occur relatively slowly because of an anticipated slowdown in activity after sufficient reserves for a pipeline are found. This slowdown could be expected to continue until completion of the pipeline. Total reserve additions of 43.4 TCF are projected through 1985. A 10-percent allocation of wellhead production for fuel, flaring, shrinkage and losses is estimated, assuming reserve additions are principally non-associated gas.

The Arctic Island potential is indicated by data released on the King Christian Island discovery. This reservoir could contain about 15 TCF of gas in place.§ The King Christian structure is ranked as medium size for the area.

In projecting the gas reserve additions, the methodology attempts to predict only proved reserves as they would be added under CPA definitions. An operator and a pipeliner will normally include some potential reserves in estimates for determining the timing of a pipeline. Therefore, in the projection, pipeline construction starts prior to the time when proved reserve additions were sufficient to justify the construction.

Projections of Canada's reserve additions and production could recognize numerous variations by areas that would be reasonable and yet not appreciably change total additions and production. Also, somewhat different totals could be reasonably supported. However, the export volume projection is considered reasonable under the basic assumptions: (1) that each frontier area could support a 48-inch gas pipeline or its equivalent within the 1985 time frame, (2) that the NEB's present standards of export evaluation will continue, and (3) that insufficient reserves are left to be found in western Canada to increase the 1970's reserve additions to a high enough point to permit additional exports from that area.

Production after the time of the first pipeline throughputs can be modified up or down and change the export volume slightly. A 56-inch pipeline could possibly be prognosticated for either of the northwest areas, permitting a significant change in export volume, but this might delay initial throughputs. Changes in Canada's domestic demand could be compensated for by production changes without affecting the export projections. The principal factor that could affect the export volume is delay in the timing of pipeline completion from the northwest areas.

In summary, it is projected that only Canadian frontier areas have large enough reserves to supply sufficient gas to appreciably offset the anticipated U.S. shortfall. Until such time as these areas are developed and the gas brought to market, Canada's gas exports to the United States would be held to about 1 TCF per year. The earliest that frontier gas would be available for export is 1978.

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* *Oil and Gas Discoveries* (March 1972), p. 1.

† "Odds Improve for MacKenzie Valley Gas Line," *Oil & Gas Journal* (February 28, 1972), p. 28.

‡ "Artic Research Ahead of Politics," *Oilweek* (November 22, 1971), pp. 60-64.

§ "Oil & Gas Journal Newsletter," *Oil & Gas Journal* (September 13, 1971); "Panarctic Provides Impetus," *Canadian Petroleum* (October 1971), pp. 20-24.

Chapter Thirteen
Oil and Gas Logistics and Imports

Introduction

Oil and gas demand increases, coupled with changing supply sources, underlie the projected changes in logistical systems. This chapter discusses (1) U.S. petroleum supply/demand balances for Cases I through IV, including regional implications and domestic pipeline distribution systems; (2) oil imports; (3) refinery capacity requirements, including desulfurization facilities; (4) tank ships and deepwater terminals; and (5) gas logistics with emphasis on the capital costs of processing, transporting and storing natural gas, LPG, syngas and LNG.

Oil Logistics

Summary and Conclusions

With the exception of Case I, total oil requirements will rise faster than domestic production. The United States will have to rely on increased oil imports to meet its total energy requirements. These imports will increase very rapidly until delivery of Alaskan North Slope oil begins (assumed to be in 1976). Thereafter, imports will continue to increase, but at a somewhat slower rate than in earlier years.

The supply/demand balances for Cases II and III for the 1971-1985 period indicate the following:

- Total U.S. oil requirements will increase from 14.7 MMB/D in 1970 to 23.1 MMB/D to 25.8 MMB/D in 1985. Domestic production of crude oil and natural gas liquids will continue to decline from the 1970 peak of 11.3 MMB/D through 1975. After 1975, total production will increase slightly as Alaskan North Slope oil production and synthetic crude output begin.
- In Case III, total imports of crude oil and refined products rise sharply from 23.2 percent of required oil supply in 1970 to 46.6 percent by 1975 and 52.2 percent by 1985. In Case II, imports represent 42.0 percent of required oil supply in 1975 and 37.7 percent of supply in 1985.*
- As demand for refined petroleum products increases, additional petroleum refining capacity will be needed to satisfy U.S. requirements. The growth of refinery capacity in the United States will be dependent on U.S. import policies, comparative economics of domestic versus foreign refining, and a resolution of environmental problems. National policies which favor importation of residual fuel oil, semi-refined oils and other petroleum products will result in refining capacity being built abroad rather than in the United States.
- Economic and environmental considerations favor the use of very large tank ships of 250,000 to 400,000 DWT in international oil movements. At the present time, however, there are no U.S. ports that are capable of handling vessels of this size.
- The capital costs for refineries and logistical facilities necessary to accommodate U.S. oil requirements between 1971 and 1985 will be approximately $58 billion.

U.S. Petroleum Supply and Demand

Total import requirements are the difference between required oil supply and total domestic production of conventional and synthetic liquid fuels. Tables 160 through 163 summarize the oil import requirements resulting from the energy supply/demand balances of Cases I through IV.

* Percentage figures cited in this chapter are based on volumes of imports and differ slightly from those in Chapter Two which are based on BTU's.

TABLE 160

U.S. PETROLEUM SUPPLY/DEMAND BALANCE—CASE I
(MB/D)

	1970	1975	1980	1985
Requirements*	14,716	17,454	19,600	20,458
Petroleum Liquid Production	11,297	10,239	13,580	15,464
Synthetic Oil Production	—	—	230	1,430
Total Domestic Petroleum Supply	**11,297**	**10,239**	**13,810**	**16,894**
Petroleum Imports	3,419	7,215	5,790	3,564
Percent of Total Required Supply	23.2	41.3	29.5	17.4
Source of Imports				
Canadian Overland	766	1,275	1,925	2,750
Foreign Waterborne	2,653	5,940	3,865	814

* Oil required to balance total energy demand, net of processing gain, stock change, unaccounted for crude and other hydrocarbon inputs.

TABLE 161

U.S. PETROLEUM SUPPLY/DEMAND BALANCE—CASE II
(MB/D)

	1970	1975	1980	1985
Requirements*	14,716	17,551	20,513	23,068
Petroleum Liquid Production	11,297	10,186	12,939	13,887
Synthetic Oil Production	—	—	100	480
Total Domestic Petroleum Supply	**11,297**	**10,186**	**13,039**	**14,367**
Petroleum Imports	3,419	7,365	7,474	8,701
Percent of Total Required Supply	23.2	42.0	36.4	37.7
Source of Imports				
Canadian Overland	766	1,275	1,925	2,750
Foreign Waterborne	2,653	6,090	5,549	5,951

* Oil required to balance total energy demand, net of processing gain, stock change, unaccounted for crude and other hydrocarbon inputs.

This study has examined 22 total energy supply/demand balances, each of which leads directly to an oil import requirement. In this chapter—as has been the case throughout much of this report—the mid-range Cases II and III have been used for illustrative purposes.

TABLE 162

U.S. PETROLEUM SUPPLY/DEMAND BALANCE—CASE III
(MB/D)

	1970	1975	1980	1985
Requirements*	14,716	18,251	22,335	25,787
Petroleum Liquid Production	11,297	9,747	11,611	11,833
Synthetic Oil Production	—	—	100	480
Total Domestic Petroleum Supply	**11,297**	**9,747**	**11,711**	**12,313**
Petroleum Imports	3,419	8,504	10,624	13,474
Percent of Total Required Supply	23.2	46.6	47.6	52.2
Source of Imports				
Canadian Overland	766	1,275	1,925	2,750
Foreign Waterborne	2,653	7,229	8,699	10,724

* Oil required to balance total energy demand, net of processing gain, stock change, unaccounted for crude and other hydrocarbon inputs.

While both cases use the same drilling rates, Case II depicts high finding rates for oil and gas while Case III reflects low finding rates. The Case II total demand for petroleum liquids is lower than the Case III demand because higher gas production meets a large share of the total energy demand. In Case II, both the higher domestic production of petroleum liquids and lower demand act directly to lower total imports.

Conversely, the low finding rate in Case III results in a higher oil demand because of the lower production level for natural gas. The combined effect of lower oil production and higher oil demand requires a significant increase in oil imports.

Cases I and IV show the possible extremes of U.S. dependence on imported oil. In Case I, imports exceed 40 percent of requirements in 1975, but the effects of the increased effort to find and produce more domestic oil and gas begin to show in 1980, and by 1985 required imports are reduced to 3.4 MMB/D, or about the same as the 1970 volume. Case IV shows imports reaching 19.2 MMB/D in 1985 or nearly two-thirds of the total oil requirement. These cases indicate the sensitivity of oil imports as the swing source of energy for the United States during the next 15 years.

Dramatic increases in imports during the next 3 to 5 years appear to be unavoidable. While requirements for petroleum liquids continue to expand between 1971 and 1975, total domestic production appears to have peaked in 1970 and has begun a moderate decline. In the Case III situation, required oil supply increases 3.5 MMB/D from 1970 to 1975 while domestic production declines 1.6 MMB/D. Total imports needed to supplement available domestic production would therefore have to increase 5.1 MMB/D in 5 years, from 3.4 MMB/D in 1970 to 8.5 MMB/D in 1975. In the high finding rate (Case II), required imports double in 5 years. Imports as a proportion of required oil supply rise from 23 percent in 1970 to 42 and 46 percent by 1975 for Cases II and III respectively.

Because of the long lead time needed to plan, approve and construct the required facilities, the stresses on present logistical systems will intensify markedly, particularly until 1975. After 1975 the effects of current national policy decisions concerning energy production and imports may either relieve or further aggravate this situation.

As projected in Cases II and III, the ratio of imports to required new supply continues to in-

TABLE 163

U.S. PETROLEUM SUPPLY/DEMAND BALANCE—CASE IV
(MB/D)

	1970	1975	1980	1985
Requirements*	14,716	19,300	25,301	29,727
Petroleum Liquid Production	11,297	9,622	8,896	10,379
Synthetic Oil Production	—	—	—	100
Total Domestic Petroleum Supply	**11,297**	**9,622**	**8,896**	**10,479**
Petroleum Imports	3,419	9,678	16,405	19,248
Percent of Total Required Supply	23.2	50.1	64.8	64.7
Source of Imports				
Canadian Overland	766	1,275	1,925	2,750
Foreign Waterborne	2,653	8,403	14,480	16,498

* Oil required to balance total energy demand, net of processing gain, stock change, unaccounted for crude and other hydrocarbon inputs.

crease in the 1976-1985 period. The rate of increase is much slower than in the 1971-1975 period because of the projected delivery of Alaskan North Slope oil and the beginning of synthetic petroleum production.

Regional Implications

For the purpose of regional logistical discussion, the five Petroleum Administration for Defense (PAD) Districts shown in Figure 105 are used.

In the Initial Appraisal, supply/demand balances were constructed for the East and West Coast Districts I and V. In preparing this study, however, it was determined that any attempt to project detailed balances by districts would require too many arbitrary assumptions regarding types and methods of petroleum movements throughout the country. However, while the district details were not calculated, a general outlook for the districts was formulated. Table 164 summarizes the 1970 actual district balance situation.

For purposes of simplicity, this study has focused, in general, on analyses of U.S. petroleum supply problems as they are reflected in Cases II and III. Of these two cases, future oil logistics requirements and problems are more severe in Case III, and it has therefore been selected for further study to illustrate the magnitude of these problems.

Table 165 shows the projected 1985 oil production and demand by districts for Case III. The demand figures are derived from the districts' percentages of total demand developed in the Initial Appraisal. Little shift is projected in the distribution of demand, but logistical problems will be compounded by the concentration of deficits in PAD Districts I and II.

As show in Table 165, District I will be especially hard pressed because of its almost complete dependence on outside sources of oil. By 1985 about 10 MMB/D will have to be brought into District I. Furthermore, if the 1970 level of receipts from other districts remains constant, which is questionable, over 6 MMB/D would have to be imported. If import policies required that volume to be entirely crude oil, East Coast refining capacity would have to be increased to 5 times its 1970 level of 1.3 MMB/D.

While District V is shown to be in relative balance in 1985, primarily due to the availability

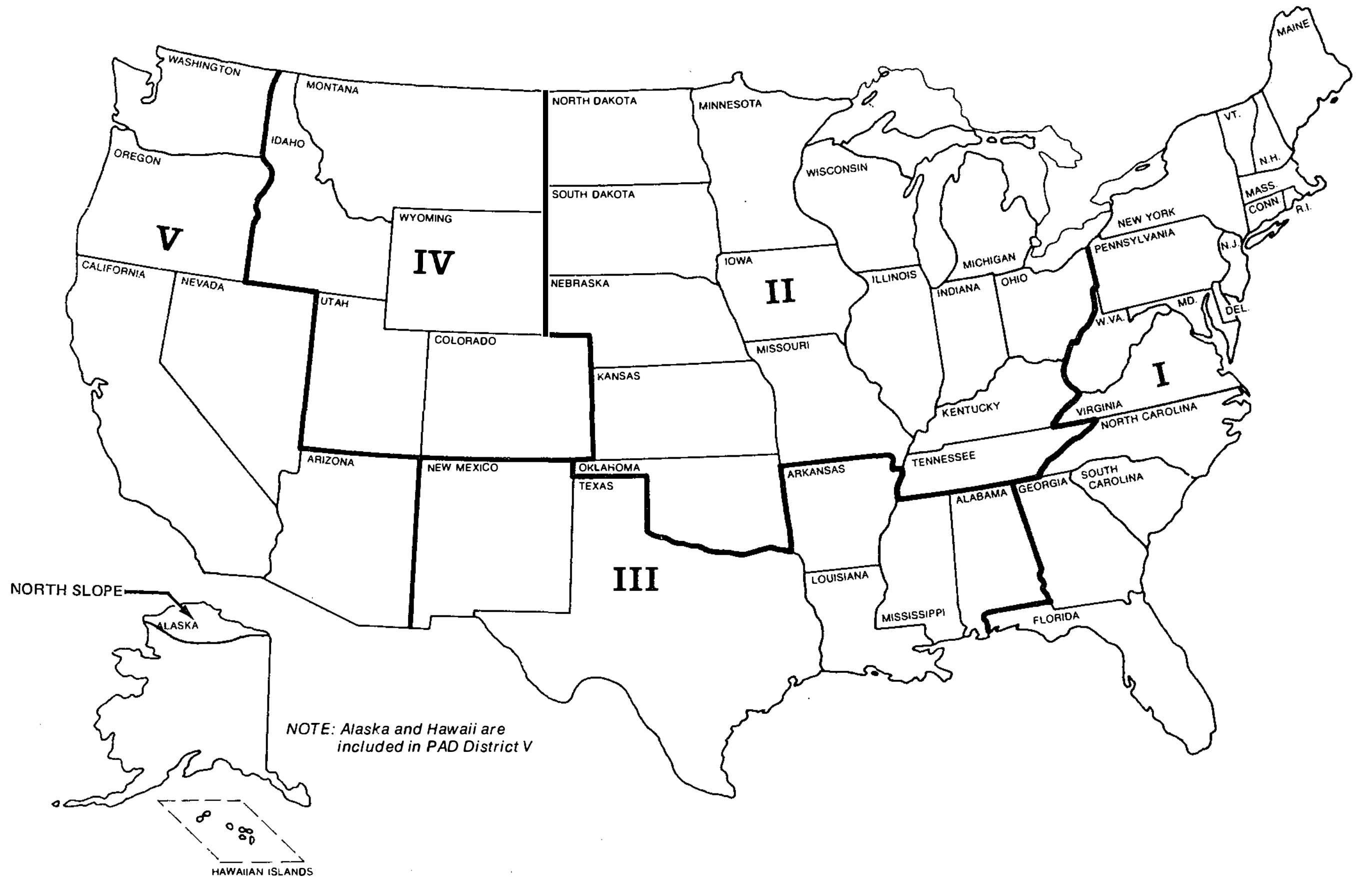

Figure 105. Petroleum Administration for Defense (PAD) Districts.

of Alaskan North Slope oil production, continued increased growth in West Coast demand beyond 1985 will probably have to be met from imports. District IV is shown to be a net shipper of petroleum. District III will continue to produce more petroleum than it consumes, but the differential is decreasing.

District II, like District I, has a much larger demand than production of oil. Because of its proximity to Canada and District III, District II can expect significant receipts from both. However, if all projected Canadian overland imports and all the District III surplus production were received, District II would still require approximately 1 MMB/D of additional oil.

Foreign oil reaching PAD District II in 1970 amounted to 0.4 MMB/D, and total domestic movements into the district were 2.6 MMB/D. As the deficit grows to 5.9 MMB/D during the next 15 years, logistical systems must be expanded to meet oil requirements in the upper midwest and midcontinent areas.

Any number of configurations of such a system might evolve, and each would likely have to provide for additional movements of crude or products into the Gulf Coast and/or the East Coast and subsequently to interior markets. This would require construction of new crude and/or products pipelines or additional barge traffic on the Mississippi River system. The nature of the system will be affected by many factors, principally, whether the added supplies move from the East Coast or from the Gulf Coast and whether the movements are crude or products. This latter point also obviously has implications for refining locations. These volumes show the net required movements among the districts. No attempt has been made to define this system in any detail. In actual practice, no single integrated system exists, and gross movements and requirements will exceed those

TABLE 164

PETROLEUM SUPPLY/DEMAND SITUATION—ALL OILS—1970
(MB/D)

	PAD Districts					
	I	II	III	IV	V	Total U.S.
Domestic and Export Demand	5,907	4,023	2,593	375	2,070	14,968
Domestic Production*	55	1,413	7,817	709	1,320	11,314
Shipments to Other Districts	120	183	5,507	436	24	—
Receipts from Other Districts	3,546	2,405	82	45	192	—
Total Imports	**2,446**	**371**	**61**	**57**	**484**	**3,419**

* Crude oil, condensate, natural gas liquids, other hydrocarbons and hydrogen input.

TABLE 165

1985 U.S. PETROLEUM LIQUIDS PRODUCTION* AND DEMAND—CASE III
(MB/D)

PAD District	Production	Demand	Surplus (Deficit)
I	201	10,211	(10,010)
II	906	6,859	(5,899)
III	6,458	4,332	2,126
IV	952	697	255
V	3,742†	3,688	54
Total United States	**12,313**	**25,787**	**(13,474)**

* Includes synthetics.
† Includes Alaska.

shown here. It seems inescapable that in the future significant volumes of foreign petroleum will be imported on the Gulf Coast.

Domestic Pipelines

As U.S. demand for petroleum continues to expand, internal distribution systems must also prepare to handle larger volumes of liquid petroleum. The existing network of crude oil and refined products pipelines was constructed basically to transport domestic crude oil to U.S. refining centers and move light refined products to consumer markets. Most of these lines are in natural transport corridors, moving oil from producer to consumer in a fairly direct fashion.

As more of the liquid petroleum requirements are met by imported oil, new pipelines may be needed to move oil from ports of entry to interior consumer markets. Whether such trunklines are for crude oil or refined products will depend on national policies with respect to oil imports, the environment and the construction of refinery capacity in or near major consuming markets. In the absence of prompt and firm resolutions of uncertainties in oil import regulations and environmental restraints on refining and deepwater terminal siting, it is not possible to project these logistical requirements in specific detail.

In addition to potential requirements for new pipelines, some existing lines are finding it more difficult to meet the new standards for pipeline safety. Older lines may have to operate at lower pressures and throughput rates or be paralleled with new larger diameter lines.

Although no detailed analysis of pipeline networks has been prepared for this study, new or replacement pipeline capacity will have to be built to cover demands which may almost double over the next 15 years. Based on recent activity, the capital costs for oil pipelines may average $0.5

TABLE 166

U. S. PETROLEUM IMPORTS*
(MB/D)

	1969	1970	1971	Program 1972
		Districts I-IV		
Crude and Unfinished				
Refining Companies	543	487	663	657
Carry-Over	74	—	—	—
Petrochemical Companies	85	84	102	94
From Canada	349	448	493	540
From Mexico	30	28	29	36
OIAB Set-Aside	—	—	—	36
Unallocated	—	—	—	43
Total	**1,081**	**1,047**	**1,287**	**1,406**
Finished Products (Ex. Resid.)				
Virgin Islands	15	15	15	15
Puerto Rico	45	45	64	64
Defense Department	—	—	—	20
Total	**60**	**60**	**79**	**99**
Total Controlled 12.2 Ratio	**1,141**	**1,107**	**1,366**	**1,505**
Other Imports				
Bonded Light Products	83	90	112	130
Shipments from Puerto Rico	47	58	30	50
Virgin Islands (Ref. Prod.)	8	2	17	20
No. 4 Fuel Oil	75	70	66	75
No. 2 Fuel Oil	18	30	61	45
Canadian Finished Products	30	42	12	60
Canadian & W. Hem. LPG	—	6	36	90
Asphalt	13	17	20	30
Imports for Petrochemical Exports	—	—	—	40
Total	**274**	**315**	**354**	**540**
Residual Fuel	1,244	1,513	1,560	1,665
Total Districts I-IV	**2,659**	**2,935**	**3,280**	**3,710**
		District V		
Crude and Unfinished				
Refining Companies	203	182	338	271
Carry-Over	5	—	—	—
Petrochemical Companies	3	3	3	3
From Canada	211	222	210	240
Total	**422**	**407**	**551**	**514**
Finished Products	7	8	15	20
Finished Products from Canada	11	8	—	10
Bonded Light Products	45	46	52	60
Residual Fuel Oil	21	15	22	25
Total District V	**507**	484	640	**629**
Total U. S. Imports	**3,166**	**3,419**	**3,920**	4,339

* Independent Petroleum Association of America, Media Meeting IPAA (New Orleans, May 1972).

billion per year (in constant 1970 dollars), or a total of $7.5 billion between 1971 and 1985.

Oil Imports

Import Policy and Its Implications

As the level of total imports rises in Case III, federal oil import policies which govern the mix of total imports become increasingly important. One basic issue is the extent to which national security and balance of trade considerations dictate a public policy requiring imports to be petroleum raw materials rather than products. A policy of importing petroleum raw materials into the United States would foster the construction of U.S. petroleum refining capacity. Conversely, a policy of permitting importation of finished petroleum products and unfinished oils would, in effect, "export" U.S. refinery capacity, causing it to be built abroad rather than in the United States. This would compound the effects that U.S. dependence on foreign oil would have on national security. In addition, many associated jobs would be exported. Oil import policies have been trending in the latter direction for a number of years.

The U.S. mandatory import program has been in existence since 1959. Since that time, many situations have arisen which have resulted in modifications to the program. Becoming progressively more complex, the program has tended to be more sensitive to the demands for special-purpose finished products. Residual fuel oil imports have been essentially exempted from controls in PAD District I, while still controlled in PAD Districts II through IV. Also, import allocations for heating oil have been granted to independent East Coast deepwater terminal operators. While Canadian crude and products limitations into Districts I through IV have been more a function of availability than of control, current policy does limit Canadian imports to less than that which is available. A completely different situation exists in District V, where waterborne imports are limited to the difference between local demand and local production plus Canadian overland imports. Table 166, showing a breakdown of the 1969-1971 actual import volumes and the programmed imports for 1972 before the September supplemental authorization, illustrates the exceptions that have been added to the program.

Residual fuel oil imports have absorbed all the increase in heavy fuel consumption for the past decade. Domestic refinery output of residual fuel oil, which had been declining for a number of years, has remained relatively constant since 1963 (see Table 167).

Imports of liquefied gases from Western Hemisphere sources, refined products overland from Canada, asphalt, No. 4 fuel oil, No. 2 fuel oil for East Coast deepwater terminal operators, and more recently imports of unfinished oil for "heavy liquid" petrochemical plants have been authorized within the oil import control program. Moreover, the uncontrolled imports of bonded aircraft and vessel fuels have been rising sharply in recent years. As a result of all these exceptions, the volume of refined products imports has been growing larger each year. In 1970, U.S. imports of refined products amounted to 2.1 MMB/D or 61 percent of total imports. This is over 1.6 times the 1.3 MMB/D of crude oil imported for processing in U.S. refineries. The composition of the future imported crude-product mix will have a very significant impact on the domestic refinery industry.

TABLE 167

SOURCE OF U.S. RESIDUAL FUEL OIL SUPPLY*
(MB/D)

	U.S. Refinery Output	Residual Imports
1956	1,165	445
1957	1,138	475
1958	995	499
1959	953	610
1960	907	637
1961	865	667
1962	810	724
1963	756	747
1964	729	808
1965	736	946
1966	723	1,032
1967	756	1,085
1968	754	1,120
1969	728	1,265
1970	706	1,528
1971	753	1,582

* U.S. Bureau of Mines.

The range of possible effects of the mix are discussed in the "Refinery Capacity" section of this chapter.

Residual Fuel Oil Imports and Crude Oil Import Alternatives

As the contribution of domestic crude oil and natural gas to total primary energy begins to decline, interfuel substitutions of imported oil in domestic bulk energy markets (e.g., industrial and electrical utilities) present a new set of problems. Not only will it be necessary to meet normal growth in utility and industrial market demand, but it will also require that some markets previously served by natural gas and natural gas liquids be converted to imported oil.

This situation has given rise to the proposed Imported Crude Oil Processing (ICOP) alternative * and other crude oil import alternatives. An ICOP facility would operate along the same general lines as a refinery in a foreign country. An ICOP facility would, however, be a domestic refining facility which would import crude oil or unfinished oils under federal regulations for processing. The refiner would then "import" the output products in accordance with existing import policies. For example, if residual fuel oil could be imported from foreign refineries, then residual fuel oil could be withdrawn from the ICOP facility. Similarly, if SNG, liquid or otherwise, were allowed to be imported without restriction, SNG could also be withdrawn from the ICOP refinery without restriction.

An ICOP facility would be a convenient mechanism by which imported crude oil could be processed into naphtha for the manufacture of SNG and/or residual fuel for utility and industrial use. However, the ICOP proposal provides no special economic incentive. The principal merit to the ICOP proposal is that it would encourage the placement of refinery capacity in the United States rather than in foreign countries.

Other possible options exist in the import control mechanism which would achieve the same purpose as the ICOP proposal. In particular, utilizing and expanding existing facilities rather than requiring new facilities would minimize capital expenditures and thus reduce product costs to consumers. Such an import "bonus-type" plan could be designed to maximize the domestic output of select products which otherwise would be imported. One particular version of this plan is in operation on the West Coast. It involves foreign crude import allocations on a barrel-for-barrel basis for certified sales of 0.5-percent sulfur residual fuel oil. Other possible plans could be devised where import allocations are earned by select product output over and above certain base-period levels rather than on sales. Such a plan, which would allow refineries to produce their own fuel, could stimulate the use of existing spare and add-on capacity as dictated by market demand changes.

* At the time of the writing of this report, the Federal Government was soliciting comment on such a proposed plan.

Refinery Capacity

Maximum and Minimum Requirements: U.S. domestic refinery capacity (operating and operable shutdown) as of January 1, 1971, was 12.9 MMB/D as shown in the following tabulation.

PAD District	Capacity (MMB/D)
I	1.5
II	3.7
III	5.3
IV	0.4
V	2.0
Total	12.9

Considering that oil imports must rise rapidly in the short term to cover the growing gap between total requirements and domestic production, oil import policies, comparative economics and environmental concerns bear importantly on how much oil refining capacity will be built in the United States during the next 15 years. The more recent import policy decisions, permitting additional imports of light refined products and unfinished oils, have tended to discourage the placement of new refinery capacity in the United States. Unless sufficient refinery capacity is added to meet growing consumer needs for non-residual products, the United States may be forced into undue reliance on imported light products. This could happen in much the same manner that the U.S. East Coast became almost totally dependent on foreign heavy fuel oil when residual fuel oil imports were granted virtually unrestricted entry into the East Coast.

Figure 106 illustrates the current sources of petroleum products for U.S. consumption. The breakdown between imported and domestically produced products is also shown.

The maximum refinery requirement in the United States would occur under conditions which would require the total supply of petroleum product demand to be met from U.S. refineries. Under this circumstance, all imports would be crude oil, and crude runs would be on the order of 22 MMB/D in 1980 and approximately 26 MMB/D in 1985 for Case III, compared with actual crude runs of 10.9 MMB/D in 1970.

The minimum refinery capacity in the United States would reflect a situation in which essentially all imports would be products and petrochemical and SNG feedstocks. Under these conditions, it would be necessary to provide only enough crude throughput capacity to accommodate domestic production of crude oil, condensate and synthetic crude oil. In Case III, which has lower domestic production than Case II, the minimum crude throughput requirement would be on the order of 12 MMB/D in both 1980 and 1985, slightly more than actual crude runs in 1970. Nevertheless, the retirement of old and obsolete refining capacity, and possibly other factors such as economies of scale, would require some new refining capacity throughout the period to 1985.

There are many parametric variations that could be considered between the minimum and maximum cases. In practice, the extreme cases would not be readily obtainable in the short term. It is more likely that the resultant refining capacity requirement would be somewhere between the extremes, perhaps on the high side of the mid-range value.

With respect to capital requirements, the maximum refining situation in Case III requires an increase in crude runs of about 15 MMB/D between 1971 and 1985. This would require the construction of 16 to 17 MMB/D of net new capacity at a capital cost of approximately $30 billion (constant 1970 dollars). In the minimum refinery case, there is practically sufficient refinery capacity now in place to meet the projected future requirements. There would, however, still be significant capital requirements in the refinery industry for replacement of capacity as it becomes obsolete or economically marginal. Additionally, while some of the increased capacity would be located in foreign countries, it may be built in whole or part with U.S. capital with concomitant implications for balance of payments.

Desulfurization Facilities

Air pollution regulations on sulfur oxide emissions will cause the petroleum industry to make large investments to provide low-sulfur fuels for consumers and to curtail refinery emissions. To comply with regulations, domestic refiners will have to add high-efficiency sulfur recovery plants, desulfurize gas oils and middle distillates, and remove hydrogen sulfide from refinery gases.

Domestic residual fuel oil averaged 1.4-weight-percent sulfur in 1971 compared to 1.5-weight-percent for imported residual. Blending with lower-sulfur oils will be sufficient for present domestic residual production to meet the anticipated 0.3- to 1.0-weight-percent sulfur range for heavy fuels that currrent regulations require. Domestic residual fuel oils have tended to be predominantly the heavy No. 6 grade. In order to meet sulfur-in-fuel specifications, low-sulfur oils such as No. 2 furnace oil, desulfurized gas oil, or low-sulfur crude oil can be blended with higher-sulfur residual oil. The resultant blends may be as light as No. 4 fuel and are similar to many of the residual fuel oils imported into the U.S. East Coast.

Depending on import policies, domestic refiners under Case III assumptions will need to process up to 11 MMB/D of imported waterborne crude by 1985. One-half to two-thirds of crude imports is likely to be high-sulfur Middle East crude (more than 2.0-weight-percent sulfur) since low-sulfur African and Indonesian crudes are insufficient to meet world demand. Caribbean refiners will also have to process large volumes of Middle East crudes because of the anticipated limited availability of Venezuelan crudes.

To handle Middle East and most Venezuelan crudes and to meet U.S. sulfur-in-fuels regulations, expensive processing will be required. Current capital estimates (in constant 1970 dollars) for the sulfur removal equipment range from $600 to $900 per daily barrel of crude oil processed. Using an average value of $750 per daily barrel of crude

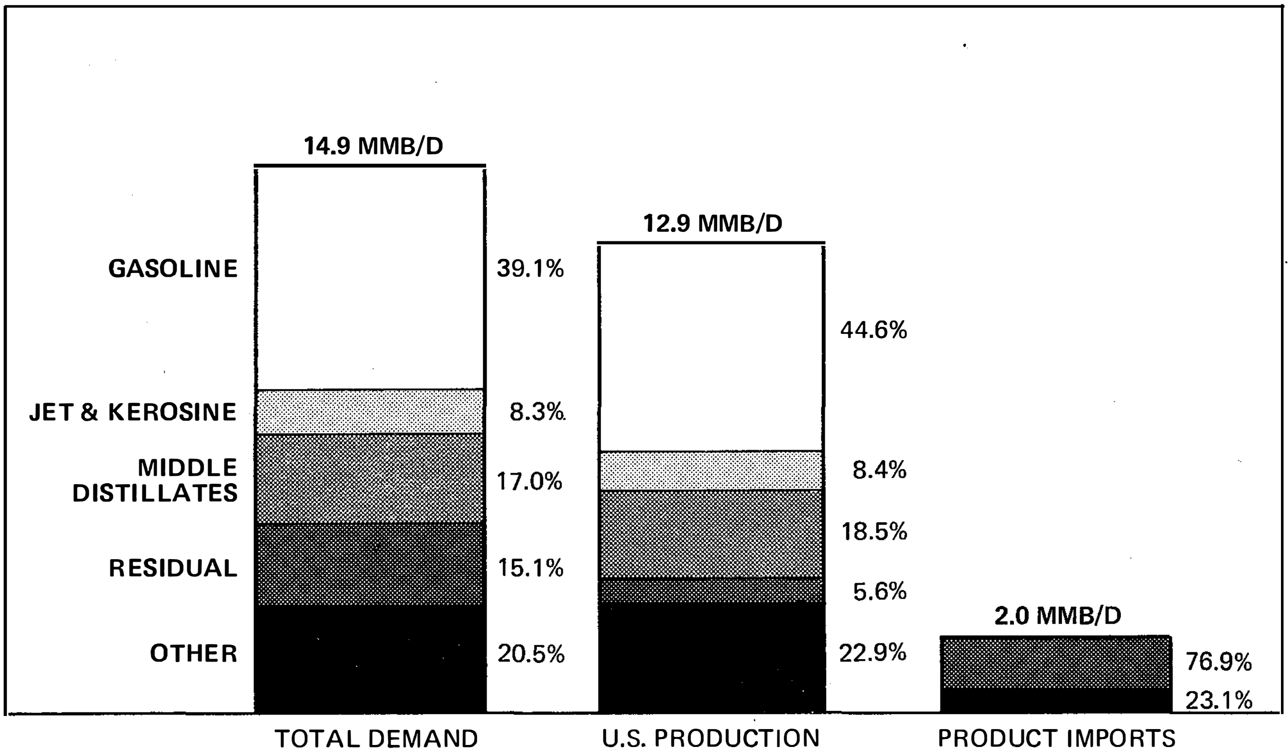

Figure 106. U.S. Petroleum Product Demand and Production.

capacity and assuming that imports of high-sulfur crude oil to make fuel oil amount to 7 MMB/D by 1985, the cost of desulfurization facilities would imply an increase in refinery investment of about $5 billion. This would bring the total refinery investment to $35 billion by 1985.

Tank Ships and Deepwater Terminals

For Case III, the prospective growth in U.S. waterborne petroleum imports from 2.7 MMB/D in 1970 to a maximum of 10.7 MMB/D by 1985 adds a completely new dimension to U.S. external petroleum logistics, particularly with respect to tank ships and deepwater terminals. Historically, U.S. waterborne petroleum imports have originated principally in Latin America, requiring only short tanker hauls from Caribbean ports. However, the prospect for continuing growth in Latin American petroleum export capacity is not promising, and most of the future increases in waterborne petroleum imports into the United States are expected to involve long hauls from the Eastern Hemisphere, primarily from the Middle East.

The typical-size tank ship entering international crude oil trade (excluding the United States) over the next 15 years is expected to range between 200,000 and 400,000 DWT, with the larger units being employed on the longer runs and between ports which can accommodate deep drafts. Although crude carriers ranging from 250,000 to 300,000 DWT are predominant on shipyard order books today, there are a number of vessels up to 477,000 DWT on order. While vessels in the 250,000 to 300,000 DWT range draw 65 to 72 feet of water when fully laden, a 477,000 DWT tanker will draw 92 feet.

At mid-year 1972, there were 237 very large crude carriers of 200,000 DWT or more which were employed almost entirely in transporting crude oil to Western Europe and Japan. In contrast, the United States has no ports now capable of handling tank ships above 100,000 DWT without lightering, as indicated in Table 168. Thus, the construction of large-scale deepwater terminals on the U.S. East, Gulf and West Coasts is essential to obtain the lowest possible ocean transport costs for the large volume of long-haul oils to be transported during the years ahead.

Deepwater terminals on U.S. coasts will improve both the economic and the environmental implications of the projected volumes of required oil imports. They would reduce the congestion of existing ports and port entrances and thus reduce the possibility of collisions or groundings. Newer deepwater ports could also be designed with better spill control capabilities and would, in general, lessen the overall probability of environmental pollution by oil spills from tanker operations.

In 1970, the equivalent of six 70,000 DWT tank ships were required to be unloaded every day to deliver 2.7 MMB/D of imported waterborne oil to the United States. For Case III in 1985, waterborne imports (and tanker unloading capacities) are projected to more than triple. If VLCC's, 250,000 DWT for example, could be used to deliver oil to the United States, the number of tank ships required to call on U.S. ports in 1985 could be about one-third the number of 70,000 DWT tankers required. As was mentioned above, this would greatly alleviate the strain on already congested U.S. ports.

A 250,000 DWT tank ship has been used as an average that is believed to be reasonably representative of the size vessel that will be employed in the transport of long-haul oils to the United States during the years ahead. Such a tanker has a delivery capability of 26 MB/D in movements between the Persian Gulf and the U.S. East Coast. Approximately the same delivery capabilities apply to movements from the Persian Gulf to the West Coast. On voyages from North and West African ports to the U.S. East and Gulf Coasts, the delivery capability of a 250,000 DWT tank ship ranges from 52 to 65 MB/D.

If, for example, Persian Gulf oil were delivered to existing U.S. ports, 50,000 to 70,000 DWT tankers would have to be used. The estimated transportation cost would be in excess of $9.00 per ton. Figure 107 shows that a 250,000 DWT tanker could deliver the same ton of oil for about $6.55. However, until such time as deepwater terminals are built—again using the Persian Gulf/U.S. East Coast example—VLCC's will be used for the majority of the voyage to neighboring foreign deepwater terminals (e.g., eastern Canada or the Bahamas) with 50,000 to 70,000 DWT tank ships

TABLE 168

U.S. TANKER PORTS*

Port	Maximum Vessel Size (DWT)	Port	Maximum Vessel Size (DWT)
Alaska—Nisiki	60,000	Massachusetts—Boston	50,000
California—Long Beach	100,000	New Jersey—Newark	25,000
California—Los Angeles	100,000	New York	55,000
California—Port San Louis Obispo	20,000	Pennsylvania—Philadelphia	55,000
California—San Diego	35,000	Texas—Baytown	30,000
California—San Francisco	35,000	Texas—Beaumont	80,000
Florida—Jacksonville	30,000	Texas—Brownsville	35,000
Florida—Miami	20,000	Texas—Corpus Christi	50,000
Florida—Port Everglades	35,000	Texas—Freeport	30,000
Hawaii—Honolulu	35,000	Texas—Houston	55,000
Louisiana—Baton Rouge	45,000	Texas—Port Arthur	55,000
Louisiana—New Orleans	45,000	Texas—Texas City	45,000
Maine—Portland	80,000	Virginia—Hampton Roads	50,000
Maryland—Baltimore	55,000	Washington—Seattle	45,000

* George Weber, ed., *International Petroleum Encyclopedia* (1972), p. 407.

being used for transshipment into U.S. ports. Figure 107 shows that such an arrangement requires a $0.50 to $0.70 increase per ton in transportation charges.

Capital Costs for Tank Ships and Deepwater Terminals

A precise evaluation of capital requirements for tank ships to haul incremental U.S. oil imports

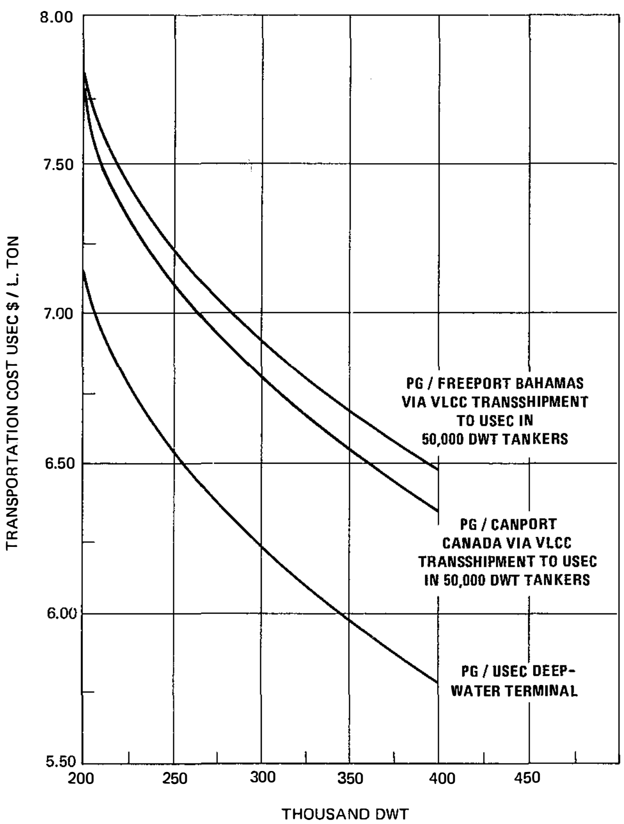

Figure 107. Transportation Costs to U.S. East Coast (USEC) from Middle East VLCC Transportation Costs Including Terminalling and Transshipment Costs, 1975-1985.

over the 1971-1985 period hinges upon the accuracy of projecting supply sources. However, under Case III assmuptions, if it is assumed that the total waterborne oil requirements in 1985 were to originate in the Persian Gulf, a fleet of at least four hundred 250,000 DWT tankers would be required. At $35 million per vessel (the current price quoted for 1975 delivery of foreign-built tank ships), the capital requirement amounts to about $14 billion by 1985. However, for each MMB/D supplied to the United States from North or West Africa in lieu of the Persian Gulf, the investment in tankers would be reduced by about $0.6 billion. Although the Persian Gulf is expected to be the predominant source of incremental oil imports into the United States, it is possible that some low-sulfur African crudes will be imported to the U.S. East and Gulf Coasts. Accordingly, assuming 1 to 2 MMB/D of U.S. bound crude originates in Africa, a capital investment in tankers of about $13 billion, or about $1 billion per year, would be required.

The shipment of Alaskan North Slope crude oil from Valdez, Alaska, to West Coast destinations could contribute to the modernization of the U.S. tanker fleet. By 1980, approximately 2 million DWT of additional tanker tonnage to deliver this oil will have to be constructed at a cost of $0.5 billion.

Gulf to East Coast waterborne movements of refined products could also increase, particularly if the combination of bigger ships and deeper harbors make waterborne movement costs competitive with products pipelines.

The required capital investment for large-scale deepwater transfer terminals on the East, Gulf and West Coasts would be on the order of $2.0 billion.

Gas Logistics

Summary and Conclusions

The capital costs of transporting, processing and storing natural gas, LPG, syngas and LNG projected for the four principal cases analyzed are shown in Table 169.

TABLE 169

TOTAL CAPITAL REQUIREMENTS
(Millions of Constant 1970 Dollars)

	Case I	Case II	Case III	Case IV
1971-1975	6,800	6,500	4,700	3,700
1976-1980	21,300	18,700	15,900	10,200
1981-1985	28,500	21,700	19,200	15,600
Total	56,600	46,900	39,800	29,500

The capital requirements include not only the cost of new facilities but also replacements of existing facilities of a capital nature. The facilities included are:

1. Cross-country natural gas pipelines
2. Natural gas pipelines from Alaska and the Canadian Arctic
3. Gas processing plants on pipelines from Alaska and Canada
4. Gathering lines to connect new wells to pipeline systems
5. Underground storage facilities
6. Pipelines to connect regasified LNG, syngas plants and nuclear stimulation projects to existing pipeline networks
7. LNG facilities including liquefaction plants on foreign soil; LNG tankers and domestic port facilities for receiving, storing and regasification
8. LPG pipelines
9. Ships and barges for importation of foreign supplies of LPG as well as for local transportation
10. Railroad tank cars and trucks for local transportation of both LPG and LNG.

A breakdown of the total capital requirements for the various sources of supply and modes of transportation is shown in Table 170. Tables 171 to 174 summarizes the gas supply and requirements volumes, calculated to be transported, which were used to estimate the transportation facilities required. These are marketed volumes, (i.e., excluding field use) for both supply and requirements and are taken from figures derived by the Gas Supply and Gas Demand Task Groups. The bases on which these capital requirements were derived are as follows:

- The location of new natural gas discoveries in the lower 48 states will result in the construction of new gathering and feeder line facilities even though total supplies from this source may remain static or decrease. Even cross-country networks are affected. For instance, in Case II, while total marketed production is projected to increase by only 1.3 TCF per year between 1971 and 1985 in the lower 48 states, the marketed production from Region 6A (offshore Gulf of Mexico) alone is projected to increase by 3.5 TCF per year during the same period.
- Unit costs of pipeline facilities generally will increase because of: (1) more difficult terrain, (2) deeper water offshore, (3) new and greater environmental restrictions, and (4) pipeline safety and other governmenf regulations.
- The total costs of pipeline capacity required to transport gas from Alaska's North Slope to the lower 48 states are included.
- Costs of pipeline capacity from Canadian Arctic areas to the U.S. border are included to transport the projected increases in Canadian imports. This assumes that capital requirements for the construction of transportation facilities from these frontier areas will have to be generated in the United States to carry the gas available for export after allowing for Canadian needs.
- Processing costs include the stripping plants at or near the U.S./Canadian border and are included on the assumption that the pipelines from Arctic areas will be designed to carry as much of such liquids as temperature conditions will permit.
- LNG costs include all necessary facilities from the inlet side of the liquefaction plant to the outlet side of the regasification plant. This is based on the assumption that U.S. capital will be required even though the plants are on foreign soil and partial foreign ownership and control will be involved.
- Location, by states, of projected coal gasification plants was furnished by the Coal Task Group. Costs of pipelines from these plants to the nearest major pipeline network are included. Pipelines from liquid syngas plants to existing networks are also included. An average length of 50 miles for each such connection was assumed in this case since many proposed plants are not definitely located at this time.
- An average length of 100 miles was assumed for pipeline connections from LNG regasification facilities to existing pipeline networks.

Transportation to U.S. and Canadian markets of the gas volumes projected to be available in Case II from Alaska and from Canadian frontier areas will require the construction of the equivalent

TABLE 170

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

	Gas Pipelines					LNG			LPG				
	1	2	3	4	5	6	7	8	9	10	11	12	13
Period	Storage & Trans-mission Lower 48	Trans-mission Alaska	Trans-mission Canada	Attachments-New Production Coal Gas, LNG & Syngas	Extrac-tion Plants	Plants	Ships	Terminals & Storage	Pipelines	Ships & Barges	Railroad Cars	Trucks	Total
							Case I						
1971-1975	4,888.4	0	0	1,258.1	0	131.0	150.0	49.0	195.0	50.0	0	92.3	6,813.8
1976-1980	6,027.8	5,576.0	1,711.0	2,527.9	164.4	2,035.0	2,179.0	701.0	123.0	77.0	44.7	144.9	21,311.7
1981-1985	8,854.8	6,919.0	3,569.0	3,425.9	254.8	1,833.0	2,570.0	672.0	123.0	73.0	55.9	180.9	28,531.3
Total	**19,771.0**	**12,495.0**	**5,280.0**	**7,211.9**	**419.2**	**3,999.0**	**4,899.0**	**1,422.0**	**441.0**	**200.0**	**100.6**	**418.1**	**56,656.8**
% of Total	**34.9**	**22.1**	**9.3**	**12.7**	**0.7**	**7.1**	**8.6**	**2.5**	**0.8**	**0.4**	**0.2**	**0.7**	**100.0**
							Case II						
1971-1975	4,676.0	0	0	1,218.9	0	131.0	150.0	49.0	180.0	50.0	0	92.3	6,547.2
1976-1980	4,552.0	5,049.0	1,743.0	1,906.7	156.2	2,035.0	2,179.0	701.0	108.0	77.0	38.8	138.7	18,684.4
1981-1985	5,768.7	4,548.0	3,499.0	2,185.3	213.7	1,833.0	2,570.0	672.0	104.0	73.0	45.9	168.3	21,680.9
Total	**14,996.7**	**9,597.0**	**5,242.0**	**5,310.9**	**369.9**	**3,999.0**	**4,899.0**	**1,422.0**	**392.0**	**200.0**	**84.7**	**399.3**	**46,912.5**
% of Total	**32.0**	**20.5**	**11.2**	**11.3**	**0.8**	**8.5**	**10.4**	**3.0**	**0.8**	**0.4**	**0.2**	**0.9**	**100.0**
							Case III						
1971-1975	3,153.4	0	0	881.9	0	131.0	150.0	49.0	170.0	50.0	0	87.6	4,672.9
1976-1980	2,977.7	4,506.0	1,743.0	1,335.7	139.7	2,035.0	2,179.0	701.0	67.0	77.0	22.0	127.7	15,910.8
1981-1985	4,510.0	3,896.0	3,499.0	1,681.6	189.1	1,833.0	2,570.0	672.0	69.0	73.0	35.4	151.0	19,179.1
Total	**10,641.1**	**8,402.0**	**5,242.0**	**3,899.2**	**328.8**	**3,999.0**	**4,899.0**	**1,422.0**	**306.0**	**200.0**	**57.4**	**366.3**	**39,762.8**
% of Total	**26.8**	**21.1**	**13.2**	**9.8**	**0.8**	**10.1**	**12.3**	**3.6**	**0.8**	**0.5**	**0.1**	**0.9**	**100.0**
							Case IV						
1971-1975	2,298.1	0	0	803.6	0	131.0	150.0	49.0	170.0	50.0	0	85.1	3,736.8
1976-1980	1,858.4	0	2,283.0	884.4	49.3	2,035.0	2,179.0	701.0	37.0	77.0	5.4	119.1	10,228.6
1981-1985	1,968.8	4,370.0	3,135.0	588.3	205.5	1,833.0	2,570.0	672.0	46.0	73.0	26.5	134.6	15,622.7
Total	**6,125.3**	**4,370.0**	**5,418.0**	**2,276.3**	**254.8**	**3,999.0**	**4,899.0**	**1,422.0**	**253.0**	**200.0**	**31.9**	**338.8**	**29,588.1**
% of Total	**20.7**	**14.8**	**18.3**	**7.7**	**0.9**	**13.5**	**16.5**	**4.8**	**0.9**	**0.7**	**0.1**	**1.1**	**100.0**

TABLE 171

TOTAL U.S. NATURAL AND SYNTHETIC GAS REQUIREMENTS VERSUS GAS SUPPLY—CASE I*

	1971		1975		1980		1985	
	TCF	$BTU \times 10^{15}$	TCF	$BTU \times 10^{15}$	TCF	$BTU \times 10^{15}$	TCF	$BTU \times 10^{15}$
Gas Supply								
Conventional Domestic	19.97	20.61	21.74	22.44	22.34	23.05	24.17	24.94
Alaska North Slope	0	0	0	0	1.30	1.34	3.00	3.10
Canadian Imports	0.90	0.93	1.00	1.03	1.60	1.65	2.70	2.79
Mexican Imports	0.05	0.05	0.05	0.05	0	0	0	0
Total Natural	**20.92**	**21.59**	**22.79**	**23.52**	**25.24**	**26.04**	**29.87**	**30.83**
LNG Imports †	0	0	0.24	0.26	2.28	2.51	4.11	4.52
Coal Gasification	0	0	0	0	0.56	0.52	2.48	2.29
Liquid Gasification	0	0	0.64	0.64	1.32	1.32	1.32	1.32
Total Syngas	**0**	**0**	**0.64**	**0.64**	**1.88**	**1.84**	**3.80**	**3.61**
Nuclear Stimulation	0	0	0.01	0.01	0.19	0.20	1.20	1.24
Grand Total—Gas Supply	**20.92**	**21.59**	**23.68**	**24.43**	**29.59**	**30.59**	**38.98**	**40.20**
Requirements ‡		20.27		25.56		30.89		36.99
(Shortage) or Surplus		1.32		(1.13)		(0.30)		3.21

* Conversion factors:

All Natural Gas	1,032 BTU/cu.ft.
LNG Imports	1,100 BTU/cu.ft.
Coal Syngas	925 BTU/cu.ft.
Liquid Syngas	1,000 BTU/cu.ft.

These figures do not include gas consumed in production and distribution as this chapter is primarily concerned with logistics. Consequently, these figures will not coincide in all respects with those in Chapter Four.

† These figures include gas from South Alaska.

‡ From Gas Demand Task Group.

of some 10,000 miles of 48-inch pipeline by 1984. Approximately 75 percent of this capacity will be required for projected U.S. markets. At least 10 million tons of steel pipe and fittings will be required in sizes for which there are no presently existing manufacturing facilities in the United States or Canada. Since actual construction cannot be reasonably expected to start before 1974, the accomplishment of such a program will be extremely difficult. Moreover, capital requirements for this transportation are estimated at some $15 billion, 80 to 85 percent of which will be invested in Canada.

Details of the capital requirements were developed in three separate groups as indicated in Table 170. They are pipelines and underground storage, LNG facilities, and LPG pipelines and facilities.

Gas pipelines and underground storage constitute the largest of these three elements of gas logistics capital expenditures, ranging from about 62 percent in Case IV to almost 80 percent in Case I. The dollar amounts vary from $18.4 to $45.2 billion for the 15-year period between Cases IV and I, respectively. Within this category, lower 48 state transmission and storage requirements represent more than one-third of the total and Alaskan transmission about one-fourth.

TABLE 172

TOTAL U.S. NATURAL AND SYNTHETIC GAS REQUIREMENTS VERSUS GAS SUPPLY—CASE II*

	1971		1975		1980		1985	
	TCF	BTU x 10^{15}	TCF	BTU x 10^{15}	TCF	BTU x 10^{15}	TCF	BTU x 10^{15}
Gas Supply								
Conventional Domestic	19.97	20.61	21.55	22.24	20.99	21.66	21.16	21.84
Alaska North Slope	0	0	0	0	1.20	1.24	2.40	2.48
Canadian Imports	0.90	0.93	1.00	1.03	1.60	1.65	2.70	2.79
Mexican Imports	0.05	0.05	0.05	0.05	0	0	0	0
Total Natural	**20.92**	**21.59**	**22.60**	**23.32**	**23.79**	**24.55**	**26.26**	**27.11**
LNG Imports†	0	0	0.24	0.26	2.28	2.51	4.11	4.52
Coal Gasification	0	0	0	0	0.36	0.33	1.31	1.21
Liquid Gasification	0	0	0.64	0.64	1.32	1.32	1.32	1.32
Total Syngas	**0**	**0**	**0.64**	**0.64**	**1.68**	**1.65**	**2.63**	**2.53**
Nuclear Stimulation	0	0	0	0	0.09	0.09	0.73	0.75
Grand Total—Gas Supply	**20.92**	**21.59**	**23.48**	**24.22**	**27.84**	**28.80**	**33.73**	**34.91**
Requirements‡		20.27		25.56		30.89		36.99
(Shortage) or Surplus		1.32		(1.34)		(2.09)		(2.08)

* Conversion factors:

All Natural Gas	1,032 BTU/cu.ft.
LNG Imports	1,100 BTU/cu.ft.
Coal Syngas	925 BTU/cu.ft.
Liquid Syngas	1,000 BTU/cu.ft.

These figures do not include gas consumed in production and distribution as this chapter is primarily concerned with logistics. Consequently, these figures will not coincide in all respects with those in Chapter Four.

† These figures include gas from South Alaska.

‡ From Gas Demand Task Group.

Capital investment for LNG remains constant at $10.3 billion for all cases in the 1971-1985 period; however, its percent of the total ranges from 18 to almost 35 percent (Case I *vs.* Case IV) as domestic supply and the transportation expenditures required decreases substantially.

The third major category of expense, that required for LPG supply, is small both dollar-wise and percentage-wise. Cumulative 1971-1985 expenditures range from a low of $824 million to a high of $1,160 million.

Pipelines and Underground Storage

Expenditures for gas pipelines were developed in three steps:

1. Determination of a gas demand/supply relationship for each PAD district and for the total United States. (Tables 171 through 174 show this relationship for the total United States.) These demand/supply relationships were used to allocate total gas supplies, proportionately, among PAD districts. These allocations were then used to determine the amounts of new facilities required to transport available supplies—both within and between PAD districts.
2. Development of historical unit costs (dollars per annual billion cubic feet).
3. Application of unit costs to volumes determined under No. 1 above.

TABLE 173

TOTAL U.S. NATURAL AND SYNTHETIC GAS REQUIREMENTS VERSUS GAS SUPPLY—CASE III*

	1971		1975		1980		1985	
	TCF	BTU x 10^{15}	TCF	BTU x 10^{15}	TCF	BTU x 10^{15}	TCF	BTU x 10^{15}
Gas Supply								
Conventional Domestic	19.97	20.61	20.17	20.82	17.60	18.16	16.11	16.63
Alaska North Slope	0	0	0	0	1.00	1.03	2.00	2.06
Canadian Imports	0.90	0.93	1.00	1.03	1.60	1.65	2.70	2.79
Mexican Imports	0.05	0.05	0.05	0.05	0	0	0	0
Total Natural	**20.92**	**21.59**	**21.22**	**21.90**	**20.20**	**20.84**	**20.81**	**21.48**
LNG Imports†	0	0	0.24	0.26	2.28	2.51	4.11	4.52
Coal Gasification	0	0	0	0	0.36	0.33	1.31	1.21
Liquid Gasification	0	0	0.64	0.64	1.32	1.32	1.32	1.32
Total Syngas	**0**	**0**	**0.64**	**0.64**	**1.68**	**1.65**	**2.63**	**2.53**
Nuclear Stimulation	0	0	0	0	0.09	0.09	0.73	0.75
Grand Total—Gas Supply	**20.92**	**21.59**	**22.10**	**22.80**	**24.25**	**25.09**	**28.28**	**29.28**
Requirements‡		20.27		25.56		30.89		36.99
(Shortage) or Surplus		1.32		(2.76)		(5.80)		(7.71)

* Conversion factors:

All Natural Gas	1,032 BTU/cu.ft.
LNG Imports	1,100 BTU/cu.ft.
Coal Syngas	925 BTU/cu.ft.
Liquid Syngas	1,000 BTU/cu.ft.

These figures do not include gas consumed in production and distribution as this chapter is primarily concerned with logistics. Consequently, these figures will not coincide in all respects with those in Chapter Four.

† These figures include gas from South Alaska.

‡ From Gas Demand Task Group.

Historical unit costs were developed from the FPC Form 2 reports of 35 major pipeline companies for the period from 1966 through 1969, and updated to 1970 by the use of historical escalation factors. These historical cost factors were developed on a regional basis and directly correlated to PAD districts. The cost factors account for all capital requirements for the pipelines, including testing and replacement costs for compliance with new federal regulations and normal construction and replacement cost, as well as costs of expansion facilities.

Underground storage costs were calculated by applying a storage cost factor to estimated increases in storage use. The storage cost factor was developed by dividing historical increases in storage costs by corresponding increases in storage use, giving a cost in dollars per MMCF.

Projected increases in storage use, i.e., total gas injected annually, were calculated using a linear projection based on historical patterns from 1955 to 1970.

A computer program was set up which applied historical unit costs per unit of volume to volumes calculated to be transported between PAD districts and within PAD districts. This program also applied similar unit costs to volumes of new gas to be connected to existing pipeline networks in the

TABLE 174

TOTAL U.S. NATURAL AND SYNTHETIC GAS REQUIREMENTS VERSUS GAS SUPPLY—CASE IV*

	1971		1975		1980		1985	
	TCF	BTU x 10^{15}	TCF	BTU x 10^{15}	TCF	BTU x 10^{15}	TCF	BTU x 10^{15}
Gas Supply								
Conventional Domestic	19.97	20.61	19.86	20.50	15.81	16.32	12.13	12.52
Alaska North Slope	0	0	0	0	0	0	1.20	1.24
Canadian Imports	0.90	0.93	1.00	1.03	1.60	1.65	2.70	2.79
Mexican Imports	0.05	0.05	0.05	0.05	0	0	0	0
Total Natural	**20.92**	**21.59**	**20.91**	**21.58**	**17.41**	**17.97**	**16.03**	**16.55**
LNG Imports†	0	0	0.24	0.26	2.28	2.51	4.11	4.52
Coal Gasification	0	0	0	0	0.18	0.17	0.54	0.50
Liquid Gasification	0	0	0.64	0.64	1.32	1.32	1.32	1.32
Total Syngas	**0**	**0**	**0.64**	**0.64**	**1.50**	**1.49**	**1.86**	**1.82**
Nuclear Stimulation	0	0	0	0	0	0	0	0
Grand Total—Gas Supply	**20.92**	**21.59**	**21.79**	**22.48**	**21.19**	**21.97**	**22.00**	**22.89**
Requirements‡		20.27		25.56		30.89		36.99
(Shortage) or Surplus		1.32		(3.08)		(8.92)		(14.10)

* Conversion factors: All Natural Gas 1,032 BTU/cu.ft.; LNG Imports 1,100 BTU/cu.ft.; Coal Syngas 925 BTU/cu.ft.; Liquid Syngas 1,000 BTU/cu.ft.

These figures do not include gas consumed in production and distribution as this chapter is primarily concerned with logistics. Consequently, these figures will not coincide in all respects with those in Chapter Four.

† These figures include gas from South Alaska.

‡ From Gas Demand Task Group.

form of gathering facilities and to underground storage volumes. Separate computations were made for the cost of connecting new gas supplies from Alaska, Canada, LNG regasification plants and nuclear stimulation projects. Other separate computations were made for the cost of connecting projected syngas and coal gasification facilities.

LNG Facilities

While liquefaction plant technology is fairly well established and costs are reasonably well known, neither the technology of ship construction nor the costs are really established at this time. At least four different containment systems are under construction or contemplated at this time, and the maximum economic size is more dependent on port restrictions, delivered annual volumes and shipping distance than on technology.

Costs have skyrocketed since the construction of such ships as the *Methane Progress* and the *Methane Princess*, and even since the construction of the *Arctic Tokyo* and *Polar Alaska*. For these reasons the costs of both ships and port facilities are highly speculative even without considering the effects of probable inflation. With these things in mind, the costs of LNG facilities as show in Table 179 were developed as discussed below.

TABLE 175

TOTAL U.S. LPG REQUIREMENTS VERSUS LPG SUPPLY—CASE I*

	1971		1975		1980		1985	
	MMB	BTU x 10^{12}	MMB	BTU x 10^{12}	MMB	BTU x 10^{12}	MMB	BTU x 10^{12}
LPG Supplies								
Conventional Domestic								
From Non-Associated and Associated-Dissolved Gas	389.90	1,555.70	331.70	1,323.48	341.80	1,363.78	359.50	1,434.41
From Refineries	122.64	489.33	147.83	589.84	178.49	712.18	206.96	825.77
Total Conventional	**512.54**	**2,045.03**	**479.53**	**1,913.32**	**520.29**	**2,075.96**	**566.46**	**2,260.18**
Imports								
Liquid Pipelines	20.00	79.80	27.25	108.73	34.75	138.65	44.00	175.56
Suspension in Gas Pipelines	0	0	0	0	51.00	203.49	100.80	402.19
Ships and Barges	0.90	3.59	12.50	49.88	71.00	283.29	110.00	438.90
Total Imports	**20.90**	**83.39**	**39.75**	**158.61**	**156.75**	**625.43**	**254.80**	**1,016.65**
Total LPG Supplies	**533.44**	**2,128.42**	**519.28**	**2,071.93**	**677.04**	**2,701.39**	**821.26**	**3,276.83**
Requirements†								
For Syngas Plants	0	0	40.95	163.39	61.43	245.11	61.43	245.11
For Chemical Plants	155.39	620.01	201.25	802.99	256.39	1,023.00	299.75	1,196.00
For Other Uses	268.17	1,070.00	300.00	1,197.00	336.09	1,341.00	371.68	1,483.00
Total Requirements	**423.56**	**1,690.01**	**542.20**	**2,163.38**	**653.91**	**2,609.11**	**732.86**	**2,924.11**
(Shortage) or Oversupply	109.88	438.41	(22.92)	(91.45)	23.13	92.28	88.40	352.72

* Conversion factors: 95,000 BTU/gal.
3,990,000 BTU/bbl.

† From Gas Demand Task Group. These figures do not include LPG for motor gasoline at refineries and at chemical plants.

Ship Costs

Using British Petroleum's Sailing Distance Manual, the round trip nautical mileage for each of the cases concerned was obtained. Ships sailing speed was assumed to average 20.0 knots. Three days for loading and unloading plus one day weather delay were allowed for each voyage.

Ships were sized to provide for loading sufficient liquid to meet the required delivery plus the necessary boil-off and return voyage cool-down liquid of 0.25 percent per day. The maximum-sized vessel was limited to 160,000 cubic meters or approximately 1 MMB. Maximum loaded capacity was 98 percent of total volume per U.S. Coast Guard requirements.

Vessel availability was 345 days per year based upon 20 days annual docking and survey time.

Ship costs were based upon published data, from actual costs of vessels in service and from tentative bids for proposed projects.

To the extent reasonably possible, it was assumed that advantage would be taken of maxi-

TABLE 176

TOTAL U.S. LPG REQUIREMENTS VERSUS LPG SUPPLY—CASE II*

	1971		1975		1980		1985	
	MMB	BTU x 10^{12}	MMB	BTU x 10^{12}	MMB	BTU x 10^{12}	MMB	BTU x 10^{12}
LPG Supplies								
Conventional Domestic								
From Non-Associated and Associated-Dissolved Gas	389.90	1,555.70	329.20	1,313.51	323.60	1,291.16	317.60	1,267.22
From Refineries	122.64	489.33	147.83	589.84	178.49	712.18	206.96	825.77
Total Conventional	**512.54**	**2,045.03**	**477.03**	**1,903.35**	**502.09**	**2,003.34**	**524.56**	**2,092.99**
Imports								
Liquid Pipelines	20.00	79.80	27.25	108.73	34.75	138.65	44.00	175.56
Suspension in Gas Pipelines	0	0	0	0	51.00	203.49	93.60	373.46
Ships and Barges	0.90	3.59	12.50	49.88	71.00	283.29	110.00	438.90
Total Imports	**20.90**	**83.39**	**39.75**	**158.61**	**156.75**	**625.43**	**247.60**	**987.92**
Total LPG Supplies	**533.44**	**2,128.42**	**516.78**	**2,061.96**	**658.84**	**2,628.77**	**772.16**	**3,080.91**
Requirements†								
For Syngas Plants	0	0	40.95	163.39	61.43	245.11	61.43	245.11
For Chemical Plants	155.39	620.00	201.25	803.00	256.39	1,023.00	299.75	1,196.00
For Other Uses	268.17	1,070.00	300.00	1,197.00	336.09	1,341.00	371.68	1,483.00
Total Requirements	**423.56**	**1,690.00**	**542.20**	**2,163.39**	**653.91**	**2,609.11**	**732.86**	**2,924.11**
(Shortage) or Oversupply	109.88	438.42	(25.42)	(101.43)	4.93	19.66	39.30	156.80

* Conversion factors: 95,000 BTU/gal.
3,990,000 BTU/bbl.

† From Gas Demand Task Group. These figures do not include LPG for motor gasoline at refineries and at chemical plants.

mum-sized ships, but ships are to be dedicated to a specific project.

Liquefaction Plant Costs

Liquefaction plant costs are based upon the modular concept, with 150 MMCF per day used as the most efficient-sized module. Costs were developed for four different capacity plants and a cost curve obtained. Plant costs for each were taken from this curve based on liquefaction to meet deliveries plus boil-off and cool-down requirements for the LNG tankers.

Unloading Terminals and Regasification Plants

The cost of these plants varies even for the same delivered quantities to various ports due to the difference in storage capacity calculated for each case.

Storage required was assumed to be equivalent to the capacity of two ship loads. Under this system, the storage under all cases varies from 0.9

TABLE 177

TOTAL U.S. LPG REQUIREMENTS VERSUS LPG SUPPLY—CASE III*

	1971		1975		1980		1985	
	MMB	BTU x 10^{12}	MMB	BTU x 10^{12}	MMB	BTU x 10^{12}	MMB	BTU x 10^{12}
LPG Supplies								
Conventional Domestic								
From Non-Associated and Associated-Dissolved Gas	389.90	1,555.70	311.80	1,244.08	276.60	1,103.63	245.60	979.94
From Refineries	122.64	489.33	147.83	589.84	178.49	712.18	206.96	825.77
Total Conventional	**512.54**	**2,045.03**	**459.63**	**1,833.92**	**455.09**	**1,815.81**	**452.56**	**1,805.71**
Imports								
Liquid Pipelines	20.00	79.80	27.25	108.73	34.75	138.65	44.00	175.56
Suspension in Gas Pipelines	0	0	0	0	46.20	184.34	81.60	325.58
Ships and Barges	0.90	3.59	12.50	49.88	71.00	283.29	110.00	438.90
Total Imports	**20.90**	**83.39**	**39.75**	**158.61**	**151.95**	**606.28**	**235.60**	**940.04**
Total LPG Supplies	**533.44**	**2,128.42**	**499.38**	**1,992.53**	**607.04**	**2,422.09**	**688.16**	**2,745.75**
Requirements†								
For Syngas Plants	0	0	40.95	163.39	61.43	245.11	61.43	245.11
For Chemical Plants	155.39	620.00	201.25	803.00	256.39	1,023.00	299.75	1,196.00
For Other Uses	268.17	1,070.00	300.00	1,197.00	336.09	1,341.00	371.68	1,483.00
Total Requirements	**423.56**	**1,690.00**	**542.20**	**2,163.39**	**653.91**	**2,609.11**	**732.86**	**2,924.11**
(Shortage) or Oversupply	109.88	438.42	(42.82)	(170.86)	(46.87)	(187.02)	(44.70)	(178.36)

* Conversion factors: 95,000 BTU/gal.
3,990,000 BTU/bbl.

† From Gas Demand Task Group. These figures do not include LPG for motor gasoline at refineries and at chemical plants.

to 2.0 MMB, using an assumed cost of $15 per barrel.

LPG Pipelines and Facilities

LPG supplies from conventional sources in the lower 48 states are projected to increase slightly through 1975 and decrease thereafter. However, substantial increases are forecast from:

- LPG in pipeline suspension with natural gas from Alaska's North Slope and in Canadian gas imports
- LPG pipeline imports from Canada
- LPG tanker imports from South America and elsewhere.

Tables 175 through 178 detail the sources and volumes of these supplies as projected by the Gas Supply and Oil Supply Task Groups and the requirements projected by the Gas Demand Task Group. Note that requirements projected by the Gas Demand Task Group do not include LPG used for motor gasoline at refineries and chemical plants.

TABLE 178

TOTAL U.S. LPG REQUIREMENTS VERSUS LPG SUPPLY—CASE IV*

	1971		1975		1980		1985	
	MMB	BTU x 10^{12}	MMB	BTU x 10^{12}	MMB	BTU x 10^{12}	MMB	BTU x 10^{12}
LPG Supplies								
Conventional Domestic								
From Non-Associated and Associated-Dissolved Gas	389.90	1,555.70	307.70	1,227.72	252.20	1,006.28	191.60	764.48
From Refineries	122.64	489.33	147.83	589.84	178.49	712.18	206.96	825.77
Total Conventional	**512.54**	**2,045.03**	**455.53**	**1,817.56**	**430.69**	**1,718.46**	**398.56**	**1,590.25**
Imports								
Liquid Pipelines	20.00	79.80	27.25	108.73	34.75	138.65	44.00	175.56
Suspension in Gas Pipelines	0	0	0	0	19.80	79.00	57.60	229.82
Ships and Barges	0.90	3.59	12.50	49.88	71.00	283.29	110.00	438.90
Total Imports	**20.90**	**83.39**	**39.75**	**158.61**	**125.55**	**500.94**	**211.60**	**844.28**
Total LPG Supplies	**533.44**	**2,128.42**	**495.28**	**1,976.17**	**556.24**	**2,219.40**	**610.16**	**2,434.53**
Requirements†								
For Syngas Plants	0	0	40.95	163.39	61.43	245.11	61.43	245.11
For Chemical Plants	155.39	620.00	201.25	803.00	256.39	1,023.00	299.75	1,196.00
For Other Uses	268.17	1,070.00	300.00	1,197.00	336.09	1,341.00	371.68	1,483.00
Total Requirements	**423.56**	**1,690.00**	**542.20**	**2,163.39**	**653.91**	**2,609.11**	**732.86**	**2,924.11**
(Shortage) or Oversupply	109.88	438.42	(46.92)	(187.22)	(97.67)	(389.71)	(122.70)	(489.58)

* Conversion factors: 95,000 BTU/gal.
3,990,000 BTU/bbl.

† From Gas Demand Task Group. These figures do not include LPG for motor gasoline at refineries and at chemical plants.

Historical figures were used to determine volumes of LPG transported and the distances, for each mode of transportation, i.e., pipeline, rail tank cars and tank trucks.

Historical unit costs of LPG pipelines, tank cars and tank trucks were then applied to these volumes. The cost of replacement units projected to be necessary as indicated by past experience was added. Also included in this section are the projected costs of tank trucks for the local transportation of LNG. All of these costs are shown in column 9 through 12 of Table 170.

TABLE 179

LNG CAPITAL REQUIREMENTS FOR LIQUEFACTION, TRANSPORTATION AND REGASIFICATIDN—ALL CASES
(Millions of Constant 1970 Dollars)

Period	Voyage Route Source	– Delivery Point	Quantity BCF/Day	Round Trip Nautical Miles	Ships Required	Capital Requirements Millions Dollars Ships	Liquefaction Plant	Unloading Terminal	Total Capital
Last Half 1975	Algeria	– Cove Point	.350	7,300	3	150	131	49	230
	Total by End of 1975		**.350**		**3**	**150**	**131**	**49**	**230**
Additional 1976 – 1980	Algeria	– Cove Point	.300	7,300	2	117	120	54	291
		– Savannah	.500	7,900	4	220	175	56	451
		– Delaware River	.900	7,200	6	349	291	66	706
		– New York	.300	6,900	2	114	120	53	287
	Nigeria	– Delaware River	.650	9,800	6	337	222	60	619
		– New York	.200	9,700	2	106	91	46	243
		– Chesapeake Bay	.350	9,800	3	176	131	56	363
		– Boston	.300	9,500	3	158	120	50	328
	Venezuela	– Delaware River	.500	3,900	2	118	175	59	352
		– Lake Charles	.500	3,800	2	116	175	59	350
	Trinidad	– Lake Charles	.300	3,800	2	85	120	43	248
	Alaska	– Portland	.300	2,800	2	106	120	40	266
	Ecuador	– Los Angeles	.500	6,500	3	117	175	59	411
	Total Additional 1976-1980		**5.600**		**39**	**2,179**	**2,035**	**701**	**4,915**
Additional 1981— 1985	Algeria	– New York	.500	6,900	3	183	175	61	419
		– Delaware River	.250	7,200	2	104	104	48	256
		– Chesapeake Bay	.500	7,300	4	211	175	55	441
		– Boston	.250	6,600	2	100	104	46	250
		– Savannah	.250	7,900	2	110	104	50	264
	Nigeria	– New York	.500	9,700	4	245	175	61	481
		– Delaware River	.500	9,800	4	248	175	61	484
		– Chesapeake Bay	.250	9,800	2	124	104	55	283
		– Boston	.250	9,500	2	121	104	54	279
		– Savannah	.250	9,900	2	124	104	55	283
	Pacific	– San Francisco	.500	13,200	6	341	180	58	579
		– Los Angeles	1.000	13,000	11	659	329	68	1,056
	Total Additional 1981-1985		**5.000**		**44**	**2,570**	**1,833**	**672**	**5,075**

Chapter Fourteen
Financial Effects

Capital Requirements

Total capital requirements for the period 1971-1985 for resource development, processing and primary distribution are projected to range from $215 billion to $311 billion in the four principal cases studied.

Under the Electricity Task Group's base case (Condition 1), an additional $235 billion would be required for power plant construction and transmission facilities. Over the same period, $0.7 billion to $1.1 billion would be needed for water requirements, bringing the total capital requirements to a range of $451 billion to $547 billion.

Not included in these estimates are other major sums required for petroleum marketing, gas and electricity distribution, and the development of overseas natural resources to satisfy U.S. import requirements.

Capital requirements by individual resource sectors are summarized in Table 180 and commented upon in the following paragraphs.

Oil and Gas

Projected U.S. capital expenditures over the 1971-1985 period for the exploration, development and production of domestic oil and gas range from $88 billion (Case IV) to $171.8 billion (Case I)—or an annual average investment over the period of $5.8 billion to $11.5 billion. These figures compare with $4.8 billion for 1970.

Capital investment for oil pipelines, including the Alaska pipeline and expansion of existing domestic pipeline systems, is estimated at $7.5 billion. Total gas transportation capital requirements, including pipelines, underground storage, ships, liquefaction plants, trucks, rail cars and processing plants, are projected to range from $29.5 billion to $56.6 billion.

The capital requirements for refineries, tankers, terminals and gas transmission systems all vary from Case I to Case IV. The reason for the variation in gas transmission requirements is obvious—with greater domestic gas development, in Case I, more transmission investment is needed. More tankers and terminals are needed for Case IV because of the increase of oil imports. The reason for the difference in refining investment is not as obvious—the greater domestic gas supply in Case I reduces total oil demand as compared to Case IV, and because total oil demand is smaller in Case I than it is in Case IV, less refining investment is needed.

Capital requirements for marine transportation of oil imports assume the use of vessels averaging 250,000 DWT each. Under Case III conditions, over 400 of these vessels would be required, at a cost of $36 million each (foreign construction), for a total capital cost of approximately $14 billion. Capital requirements for the other three cases are derived from this estimate in proportion to the volume of total waterborne oil imports.

Additional terminal and transportation costs are estimated to require capital investment on the order of $2 billion, bringing the total investment for ocean transportation and terminals into the range of $2 billion to $23 billion. In total, cumulative oil and gas capital expenditures between 1971 and 1985 range from $186.0 billion to $256.9 billion.

Synthetics

Syngas plants for gasification of petroleum liquids are estimated to require an investment of about $5.0 billion; similar plants for coal gasification and liquefaction will require $1.7 billion to $12.0 billion.

Capital requirements to support the mining and processing of oil shale to marketable syncrude are

TABLE 180

**SUMMARY OF CUMULATIVE CAPITAL REQUIREMENTS
U.S. ENERGY INDUSTRIES 1971-1985
(Billions of 1970 Dollars)**

	Initial Appraisal	Supply Cases I	II	III	IV
Oil and Gas					
Exploration & Production	92.4	171.8	144.8	135.1	88.0
Oil Pipelines	3.5	7.5	7.5	7.5	7.5
Gas Transportation	21.0	56.6	46.9	39.8	29.5
Refining*	20.0	19.0	24.0	30.0	38.0
Tankers, Terminals	14.5	2.0	9.0	16.0	23.0
Subtotal	**151.4**	**256.9**	**232.2**	**228.4**	**186.0**
Synthetics					
From Petroleum Liquids	—	5.0	5.0	5.0	5.0
From Coal (Plants Only)	1.5	12.0	4.6	4.6	1.7
From Shale (Mines & Plants)	0.5	4.0	2.2	2.2	0.5
Subtotal	**2.0**	**21.0**	**11.8**	**11.8**	**7.2**
Coal†					
Production	9.3	14.3	10.4	10.4	9.4
Transportation	6.0	6.0	6.0	6.0	6.0
Subtotal	**15.3**	**20.3**	**16.4**	**16.4**	**15.4**
Nuclear					
Production, Processing, Enriching	5.0	13.1	11.0	8.5	6.7
Total All Fuels	**173.7**	**311.3**	**271.4**	**265.1**	**215.3**
Electric Generation, Transmission‡	200.0	235.0	235.0	235.0	235.0
Water Requirements	N.A.	1.1	0.8	0.8	0.7
Total Energy Industries	**373.7**	**547.4**	**507.2**	**500.9**	**451.0**

* Based on maximum U.S. requirements, some of which may be spent outside the United States

† Cases I—IV do not include capital requirements for coal production for synthetic fuels. These requirements in billions of 1970 dollars are as follows: Case I—2.0; Cases II/III—0.8; Case IV—0.3.

‡ Condition 1; capital requirements under all six conditions postulated by the Electricity Task Group are as follows:

Condition	Cumulative Investment (1971-1985) Billion 1970 Dollars 1	2	3	4	5	6
Power Plant Construction	181	183	186	169	196	163
Transmission (estimated at 30% of Condition 1 Cumulative Power Plant Investment)	54	54	54	54	54	54
Total	235	237	240	223	250	217

calculated to range from $0.5 billion (Case IV) to $4.0 billion (Case I). Total investment for domestic manufacture of synthetic oil and gas may range from $7.2 billion to $21.0 billion.

Coal

Coal production expenditures are projected to range from $9.4 billion to $14.3 billion; to this must be added transportation expenditures approximating $6.0 billion, for a range of required total coal capital investment of $15.4 billion to $20.3 billion.

Nuclear

Production of uranium and processing through the nuclear fuel cycle (including enrichment) are projected to require capital expenditures in the range of $6.7 billion to $13.1 billion in the four cases analyzed. The capital required for the construction of nuclear electric generating plants is included in the electricity total capital requirement.

Balance of Trade Considerations

Introduction

Trade in energy fuels, transactions traceable to the international operations of U.S. based energy companies, and trade in activities closely related to energy have been major factors in the overall balance of payments during the last decade. Some figures available for oil provide an insight into the magnitudes involved. In recent years imports of oil and refined products have equalled in value, roughly 7 percent of all imports, and the petroleum industry has accounted for approximately 25 percent of U.S. net capital outflows and 33 percent of U.S. net earnings abroad. It is difficult, however, to measure exactly the importance of trade in all energy fuels, of the overseas activity of the several energy industries, or of energy-related trade. Some elements of this complex equation have never been quantified, and information on other elements is not available on a current or continuing basis. In this chapter, estimates are made to quantify the several components of the balance of trade in energy fuels for the years 1970, 1975 and 1985, and the possible policy implications of these estimates are set out. Other dimensions of the relationship between energy and the overall balance of payments are identified but cannot be quantified. For example, no effort was made to measure the impact of recent negotiations with foreign producing nations on profit flows of U.S. oil companies.

Summary and Conclusions

The balance of trade in energy is more relevant to this report than are the other elements of the relationship between energy and the overall balance of payments.

In 1970, the value of U.S. oil imports was $3.4 billion, and natural gas imports cost $0.2 billion. As these were the only fuels imported, the total energy fuel import bill was $3.6 billion. Oil, steam and metallurgical coal export earnings provided an offset of $1.5 billion. Therefore, the total deficit arising from trade in energy fuels was $2.1 billion.

Considering the same factors in 1975, the estimated deficit of the balance of trade in energy fuels would range from $9.4 billion to $13.1 billion in the various cases studied. These estimates are broken down in Table 181.

The 1975 energy fuel deficits are 4.5 to 6.3 times greater than the 1970 deficit of $2.1 billion, and 2.0 to 2.8 times the 1970 overall balance of payments deficit of $4.7 billion. These substantial deficits are close at hand.

After 1975 the deficit can be expected to grow even greater, except under the favorable assumptions of Case I. The 1985 projections are shown in Table 182.

By 1985, the deficit for Case II is projected to increase to $15.3 billion. In comparison with 1975, Cases III and IV in 1985 are estimated to be higher by $11 billion and $18 billion, respectively.

Indirect or direct action can be taken either to offset the impact of the energy fuel deficit and/or to actually reduce the deficit. Indirect action might include campaigns for concessions on agricultural tariffs in Europe, various export promotion schemes, plans for restricting imports of goods other than energy fuels, or alteration of relative exchange rates. Direct action would encompass policies to provide greater access to federal lands, tax incentives to develop domestic energy resources, higher prices to promote development of domestic energy resources and maintenance of energy import controls.

The projected sizable increase in the deficit resulting from trade in energy fuels deserves careful attention. Unless export earnings are very strong in areas other than energy, the substantial demand for foreign exchange which the forecast energy deficit represents may create problems for the dollar. Furthermore, aside from any balance of payment difficulties, large scale energy imports pose significant issues in regard to national secu-

TABLE 181

BALANCE OF TRADE DEFICIT IN ENERGY FUELS—1975
(Billion Dollars)

	Initial Appraisal	Case I	Case II	Case III	Case IV
Oil Imports (Delivered)*	11.0	10.9	11.1	12.9	14.6
Natural Gas and LNG Imports	0.5	0.5	0.5	0.5	0.5
Total Energy Fuels Imports	**11.5**	**11.4**	**11.6**	**13.4**	**15.1**
Oil Exports	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)
Steam Coal Exports	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)
Metallurgical Coal Exports	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)
Total Energy Fuels Exports	**(1.9)**	**(1.9)**	**(1.9)**	**(1.9)**	**(1.9)**
Total Energy Fuel Deficit	**9.6**	**9.5**	**9.7**	**11.5**	**13.2**

* Including synthetic gas feedstocks.

TABLE 182

BALANCE OF TRADE DEFICIT IN ENERGY FUELS—1985
(Billion Dollars)

	Initial Appraisal	Case I	Case II	Case III	Case IV
Oil Imports (Delivered)*	22.4	5.4	13.1	20.4	29.1
Natural Gas and LNG Imports	5.5	4.9	5.0	5.3	5.4
Total Energy Fuels Imports	**27.9**	**10.3**	**18.1**	**25.7**	**34.5**
Oil Exports	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)
Steam Coal Exports	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)
Metallurgical Coal Exports	(2.1)	(2.1)	(2.1)	(2.1)	(2.1)
Total Energy Fuels Exports	**(2.8)**	**(2.8)**	**(2.8)**	**(2.8)**	**(2.8)**
Total Energy Fuel Deficit	**25.1**	**7.5**	**15.3**	**22.9**	**31.7**

* Including synthetic gas feedstocks.

rity. Therefore, to correct the deterioration of national security implicit in the forecast, the deficit of domestic energy requires reducing, rather than simply offsetting, the deficit.

The sections which follow define the various possible dimensions of the relationship between energy and the overall balance of payments. These sections also indicate the assumptions upon which the above estimates and conclusions are based.

Framework for Analysis

BACK

In any discussion of energy's influence on the U.S. balance of payments, it is helpful to distinguish among the classes of transactions described in the following:

- **The Impact of Trade in Energy Fuels:** This refers to the net entry in the overall U.S. balance of payments arising from the discepancy between the Nation's energy needs and domestic production of energy. Thus it is directly related to the demand and supply balances forecast in the preceding chapters. The factors relevant to calculating the impact of imports and exports in energy fuels on the U.S. payments would be the f.o.b. values of imported and exported fuels (crude oil, refined products, gas and coal) and the payments for international transportation of each fuel.

  The balance of these factors can have significant policy implications. A deficit balance puts pressure on the value of the dollar in international markets and creates the potential for painful balance of payments adjustment problems. Since the trade deficit in fuels is large and occurs within the context of a deficit in the overall balance of payments, it must be a matter of concern to policy makers.

- **The Impact of the Overseas Operations of U.S. Energy Companies:** Exploration for, development, refining and marketing of energy fuels overseas draw capital abroad. These activities also generate a return flow of funds to the U.S. investors that finance them. The net effect on the overall U.S. balance of payments could be calculated as the balance of the international capital movement and income flows related to each of the energy fuels —oil, gas and coal.

  This balance, like the balance of trade in energy fuels, has particular policy implications. If a deficit in the overall U.S. balance of payments threatens, then a positive contribution to that overall balance by the overseas operations would indicate that the flow of capital abroad to establish these overseas operations should not be restricted. Since policy on international capital flows is generally applied "across the board" to all investors, a positive contribution by U.S. energy companies argues for a liberal treatment of foreign investments made by all U.S. companies. The balances resulting from trade in energy fuels and from operations of U.S. energy companies abroad are obviously interrelated, but there is no necessary connection between the two. For example, the balance of trade in energy fuels is probably not affected by ownership, U.S. or foreign, of overseas energy operations. The balance of trade in energy and the balance arising from international activities of U.S. energy companies are each subject to a variety of independent influences and each has its own policy implications.

- **Ancillary Activities:** International transactions closely related to energy fuels include exports of petroleum products not consumed for energy such as lubricants, waxes and petrochemicals. Transactions often referred to as ancillary to energy-motivated international flows of capital are: (1) exports of capital goods, such as drilling or coal mining equipment, to foreign affiliates of U.S. firms, (2) exports of management or engineering consulting services, and (3) receipts of royalties on U.S. patents used abroad by affiliates or subsidiaries of U.S. energy companies.

- **The Effect of Secondary Factors:** No final conclusions can be drawn from the balances prevailing in trade of energy fuels, overseas operations of U.S. energy companies, or ancillary activities without some consideration of the secondary effects.

  U.S. dollars which flow abroad to purchase energy fuels and/or to finance the overseas operations of U.S. energy companies will generate return flows in the same period and/or subsequent periods. This occurs as foreigners spend a part of the increased incomes, which result from the initial dollar outflow, on U.S. goods and services and/or increase their savings by investing in the United States. These offsetting flows may come directly from the first recipient of the U.S. dollars or more indirectly from countries once or more removed, whose incomes and imports from the United States are increased by exporting to countries earlier affected by the dollar outflow.

  The significance of these return flows depends crucially upon their timing. Eventually, of course, almost all of the dollar outflow which derives from U.S. energy consumption or from the overseas operations of U.S. energy companies will be repatriated, but whether the repatriation occurs sooner or later makes a great deal of difference to policy makers. Large outflows in any one period are less worrisome to deficit-wary public officials when the return flows occasioned by the outflows are substantially completed within a short space of time rather than over many subsequent periods. Policies designed to reduce the initial dollar outflow are more appropriate to the latter case than to the former. Failure to institute such policies when return flows are long delayed can expose the country to painful adjustment problems, for example, international political tensions and exchange crises.

Flows of foreign exchange into the United States in the form of repatriated energy profits, or in payment for U.S. exports of energy fuels or energy related goods and services, will also give rise to offsets. Part of the increase in U.S. income caused by such inflows will return abroad either in the same period or in subsequent periods.

Each of the classes of transactions described in the foregoing text will have associated with it a certain pattern of secondary money flows. The distinction between the impact on the overall balance of payments of the balances described and the impacts of their associated secondary flows is made not because the pattern of secondary flows can be determined independently of the history of the balances mentioned, but because it is determined by a much more complicated sequence of events.

Energy and the U.S. Balance of Payments — 1970

A comprehensive analysis of the balance of trade in oil fuels, the balance arising from overseas operations of U.S. petroleum companies, and the balance arising from ancillary activities was developed in 1965 by the Chase Manhattan Bank. Secondary effects were not considered. Table 183 is a summary table from that report indicating the many factors involved. Chase relied heavily on a survey of U.S. oil companies to obtain the information in Table 183. Many of the statistics present in that table are not available on a continuing basis.

Without a major survey of the type Chase Manhattan conducted for the petroleum industry, the balance of trade in energy fuels is the only dimension of the influence of energy on the overall balance of payments that can be quantified for 1970. It is possible to build up to the net effect of trade in energy fuels from the balance of trade in each fuel.

Oil

Imports in this category were worth $2,770 million in 1970 on an f.o.b. basis. The transportation cost of petroleum imports to the United States is not reported separately, nor can it be calculated exactly; it can, however, be approximated. For a variety of reasons, average tanker rates in 1970 were unusually high, at about Worldscale 100. In order to arrive at a more representative figure for the cost of landed 1970 import volumes, 1971 rates were used in place of 1970 rates. Applying 1971 transportation rates from the Persian Gulf, North Africa and Venezuela and crude oil pipeline rates from Canada to the volumes of imports from the various oil supply areas (as reported by the Department of the Interior) provides a total transportation bill of $657 milion.* Thus, under normal circumstances, the landed value of oil imports in that year would have been approximately $3,427 million.

In 1970, oil exports were about 258 MB/D, and their average value was $5.16 per barrel, according to Department of Commerce data. Thus, for the year 1970, petroleum exports earned $486 million of foreign exchange.

The 1970 dollar balance arising from trade in petroleum and products, under likely long-term tanker transportation costs, would have been a deficit of $2,941 million.

Gas

In 1970, imports from Canada were 0.8 TCF of gas. Imports from Mexico were negligible. The average price of imported gas in 1970 was 25.4 cents per MCF, and the balance of payments

* This assumes transportation charges are paid almost entirely to foreigners.

TABLE 183

BALANCE OF PAYMENTS FOR THE U.S. PETROLEUM INDUSTRY*
(Millions of Dollars)

	1964		1960	
I. Trade	Canada	Total	Canada	Total
A. Total Exports (f.o.b.)	83.5	1,028.8	78.2	995.3
1. Crude oil and refined petroleum products	42.4	418.8	62.5	478.5
a. U.S. exports to foreign affiliates	17.8	167.9	19.0	198.1
b. U.S. exports sold by foreign affiliates on a commission basis and not included in the preceeding category	–	44.4	2.8	45.5
c. Exports of crude oil and refined petrolëum products to all other foreigners	24.6	206.5	40.7	234.9
2. Petrochemicals	14.3	250.0	10.0	157.4
a. U.S. exports to foreign affiliates	6.6	106.5	4.1	68.4
b. U.S. exports sold by foreign affiliates on a commission basis and not included in the preceeding category	–	16.8	–	–
c. Exports of petrochemicals to all other foreigners	7.7	126.7	5.9	89.0
3. All other exports	26.8	360.0	5.7	359.4
a. To foreign affiliates	23.6	344.3	5.7	354.0
b. Sold by foreign affiliates on a commission basis and not included in the preceding category	–	–	–	–
c. To all other foreigners, not included above	3.2	15.7	–	5.4
B. Total Imports (f.o.b.)	(271.9)	(1,677.8)	(103.9)	(1,368.8)
1. Crude oil	(258.0)	(1,079.8)	(96.3)	(895.2)
a. From U.S. foreign affiliates	(97.3)	(801.2)	(60.5)	(683.9)
1. From own affiliates	(17.8)	(665.2)	(4.8)	(532.6)
2. From the foreign affiliates of other U.S. oil companies	(79.5)	(136.0)	(55.7)	(151.3)
b. From all other foreigners	(160.7)	(278.6)	(35.8)	(211.3)
2. Refined petroleum products	(8.0)	(589.9)	(6.9)	(467.0)
a. From U.S. affiliates	(2.6)	(463.7)	(3.7)	(406.8)
1. From own affiliates	(2.6)	(454.3)	(3.7)	(405.8)
2. From the foreign affiliates of other U.S. oil companies	–	(9.4)	–	(2.0)
b. From all other foreigners	(5.4)	(126.2)	(3.2)	(60.2)
3. Petrochemicals	(0.5)	(3.1)	(0.7)	(1.7)
a. From U.S. affiliates	–	(1.6)	–	(1.0)
b. From all other foreigners	(0.5)	(1.5)	(0.7)	(0.7)
4. All other imports	–	(5.0)	–	(4.9)
a. From affiliates	–	(2.5)	–	–
b. From all other foreigners	–	(2.5)	–	(4.9)
Trade Balance (Line A less Line B)	**(188.4)**	**(649.0)**	**(25.7)**	**(373.5)**

	1964		1960	
II. Services	Canada	Total	Canada	Total
A. Transport and Shipping	(17.6)	(193.0)	(12.2)	(188.2)
1. Total Receipts	0.1	27.0	–	21.8
a. Total receipts from foreigners by U.S. shippers for freight and shipping charges on U.S. exports	0.1	19.0	–	11.8
1. From affiliates	–	16.0	–	9.9
2. From all other foreigners	0.1	3.0	–	1.9
b. Port charges received from foreigners	–	8.0	–	10.0
1. From affiliates	–	6.0	–	7.5
2. From all other foreigners	–	2.0	–	2.5
2. Total payments to foreigners for transport and shipping charges for imports	(17.7)	(210.0)	(12.2)	(210.0)
a. To affiliates	(N.A.)†	(81.9)	(N.A.)	(81.9)
b. To all other foreigners	(N.A.)	(128.1)	(N.A.)	(128.1)
B. Patent and Licensing Fees	1.4	15.0	1.2	8.7
1. Total Receipts	1.4	16.3	1.2	11.1
a. From affiliates	0.3	3.6	–	0.3
b. From all other foreigners	1.1	12.7	1.2	10.8
2. Total Payments	–	(1.3)	–	(2.4)
a. To affiliates	–	(1.2)	–	(2.0)
b. To all other foreigners	–	(0.1)	–	(0.4)
C. Managerial and Other Service Fees Reported by U.S. Petroleum Companies	13.3	126.4	9.3	110.5
1. Total Receipts	13.3	150.3	12.3	128.4
a. From affiliates	12.7	139.1	8.9	111.7
b. From all other foreigners	0.6	11.2	3.3	16.7
2. Total Payments	–	(23.9)	(3.0)	(17.9)
a. To affiliates	–	(23.1)	(3.0)	(7.8)
b. To all other foreigners	–	(0.8)	–	(0.8)
D. Service Receipts by Other U.S. Residents from Foreign Affiliates	N.A.	91.0	N.A.	94.0
1. Management and consulting fees received by U.S. contractors	N.A.	74.0	N.A.	72.0
2. Payment of wages to American workers credited to U.S. bank accounts	N.A.	17.0	N.A.	22.0
Balance on Services (Line A plus Line B plus Line C plus Line D)	**(2.9)**	**49.4**	**(1.7)**	**25.0**
III. Capital and Income Account				
A. Capital	(21.5)	(870.0)	(143.0)	(596.5)
1. Net increase (–) in subsidiary and branch assets	(30.0)	(739.0)	(138.0)	(455.0)
2. Net increase (–) in all other assets	8.5	(131.0)	(5.0)	(141.1)
a. Short-term financial assets	8.4	(53.0)	(5.0)	(139.1)
b. Long-term financial assets	0.1	(78.0)	–	(2.2)
B. Income	(123.1)	(1,936.4)	60.1	1,152.4
1. From foreign affiliates (dividends and interest received from subsidiaries, plus net branch income)	118.0	1,922.0	60.0	1,150.0
2. Other Income	5.1	14.4	0.1	2.4
a. From short-term financial assets	4.9	8.1	0.1	0.3
b. Long-term financial assets	0.2	6.3	–	2.1
Balance on Capital and Income Account (Line A plus Line B)	**101.6**	**1,066.4**	**(82.9)**	**555.9**
Summary Balance	**(89.7)**	**466.8**	**(110.3)**	**207.4**

* The Chase Manhattan Bank, *Balance of Payments of the Petroleum Industry* (1966), pp. 12-13.

† Not available.

deficit due strictly to trade in gas itself was $203 million.

Coal

In 1970, 15 million tons of steam coal were exported, almost entirely to Canada. Reported prices of exported energy coal at the border are available on an occasional basis in trade publications. The average Canadian border delivered price was $9.00 per ton in 1970. Applying that unit price to total exports, the total value of exported steam coal was $135 billion.

Exports of metallurgical coal were 56 million tons in 1970 at an average harbor delivered price of approximately $16.70 per ton. Exports of metallurgical coal therefore added $935 million to the plus side of the balance of payments in 1970.

The Balance of Trade in Energy Fuels—1970

The foregoing information can be set up in tabular form and the deficit in 1970 resulting from trade in energy fuels derived (see Table 184).

The 1970 balance of payments impacts of the overseas operations of U.S. energy companies or of ancillary activities cannot be quantified from currently published data. In the absence of pilot studies, such as Chase's study for the oil industry, considerable work would have to be done just to identify the detailed items that would enter into a reckoning of these effects in the gas and coal industries.

Even where information on primary factors is available, as it is for trade in energy fuels, it would be particularly difficult to include secondary flows in the analysis. To do so would require (1) a record of primary flows over a number of periods, (2) estimation of both the magnitude and timing of the impact of foreign exchange earnings on incomes at home and abroad, (3) estimation of national propensities to spend increases in income abroad, and (4) estimation of foreign propensities to spend in the United States and in other countries.*

* As indicated, the Chase study does not attempt to incorporate these effects. Appendix H of the Cabinet Task Force on Oil Import Control report, *The Oil Import Question*, gives some attention to the problem and suggests several simplifying assumptions.

TABLE 184

DEFICIT FROM TRADE IN ENERGY FUELS—1970

	Million $
Oil Imports	2,770
Transport Charges, Petroleum	657
Oil Imports (Delivered)	3,427
Natural Gas Imports, Delivered Value	203
Total Energy Fuel Imports	**3,630**
Oil Exports, Value at Seaboard	(486)
Steam Coal Exports, Value at Border	(135)
Metallurgical Coal Exports, at Harbor	(935)
Total Energy Fuel Exports	**(1,556)**
Total Energy Fuel Deficit	**2,074**

Energy and the U.S. Balance of Payments—1975, 1985

The balance of trade in energy fuels is the only component of the multi-faceted relationship between energy and the overall balance of payments that can be projected with a reasonable degree of accuracy. The difficulties of projecting other components of the relationship are discussed subsequently.

The conditions impinging on the future prices and volumes of energy fuels in international trade are numerous, and various assumptions have to be made. Such assumptions permit "for instance" estimates of 1975 and 1985 balances of payments in energy fuels. Proceeding fuel by fuel, a discussion of these estimates follows:

Oil

In Chapter Thirteen of this report, oil import volumes, depending on the case assumed, were projected as depicted in Table 185.

Projection of an average landed price on this oil requires judgment on (1) the rate of escalation of foreign royalties and taxes, involving a forecast of highly changeable political conditions; (2) the prices of oils from different geographic areas which would reflect differences in quality, production cost and cost of transportation to the United States; (3) the future relative importance of dif-

TABLE 185

PROJECTIONS OF OIL IMPORT VOLUMES (MMB/D)

	1975	1985
Case I	7.2	3.6
Case II	7.4	8.7
Case III	8.5	13.5
Case IV	9.7	19.2
Initial Appraisal	7.3	14.8

ferent foreign sources of oil; and (4) the mix of crude oil, residual and other products that will be imported.

The following assumptions are used for illustrative purposes: (1) f.o.b. oil prices by 1975 and 1985 will be no higher than projected 1975 prices under currently existing contract provisions with producing nations' governments; (2) the relative prices of oil from different sources will remain unchanged; (3) imported crude oil in 1975 and 1985 will come predominantly from the Middle East and Africa; (4) oil will be transported here in tankers registered in foreign countries; (5) the level of world tanker rates will not increase above 1971 levels; (6) the mix of crude, residual and other finished product imports will be the same as the mix in 1971.

Under these assumptions, the approximate landed cost of imported oil would be as shown in Table 186 under the various cases.*

Cost and price assumptions underlying the derivation of these estimates are likely to prove to be conservative, which would cause the size of the import bill to be understated.

Oil and product exports in 1975 and 1985 are estimated at 235 and 210 MB/D respectively. If there is no real escalation in export prices above 1970 levels, U.S. petroleum exports in 1975 will earn, in constant 1970 dollars, $443 million of foreign exchange and $396 million in 1985.

Gas

The future average price of imported gas requires judgment on production taxes and permitted wellhead prices in Canada, the costs of transporting gas from the Canadian Arctic, and the delivered price of Algerian LNG. Obviously, such projections involve complex political, technical and economic questions.

Reasonable estimates of 1975 border delivered constant dollar prices for average of all long-term base-load contracts for gas from Canada and Algeria might be 30 cents per MCF and 82.5 cents per MCF, respectively. If these prices are applied to estimated import volumes of 1.00 TCF from Canada and 0.24 TCF from Algeria in 1975,† the gas import bill in that year would be $498 million. Using a single estimate for the 1985 price of gas imports, 82.5 cents per MCF,‡ and applying it to total estimated imports in 1985 gives an import bill for that year ranging between $4.9 billion and $5.4 billion, depending on the case, as illustrated in Table 187.

Coal

The United States may be exporting 16 million tons of steam coal by 1975 and 18 million tons by 1985. The volume and price of this coal at the Canadian border (which would be representative for all steam coal exports) must reflect estimated future costs, the location of fields from which export steam coal will originate, the sulfur content of the coal and future Canadian anti-pollution legislation, the date of introduction of nuclear power plants in Canada, and future transport costs.

TABLE 186

LANDED COST OF IMPORTED OIL (Billion Dollars)

	1975	1985
Case I	10.9	5.4
Case II	11.1	13.1
Case III	12.9	20.4
Case IV	14.6	29.1
Initial Appraisal	11.0	22.4

* These estimates of landed cost are expressed as constant 1970 dollar costs.

† See Chapter Thirteen, this report.

‡ Canadian prices are assumed to catch up to the import price of Algerian LNG as more remote Arctic supplies are developed.

TABLE 187				
COST OF GAS IMPORTS IN 1985				
	Case I	Case II	Case III	Case IV
Volume, Total (TCF)	5.9	6.1	6.4	6.6
LNG (TCF)	3.2	3.4	3.7	3.9
Pipeline (TCF)	2.7	2.7	2.7	2.7
Value, $ Million	4,867.5	5,032.5	5,280.0	5,445.0

Assuming a consideration of these several factors leads to a projection of an export price of $12.60 per ton by 1975 and $14.80 per ton by 1985, steam coal exports will add $202 million and $266 million to the plus side of our balance of payments in 1975 and 1985 respectively.

Metallurgical coal exports in 1975 are projected to be 76 million tons. If an East Coast harbor price of $17.25 is expected by 1975, these exports will be worth $1.3 billion in that year. If the price escalates to $17.75 (constant 1970 dollars) per ton by 1985, the estimated exports for 1985, 120 million tons, will be worth $2.1 billion.

The Balance of Trade in Energy Fuels—1975, 1985

Calculated from the foregoing paragraphs, the estimated deficit of the balance of trade in energy fuels under conditions of the various cases would range from $9.5 billion to $13.2 billion in 1975 and from $7.5 billion to $31.7 billion in 1985. The several balances and the estimates of items which are used in their derivation are presented in tabular form in Tables 181 and 182. The forecast energy fuel deficits for 1975 are 4.5 to 6.3 times greater than the corresponding 1970 deficit estimated at $2.1 billion, and 2.0 to 2.8 times the 1970 overall balance of payments deficit of $4.7 billion.

The balance of trade in energy fuels is directly related to the rest of the U.S. Energy Outlook report which deals with U.S. energy supply/demand, not with investments of U.S. companies abroad or trade in energy related activities. Other dimensions of the energy/balance of payments relationship, however, are more tenously related to the report and are more difficult to estimate.

A projection of the balance of payments impact in 1985 of the overseas activities of U.S. energy companies would require making assumptions about the future in highly problematic areas. The projection would necessarily be subject to very wide margins of error. Future outflows of U.S. capital will depend upon the future opportunities and incentives for investors in the discovery, production or marketing of energy abroad. These opportunities and incentives will be influenced, not only by customary demand and supply considerations, but also by political developments abroad related to such issues as the likelihood and form of foreign participation in U.S. investments, the general security of operations, rates of taxation, and U.S. government policy concerning capital outflows. Dollar outflows for investment in energy activities will also depend upon the extent to which investment funds can be raised in foreign capital markets in coming years. Future dollar inflows will depend upon the same considerations, both immediately and through their necessary connection with capital outflows. An estimate of the 1985 net balance of payments impact of the overseas activities of U.S. energy companies will thus require judgment as to: (1) the nature and timing of future political and economic developments, (2) future rates of return on investment, and (3) the time profile of capital outflows and earnings repatriation on overseas operations.

Projecting the impact on the balance of payments of international transactions ancillary to energy transactions would be attended by all of the general difficulties of predicting the balance of trade in energy fuels.

Finally, projecting the effect of energy-induced secondary flows on the 1985 overall balance of payments would require predicting the distribution of future energy-related dollar outflows across countries, and future dollar inflows, in addition to repeating for future periods the complicated estimations listed earlier.

Sources and Calculations for "Balance of Trade Considerations"

There follows a summary of data sources and calculations used in arriving at the figures presented in this chapter.

Balance of Trade in Energy Fuels—1970

Oil:

Data Sources

Value (f.o.b.) of imports: *Survey of Current Business.*

Volumes of imports by country: *Oil Import Activity for the Year 1970* (Annual Release OIA).

Tanker freight charges/barrel: can be worked up from rates in *Worldwide Crude Oil Prices* (quarterly, Office of Oil and Gas); 1971 rates used.

Transportation charge/barrel from Canada: published tariff (ICC).

Value and volume of exports: *Survey of Current Business.*

Calculations

Transportation charges were calculated using the following prices and quantities:

Country	Transport Charges $/B		MMB/D		$ Million/D
Venezuela	0.28	×	1.98	=	0.56
Middle East	1.24	×	0.76	=	0.94
Canada	0.45	×	0.66	=	0.30
Total			3.40		1.80

A daily bill of $1.8 million amounts to $1.8 × 365=$657 million for the year.

Gas:

Data Sources

Volume: *Mineral Industries Survey.*

Average import price: FPC Annual Release (#175-61).

Calculations

0.8 TCF × $0.254/MCF = $203 million

Coal:

Data Sources

Volumes: NPC Initial Appraisal. Available annually in *World Coal Trade* (NCA).

Prices: Mine mouth prices for representative areas from working papers of Coal Group Phase II. Representative transport charges to border or harbor from Consol and Island Creek.

Calculations

15 million tons × $ 9.00/ton = $135 million

56 million tons × $16.70/ton = $935 million

Balance of Trade in Energy Fuels—1975, 1985

Oil:

Data Sources

Volumes: NPC Phase II.

Prices: Base prices (1971) for crude from *World-Wide Crude Oil Prices* (Fall 1971, Office of Oil and Gas). 1970 prices for other products from *Platt's Oil Price Handbook*.

Adjustments for changes in price of crude by Middle East, Venezuela and Libya after devaluation: widely published figures—*Platt's Oil Gram, Oil & Gas Journal*, PIW, etc.

Escalation rate (to 1975) in current contracts: Teheran and Tripoli agreements.

Transportation charges: *World-Wide Crude Oil Prices.*

Calculations: 1975, 1985 prices of crude

Country	(1)		(2)		(3)		(4)		(5)		(6)	(7)
Venezuela	(2.78	+	0.06)	×	1.16	=	3.29	+	0.28	=	3.57	0.05
Middle East	(1.75	+	0.12)	×	1.16	=	2.17	+	1.24	=	3.41	0.41
N. Africa	(2.80	+	0.17)	×	1.16	=	3.45	+	0.55	=	4.00	0.22
Canada	(3.05	+	0.00)	×	1.16	=	3.54	+	0.45	=	3.99	0.32

Where:

(1) 1971 f.o.b. price of crude.

(2) Correction for Geneva changes by Mid-East countries, and for Venezuelan and Libyan change in response to dollar devaluation.

(3) Escalation factor (1971-1975) in currently negotiated contracts (expiring 1975); prices are assumed to rise at contract rate even in countries where no contracts exist.

(4) 1975 f.o.b. prices of crude.

(5) Transport charges per barrel to the United States, assume unchanged to 1975, 1985.

(6) Landed cost of crude per barrel, 1975, 1985.

(7) Arbitrary volume weights used to calculate average landed price of crude oil.

From columns 6 and 7:

Average landed price of crude oil:

$(3.57 \times 0.05) + (3.41 \times 0.41) + (4.00 \times 0.22) + (3.99 \times 0.32) = \$3.73/\text{bbl.}$

1975, 1985 price of residual fuel oil

This price was assumed to equal (adjusted for the difference in BTU content) the landed price of Libyan sweet crude in 1975.

Calculation: $\$4.00 \times 6.3/5.8 = \$4.34/\text{bbl.}$

1975, 1985 price of other products

The 1970 price is based on the weighted average of the various product components of this category. The 1970 weighted average price was escalated to 1975 on the same basis as the crude escalation and is calculated to be approximately $5.00 per barrel.

1975, 1985 oil import values

NPC petroleum import projections for 1975 and 1985 are as follows, in MB/D:

	1975	1985
Case I	7,215	3,564
Case II	7,365	8,701
Case III	8,504	13,474
Case IV	9,678	19,248
Initial Appraisal	7,255	14,820

Assuming that the future product mix of imports will be as it is now (46.9-percent crude, 40.4-percent residual and 12.7-percent products) a weighted average price of future oil imports can be derived as follows:

$$\$3.73 \times .469 + \$4.34 \times .404 + \$5.00 \times .127 = \$4.14$$

Multiply this price by the above estimated volumes to obtain future import values used in the text.

Sensitivity of the total import bill to the assumption made about product mix of imports, in billions of dollars:

	1975		1985	
Assumption	Case II	Case III	Case II	Case III
All Crude	10.0	11.6	11.8	18.3
All Other Products	13.4	15.5	15.9	24.6
Mix Unchanged from 1971	11.1	12.9	13.1	20.4

1975, 1985 export values

Average 1970 export price of petroleum, \$5.16 can be calculated from *Survey of Current Business* value and volume figures. The 1975, 1985 volumes used are from the NPC Initial Appraisal: 235 MB/D in 1975. 210 MB/D in 1985. Estimated 1975 and 1985 export values in constant 1970 dollars are $\$5.16 \times 235 \times 365 = \$443$ million and $\$5.16 \times 210 \times 365 = \$396$ million respectively.

Gas:

Data Sources

Volumes: NPC

Calculations

1975: (1.00 TCF × 30.0¢/MCF + (0.24 TCF × 82.5¢/MCF) = \$498 million

1985: Canadian pipeline gas and Algerian LNG were assumed to have the same import price, 82.5¢/MCF, which was applied to the total import volumes forecast for the various cases by the NPC:

	CASE			
	I	II	III	IV
Volume, Total TCF	5.9	6.1	6.1	6.9
LNG	3.2	3.4	3.7	3.9
Pipeline	2.7	2.7	2.7	2.7
Value, \$ Million	4,867.5	5,032.5	5,280.0	5,445.0

Coal:

Data Sources

Volumes: NPC Initial Appraisal, Volume II, p. 128.

Prices: Mine mouth prices for representative areas from NPC Coal Task Group. Representative transport charges to border or harbor from Consol and Island Creek.

Calculations

1975: 16 million tons $\times$ \$12.60/ton = \$ 201.6 million (Steam)
76 million tons $\times$ \$17.25/ton = \$1,311.0 million (Metallurgical)

1985: 18 million tons $\times$ \$14.80/ton = \$ 266.4 million (Steam)
120 million tons $\times$ \$17.75/ton = \$2,130.0 million (Metallurgical)

Chapter Fifteen
Energy Trends Beyond 1985

Introduction

Suggesting developments in the U.S. energy situation in the period from 1985 to 2000 involves considerable conjecture. Energy production, distribution and consumption—inextricably interwoven through economic and social activities—change as the latter change. Also, government regulations and policies profoundly influence the operations of the energy industries. Consequently, a multitude of developments may occur over the next 30 years that would affect the Nation's demand for energy as well as the technology to develop and utilize energy. Since so many factors impinge on the Nation's energy outlook, only broad trends can be identified. These trends reveal the future energy options available to the Nation and the related actions needed to implement these options. Projection of these general trends should be frequently monitored in the future against actual developments to assure that they have continuing validity.

It was considered inappropriate to develop supply/demand balances for the year 2000. The four supply cases developed for the 1971-1985 period indicate a wide range of future possibilities. With such diverse starting points for 1985, it is evident that a much wider range of demand and supply projections are possible by the end of the century. Indeed, depending on developments, the Nation's supply/demand balance in 2000 could range all the way from total national self-sufficiency in energy supplies to an alarming degree of dependency on imports.

Assuming the continuation of the projected growth in energy requirements, the present assessment of the energy resource base, and only moderate advances over the existing technology for developing and delivering energy supplies, there will likely be a trend toward sharply rising costs and physical limitations of energy resources. This is particularly true of oil and gas, both domestic and foreign.

At present, the identifiable approaches for countering this trend toward higher energy costs and physical limitations on domestic sources of supply may be grouped within seven principal categories: (1) location of more reserves of the energy fuels now used, (2) development of greater ability to make synthetic fuels, (3) increased efficiency of producing fuels, (4) reduced energy demand through increased efficiency in the utilization of fuels, (5) a shift from the less abundant to the more abundant sources of energy supply, (6) increased imports of fuels, and (7) a turn to totally new technologies for the supply of energy. Each of these seven approaches will be discussed more fully in a later section. The demands on energy supplies in the last part of this century are likely to be so great that all of them will probably have to be employed in varying degrees, if the energy needs of American society are to be satisfied.

Requirements for Energy

In projecting energy requirements to the year 2000, special consideration needs to be given to population trends, economic activity, efforts to improve environmental quality, and cost and efficiency in utilizing fuels. Depending on future developments in these basic factors, total energy demand at the end of the century might range between 170 and 215 quadrillion BTU's, as shown in Table 188.

While factors such as a continued high level of emphasis on environmental quality tend to increase energy consumption, the growth rate in U.S. energy demand is expected to slacken in the last 15 years of the century because of the effect of the following trends:

- A lower rate of population growth
- A more service-oriented economy
- Changes in social values and life-styles, including smaller families, increased multiple dwellings, smaller cars and greater use of mass transit
- Higher energy costs.

TABLE 188

PROJECTIONS OF U.S. TOTAL ENERGY DEMAND

Case	Volume (Quadrillion BTU/Yr) 1985	Volume (Quadrillion BTU/Yr) 2000	Growth Rate (Percent) 1981-1985	Growth Rate (Percent) 1985-2000
High	130.0	215	4.4	3.4
Intermediate	124.9	200	4.2	3.2
Low	112.5	170	3.4	2.8

The dominant factor in energy growth during the 1985-2000 period will be energy requirements for electricity. By the year 2000, such requirements will account for nearly half the primary fuels consumed. During this period the growth rate for electricity is expected to average more than 5 percent per year, while non-electric energy consumption will grow at less than 2 percent per year. This high rate of growth for electricity will be stimulated by economic factors (the costs of electricity generated in nuclear power stations are expected to increase at a slower rate than fossil fuel costs) and changing life-styles (more multiple-family dwellings and greater population concentration in the moderate climate areas will bolster electrical heating and air conditioning).

Recapitulation of 1985 Fuels Technology and Resource Positions

Three essentials are necessary if the Nation's energy resource potential is to be fully realized:

- A workable societal consensus regarding the proper balance between environmental safeguards and energy development and utilization
- Sound government policies to provide access to and incentives for resource development
- Capable, far-sighted energy industries to develop the required resources while satisfying the Nation's need for clean energy.

If these three fundamental prerequisites exist, the primary determinants of how successfully the Nation can meet its energy requirements in the 1985-2000 period will be (a) the technology available in 1985 and later years for producing the major fuels, and (b) the size of the resource base for these fuels. Alternative new energy sources, such as fusion power or solar energy, are not likely to be in widespread use by the year 2000, because a lead time of decades probably will be required to bring the requisite technologies to full commercial availability.

The sections that follow discuss the fuel technology and fuel resources likely to be available in 1985.

Fuels Technology

Based on the analyses of 1985 conditions earlier in this report, the "state-of-the-art" in fuels technology at the outset of the 1985-2000 period is likely to be as follows:

- **Oil:** Anticipated recovery efficiency of oil-in-place will have increased from an average of 31 percent in 1970 to 37 percent in 1985. By 1985 anticipated ultimate recovery efficiency in new reservoirs discovered will be about 50 percent, due to technological improvements. Drilling will be carried out in increasingly deeper formations. Hopefully, drilling capability will have advanced to the point where it can cope with the formidable conditions found in such areas as the offshore Arctic. This latter ability will be of particular importance, because vast resources are believed to exist in that region.
- **Gas:** Improved drilling capability will make it possible to develop very deep gas formations. Nuclear explosives should be proved as a means of fracturing low-productivity gas reservoirs. Systems for liquefying and transporting LNG should be well developed.
- **Coal:** The environmental problems associated with use of high-sulfur coal will have been solved. Underground mining methods will have made considerable improvements.
- **Nuclear:** The breeder reactor, approaching the commercial application stage, will extend the useful life of domestic uranium resources. The breeder and the high-temperature gas

reactor will have greater thermal efficiency than the light-water reactor.

- **Synthetic Fuels:** Shale oil, Canadian tar sands and coal gasification industries all will be advanced beyond the pioneering stage. Production of liquids from coal is expected to be in the pioneering stage.
- **New Energy Forms and New Conversion Devices:** Combined-cycle power plants will be commercially available. Fusion reactors, solar energy, MHD units, hydrogen and other new energy forms are likely to still be in the research and development or working prototype stage. Of course, technological advances unforeseen at this time could occur to hasten their development.

Domestic Resource Position

A rough projection of the resource base available at the outset of the 1985-2000 period has been developed from present estimates of potential domestic resources, adjusted to reflect reserve additions and production withdrawals in the 1971-1985 period. (The data below reflect the range of supply Cases I-IV in the 1971-1985 period which have been described in Chapter Two.) The estimates of the resource position for various fuels thereby reflect current thinking; however, advances in technology (greater than those identified above) and increased knowledge could further add to the resource base for particular fuels.

- **Oil:** In 1985, between 58 and 67 percent of the present estimate of discoverable oil-in-place will have been found; the amounts remaining to be discovered will range from 265 to 340 billion barrels of oil-in-place. If Case II assumptions were to prevail in the 1971-1985 period, the additional amount of oil available for discovery, assuming a 50-percent recovery rate, would correspond to 32 years' supply at the 1985 rate of production. Under Case III, the corresponding figure would be 40 years' supply.
- **Gas:** By 1985, between 44 and 58 percent of the present estimate of ultimately discoverable natural gas will have been found; the amounts remaining to be discovered will range from 770 to 1,040 TCF. Under Case II assumptions, the additional resource available for discovery would correspond to 32 years of supply at 1985 production rates; under Case III, the corresponding figure would be 46 years.
- **Coal:** Remaining coal reserves recoverable **in** 1985 under present mining methods will range from 133 to 136 billion tons, depending on whether Case I-IV conditions prevail over the 1971-1985 period. These reserves would suffice for over 100 years at the Case II, 1985 level of demand; they also represent only about 4 percent of the 3.2 trillion tons of estimated total potential coal resources in place.
- **Oil Shale:** Well defined and readily accessible resources of oil shale in place will be at least 125 billion barrels. Assuming a 60-percent recovery rate, this resource base would be equivalent to about 20 years' supply of conventional crude at the 1985 Case II conventional crude oil production rate. In addition to these defined resources, potential and speculative resources total an additional 1,550 billion barrels.
- **Uranium:** Previous uranium exploration activity has been concentrated in the present producing areas, which make up less than 10 percent of the total region where signs of uranium occur; even these areas are not completely explored. It is, therefore, impossible to estimate accurately ultimate domestic uranium reserves. Because of the large unexplored regions with potential for uranium ores, the uranium resource base is presumed adequate to meet rapidly rising requirements until the breeder reactor becomes the major reactor type ordered in the 1990's and beyond.

In speculating about the Nation's energy resources at a future point in time—1985, 2000 or even later—there is a tendency to regard the Nation's resource position as a static amount of available resources. This concept assumes that there is a fixed stock of energy resources; when the stock is used up, our resources are gone. More realistically, more usefully, the Nation's energy resources should be regarded in a dynamic sense. The character of energy resources available for use in industrialized societies is changing as are judgments regarding the size of the resource base for various fuels. Two fundamental facts support this point of view:

- The ultimate size of the energy resources available in the outer crust of the earth cannot be accurately estimated. Past estimates of total resources in place have generally been low. As knowledge and engineering ability improve, estimates of energy resources may increase as a result of discoveries of very large additional deposits of oil, gas, coal, geothermal energy and uranium.
- Technological advances alter traditional measures of resources available. For example, the development of nuclear power increased total energy resources by enabling a new fuel—uranium—to become a utilizable energy source. Similarly, in future years large quantities of liquid fuel will be available from a source other than underground oil reserves, namely, from shale oil or coal liquefaction. Similarly, the advent of the fast breeder reactor will increase effective world reserves of fissionable uranium.

For thousands of years, man burned wood for energy. A few hundred years ago, the more developed countries switched to coal, and then in turn to the other fossil fuels—oil and gas. At present the industrialized countries are in the early stages of large-scale use of nuclear energy. The full range of ways that society's increasing energy needs will be met in the future is uncertain. However, historical precedent provides assurance of man's increasing technological capability to create and use new energy forms. Nuclear energy represents the first major supplement to the conventional fossil fuels. The next major contributor might be either (a) fusion, which would utilize the virtually limitless quantities of hydrogen isotopes in seawater; (b) solar energy, which originally provided the energy stored in fossil fuels hundreds of millions of years ago; or (c) the geothermal energy stored within the earth's crust.

In planning for the Nation's energy supply and utilization through the end of the century, attention should concentrate on the resource base for the fuels presently utilized. But the broader perspective of technological possibilities toward the end of the century should also be considered.

Domestic Fuel Availability

Because conditions at the end of the century are subject to a great deal of uncertainty, the role of conventional domestic fuels in the year 2000 can be only approximated. Table 189 summarizes a range of estimates for conventional fuel supplies in the year 2000. The four supply cases for the 1971-1985 period give a wide range of possible starting points in 1985 for projecting fuel supplies during the subsequent 15-year period. With such diverse starting points, the range of supply and demand projections possible by the end of the century could extend from total national self-sufficiency in energy supplies to an alarming degree of dependence on imports. The projections for the year 2000 which appear on Table 189 are based on the assumption of an intermediate level of domestic supplies in 1985. Under different assumptions for the 1985 supply position, it would be possible to develop additional projections of potential energy fuel supplies for the year 2000.

According to these projections for the 1985-2000 period, oil production generally remains at about the same level, natural gas trends downward, coal grows substantially, hydro remains relatively insignificant, and nuclear grows dramatically. The estimated volumes of oil and gas available in the year 2000 have been derived assuming an intermediate level of supply as a starting point in 1985 and a constant level of drilling in the last 15 years of the century. Increased knowledge of unexplored areas might lead to an upward reappraisal of the hydrocarbon resource base and a corresponding increase in drilling activity and resulting production.

For all of the energy sources but hydro, the projected ranges of production for 2000 are quite broad. When the extremes of these ranges are totaled, the result is a total BTU range for conventional fuels which extends from 131 to 211 quadrillion BTU's.

Energy Supply/Demand Balances and Implications

As indicated earlier, supply/demand balances have not been developed for the year 2000. Depending on developments in supply and demand, a wide range of very different conditions could be postulated. There is little foundation to judge which possible supply/demand balance is likely to

TABLE 189

DOMESTIC ENERGY OUTPUT POTENTIAL IN THE YEAR 2000
BASED ON AN INTERMEDIATE LEVEL OF SUPPLY IN 1985
(Conventional Energy Sources)

	Units	1985	2000
Oil, total domestic liquid production	MMB/D	14	10 - 18
Natural gas production	TCF/yr	27	15 - 25
Coal, traditional uses only	Million tons/yr	863	1,200 - 1,700
Hydro	Billion KWH	316	340 - 380
Nuclear	Billion KWH	2,463	7,500 - 9,500
Oil, total domestic liquid production	Quadrillion BTU's/Yr	29	21 - 37
Natural gas production	Quadrillion BTU's/Yr	28	15 - 26
Coal, traditional uses only	Quadrillion BTU's/Yr	21	30 - 42
Hydro	Quadrillion BTU's/Yr	3	4
Nuclear	Quadrillion BTU's/Yr	25	61 - 102
Total	**Quadrillion BTU's/Yr**	**106**	**131 - 211**

exist in the year 2000 within this wide range.

Despite the considerable uncertainties regarding future demand and supply developments, it is possible to make certain inferences about conditions that will exist in the year 2000 and the proper orientation of policies in the meantime. Among the conventional domestic fuels, increases in fuel availability are more likely to come from coal and nuclear, which can be used primarily for electricity generation, while the more interchangeable fuels—oil and gas—will be less readily available, based on the current estimated resource position. Chapter Two has indicated the limitations involved in interfuel substitution.

Seven approaches to providing sufficient energy supplies to meet U.S. requirements in the 1985-2000 period are discussed in the next sections.

Better Definition of the Resource Base and Location of More Reserves of Traditional Fuels

This is an area of special need for oil and gas, the fuels in shortest supply. But the need for finding new reserves will increasingly apply to other fuels as well. Environmental considerations in the development of energy supplies will be of great importance in the remainder of the century. This will create continuous upward pressure on the cost of producing and processing energy fuels. Proper economic incentives and access to promising areas will be necessary to enable companies in the energy industries to undertake the necessary exploratory activity to locate and develop additional reserves.

Discovery and development of deep offshore petroleum reserves could substantially increase domestic oil and gas production during the 1985-2000 period. Large areas of the continental shelf (those areas with water depths generally less than 660 feet) and virtually all of the continental slope (with water depth between 660 and 8,000 feet) are unexplored. While estimates of potential resources in these areas are highly speculative, a large proportion of undiscovered domestic oil and gas resources is believed to be located in these offshore areas.

Discovery and development of deep offshore reserves could yield significant results, but only if the following four conditions prevail: (a) international agreement is reached on the right to develop undersea resources, (b) there is a clear definition of the jurisdiction between state and federal governments to permit companies to develop these resources, (c) technology advances sufficiently to permit these resources to be found and recovered in a manner compatible with environmental goals, and (d) economic incentives are adequate to compensate for the increased costs and risks associated with operations in these areas. Unless the legal necessities and economic issues are satisfactorily resolved, corporations will not have the incentive to devise the advanced technology required to develop these vast resources in a timely manner.

Develop Production of Synthetics and Canadian Tar Sands

Synthetics represent another major source of energy to fill any existing energy gap. Because the availability of domestic conventional fuels is subject to considerable variation and because the respective technologies of several synthetics have not been fully developed, the overall contribution of these sources and their relative roles by the end of the century are by no means clear at this time. However, provisional judgments suggest that:

Shale Oil: Supplies by the year 2000 could reach about 2 MMB/D or approximately 4 quadrillion BTU's. This implies that 16 billion barrels of an estimated 54 billion barrels of reserves in the preferred minable section of the Mahogany Zone in the Piceance and Uinta Basin would have been committed by the 21st century. Thus, 38 billion barrels of preferred reserves, plus other reserves in deeper and less explored areas, would be available for future development. However, production greater than the foregoing estimate could be limited by difficulties associated with spent shale disposal, other environmental considerations and water availability. Greater development could require either the use of water now allocated to agriculture or large-scale trans-basin diversions. On the other hand, more rapid progress with *in situ* production methods could result in higher shale oil output than the foregoing estimate.

Coal-Based Gas and Liquids: Production will grow rapidly in the last part of the century. The contribution of synthetic gas and liquids from surface reserves of western coal could be about 8-10 quadrillion BTU's/year by the end of the century. Since technological problems must be solved for coal liquefaction, the largest part of this total will be syngas. Available resources of western coal will be sufficient to meet this projection.

Canadian Tar Sands: Resources are abundant. Sizable volumes of tar sands production will be required by the Canadian economy. Under favorable circumstances, these hydrocarbon resources in Canada could contribute slightly over 5 MMB/D or about 10 quadrillion BTU's to U.S. energy supplies. (This assumes that 25 percent of projected Canadian tar sands production is utilized in that country and 75 percent is exported to the United States.)

Adding together the potential contributions of oil shale, coal-based synthetics and Canadian tar sands, these energy sources could supply approximately 20-25 quadrillion BTU's. Achievement of an even higher level of supplies from synthetics and tar sands for the year 2000 should be possible, given the proper economic environment. As indicated elsewhere in this report, the basic resources are clearly present, although the degree of development possible over and above this projection is speculative. Generation of these additional supplies will depend, in varying degree, on (a) the resolution of the environmental problems; (b) the availability of sufficient water supplies; and (c) the extent of the commitment to further research and development.

Increase the Efficiency of Fuel Production, Conversion and Distribution

Increased efficiency in energy production, conversion and distribution holds perhaps the greatest potential for expanding the effective availability of energy fuels. (Efficiency in the utilization of fuels is analyzed in the next section.) Efficiency improvements can be made in several ways:

- Much can be done to increase the effective recovery of identified reserves—e.g., by employing new stimulation techniques in the production of oil and gas, developing new mining techniques to increase recovery of coal, pursuing *in situ* development of oil shales, tar sands and coal. At present rates of research spending, progress in *in situ* resource development is likely to be limited by the year 2000.
- Efficiency can be improved in the conversion of conventional energy fuels to electricity. The potential is great here. In 1970, electric power plants converted only about 33 percent of the

energy in the fuels they burned into electricity. Efficiency may be improved in several ways. Combined-cycle power generators ultimately will be able to reach an efficiency of over 50 percent. The breeder reactor will greatly increase the efficiency of nuclear power plants.

- Magnetohydrodynamic generators are potentially capable of serving as high-temperature "topping" devices to be operated in series with steam turbines and generators in producing electricity. But there are a number of difficult engineering problems to be solved before MHD can approach commercial feasibility. Construction of the first large commercial unit is unlikely before 1985. An expenditure of $100 million to $300 million in R&D funds will be required before commercial application of MHD can be achieved.
- Transmission losses accounted for about 10 percent of the total amount of electricity generated. Development of high-voltage transmission lines and the use of cryogenic techniques can reduce power transmission losses. Reducing transmission losses will be of increasing importance as energy sources are developed in areas remote from major load centers. Better means for storing electricity to meet the surge of peak load requirements are needed. Such areas of potential improvement in energy conversion and distribution should be pursued to better utilize coal and nuclear resources and to make solar power practicable.
- The projected increased use of electrical energy will result in the production of tremendous volumes of waste heat, which are not used in the generation of power. This thermal energy is presently a waste product, the disposition of which poses a potential threat to the environment in the form of thermal pollution. A more positive approach would be to recognize the heat losses as a potential energy resource and to begin to devise means of converting these losses to constructive use.

Reduce Growth of Energy Demand Through Greater Efficiency in Energy Utilization

The gap between projected domestic supply and demand could be reduced by lowering demand growth. Earlier it was indicated that total demand might be as low as 170 quadrillion BTU's in 2000; this represents a level of demand that is 15 percent less than the intermediate demand level. Reduction of energy demand growth could be accomplished either by (a) improving efficiency in energy consumption, or (b) arbitrarily restricting energy demand growth. The latter alternative would not be desirable because it would seriously retard economic growth, increase unemployment and adversely affect consumers' freedom of choice.

Greater efficiency in energy utilization is always desirable. Over the 1971-1985 period, however, the contribution to reducing energy demand from improved efficiency is limited because of the difficulty of altering existing equipment and the long lead time before more efficient equipment can be developed and put into use. Over the longer range from 1985 to 2000, significant reduction of energy demand growth is more feasible. Since enough time would be available to permit more efficient equipment to be developed and put into use, it is possible that the lower demand level for 2000 (shown in Table 188) could be achieved solely by improving efficiency in energy consumption.

- Efficiency can be increased in the use of energy both through more efficient systems and through energy conservation. Development of more efficient automotive engines could greatly increase the efficiency of energy use in the transportation sector; the average automobile engine, for example, operates at an average efficiency of less than 25 percent. The automobile itself has even less efficiency. Also, institutional changes such as increased emphasis on mass transit or urban planning that reduces commuter transportation requirements could contribute to greater efficiency in energy utilization. In the residential/commercial sector, heating and cooling energy requirements could be reduced by over one-third through improved building design and through the use of better insulation and more efficient furnaces and air conditioners.
- The most significant changes in energy use are expected to occur in the industrial sector, where (a) wider use of nuclear fuels for generation of electricity or directly for providing process heat will occur, and (b) the use of synthetic oil and gas may increase as a way

to effectively utilize high-sulfur coal. The latter development, which bears primarily on the generation of process steam, will mean substantially higher fuel costs, but these higher costs can be compensated for, to some degree, through the use of higher efficiency gas turbines and compact pressurized boilers, if the relevant technologies are developed.

Shift Demand to Increased Use of Coal and Nuclear

Shifting energy demand to utilize the Nation's sizable resources of uranium and coal should be a primary goal of future energy policies. Both uranium and coal resources are potentially available in such abundance that they could satisfy requirements even under very rapid demand growth assumptions.

The projection for the year 2000 already indicates a very significant trend toward the use of electric energy—from less than 25 percent of energy consumption in 1970 to perhaps 50 percent in 2000. The projected domestic oil and gas deficit could be further reduced if the Nation's abundant resources of coal and uranium can be brought into wider use. Both coal and nuclear power are by their nature oriented toward electricity generation; hence, emphasizing electricity use would help accomplish this end. Electricity use could be increased by greater reliance on electricity for home heating, by large-scale development of mass transportation systems utilizing electricity, and by fuller use of electricity for industrial purposes. All of these approaches would obviously require a significant transformation in the Nation's means of utilizing energy, but perhaps by the end of the century such a transformation may be possible. In the non-utility market, both coal and nuclear could be more fully employed for process heating within the industrial sector.

Coal has the capability of being able to undergo form transformation—from a solid to a liquid or gaseous state. By devoting the resources necessary to move coal gasification and liquefaction programs forward, coal could also supply substantial quantities of synthetics for internal combustion fuels, home-heating fuels and fuels for other purposes by the end of the century.

Increase Imported Oil and Gas

Energy imports provided 12 percent of total energy consumption in the United States in 1970. They could account for 20 percent in 1985 under the Case II assumption, or even more under supply Cases III and IV. Because of the wide range of possible supply/demand balances in the year 2000, it is pointless to speculate on the role of imports at the end of the century. If they were to comprise 15 percent of total demand under the intermediate demand case, this would represent 14 MMB/D (oil equivalent basis); if 20 percent of the total, 19 MMB/D (oil equivalent basis).

The availability of such large volumes of hydrocarbons to U.S. purchasers is by no means assured. The world's oil and gas resource base, though great, is finite, and the United States must compete with the rapidly expanding economies of other nations for the available foreign oil. Requirements for the developing countries will grow particularly rapidly as their industrialization efforts move forward. In addition to the question of physical availability of imported hydrocarbons, there are significant national security and economic considerations, including a potential burden on the U.S. balance of payments.

Augment Energy Supplies Through New Technology

In the preceding 25 years, U.S. petroleum companies deployed their skills and capital effectively throughout much of the world to find and develop the oil and gas needed by the rapidly expanding economies of the non-Communist nations. The next 25 years to the end of the century will be equally challenging for all of the Nation's energy industries. As already discussed, the task ahead will require developing new technologies for more efficient production and use of present energy fuels. It will also be important to develop new technologies that will translate novel energy concepts into practical new energy forms. Some possibilities in this area are—

- *Geothermal power* utilizes the large reservoir of thermal energy stored in the earth's crust. The known geothermal resources that are presently economic are limited and the full energy production potential from defined localized areas will probably have been developed by about 1990. Further development of geothermal energy will depend on (a) identification of additional localized geothermal energy areas, and (b) development of deep drilling methods to exploit deep geothermal areas.

- *Solar energy* represents a vast potential source of energy. It is unlikely that large-scale use of solar energy would occur until close to the end of the century because of the high cost of energy production, the intermittent nature of solar energy, the large amount of area required to collect solar energy, and the need for significant technological advances in such areas as the utilization of solar energy from orbiting satellites. Much more work of a sophisticated and fundamental nature will be required to provide a technical base for practical schemes which would utilize solar energy.
- *Thermonuclear fusion* represents a virtually limitless source of energy available from hydrogen isotopes in seawater. This energy source is a possibility by the year 2000 although there is great uncertainty about its feasibility. A large amount of scientific research and engineering effort will be required to control the fusion process.
- *Energy from refuse* is a possibility. With the advent of the fluidized bed boiler, after 1985, agricultural and municipal wastes in selected areas may be able to provide some energy. The feasibility of incineration of waste depends on a dual purpose—power generation as well as efficient waste disposal. Energy from agricultural waste suffers from the widely scattered nature of the raw material, which makes for high collection costs. Munich and San Diego are already experimenting with plants that will convert urban refuse to energy. The feasibility of burning urban waste would be increased if people were to sort combustible and noncombustible refuse prior to disposal. However, such wastes are not considered a likely major source of relatively low-cost fuel.
- *Hydrogen* could play a role as a liquid and gaseous energy form in the long-term future if economic methods for production of hydrogen can be developed. Hydrogen has clean burning characteristics and, on a limited scale, its utilization to meet transportation and residential needs has been demonstrated; however, major technological problems remain to be solved.
- *Methyl alcohol* made from coal could be developed into an economical transportation fuel after 1985, partially compensating for the dwindling supplies of petroleum. An alternative to liquefaction of foreign natural gas and transportation in specialized tankers is conversion of the gas to methanol at the source of production, and transportation of the liquid methanol in conventional ships. Use of methanol would require changes in equipment at the point of consumption. The motivation to develop a methanol industry for this purpose would need to be established soon, however.
- *Fuel cells,* utilizing natural gas, methane or methanol, are not likely to have a major impact on fuel utilization by the year 2000. The development of rugged low-cost catalysts would be required to make fuel cells competitive with other energy conversion devices. The utilization of hydrogen as a major energy source could provide the economic incentives for the use of fuel cells for the localized generation of electricity.
- *Thermionics* conversion of heat directly into electricity is not expected to be a major energy source because of high capital costs and poor reliability of such devices.

All of these ideas are appealing, but they require considerable attention to translate the concepts into practical, economic technologies. It is necessary for the Nation to begin focusing attention on such possibilities and to search for others not visualized at this time for two interrelated reasons.

Firstly, the energy industries are highly complex. Long lead times have historically existed in energy supply response to both demand and policy changes. Moreover, long lead times exist in the development of specific energy technologies. For example, the development of the breeder reactor began in earnest in the late 1940's; it is not expected to be commercially available until the late 1980's. In the absence of top national priorities and commitments, similar time lags should be expected in other new areas of development.

Secondly, any speculative projections about the role of new technology in strengthening the U.S.

energy position or in alleviating upward cost pressures in the last years of the century must be qualified by the recognition that inventions cannot be forecast. It is safe to assume, however, that in the coming three decades some major developments will be made in the energy area. This judgment is supported by historical analogy. In comparing the world of 1972 with that of 1942, for example, it is clear that technological conditions are very different; a number of developments made in this 30-year period were not predicted, and the impact of these technological innovations could not be clearly foreseen. During this 30-year period, diesel engines have expanded from limited use to widespread application for railroads, trucks and buses; jet aircraft, which were only in an early stage of development in 1942, have become the predominant type of aircraft; nuclear power has been transformed from potential military weapons to economic use in electricity generation; the technology for production and transportation of oil has grown increasingly sophisticated, permitting the development of such remote areas as the North Slope of Alaska.

Because of the long lead times involved and the inability to accurately forecast technological developments, a firm public commitment to long-term domestic energy development is essential. It is first necessary to decide on the domestic fuels most amenable to expansion and the several technological areas susceptible to productive energy research and development. Then, with the establishment of sound policies and a favorable economic climate, the Country's resources can be marshaled to develop the energy supplies needed over the longer term. Because of the complex nature of the task ahead, it will be necessary to retain some flexibility in defining those technological areas that should be developed and to pursue simultaneously a number of such programs until the approach most desirable for the national well-being is clear.

Chapter Sixteen
Recommendations for a United States Energy Policy
(by the National Petroleum Council)

Introduction

The National Petroleum Council's studies of the outlook for energy in the United States indicate that the country's remaining energy resources are extensive although certainly production from these resources will be of higher cost than was that in the past. Thus, a large portion of the Nation's future energy needs can be met from secure domestic sources. U.S. energy resources must be developed efficiently on a basis that will permit these resources to be converted to available supply at the lowest possible cost. To accomplish this, appropriate policies or programs must permit competition to the extent practical under constant or changing social or environmental goals.

To make these resources available on a reasonable basis will require sound enabling government guidelines so the various energy suppliers of this country can set about developing the supplies to meet the Nation's energy needs. These government policies must, in an equitable manner, ensure orderly development and a stable policy climate for all forms of energy development and supply.

U.S. Energy Policy Objectives

The primary energy industries, in cooperation with the Government, are responsible for meeting the energy needs of American society, while at the same time assuring free consumer choice at the lowest costs consistent with adequacy of long-term supply, adequate environmental standards, other social goals and, most importantly, national security.

The United States is generously endowed with energy resources. It has prospered under an industrial system built primarily upon interfuel competition for the available market. This system encouraged the development of energy resources. It is essential, therefore, to retain the security and performance that this system provides to the United States.

The National Petroleum Council believes that the fundamental objectives of public policies dealing with energy should be to—

- Assure adequate supplies of secure sources of energy
- Preserve the environment in the production and use of energy
- Promote efficiency and conservation in all energy operations and uses
- Recognize that in all three of the above objectives appropriate consideration must be given to the impact of energy costs on economic welfare and progress.

Major U.S. Energy Policies

Sound enabling government guidelines are required if the various energy suppliers of this country are to develop the maximum domestic energy supplies. The following major policy views are suggested as fundamental steps to the achievement of increased U.S. energy supplies.

1. *The United States Must Adopt a National Sense of Purpose to Solve the Energy Problem.*

A long-term sense of purpose in meeting this country's energy goals must evolve similar to the national dedication to the socio-economic goals of environmental conservation and full employment. National energy policies which are subject to constant short-term changes are wholly unsuitable for industry and government planning purposes. The long lead times inherent in energy planning and development require stability of goals and policies.

In order to attain a national resolve or commitment on a sound U.S. energy posture, cooperation among Government, industry and the general public will be essential. There is a basic need for education and cooperation in developing a common understanding of the social benefit and necessity of energy usage and the realities of resource development to fulfill energy needs.

This will require continuity of policy to assure the investor confidence essential to providing the vast capital requirements needed by the domestic energy industries.

National Security

2. *The Security of the United States Is Dependent Upon Secure Supplies of Energy, and Therefore Healthy, Viable and Expanding Domestic Energy Industries Should Be Encouraged by Government.*

Attaining a high level of national self-sufficiency in the energy sector at a manageable cost should be a prime element of national policy.

Over-dependence on foreign energy sources can (a) make the United States vulnerable to threatened or actual economic sanctions and boycotts by other countries, (b) restrict U.S. international policies, and (c) adversely affect the U.S. economy by increasing balance of trade problems, decreasing government revenues and reducing employment.

3. *The Mandatory Oil Import Control Program Should Continue to Be a Fundamental Part of the National Energy Policy of the United States.*

In the interest of national security, the Government has concluded that a healthy and viable petroleum industry must be maintained. To assist in meeting this objective, the United States by a 1959 Presidential Proclamation placed a limit on petroleum import levels. As domestic energy supplies best serve the Nation's security interests, the continuation of oil import quotas is essential.

Without oil import quotas, both domestic oil and gas availablity would decline. In addition, development of synthetic fuels from domestic sources could be retarded by the lack of economic incentives to develop such energy sources and by the threat of unrestricted imports at price levels which would not yield an adequate return for producers of synthetic fuels.

The present import quotas provide protection against the dramatic adverse effects of unrestrained imports of foreign oil. These effects could take the form of sharp increases in price or even a cutoff of supply. The national cost of the import quota system is considerably less than the cost of other alternatives such as maintenance of standby production and storage capacity.

Although increased imports of oil and gas will be needed in the immediate years ahead, import control policies should aim to increase domestic supply availability over the long term. While certain aspects of the oil import quotas have been subject to criticism, the basic purposes of the system are sound.

An import program will not serve its basic national security objective if it is subjected to short-term alterations designed to achieve unrelated objectives, such as curbs on inflation. Import programs should apply equitably to all parties and should be designed to interfere as little as possible with normal economic forces and competitive relationships.

4. *Import Policies Should Be Designed to Encourage the Growth of Domestic Refining Capacity.*

The Mandatory Oil Import Program should be designed to assure refiners of adequate access to long-term crude oil supplies; otherwise, required domestic refinery construction will not be undertaken.

The import program's implementing regulations are currently fragmented and contain a growing number of special exceptions, resulting in an atmosphere of uncertainty about future regulations. This creates reluctance to commit the massive investments required for U.S. refining capacity.

Equitable distribution of import allocations and the adoption of provisions to allow the domestic refiner to compete with imported products are of prime importance.

5. *Policies for Imports, Enrichment Operations and Government Stockpile Disposal Should Continue to Encourage Growth of the Domestic Uranium Mining Industry.*

Present national policy requires that uranium used in reactors by U.S. electric utilities, and which have been enriched in U.S. government facilities, must be of U.S. origin as required to ensure that a viable domestic uranium mining industry exists. Continuation of a policy to restrict importation of uranium is necessary if uranium producers are to make the transition from supplying solely a government market to supplying a mature commercial market.

Future demand for nuclear fuel is projected to reach levels that are several times the quantities used in the past. In the long term, nuclear power will become not only the major source of electric power but also a major source of energy in the United States. Uranium resources in the United States are believed to be adequate to supply the necessary nuclear fuel. However, large investments will have to be made in exploration, mining, milling and enrichment. Investments in uranium exploration and production of uranium concentrates are unlikely to be forthcoming unless government import policy encourages suppliers to make the long-range plans and commitments necessary to minimize U.S. dependence upon foreign sources of uranium.

The program proposed by the AEC in March 1972 for operation of government enrichment facilities and disposal of the government-owned stockpile is reasonable in conjunction with present import policy if domestic uranium suppliers find economic incentives adequate to promptly initiate and maintain sharply increased uranium supply capability. However, when a condition of oversupply leads to erosion of investment in domestic supply capability, the program for disposal of the government stockpile should cease and the existing stockpile be reserved for emergency use.

Energy in the Marketplace

6. *The Federal Government Should Establish an Economic and Political Climate Which Encourages Energy Development and Competition Among Domestic Energy Suppliers.*

Competitive markets are a particularly effective mechanism for determining price levels necessary to balance energy demand and supply. The complex operation of market forces will best serve consumers and the national interest by providing energy in amounts needed and in forms preferred for environmental reasons. Market forces, if unfettered, would promote efficient use of energy and allocate resources among energy activities on an economical basis. The results of the U.S. Energy Outlook study clearly indicate that there is a substantial capability on the part of fuel suppliers to provide additional energy raw materials from domestic resources, given the opportunity and incentive to do so. To approach the full potential of U.S. energy resources indicated in this study will require the ingenuity and effort of thousands of firms, ranging from small to large, and of millions of people.

Vigorous competition in the fuels markets presumes unrestricted entry into the various energy fuels industries, subject to applicable antitrust laws. Competition is stimulated when a supplier of one fuel can provide additional capital investment, technology and management skill for the development of other fuels. Diverse talents and resources from different fuel businesses can also be blended in such important areas as research and development. This is particularly true in the case of synthetic fuels.

7. *The Field Prices of Natural Gas Should Be Allowed to Reach Their Competitive Level.*

Federal regulation has substantially reduced exploration incentives and encouraged artificial expansion of natural gas demand. Despite its superior characteristics, natural gas currently is priced less than alternative fuels because of price controls. This results in a paradoxical situation. At the wellhead, domestic natural gas prices are held to a fraction of substitutable fuel prices in the face of present and prospective major supply shortages. Such actions, concurrent with serious consideration by government agencies and industry of the importation of natural gas from foreign sources at substantially higher prices, further illustrate the inconsistencies in current regulatory policies.

The Federal Power Commission has now apparently recognized the fallacy of holding the field prices of natural gas at artificially low levels. Uncertainty and confusion generated by current methods of price regulation of natural gas, LNG imports and synthetic gas production should be eliminated by permitting the normal interplay of economic forces in the marketplace to establish proper value. Permitting market forces to work is certainly a better solution than to continue the counter-productive regulation of natural gas prices and thereby the arbitrary allocation of supplies.

Environmental Conservation

8. *A Rational Balance Must Be Achieved Between Environmental Goals and Energy Requirements.*

Standards for a better environment, taking account of the time required to effect the desired results, must be compatible with other important national goals, including full employment, reduction of poverty, further improvement in average living standards, and assurance of energy supplies at all times for health, comfort and national security.

Prompt action is now needed to eliminate the serious delays being caused by environmental issues. The dilemmas occasioned by such issues require immediate attention in every supply sector of the energy industries: nuclear, electric power, coal, oil shale, geothermal, oil and gas. For example, the following matters require immediate governmental attention.

- Minimize delays in oil and gas exploration and development, laying of pipelines, construction of deepwater terminals and new refinery construction.
- Establish effective government siting and licensing procedures for nuclear and other electric power plant construction and operation in order to eliminate undue delays.
- Accelerate development of commercially viable stack gas desulfurization technology and other means to use high-sulfur fuels.
- Establish guidelines for land restoration to ensure minimum environmental impairment in surface coal mining operations.
- Reach early agreement on what is acceptable from an environmental standpoint for the disposal of waste oil shale rock subsequent to extraction and processing.
- Resolve serious problems relating to legal issues, planning, authorization, funding and construction of large water resource projects. This is essential in order to assure water supply availability to support the maximum level of energy growth from natural resources in the western states.

The fuel suppliers are capable of operating in such a way as to satisfy reasonable demands of society with respect to the environment. Improvement programs involve large sums of capital. In reordering its priorities, the Nation must recognize the inescapable impact of added environmental costs on supplies and prices.

The role of Government should be to ascertain the effects of pollutants and to prescribe workable standards of air, water and land quality. The means whereby the standards will be achieved should be left to the creativity of diverse private initiatives. There is a necessity to simplify requisite regulatory approvals by city, county and state authorities.

Where a cooperative approach to the solution of an environmental problem would serve the public interest, the Executive Branch should clarify the extent of cooperation that is consistent with the intent of present antitrust laws and, if necessary, seek enactment of such further enabling legislation as would be advisable.

Energy Conservation

9. *Both the Government and Industry Should Continue to Promote Energy Conservation and Efficiency of Energy Use in Order to Eliminate Waste of Our Resources.*

The United States should recognize the need for conservation and efficiency in the use of energy. In the years ahead, the pace of technological advance will probably accelerate all processes of economic growth and social and institutional change. These trends will bring change in total energy development and utilization. The growth in per capita energy consumption during the past quarter of a century has created new jobs, expanded productivity, increased living standards, and provided increasing time for cultural, recreational and intellectual pursuits. Wise policies can provide the basis for continuance of these desirable objectives.

Energy producers and the U.S. Government must take positive leadership in advocating the application of advanced technology and elimination of waste to conserve valuable domestic resources. Forced reductions in energy consumption are undesirable and should be employed only on an emergency basis.

Access to U. S. Energy Resources

10. *Access to the Nation's Energy Resource Potential Underlying Public Lands Should Be Encouraged.*

The energy resources of the Nation are extensive. At least 50 percent of the Nation's remaining oil and gas potential, approximately 40 percent of the coal, 50 percent of the uranium, 80 percent of the oil shale, and some 60 percent of geothermal energy sources are located on federal lands. Government should encourage and accelerate the orderly leasing of public lands for exploration and development of energy resources by private enterprise consonant with environmental conservation goals.

Any leasing system should provide sufficient total acreage for each fuel and should schedule sales at frequent and regular intervals, so that energy suppliers can efficiently deploy their skills towards developing needed energy supplies.

The system of leasing public lands should be reviewed in the context of urgency to develop additional reserves of oil, gas, coal, uranium, oil shale and geothermal steam. An equitable system should be designed to foster and encourage exploration for the discovery of additional energy resources.

The Outer Continental Shelf Lands Act, of August 1953, has proved to be effective legislation for the exploration and leasing of the outer continental shelf of the United States. On the other hand, the administration of the Act leaves much to be desired. Administrative actions have resulted in irregular lease sale schedules, and limited acreage offerings have worked to the detriment of exploration planning, particularly in the case of less explored frontier areas.

11. *The United States Should Maintain Jurisdiction Over Exploration and Development of the Seabed Energy Resources Underlying the Continental Margins Off Its Coasts, and Urge That Other Coastal Nations Do the Same.*

The U.S. submerged continental mass between 200 meters water depth and the seaward edge of the continental margin has been described by the U.S. Geological Survey as having great potential for petroleum. Technology is presently available to permit exploration and development in areas where water depth exceeds 200 meters, and such exploration and development should be encouraged and accelerated.

Any proposed international treaty dealing with seabed mineral resources should confirm the jurisdiction of coastal nations over the exploration and development of the mineral resources of the entire submerged continental mass off their coasts. Additionally, any such treaty should provide for the security of investments made in resource development in areas of the continental margin pursuant to agreement with or license from the coastal nation.

These provisions should take the form of assurances that the terms of such agreements or licenses will be adhered to by the parties to them and that any disputes arising will be referred to an international tribunal for compulsory objective decision. Such provisions will be essential to the investor confidence needed to provide the vast capital resources for the high costs of finding and developing mineral resources in the continental margin. In addition, a convention dealing with seabeds mineral resource development beyond national jurisdiction should also provide for a regime that will encourage private investment as required to develop these resources, and that will assure a meaningful role for private enterprise, preventing an international government cartel arrangement to control production, distribution and marketing.

Energy Research and Development

12. *Energy Research and Technology Must Be Permitted to Make the Advances Necessary for the Nation's Longer Term Development of Energy Resources.*

Research into a broad range of energy related technology could provide the means to increase future energy supplies.

If research is to make its maximum contribution, energy policies must recognize that strengthened incentives for research spending are needed. Reduced profitability in the energy industries has retarded the expansion of funds available for research and development. Improved revenues are essential to a healthy and growing research effort. In addition, commitment of large amounts of capital dollars for research requires an expectation that future government policies will continue to recognize the importance of expanding research and development programs.

Historically, research expenditures by the oil and gas industry have primarily been privately funded. Other fuel suppliers, however, particularly coal and nuclear, have historically relied largely on government funding. The National Petroleum Council endorses continued reliance on private industry as the principal source of funds for oil and gas research and takes no position on the optimal way to fund research in other fuel areas.

Areas for augmenting energy supplies that require particular attention are: perfection of a stack gas control device which would permit the use of high-sulfur coal consistent with environmental standards; research on conversion of oil shale and coal into synthetic fuels; and development of advanced nuclear reactor technology.

Taxation

13. *Fiscal Policies Should Foster the Finding and Development of All Domestic Energy Resources.*

In the past, federal tax provisions applicable to primary energy raw material resources have taken into account such factors as the risks encountered in exploration, the need for commensurate rewards in case of success and the problems involved in replacing the reserves and values depleted by production. These provisions, in turn, serve to attract requisite capital into exploration and to stimulate discovery and development of primary energy resources.

Recent developments have had a contrary effect. For example, the 1969 Tax Reform Act alone placed an additional tax burden on the domestic petroleum industry of some $500 million per annum.

Fiscal policies should encourage the creation of capital requisite for increasing energy supplies and reducing costs to the consumer. Unless more effective tax provisions are devised for all energy resources, existing measures should be retained and improved.

14. *The United States Should Support Its Nationals Engaged in Energy Operations Abroad.*

The investments and operations abroad of the U.S. energy industries are of great importance to the United States. The foreign producing interests of U.S. nationals provide supplies of energy to much of the Free World and will increasingly provide such supplies to the United States. The economic return from these activities represents a strong, favorable element in this country's balance of payments.

The U. S. Government should continue equitable tax treatment of U.S. investments abroad, including U.S. income tax credits for foreign income taxes paid.

These interests are deserving of the understanding and support of the Government of the United States. Our Government should continue to advocate the free flow of capital and technology to the oil producing countries but on the understanding that U.S. private investments will be equitably treated on the basis of commitments made by both the host country and the U.S. investor.

Concluding Recommendation

15. *The Federal Government Should Coordinate the Many Competing and Conflicting Agencies Dealing with Energy.*

Much of the confusion and delay that now plagues energy suppliers stems from conflicts among government agencies. All too often one agency may encourage an action while another agency prohibits it. Coordination of federal energy policies in the Executive Branch is necessary to provide focused, consistent guidance on energy matters to ensure that the Nation's vital needs are met.

Appendices

Appendix 1

C
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UNITED STATES
DEPARTMENT OF THE INTERIOR
Office of the Secretary
Washington, D.C. 20240

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,

/s/ HOLLIS M. DOLE
Assistant Secretary of the Interior

Mr. Jack H. Abernathy
Chairman
National Petroleum Council
1625 K Street, N.W.
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C
O
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Y

UNITED STATES
DEPARTMENT OF THE INTERIOR
Office of the Secretary
Washington, D.C. 20240

August 31, 1970

Dear Mr. Brockett:

I am writing to express my interest in seeing that the energy studies being done by both Dr. McKetta and the National Petroleum Council be continued.

As requested in Assistant Secretary Dole's letter of January 20, 1970, I wish to have the NPC continue on its study emphasizing oil and gas in the Western Hemisphere but taking full account of the influence of other energy forms.

I have asked Dr. McKetta to continue with his study and to report to me on all forms of energy in a parallel examination. Dr. McKetta will be calling principally upon the American Petroleum Institute for data input on oil and gas.

To coordinate the efforts of both studies, I have directed the Deputy Assistant Secretary for Mineral Resources, Mr. Gene Morrell, and my Science Adviser, D. Donald Dunlop, to meet weekly to communicate and coordinate the activities of the two groups.

I am sure that you are acutely aware of the importance of the energy problem. I look forward to the opportunity to review the results of both studies in formulating my views on a Government energy policy. Your cooperation in working with Dr. McKetta will be very much appreciated. To this end I urge that you and Dr. McKetta meet with Assistant Secretary Dole and Dr. Dunlop to discuss the objectives and working procedures of your two groups.

Best wishes for the successful completion of your work.

Sincerely yours,

/s/ WALTER J. HICKEL
Secretary of the Interior

Mr. E. D. Brockett, Chairman
National Petroleum Council
P.O. Box 166
Pittsburgh, Pennsylvania 15203
cc—Dr. John J. McKetta

Appendix 2

National Petroleum Council

(Established by the Secretary of the Interior)

December 11, 1972

My dear Mr. Secretary:

On behalf of the members of the National Petroleum Council, I am pleased to transmit to you herewith the NPC report, *U.S. Energy Outlook—A Summary,* approved by the Council at its meeting on December 11, 1972. In addition, a preprint version of the full report of the Main Committee is also enclosed. The detailed studies of the various fuel task groups will be transmitted to you upon completion in the first quarter of 1973.

On January 20, 1970, Assistant Secretary of the Interior Hollis M. Dole asked the National Petroleum Council to undertake a comprehensive study of the U.S. energy outlook from now until the end of the century. In response to this request, the NPC Committee on U.S. Energy Outlook was established under the chairmanship of John G. McLean with the assistance of M. A. Wright, Vice Chairman—Oil; Howard Boyd, Vice Chairman—Gas; D. A. McGee, Vice Chairman—Other Energy Resources; and John M. Kelly, Vice Chairman—Government Policies. The Coordinating Subcommittee was chaired by Warren B. Davis.

On July 15, 1971, the Council submitted to you an Interim Report. This Initial Appraisal assumed that 1970 governmental policies and regulations and the economic climate for the energy industries would continue without major changes in the 1971-1985 period. The findings of the Initial Appraisal demonstrated that significant changes in the economic climate and government policies are essential if the present trend toward growing insufficiency of the U.S. fuel supplies is to be substantially altered. The Committee on U.S. Energy Outlook used the findings of the Initial Appraisal as a point of departure for the second phase of the study.

This final stage of the study has been considerably more complex than the Initial Appraisal. A central feature of the approach for this final report involved the identification of the various economic and government policies which affect the energy situation. Changes in these policies were then postulated and, through a series of parametric studies, the effects of the changes on our energy position were estimated.

The Committee also identified those factors which will influence the Nation's long-term energy posture—from 1985 to the end of the century.

Lastly, at your Department's request, the Committee has offered its recommendations for a United States Energy Policy.

The findings and recommendations in this report represent the best judgment of many energy experts. In addition to representatives of the oil and gas industries working on the study, we also had the generous support and input of some 68 experts drawn from the coal, nuclear and electric utility industries, as well as government, who provided a uniquely broad base for the assessments made in this study.

1625 K Street, N.W., Washington, D. C. 20006 (202) 393-6100

The political, economic, social and technological factors bearing upon the U.S. energy outlook are subject to substantial change with the passage of time. Thus future developments will undoubtedly provide additional insights and amend the conclusions to some degree.

In considering this report, the reader should be aware of the following points:

1. While the joint nature of oil and gas exploration and production suggests that these fuels should be considered together rather than separately, separate computer programs for oil and gas have been used in the report to provide flexibility in calculations. However, it is necessary to warn against the use of the computer programs to calculate the elasticity of supply; the impact of changes in tax provisions on ability to attract capital; and the amount of price changes required to increase oil and gas reserves and deliverability.

2. Action to stimulate and accelerate discovery and development of indigenous energy resources by private industry should be taken promptly because such resources would provide the most favorable solution for energy needs. Domestic oil and gas development jointly require strong emphasis because these fuels are now and will continue to be vitally important to the Nation.

3. U.S. energy supplies, including oil and gas, are not expected to be limited by potentially discoverable resources during the 1971-1985 period. If federal policies are designed to encourage large expenditures by private industry for new supplies and for improved recovery from producing and prospective areas, including public lands onshore and offshore, then the potential exists for significant expansion of U.S. oil and gas reserves and production, possibly even beyond the amounts projected in this report.

4. Prompt improvements in federal policies could result in expanded domestic supplies of energy; such improvements are essential before vast sums are committed to more expensive energy alternatives.

The National Petroleum Council sincerely hopes that this study will be of benefit to the Government in the difficult decision-making processes that lie ahead.

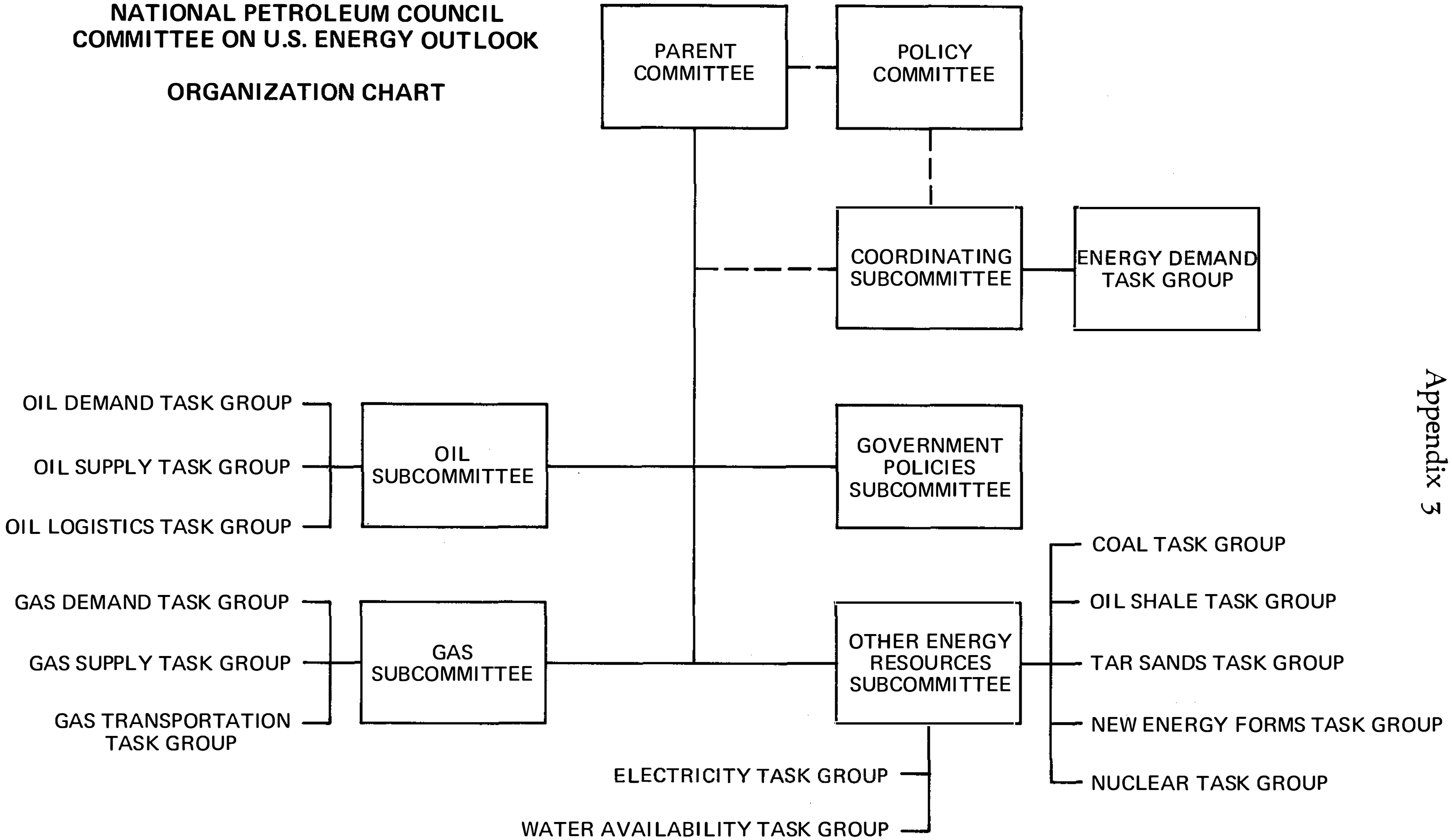
Respectfully submitted,

H. A. True, Jr.
Chairman

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

NATIONAL PETROLEUM COUNCIL
COMMITTEE ON U.S. ENERGY OUTLOOK

ORGANIZATION CHART



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Appendix 4

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Appendix 5

Additional Energy Balances

Chapter Two, "Energy Supply and Demand Balances," discusses the various domestic supply availability cases. This appendix contains an explanation of the balance calculations and the full detailed balances for each of 22 compilations.

For each balance, the domestic supplies of oil, gas, hydro, and geothermal were taken from the appropriate supply case. It was assumed that all of these supplies would be used. Then the oil and gas needed for electric power plus the hydro and geothermal were deducted from the electric power energy requirements that were derived from the Energy Demand Task Group's intermediate case. The remainder of the electric utility sector must be supplied by coal and nuclear.

To this subtotal of required supply of coal and nuclear for use in generating electric power was added coal requirements for other uses from the Initial Appraisal by the Coal Task Group. This total requirement for coal and nuclear was compared with coal and nuclear supply available. If the requirement was smaller than the supply, the difference was entered under "Surplus Coal and Nuclear" in the balance. If the requirement is larger than the supply, the electric power sector will require increased amounts of imported oil. Where this is the case, it becomes clear that all coal and nuclear fuel supplies will be utilized.

After this adjustment was made, the supplies of various fuels were added to get the total domestic supply. Gas imports as pipeline gas, LNG and LPG were projected at their practical maximum volumes, and then it was assumed that the remaining energy requirement would be met with imported oil. Thus, imported oil is the balancing figure and required oil import volumes (converted from BTU's as crude oil) were used to measure the results of the balance.

U.S. ENERGY BALANCE TABLE 1
(All Data x 10^{12} BTU/Year)

Parameters for Balance

Intermediate Case Energy Demand; Electricity Condition Number 1

Fuel Supply Cases: Oil—I; Gas—I; Coal/Nuclear—I; Other Energy Forms—I

Electric Utility Sector Calculations

	1975	1980	1985
Electric Utility Demand	23,525	32,996	44,363
Less: Geothermal	120	782	1,395
Hydroelectric	2,990	3,240	3,320
Oil	3,460	4,050	4,530
Gas	3,900	3,900	3,900
Subtotal	**10,470**	**11,972**	**13,145**
Balance to Coal and Nuclear	**13,055**	**21,024**	**31,218**
Add: Non-Utility Coal	5,594	5,684	5,692
Total Coal and Nuclear Required	**18,649**	**26,708**	**36,910**
Less: Coal and Nuclear Available	20,650	32,549	56,910
Surplus Coal and Nuclear	**2,001**	**5,841**	**20,000**

Import Requirement Calculations

	1975	1980	1985
Total U.S. Energy Demand	83,481	102,581	124,942
Less: Domestic Supplies			
Oil—Total Liquid Production	20,735	27,758	31,689
—Shale Syncrude	0	296	1,478
—Coal Syncrude	0	175	1,489
Subtotal—Oil	**20,735**	**28,229**	**34,656**
Gas—Total Production	24,513	26,746	31,604
—Nuclear Stimulation	0	206	1,341
—Coal Syngas	0	512	2,269
Subtotal—Gas	**24,513**	**27,464**	**35,214**
Hydroelectric	2,990	3,240	3,320
Geothermal	120	782	1,395
Coal and Nuclear Required	18,649	26,708	36,910
Subtotal—Domestic Supplies	**67,007**	**86,423**	**111,495**
Total Energy Imports Required	**16,474**	**16,158**	**13,447**
Less: Projected Gas Imports	1,200	3,900	5,900
Oil Imports Required (10^{12} BTU/yr)	**15,274**	**12,258**	**7,547**
Oil Imports Required (MB/D)	**7,215**	**5,790**	**3,564**

U.S. ENERGY BALANCE TABLE 2
(All Data x 10^{12} BTU/Year)

Parameters for Balance

Intermediate Case Energy Demand; Electricity Condition Number 1

Fuel Supply Cases: Oil—II; Gas—II; Coal/Nuclear—II; Other Energy Forms—II

Electric Utility Sector Calculations

	1975	1980	1985
Electric Utility Demand	23,525	32,996	44,363
Less: Geothermal	120	401	661
Hydroelectric	2,990	3,240	3,320
Oil	3,460	4,050	4,530
Gas	3,900	3,900	3,900
Subtotal	**10,470**	**11,591**	**12,411**
Balance to Coal and Nuclear	**13,055**	**21,405**	**31,952**
Add: Non-Utility Coal	5,594	5,684	5,692
Total Coal and Nuclear Required	**18,649**	**27,089**	**37,644**
Less: Coal and Nuclear Available	19,554	29,633	46,637
Surplus Coal and Nuclear	**905**	**2,544**	**8,993**

Import Requirement Calculations

	1975	1980	1985
Total U.S. Energy Demand	83,481	102,581	124,942
Less: Domestic Supplies			
Oil—Total Liquid Production	20,630	26,456	28,477
—Shale Syncrude	0	197	788
—Coal Syncrude	0	0	175
Subtotal—Oil	**20,630**	**26,653**	**29,440**
Gas—Total Production	24,300	25,043	27,324
—Nuclear Stimulation	0	103	825
—Coal Syngas	0	329	1,208
Subtotal—Gas	**24,300**	**25,475**	**29,357**
Hydroelectric	2,990	3,240	3,320
Geothermal	120	401	661
Coal and Nuclear Required	18,649	27,089	37,644
Subtotal—Domestic Supplies	**66,689**	**82,858**	**100,422**
Total Energy Imports Required	**16,792**	**19,723**	**24,520**
Less: Projected Gas Imports	1,200	3,900	6,100
Oil Imports Required (10^{12} BTU/yr)	**15,592**	**15,823**	**18,420**
Oil Imports Required (MB/D)	**7,365**	**7,474**	**8,701**

U.S. ENERGY BALANCE TABLE 3
(All Data x 10^{12} BTU/Year)

Parameters for Balance

Intermediate Case Energy Demand; Electricity Condition Number 1

Fuel Supply Cases: Oil—III; Gas—III; Coal/Nuclear—III; Other Energy Forms—III

Electric Utility Sector Calculations

	1975	1980	1985
Electric Utility Demand	23,525	32,996	44,363
Less: Geothermal	120	343	514
Hydroelectric	2,990	3,240	3,320
Oil	3,460	4,050	4,530
Gas	3,900	3,900	3,900
Subtotal	**10,470**	**11,533**	**12,264**
Balance to Coal and Nuclear	**13,055**	**21,463**	**32,099**
Add: Non-Utility Coal	5,594	5,684	5,692
Total Coal and Nuclear Required	**18,649**	**27,147**	**37,791**
Less: Coal and Nuclear Available	19,554	28,071	41,608
Surplus Coal and Nuclear	**905**	**924**	**3,817**

Import Requirement Calculations

	1975	1980	1985
Total U.S. Energy Demand	83,481	102,581	124,942
Less: Domestic Supplies			
Oil—Total Liquid Production	19,754	23,789	24,346
—Shale Syncrude	0	197	788
—Coal Syncrude	0	0	175
Subtotal—Oil	**19,754**	**23,986**	**25,309**
Gas—Total Production	22,766	21,041	21,049
—Nuclear Stimulation	0	103	825
—Coal Syngas	0	329	1,208
Subtotal—Gas	**22,766**	**21,473**	**23,082**
Hydroelectric	2,990	3,240	3,320
Geothermal	120	343	514
Coal and Nuclear Required	18,649	27,147	37,791
Subtotal—Domestic Supplies	**64,279**	**76,189**	**90,016**
Total Energy Imports Required	**19,202**	**26,392**	**34,926**
Less: Projected Gas Imports	1,200	3,900	6,400
Oil Imports Required (10^{12} BTU/yr)	**18,002**	**22,492**	**28,526**
Oil Imports Required (MB/D)	**8,504**	**10,624**	**13,474**

U.S. ENERGY BALANCE TABLE 4
(All Data x 10^{12} BTU/Year)

Parameters for Balance

Intermediate Case Energy Demand; Electricity Condition Number 1

Fuel Supply Cases: Oil—IV; Gas—IV; Coal/Nuclear—IV; Other Energy Forms—IV

Electric Utility Sector Calculations

	1975	1980	1985
Electric Utility Demand	23,525	32,996	44,363
Less: Geothermal	120	191	257
Hydroelectric	2,990	3,240	3,320
Oil	3,460	4,050	4,530
Gas	3,900	3,900	3,900
Subtotal	**10,470**	**11,381**	**12,007**
Balance to Coal and Nuclear	**13,055**	**21,615**	**32,356**
Add: Non-Utility Coal	5,594	5,684	5,692
Total Coal and Nuclear Required	**18,649**	**27,299**	**38,048**
Less: Coal and Nuclear Available	16,761	24,338	36,426
Surplus Coal and Nuclear	**0**	**0**	**0**

Import Requirement Calculations

	1975	1980	1985
Total U.S. Energy Demand	83,481	102,581	124,942
Less: Domestic Supplies			
Oil—Total Liquid Production	19,502	18,112	21,426
—Shale Syncrude	0	0	197
—Coal Syncrude	0	0	0
Subtotal—Oil	**19,502**	**18,112**	**21,623**
Gas—Total Production	22,421	17,906	15,474
—Nuclear Stimulation	0	0	0
—Coal Syngas	0	165	494
Subtotal—Gas	**22,421**	**18,071**	**15,968**
Hydroelectric	2,990	3,240	3,320
Geothermal	120	191	257
Coal and Nuclear Required	16,761	24,338	36,426
Subtotal—Domestic Supplies	**61,794**	**63,952**	**77,594**
Total Energy Imports Required	**21,687**	**38,629**	**47,348**
Less: Projected Gas Imports	1,200	3,900	6,600
Oil Imports Required (10^{12} BTU/yr)	**20,487**	**34,729**	**40,748**
Oil Imports Required (MB/D)	**9,678**	**16,405**	**19,248**

U.S. ENERGY BALANCE TABLE 5
(All Data x 10^{12} BTU/Year)

Parameters for Balance

Intermediate Case Energy Demand; Electricity Condition Number 2

Fuel Supply Cases: Oil—II; Gas—II; Coal/Nuclear--II; Other Energy Forms—II

Electric Utility Sector Calculations

	1975	1980	1985
Electric Utility Demand	23,525	32,996	44,363
Less: Geothermal	120	401	661
Hydroelectric	2,990	3,240	3,320
Oil	4,110	5,350	6,480
Gas	3,250	2,600	1,950
Subtotal	**10,470**	**11,591**	**12,411**
Balance to Coal and Nuclear	**13,055**	**21,405**	**31,952**
Add: Non-Utility Coal	5,594	5,684	5,692
Total Coal and Nuclear Required	**18,649**	**27,089**	**37,644**
Less: Coal and Nuclear Available	19,554	29,633	46,637
Surplus Coal and Nuclear	**905**	**2,544**	**8,993**

Import Requirement Calculations

	1975	1980	1985
Total U.S. Energy Demand	83,481	102,581	124,942
Less: Domestic Supplies			
Oil—Total Liquid Production	20,630	26,456	28,477
—Shale Syncrude	0	197	788
—Coal Syncrude	0	0	175
Subtotal—Oil	**20,630**	**26,653**	**29,440**
Gas—Total Production	24,300	25,043	27,324
—Nuclear Stimulation	0	103	825
—Coal Syngas	0	329	1,208
Subtotal—Gas	**24,300**	**25,475**	**29,357**
Hydroelectric	2,990	3,240	3,320
Geothermal	120	401	661
Coal and Nuclear Required	18,649	27,089	37,644
Subtotal—Domestic Supplies	**66,689**	**82,858**	**100,422**
Total Energy Imports Required	**16,792**	**19,723**	**24,520**
Less: Projected Gas Imports	1,200	3,900	6,100
Oil Imports Required (10^{12} BTU/yr)	**15,592**	**15,823**	**18,420**
Oil Imports Required (MB/D)	**7,365**	**7,474**	**8,701**

U.S. ENERGY BALANCE TABLE 6
(All Data x 10^{12} BTU/Year)

Parameters for Balance

Intermediate Case Energy Demand; Electricity Condition Number 3

Fuel Supply Cases: Oil—II; Gas--II; Coal/Nuclear--II; Other Energy Forms—II

Electric Utility Sector Calculations

	1975	1980	1985
Electric Utility Demand	23,525	32,996	44,363
Less: Geothermal	120	401	661
Hydroelectric	2,990	3,240	3,320
Oil	3,000	4,050	6,150
Gas	3,250	2,600	1,950
Subtotal	**9,360**	**10,291**	**12,081**
Balance to Coal and Nuclear	**14,165**	**22,705**	**32,282**
Add: Non-Utility Coal	5,594	5,684	5,692
Total Coal and Nuclear Required	**19,759**	**28,389**	**37,974**
Less: Coal and Nuclear Available	19,554	29,633	46,637
Surplus Coal and Nuclear	**0**	**1,244**	**8,663**

Import Requirement Calculations

	1975	1980	1985
Total U.S. Energy Demand	83,481	102,581	124,942
Less: Domestic Supplies			
Oil—Total Liquid Production	20,630	26,456	28,477
—Shale Syncrude	0	197	788
—Coal Syncrude	0	0	175
Subtotal—Oil	**20,630**	**26,653**	**29,440**
Gas—Total Production	24,300	25,043	27,324
—Nuclear Stimulation	0	103	825
—Coal Syngas	0	329	1,208
Subtotal—Gas	**24,300**	**25,475**	**29,357**
Hydroelectric	2,990	3,240	3,320
Geothermal	120	401	661
Coal and Nuclear Required	19,554	28,389	37,974
Subtotal—Domestic Supplies	**67,594**	**84,158**	**100,752**
Total Energy Imports Required	**15,887**	**18,423**	**24,190**
Less: Projected Gas Imports	1,200	3,900	6,100
Oil Imports Required (10^{12} BTU/yr)	**14,687**	**14,523**	**18,090**
Oil Imports Required (MB/D)	**6,937**	**6,860**	**8,545**

U.S. ENERGY BALANCE TABLE 7
(All Data x 10^{12} BTU/Year)

Parameters for Balance

Intermediate Case Energy Demand; Electricity Condition Number 4

Fuel Supply Cases: Oil—II; Gas—II; Coal/Nuclear--II; Other Energy Forms—II

Electric Utility Sector Calculations

	1975	1980	1985
Electric Utility Demand	23,525	32,996	44,363
Less: Geothermal	120	401	661
Hydroelectric	2,990	3,240	3,320
Oil	6,515	13,481	16,043
Gas	1,950	975	0
Subtotal	**11,575**	**18,097**	**20,024**
Balance to Coal and Nuclear	**11,950**	**14,899**	**24,339**
Add: Non-Utility Coal	5,594	5,684	5,692
Total Coal and Nuclear Required	**17,544**	**20,583**	**30,031**
Less: Coal and Nuclear Available	19,554	29,633	46,637
Surplus Coal and Nuclear	**2,010**	**9,050**	**16,606**

Import Requirement Calculations

	1975	1980	1985
Total U. S. Energy Demand	83,481	102,581	124,942
Less: Domestic Supplies			
Oil—Total Liquid Production	20,630	26,456	28,477
—Shale Syncrude	0	197	788
—Coal Syncrude	0	0	175
Subtotal—Oil	**20,630**	**26,653**	**29,440**
Gas—Total Production	24,300	25,043	27,324
—Nuclear Stimulation	0	103	825
—Coal Syngas	0	329	1,208
Subtotal—Gas	**24,300**	**25,475**	**29,357**
Hydroelectric	2,990	3,240	3,320
Geothermal	120	401	661
Coal and Nuclear Required	17,544	20,583	30,031
Subtotal—Domestic Supplies	**65,584**	**76,352**	**92,809**
Total Energy Imports Required	**17,897**	**26,229**	**32,133**
Less: Projected Gas Imports	1,200	3,900	6,100
Oil Imports Required (10^{12} BTU/yr)	**16,697**	**22,329**	**26,033**
Oil Imports Required (MB/D)	**7,887**	**10,548**	**12,297**

U.S. ENERGY BALANCE TABLE 8
(All Data x 10^{12} BTU/Year)

Parameters for Balance

Intermediate Case Energy Demand; Electricity Condition Number 5

Fuel Supply Cases: Oil—II; Gas—II; Coal/Nuclear—II; Other Energy Forms—II

Electric Utility Sector Calculations

	1975	1980	1985
Electric Utility Demand	23,525	32,996	44,363
Less: Geothermal	120	401	661
Hydroelectric	2,990	3,240	3,320
Oil	5,215	11,856	2,050
Gas	3,250	2,600	1,950
Subtotal	**11,575**	**18,097**	**7,981**
Balance to Coal and Nuclear	**11,950**	**14,899**	**36,382**
Add: Non-Utility Coal	5,594	5,684	5,692
Total Coal and Nuclear Required	**17,544**	**20,583**	**42,074**
Less: Coal and Nuclear Available	19,554	29,633	46,637
Surplus Coal and Nuclear	**2,010**	**9,050**	**4,563**

Import Requirement Calculations

	1975	1980	1985
Total U.S. Energy Demand	83,481	102,581	124,942
Less: Domestic Supplies			
Oil—Total Liquid Production	20,630	26,456	28,477
—Shale Syncrude	0	197	788
—Coal Syncrude	0	0	175
Subtotal—Oil	**20,630**	**26,653**	**29,440**
Gas—Total Production	24,300	25,043	27,324
—Nuclear Stimulation	0	103	825
—Coal Syngas	0	329	1,208
Subtotal—Gas	**24,300**	**25,475**	**29,357**
Hydroelectric	2,990	3,240	3,320
Geothermal	120	401	661
Coal and Nuclear Required	17,544	20,583	42,074
Subtotal—Domestic Supplies	**65,584**	**76,352**	**104,852**
Total Energy Imports Required	**17,897**	**26,229**	**20,090**
Less: Projected Gas Imports	1,200	3,900	6,100
Oil Imports Required (10^{12} BTU/yr)	**16,697**	**22,329**	**13,990**
Oil Imports Required (MB/D)	**7,887**	**10,548**	**6,608**

U.S. ENERGY BALANCE TABLE 9
(All Data x 10^{12} BTU/Year)

Parameters for Balance

Intermediate Case Energy Demand; Electricity Condition Number 6

Fuel Supply Cases: Oil—II; Gas—II; Coal/Nuclear—II; Other Energy Forms—II

Electric Utility Sector Calculations

	1975	1980	1985
Electric Utility Demand	23,525	32,996	44,363
Less: Geothermal	120	401	661
Hydroelectric	2,990	3,240	3,320
Oil	3,000	4,050	10,136
Gas	3,250	2,600	1,950
Subtotal	**9,360**	**10,291**	**16,067**
Balance to Coal and Nuclear	**14,165**	**22,705**	**28,296**
Add: Non-Utility Coal	5,594	5,684	5,692
Total Coal and Nuclear Required	**19,759**	**28,389**	**33,988**
Less: Coal and Nuclear Available	19,554	29,633	46,637
Surplus Coal and Nuclear	**0**	**1,244**	**12,649**

Import Requirement Calculations

	1975	1980	1985
Total U.S. Energy Demand	83,481	102,581	124,942
Less: Domestic Supplies			
Oil—Total Liquid Production	20,630	26,456	28,477
—Shale Syncrude	0	197	788
—Coal Syncrude	0	0	175
Subtotal—Oil	**20,630**	**26,653**	**29,440**
Gas—Total Production	24,300	25,043	27,324
—Nuclear Stimulation	0	103	825
—Coal Syngas	0	329	1,208
Subtotal—Gas	**24,300**	**25,475**	**29,357**
Hydroelectric	2,990	3,240	3,320
Geothermal	120	401	661
Coal and Nuclear Required	19,554	28,389	33,988
Subtotal—Domestic Supplies	**67,594**	**84,158**	**96,766**
Total Energy Imports Required	**15,887**	**18,423**	**28,176**
Less: Projected Gas Imports	1,200	3,900	6,100
Oil Imports Required (10^{12} BTU/yr)	**14,687**	**14,523**	**22,076**
Oil Imports Required (MB/D)	**6,937**	**6,860**	**10,428**

U.S. ENERGY BALANCE TABLE 10
(All Data x 10^{12} BTU/Year)

Parameters for Balance

Intermediate Case Energy Demand; Electricity Condition Number 2

Fuel Supply Cases: Oil—III; Gas—III; Coal/Nuclear—III; Other Energy Forms—III

Electric Utility Sector Calculations

	1975	1980	1985
Electric Utility Demand	23,525	32,996	44,363
Less: Geothermal	120	343	514
Hydroelectric	2,990	3,240	3,320
Oil	4,110	5,350	6,480
Gas	3,250	2,600	1,950
Subtotal	**10,470**	**11,533**	**12,264**
Balance to Coal and Nuclear	**13,055**	**21,463**	**32,099**
Add: Non-Utility Coal	5,594	5,684	5,692
Total Coal and Nuclear Required	**18,649**	**27,147**	**37,791**
Less: Coal and Nuclear Available	19,554	28,071	41,608
Surplus Coal and Nuclear	**905**	**924**	**3,817**

Import Requirement Calculations

	1975	1980	1985
Total U.S. Energy Demand	83,481	102,581	124,942
Less: Domestic Supplies			
Oil—Total Liquid Production	19,754	23,789	24,346
—Shale Syncrude	0	197	788
—Coal Syncrude	0	0	175
Subtotal—Oil	**19,754**	**23,986**	**25,309**
Gas—Total Production	22,766	21,041	21,049
—Nuclear Stimulation	0	103	825
—Coal Syngas	0	329	1,208
Subtotal—Gas	**22,766**	**21,473**	**23,082**
Hydroelectric	2,990	3,240	3,320
Geothermal	120	343	514
Coal and Nuclear Required	18,649	27,147	37,791
Subtotal—Domestic Supplies	**64,279**	**76,189**	**90,016**
Total Energy Imports Required	**19,202**	**26,392**	**34,926**
Less: Projected Gas Imports	1,200	3,900	6,400
Oil Imports Required (10^{12} BTU/yr)	**18,002**	**22,492**	**28,526**
Oil Imports Required (MB/D)	**8,504**	**10,624**	**13,474**

U.S. ENERGY BALANCE TABLE 11
(All Data x 10^{12} BTU/Year)

Parameters for Balance

Intermediate Case Energy Demand; Electricity Condition Number 3

Fuel Supply Cases: Oil—III; Gas—III; Coal/Nuclear--III; Other Energy Forms—III

Electric Utility Sector Calculations

	1975	1980	1985
Electric Utility Demand	23,525	32,996	44,363
Less: Geothermal	120	343	514
Hydroelectric	2,990	3,240	3,320
Oil	3,000	4,050	6,150
Gas	3,250	2,600	1,950
Subtotal	**9,360**	**10,233**	**11,934**
Balance to Coal and Nuclear	**14,165**	**22,763**	**32,429**
Add: Non-Utility Coal	5,594	5,684	5,692
Total Coal and Nuclear Required	**19,759**	**28,447**	**38,121**
Less: Coal and Nuclear Available	19,554	28,071	41,608
Surplus Coal and Nuclear	**0**	**0**	**3,487**

Import Requirement Calculations

	1975	1980	1985
Total U.S. Energy Demand	83,481	102,581	124,942
Less: Domestic Supplies			
Oil—Total Liquid Production	19,754	23,789	24,346
—Shale Syncrude	0	197	788
—Coal Syncrude	0	0	175
Subtotal—Oil	**19,754**	**23,986**	**25,309**
Gas—Total Production	22,766	21,041	21,049
—Nuclear Stimulation	0	103	825
—Coal Syngas	0	329	1,208
Subtotal—Gas	**22,766**	**21,473**	**23,082**
Hydroelectric	2,990	3,240	3,320
Geothermal	120	343	514
Coal and Nuclear Required	19,554	28,071	38,121
Subtotal—Domestic Supplies	**65,184**	**77,113**	**90,346**
Total Energy Imports Required	**18,297**	**25,468**	**34,596**
Less: Projected Gas Imports	1,200	3,900	6,400
Oil Imports Required (10^{12} BTU/yr)	**17,097**	**21,568**	**28,196**
Oil Imports Required (MB/D)	**8,076**	**10,188**	**13,319**

U.S. ENERGY BALANCE TABLE 12
(All Data x 10^{12} BTU/Year)

Parameters for Balance

Intermediate Case Energy Demand; Electricity Condition Number 4

Fuel Supply Cases: Oil—III; Gas—III; Coal/Nuclear—III; Other Energy Forms—III

Electric Utility Sector Calculations

	1975	1980	1985
Electric Utility Demand	23,525	32,996	44,363
Less: Geothermal	120	343	514
Hydroelectric	2,990	3,240	3,320
Oil	6,515	13,481	16,043
Gas	1,950	975	0
Subtotal	**11,575**	**18,039**	**19,877**
Balance to Coal and Nuclear	**11,950**	**14,957**	**24,486**
Add: Non-Utility Coal	5,594	5,684	5,692
Total Coal and Nuclear Required	**17,544**	**20,641**	**30,178**
Less: Coal and Nuclear Available	19,554	28,071	41,608
Surplus Coal and Nuclear	**2,010**	**7,430**	**11,430**

Import Requirement Calculations

	1975	1980	1985
Total U.S. Energy Demand	83,481	102,581	124,942
Less: Domestic Supplies			
Oil—Total Liquid Production	19,754	23,789	24,346
—Shale Syncrude	0	197	788
—Coal Syncrude	0	0	175
Subtotal—Oil	**19,754**	**23,986**	**25,309**
Gas—Total Production	22,766	21,041	21,049
—Nuclear Stimulation	0	103	825
—Coal Syngas	0	329	1,208
Subtotal—Gas	**22,766**	**21,473**	**23,082**
Hydroelectric	2,990	3,240	3,320
Geothermal	120	343	514
Coal and Nuclear Required	17,544	20,641	30,178
Subtotal—Domestic Supplies	**63,174**	**69,683**	**82,403**
Total Energy Imports Required	**20,307**	**32,898**	**42,539**
Less: Projected Gas Imports	1,200	3,900	6,400
Oil Imports Required (10^{12} BTU/yr)	**19,107**	**28,998**	**36,139**
Oil Imports Required (MB/D)	**9,026**	**13,697**	**17,071**

U.S. ENERGY DEMAND TABLE 13
(All Data x 10^{12} BTU/Year)

Parameters for Balance

Intermediate Case Energy Demand; Electricity Condition Number 5

Fuel Supply Cases: Oil—III; Gas—III; Coal/Nuclear—III; Other Energy Forms—III

Electric Utility Sector Calculations

	1975	1980	1985
Electric Utility Demand	23,525	32,996	44,363
Less: Geothermal	120	343	514
Hydroelectric	2,990	3,240	3,320
Oil	5,215	11,856	2,050
Gas	3,250	2,600	1,950
Subtotal	**11,575**	**18,039**	**7,834**
Balance to Coal and Nuclear	**11,950**	**14,957**	**36,529**
Add: Non-Utility Coal	5,594	5,684	5,692
Total Coal and Nuclear Required	**17,544**	**20,641**	**42,221**
Less: Coal and Nuclear Available	19,554	28,071	41,608
Surplus Coal and Nuclear	**2,010**	**7,430**	**0**

Import Requirement Calculations

	1975	1980	1985
Total U.S. Energy Demand	83,481	102,581	124,942
Less: Domestic Supplies			
Oil—Total Liquid Production	19,754	23,789	24,346
—Shale Syncrude	0	197	788
—Coal Syncrude	0	0	175
Subtotal—Oil	**19,754**	**23,986**	**25,309**
Gas—Total Production	22,766	21,041	21,049
—Nuclear Stimulation	0	103	825
—Coal Syngas	0	329	1,208
Subtotal—Gas	**22,766**	**21,473**	**23,082**
Hydroelectric	2,990	3,240	3,320
Geothermal	120	343	514
Coal and Nuclear Required	17,544	20,641	41,608
Subtotal—Domestic Supplies	**63,174**	**69,683**	**93,833**
Total Energy Imports Required	**20,307**	**32,898**	**31,109**
Less: Projected Gas Imports	1,200	3,900	6,400
Oil Imports Required (10^{12} BTU/yr)	**19,107**	**28,998**	**24,709**
Oil Imports Required (MB/D)	**9,026**	**13,697**	**11,671**

U.S. ENERGY BALANCE TABLE 14
(All Data x 10^{12} BTU/Year)

Parameters for Balance

Intermediate Case Energy Demand; Electricity Condition Number 6

Fuel Supply Cases: Oil–III; Gas–III; Coal/Nuclear–III; Other Energy Forms–III

Electric Utility Sector Calculations

	1975	1980	1985
Electric Utility Demand	23,525	32,996	44,363
Less: Geothermal	120	343	514
Hydroelectric	2,990	3,240	3,320
Oil	3,000	4,050	10,136
Gas	3,250	2,600	1,950
Subtotal	**9,360**	**10,233**	**15,920**
Balance to Coal and Nuclear	**14,165**	**22,763**	**28,443**
Add: Non-Utility Coal	5,594	5,684	5,692
Total Coal and Nuclear Required	**19,759**	**28,447**	**34,135**
Less: Coal and Nuclear Available	19,554	28,071	41,608
Surplus Coal and Nuclear	**0**	**0**	**7,473**

Import Requirement Calculations

	1975	1980	1985
Total U.S. Energy Demand	83,481	102,581	124,942
Less: Domestic Supplies			
Oil–Total Liquid Production	19,754	23,789	24,346
–Shale Syncrude	0	197	788
–Coal Syncrude	0	0	175
Subtotal–Oil	**19,754**	**23,986**	**25,309**
Gas–Total Production	22,766	21,041	21,049
–Nuclear Stimulation	0	103	825
–Coal Syngas	0	329	1,208
Subtotal–Gas	**22,766**	**21,473**	**23,082**
Hydroelectric	2,990	3,240	3,320
Geothermal	120	343	514
Coal and Nuclear Required	19,554	28,071	34,135
Subtotal–Domestic Supplies	**65,184**	**77,113**	**86,360**
Total Energy Imports Required	**18,297**	**25,468**	**38,582**
Less: Projected Gas Imports	1,200	3,900	6,400
Oil Imports Required (10^{12} BTU/yr)	**17,097**	**21,568**	**32,182**
Oil Imports Required (MB/D)	**8,076**	**10,188**	**15,201**

U.S. ENERGY BALANCE TABLE 15
(All Data x 10^{12} BTU/Year)

Parameters for Balance

Intermediate Case Energy Demand; Electricity Condition Number 1

Fuel Supply Cases: Oil—IV; Gas—IV; Coal/Nuclear—I; Other Energy Forms—IV

Electric Utility Sector Calculations

	1975	1980	1985
Electric Utility Demand	23,525	32,996	44,363
Less: Geothermal	120	191	257
Hydroelectric	2,990	3,240	3,320
Oil	3,460	4,050	4,530
Gas	3,900	3,900	3,900
Subtotal	**10,470**	**11,381**	**12,007**
Balance to Coal and Nuclear	**13,055**	**21,615**	**32,356**
Add: Non-Utility Coal	5,594	5,684	5,692
Total Coal and Nuclear Required	**18,649**	**27,299**	**38,048**
Less: Coal and Nuclear Available	20,650	32,549	56,910
Surplus Coal and Nuclear	**2,001**	**5,250**	**18,862**

Import Requirement Calculations

	1975	1980	1985
Total U.S. Energy Demand	83,481	102,581	124,942
Less: Domestic Supplies			
Oil—Total Liquid Production	19,502	18,112	21,426
—Shale Syncrude	0	0	197
—Coal Syncrude	0	0	0
Subtotal—Oil	**19,502**	**18,112**	**21,623**
Gas—Total Production	22,421	17,906	15,474
—Nuclear Stimulation	0	0	0
—Coal Syngas	0	165	494
Subtotal—Gas	**22,421**	**18,071**	**15,968**
Hydroelectric	2,990	3,240	3,320
Geothermal	120	191	257
Coal and Nuclear Required	18,649	27,299	38,048
Subtotal—Domestic Supplies	**63,682**	**66,913**	**79,216**
Total Energy Imports Required	**19,799**	**35,668**	**45,726**
Less: Projected Gas Imports	1,200	3,900	6,600
Oil Imports Required (10^{12} BTU/yr)	**18,599**	**31,768**	**39,126**
Oil Imports Required (MB/D)	**8,786**	**15,006**	**18,482**

U.S. ENERGY BALANCE TABLE 16
(All Data x 10^{12} BTU/Year)

Parameters for Balance

Intermediate Case Energy Demand; Electricity Condition Number 1

Fuel Supply Cases: Oil—I; Gas—I; Coal/Nuclear—IV; Other Energy Forms—IV

Electric Utility Sector Calculations

	1975	1980	1985
Electric Utility Demand	23,525	32,996	44,363
Less: Geothermal	120	191	257
Hydroelectric	2,990	3,240	3,320
Oil	3,460	4,050	4,530
Gas	3,900	3,900	3,900
Subtotal	**10,470**	**11,381**	**12,007**
Balance to Coal and Nuclear	**13,055**	**21,615**	**32,356**
Add: Non-Utility Coal	5,594	5,684	5,692
Total Coal and Nuclear Required	**18,649**	**27,299**	**38,048**
Less: Coal and Nuclear Available	16,761	24,338	36,426
Surplus Coal and Nuclear	**0**	**0**	**0**

Import Requirement Calculations

	1975	1980	1985
Total U.S. Energy Demand	83,481	102,581	124,942
Less: Domestic Supplies			
Oil—Total Liquid Production	20,735	27,758	31,689
—Shale Syncrude	0	0	197
—Coal Syncrude	0	0	0
Subtotal—Oil	**20,735**	**27,758**	**31,886**
Gas—Total Production	24,513	26,746	31,604
—Nuclear Stimulation	0	206	1,341
—Coal Syngas	0	165	494
Subtotal—Gas	**24,513**	**27,117**	**33,439**
Hydroelectric	2,990	3,240	3,320
Geothermal	120	191	257
Coal and Nuclear Required	16,761	24,338	36,426
Subtotal—Domestic Supplies	**65,119**	**82,644**	**105,328**
Total Energy Imports Required	**18,362**	**19,937**	**19,614**
Less: Projected Gas Imports	1,200	3,900	5,900
Oil Imports Required (10^{12} BTU/yr)	**17,162**	**16,037**	**13,714**
Oil Imports Required (MB/D)	**8,107**	**7,575**	**6,477**

U.S. ENERGY BALANCE TABLE 17
(All Data x 10^{12} BTU/Year)

Parameters for Balance

Intermediate Case Energy Demand; Electricity Condition Number 1

Fuel Supply Cases: Oil—II; Gas—III; Coal/Nuclear—III; Other Energy Forms—III

Electric Utility Sector Calculations

	1975	1980	1985
Electric Utility Demand	23,525	32,996	44,363
Less: Geothermal	120	343	514
Hydroelectric	2,990	3,240	3,320
Oil	3,460	4,050	4,530
Gas	3,900	3,900	3,900
Subtotal	**10,470**	**11,533**	**12,264**
Balance to Coal and Nuclear	**13,055**	**21,463**	**32,099**
Add: Non-Utility Coal	5,594	5,684	5,692
Total Coal and Nuclear Required	**18,649**	**27,147**	**37,791**
Less: Coal and Nuclear Available	19,554	28,071	41,608
Surplus Coal and Nuclear	**905**	**924**	**3,817**

Import Requirement Calculations

	1975	1980	1985
Total U.S. Energy Demand	83,481	102,581	124,942
Less: Domestic Supplies			
Oil—Total Liquid Production	20,495	26,085	27,913
—Shale Syncrude	0	197	788
—Coal Syncrude	0	0	175
Subtotal—Oil	**20,495**	**26,282**	**28,876**
Gas—Total Production	22,951	21,674	22,221
—Nuclear Stimulation	0	103	825
—Coal Syngas	0	329	1,208
Subtotal—Gas	**22,951**	**22,106**	**24,254**
Hydroelectric	2,990	3,240	3,320
Geothermal	120	343	514
Coal and Nuclear Required	18,649	27,147	37,791
Subtotal—Domestic Supplies	**65,205**	**79,118**	**94,755**
Total Energy Imports Required	**18,276**	**23,463**	**30,187**
Less: Projected Gas Imports	1,200	3,900	6,400
Oil Imports Required (10^{12} BTU/yr)	**17,076**	**19,563**	**23,787**
Oil Imports Required (MB/D)	**8,066**	**9,241**	**11,236**

U.S. ENERGY BALANCE TABLE 18
(All Data x 10^{12} BTU/Year)

Parameters for Balance

Intermediate Case Energy Demand; Electricity Condition Number 1

Fuel Supply Cases: Oil—III; Gas—II; Coal/Nuclear—III; Other Energy Forms—III

Electric Utility Sector Calculations

	1975	1980	1985
Electric Utility Demand	23,525	32,996	44,363
Less: Geothermal	120	343	514
Hydroelectric	2,990	3,240	3,320
Oil	3,460	4,050	4,530
Gas	3,900	3,900	3,900
Subtotal	**10,470**	**11,533**	**12,264**
Balance to Coal and Nuclear	**13,055**	**21,463**	**32,099**
Add: Non-Utility Coal	5,594	5,684	5,692
Total Coal and Nuclear Required	**18,649**	**27,147**	**37,791**
Less: Coal and Nuclear Available	19,554	28,071	41,608
Surplus Coal and Nuclear	**905**	**924**	**3,817**

Import Requirement Calculations

	1975	1980	1985
Total U.S. Energy Demand	83,481	102,581	124,942
Less: Domestic Supplies			
Oil—Total Liquid Production	19,889	24,160	24,910
—Shale Syncrude	0	197	788
—Coal Syncrude	0	0	175
Subtotal—Oil	**19,889**	**24,357**	**25,873**
Gas—Total Production	24,114	24,410	26,152
—Nuclear Stimulation	0	103	825
—Coal Syngas	0	329	1,208
Subtotal—Gas	**24,114**	**24,842**	**28,185**
Hydroelectric	2,990	3,240	3,320
Geothermal	120	343	514
Coal and Nuclear Required	18,649	27,147	37,791
Subtotal—Domestic Supplies	**65,762**	**79,929**	**95,683**
Total Energy Imports Required	**17,719**	**22,652**	**29,259**
Less: Projected Gas Imports	1,200	3,900	6,100
Oil Imports Required (10^{12} BTU/yr)	**16,519**	**18,752**	**23,159**
Oil Imports Required (MB/D)	**7,803**	**8,858**	**10,939**

U.S. ENERGY BALANCE TABLE 19
(All Data x 10^{12} BTU/Year)

Parameters for Balance

High Case Energy Demand; Electricity Condition Number 1

Fuel Supply Cases: Oil—II; Gas—II; Coal/Nuclear—II; Other Energy Forms—II

Electric Utility Sector Calculations

	1975	1980	1985
Electric Utility Demand	23,525	32,996	44,363
Less: Geothermal	120	401	661
Hydroelectric	2,990	3,240	3,320
Oil	3,460	4,050	4,530
Gas	3,900	3,900	3,900
Subtotal	**10,470**	**11,591**	**12,411**
Balance to Coal and Nuclear	**13,055**	**21,405**	**31,952**
Add: Non-Utility Coal	5,594	5,684	5,692
Total Coal and Nuclear Required	**18,649**	**27,089**	**37,644**
Less: Coal and Nuclear Available	19,554	29,633	46,637
Surplus Coal and Nuclear	**905**	**2,544**	**8,993**

Import Requirement Calculations

	1975	1980	1985
Total U.S. Energy Demand	83,481	105,333	130,013
Less: Domestic Supplies			
Oil—Total Liquid Production	20,630	26,456	28,477
—Shale Syncrude	0	197	788
—Coal Syncrude	0	0	175
Subtotal—Oil	**20,630**	**26,653**	**29,440**
Gas—Total Production	24,300	25,043	27,324
—Nuclear Stimulation	0	103	825
—Coal Syngas	0	329	1,208
Subtotal—Gas	**24,300**	**25,475**	**29,357**
Hydroelectric	2,990	3,240	3,320
Geothermal	120	401	661
Coal and Nuclear Required	18,649	27,089	37,644
Subtotal—Domestic Supplies	**66,689**	**82,858**	**100,422**
Total Energy Imports Required	**16,792**	**22,475**	**29,591**
Less: Projected Gas Imports	1,200	3,900	6,100
Oil Imports Required (10^{12} BTU/yr)	**15,592**	**18,575**	**23,491**
Oil Imports Required (MB/D)	**7,365**	**8,774**	**11,096**

U.S. ENERGY BALANCE TABLE 20
(All Data x 10^{12} BTU/Year)

Parameters for Balance

Low Case Energy Demand; Electricity Condition Number 1

Fuel Supply Cases: Oil—II; Gas—II; Coal/Nuclear—II; Other Energy Forms—II

Electric Utility Sector Calculations

	1975	1980	1985
Electric Utility Demand	23,525	32,996	44,363
Less: Geothermal	120	401	661
Hydroelectric	2,990	3,240	3,320
Oil	3,460	4,050	4,530
Gas	3,900	3,900	3,900
Subtotal	**10,470**	**11,591**	**12,411**
Balance to Coal and Nuclear	**13,055**	**21,405**	**31,952**
Add: Non-Utility Coal	5,594	5,684	5,692
Total Coal and Nuclear Required	**18,649**	**27,089**	**37,644**
Less: Coal and Nuclear Available	19,554	29,633	46,637
Surplus Coal and Nuclear	**905**	**2,544**	**8,993**

Import Requirement Calculations

	1975	1980	1985
Total U.S. Energy Demand	83,481	95,677	112,540
Less: Domestic Supplies			
Oil—Total Liquid Production	20,630	26,456	28,477
—Shale Syncrude	0	197	788
—Coal Syncrude	0	0	175
Subtotal—Oil	**20,630**	**26,653**	**29,440**
Gas—Total Production	24,300	25,043	27,324
—Nuclear Stimulation	0	103	825
—Coal Syngas	0	329	1,208
Subtotal—Gas	**24,300**	**25,475**	**29,357**
Hydroelectric	2,990	3,240	3,320
Geothermal	120	401	661
Coal and Nuclear Required	18,649	27,089	37,644
Subtotal—Domestic Supplies	**66,689**	**82,858**	**100,422**
Total Energy Imports Required	**16,792**	**12,819**	**12,118**
Less: Projected Gas Imports	1,200	3,900	6,100
Oil Imports Required (10^{12} BTU/yr)	**15,592**	**8,919**	**6,018**
Oil Imports Required (MB/D)	**7,365**	**4,213**	**2,843**

U.S. ENERGY BALANCE TABLE 21
(All Data x 10^{12} BTU/Year)

Parameters for Balance

High Case Energy Demand; Electricity Condition Number 1

Fuel Supply Cases: Oil—III; Gas—III; Coal/Nuclear—III; Other Energy Forms—III

Electric Utility Sector Calculations

	1975	1980	1985
Electric Utility Demand	23,525	32,996	44,363
Less: Geothermal	120	343	514
Hydroelectric	2,990	3,240	3,320
Oil	3,460	4,050	4,530
Gas	3,900	3,900	3,900
Subtotal	**10,470**	**11,533**	**12,264**
Balance to Coal and Nuclear	**13,055**	**21,463**	**32,099**
Add: Non-Utility Coal	5,594	5,684	5,692
Total Coal and Nuclear Required	**18,649**	**27,147**	**37,791**
Less: Coal and Nuclear Available	19,554	28,071	41,608
Surplus Coal and Nuclear	**905**	**924**	**3,817**

Import Requirement Calculations

	1975	1980	1985
Total U.S. Energy Demand	83,481	105,333	130,013
Less: Domestic Supplies			
Oil—Total Liquid Production	19,754	23,789	24,346
—Shale Syncrude	0	197	788
—Coal Syncrude	0	0	175
Subtotal—Oil	**19,754**	**23,986**	**25,309**
Gas—Total Production	22,766	21,041	21,049
—Nuclear Stimulation	0	103	825
—Coal Syngas	0	329	1,208
Subtotal—Gas	**22,766**	**21,473**	**23,082**
Hydroelectric	2,990	3,240	3,320
Geothermal	120	343	514
Coal and Nuclear Required	18,649	27,147	37,791
Subtotal—Domestic Supplies	**64,279**	**76,189**	**90,016**
Total Energy Imports Required	**19,202**	**29,144**	**39,997**
Less: Projected Gas Imports	1,200	3,900	6,400
Oil Imports Required (10^{12} BTU/yr)	**18,002**	**25,244**	**33,597**
Oil Imports Required (MB/D)	**8,504**	**11,924**	**15,870**

U.S. ENERGY BALANCE TABLE 22
(All Data x 10^{12} BTU/Year)

Parameters for Balance

Low Case Energy Demand; Electricity Condition Number 1

Fuel Supply Cases: Oil—III; Gas—III; Coal/Nuclear—III; Other Energy Forms—III

Electric Utility Sector Calculations

	1975	1980	1985
Electric Utility Demand	23,525	32,996	44,363
Less: Geothermal	120	343	514
Hydroelectric	2,990	3,240	3,320
Oil	3,460	4,050	4,530
Gas	3,900	3,900	3,900
Subtotal	**10,470**	**11,533**	**12,264**
Balance to Coal and Nuclear	**13,055**	**21,463**	**32,099**
Add: Non-Utility Coal	5,594	5,684	5,692
Total Coal and Nuclear Required	**18,649**	**27,147**	**37,791**
Less: Coal and Nuclear Available	19,554	28,071	41,608
Surplus Coal and Nuclear	**905**	**924**	**3,817**

Import Requirement Calculations

	1975	1980	1985
Total U.S. Energy Demand	83,481	95,677	112,540
Less: Domestic Supplies			
Oil—Total Liquid Production	19,754	23,789	24,346
—Shale Syncrude	0	197	788
—Coal Syncrude	0	0	175
Subtotal—Oil	**19,754**	**23,986**	**25,309**
Gas—Total Production	22,766	21,041	21,049
—Nuclear Stimulation	0	103	825
—Coal Syngas	0	329	1,208
Subtotal—Gas	**22,766**	**21,473**	**23,082**
Hydroelectric	2,990	3,240	3,320
Geothermal	120	343	514
Coal and Nuclear Required	18,649	27,147	37,791
Subtotal—Domestic Supplies	**64,279**	**76,189**	**90,016**
Total Energy Imports Required	**19,202**	**19,488**	**22,524**
Less: Projected Gas Imports	1,200	3,900	6,400
Oil Imports Required (10^{12} BTU/yr)	**18,002**	**15,588**	**16,124**
Oil Imports Required (MB/D)	**8,504**	**7,363**	**7,616**

Glossary

associated-dissolved gas—associated gas is free natural gas in immediate contact, but not in solution, with crude oil in the reservoir; dissolved gas is natural gas in solution in crude oil in the reservoir; in this report associated and dissolved gas are reported jointly as that gas produced from an oil field; the combined volume of natural gas which occurs in crude oil reservoirs either as free gas (associated) or as gas in solution with the crude oil (dissolved).

barrel—a liquid volume measure equal to 42 U.S. gallons.

bitumen—a general name for various solid and semisolid hydrocarbons; a native substance of dark color, comparatively hard and nonvolatile, composed principally of hydrocarbon.

breeder reactor—a nuclear reactor that produces more fissionable material than it consumes. This reactor is sometimes called the fast breeder because high energy (fast) neutrons will produce most of the fissions in current designs.

British Thermal Unit (BTU)—see box at end of Glossary.

cash bonus payment—a cash consideration paid by the lessee for the execution of an oil or gas lease by a landowner. The bonus is usually computed on a per acre basis.

coal gasification—the conversion of coal to a gas suitable for use as a fuel.

coal liquefaction (coal hydrogenation)—the conversion of coal into liquid hydrocarbons and related compounds by hydrogenation.

coastwise shipping—goods shipped from one U.S. port to another U.S. port along the same coastal region.

combined-cycle plant—a plant which utilizes waste heat from large gas turbines (driven by gases from combustion of hydrocarbon fuels) to generate steam for conventional steam turbines.

condensate—liquid hydrocarbon obtained by the combustion of a vapor or gas produced from oil or gas wells and ordinarily separated at a field separator and run as crude oil.

constant dollars—see box at end of Glossary.

conventional gas—natural gas as contrasted with synthetic gas.

conventional oil—crude oil and condensate as contrasted with synthetic oil from shale or coal.

conversion—chemical processing of uranium concentrates into uranium hexaflouride gas.

cryogenic techniques—techniques involving extremely low temperatures used to keep certain fuels in a liquid form; i.e., liquefied hydrogen, methane, propane, etc.

deadweight tonnage—the difference, in tons, between a ship's displacement at load draught and light draught. It comprises cargo, bunkers, stores, fresh water, etc.

depletion allowance—a proportion of income derived from mining or oil production that is considered to be a return of capital not subject to income tax.

distillate—the liquid obtained by condensing a vapor.

enrichment—process by which the percentage of the fissionable isotope, U_{235}, has been increased above the 0.7 percent contained in natural uranium. The United States utilizes the gaseous diffusion uranium enrichment process.

fossil fuel—any naturally occurring fuel of an organic nature, such as coal, crude oil and natural gas.

fuel cell—a cell that continuously changes the chemical energy of a fuel and oxidant to electrical energy.

fuel fabrication—the manufacturing and assembly of reactor fuel elements containing fissionable and fertile nuclear material.

gross national product (GNP)—the total market value of the goods and services produced by the

Nation before the deduction of depreciation charges and other allowances for capital consumption; a widely used measure of economic activity.

hopper car—a car for coal, gravel, etc., shaped like a hopper, with an opening to discharge the contents.

hydrocarbon fuels—fuels that contain an organic chemical compound of hydrogen and carbon.

hydrotreating—the removal of sulfur from low-octane gasoline feedstocks by replacement with hydrogen.

high-temperature gas reactor—a nuclear reactor in which helium gas is the primary coolant with graphite fuel elements containing coated particles of highly enriched uranium plus fertile thorium.

in situ—in the natural or original position; applied to a rock, soil or fossil when occurring in the situation in which it was originally formed or deposited.

ionized gas—a gas that is capable of carrying an electric current.

isotope—one of two or more atoms with the same atomic number (the same chemical element) but with different atomic weights. Isotopes usually have very nearly the same chemical properties, but somewhat different physical properties.

light-water reactor (LWR)—nuclear reactor in which water (H_2O) is the primary coolant/moderator with slightly enriched uranium fuel. There are two commercial light-water reactor types—the boiling water reactor (BWR) and the pressurized water reactor (PWR).

liquefaction of gases—any process in which gas is converted from the gaseous to the liquid phase.

liquefied natural gas (LNG)—a clear, flammable liquid both tasteless and odorless; almost pure methane.

liquefied petroleum gas (LPG)—a gas containing certain specific hydrocarbons which are gaseous under normal atmospheric conditions, but can be liquefied under moderate pressure at normal temperatures; principal examples are propane and butane.

magnetohydrodynamics (MHD)—a branch of physics that deals with magnetohydrodynamic phenomenon (of or relating to phenomena arising from the motion of electrically conducting fluids in the presence of electric and magnetic fields).

metallurgical coal—coal with strong or moderately strong coking properties that contains no more than 8.0-percent ash and 1.25-percent sulfur, as mined or after conventional cleaning.

methanol—methyl alcohol.

methyl alcohol (CH_3OH)—a poisonous liquid, also known as methanol, which is the lowest member of the alcohol series. Also known as wood alcohol, since its principal source is the destructive distillation of wood.

non-associated gas—free natural gas not in contact with, nor dissolved in, crude oil in the reservoir.

nuclear fuel cycle—the various steps which involve the production, processing, use and reprocessing of nuclear fuels.

oil-in-place—original oil-in-place less the cumulative production.

oil shale—a convenient expression used to cover a range of materials containing organic matter (Kerogen) which can be converted into crude shale oil, gas and carbonaceous residue by heating (compare shale oil).

original oil-in-place—the estimated number of barrels of crude oil in known reservoirs prior to any production, usually expressed as "stock tank" barrels or the volume that goes into a stock tank after the shrinkage that results when dissolved gas is separated from the oil.

overburden—material of any nature, consolidated or unconsolidated, that overlies a deposit of useful materials, ores or coal, especially those deposits that are mined from the surface by open cuts.

particulate matter—any matter, except water, that exists in a finely divided form as a liquid or solid.

plutonium—a fissionable element that does not occur in nature but is obtained by exposure of U_{238} to neutrons in a reactor.

primary fuel—fuel consumed in original production of energy as contrasted to a conversion of energy from one form to another.

pumped storage—an arrangement whereby additional electric power may be generated during peak load periods by hydraulic means using water pumped into a storage reservoir during off-peak periods.

reprocessing—chemical recovery of unburned uranium and plutonium and certain fission products from spent fuel elements that have produced power in a nuclear reactor.

retort—a vessel used for the distillation of volatile materials, as in the separation of some metals and the destructive distillation of coal; also a long semi-cylinder, now usually of fire clay or silica, for the manufacture of coal gas.

royalty bidding—competitive bidding for leases in which the lease is offered to the company offering to pay the landowner the largest share of the proceeds of production, free of expenses of production.

secondary recovery—oil and gas obtained by the augmentation of reservoir energy; often by the injection of air, gas or water into a production formation.

separative work—a measure of the work required to separate U_{235} and U_{238} isotopes in the gaseous diffusion process; the basis of AEC enrichment charges.

shale oil—a liquid similar to conventional crude oil but obtained from oil shale by conversion of organic matter (Kerogen) in oil shale.

stack gas desulfurization—treating of stack gases to remove sulfur compounds.

syncrude—synthetic crude oil derived from coal or oil shale.

syngas—synthetic gas (SNG).

synthetic fuel—gaseous or liquid hydrocarbon material produced from solid or liquid carbonaceous material.

tar sands—hydrocarbon bearing deposits distinguished from more conventional oil and gas reservoirs by the high viscosity of the hydrocarbon, which is not recoverable in its natural state through a well by ordinary oil production methods.

thermionic devices—devices that convert heat into electricity by evaporating electrons from a hot metal surface and condensing them on a cooler surface. No moving parts are required.

tertiary recovery—fluid injection method that will recover oil above that attainable by either natural or artificially induced water displacement.

thermonuclear fusion—source of energy available from hydrogen isotopes in seawater.

thorium (TH)—a naturally radioactive element with atomic number 90 and, as found in nature, an atomic weight of approximately 232. The fertile thorium-232 isotope is abundant and can be transmuted to fissionable uranium-233 by neutron irradiation. (A naturally radioactive metal. One of its natural isotopes can be converted in nuclear reactors to a nuclear fuel.)

topping—the distillation of crude petroleum to remove the light fractions only.

unitization—joining together of several separate leases into a single lease.

unit train—a system developed for delivering coal more efficiently in which a string of cars, with distinctive markings, and loaded to "full visible capacity," is operated without service frills or stops along the way for cars to be cut in and out. In this way, the customer receives his coal quickly and the empty car is scheduled back to the coal fields as fast as it came.

uranium (U)—a radioactive element with the atomic number 92 and, as found in natural ores, an average atomic weight of approximately 238. The two principal natural isotopes are uranium-235 (0.7 percent of natural uranium) which is fissionable (capable of being split and thereby releasing energy) and uranium-238 (99.3 percent of natural uranium) which is fertile (having the property of being convertible to a fissionable material). Natural uranium also includes a minute amount of uranium-234.

uranium hexafluoride (UF_6)—a volatile compound of uranium used in the enrichment process.

uranium oxide (U_3O_8)—refers to the natural uranium concentrate in yellow cake produced from milling of uranium ore. Yellow cake generally contains approximately 80-percent U_3O_8 by weight.

work program lease—a lease which is granted to the operator who in turn agrees to perform a stipulated amount of exploratory activity on the property.

"Constant" Versus "Current" Dollars

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

On the other hand, where used, the term "current dollars" refers to the purchasing power of the U.S. dollar in the year referred to (e.g., 1960, 1965, 1970), including such inflation or deflation as may have existed at that time.

To convert "constant" to "current" dollars for future years, it is necessary to apply such inflation or deflation factors as the reader deems appropriate. For example, assuming an inflation factor of 10 percent for the 1970-1975 period, the 1975 "current" dollar could be derived by multiplying the 1970 "constant" dollar by 1.1. Unless otherwise noted, no such conversion has been made in this report.

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 (10^{12}) and quadrillions (10^{15}) 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.

List of Abbreviations

AEC—Atomic Energy Commission
AGA—American Gas Association
API—American Petroleum Institute
BWR—boiling water reactor
CPA—Canadian Petroleum Association
CRG—Catalytic Rich Gas (process)
DCF—discounted cash flow
DWT—deadweight ton
ECCS—emergency core cooling system
EPA—Environmental Protection Agency
FBR—fast breeder reactor
FPC—Federal Power Commission
FRB—Federal Reserve Board Index of Industrial Production
GNP—gross national product
H_2S—hydrogen sulfide
HTGR—high-temperature gas-cooled reactor
ICOP—Imported Crude Oil Processing
KWH—kilowatt hour
LNG—liquefied natural gas
LPG—liquefied petroleum gas
LWR—light-water reactor
MB/D—thousand barrels per day
MCF—thousand cubic feet
MHD—magnetohydrodynamics
MMB/D—million barrels per day
MMCF—million cubic feet
MRG—Methane Rich Gas (process)
MTU—metric tons uranium
MW—megawatt
MWe—megawatt electrical generating capacity
NEB—National Energy Board (Canadian)
NGL—natural gas liquids
NO_x—nitrogen oxides
OCS—Outer Continental Shelf
OIP—oil-in-place
OPEC—Organization of Petroleum Exporting Countries
PAD—Petroleum Administration for Defense
PGC—Potential Gas Committee
Pu—plutonium
PWR—pressurized water reactor
R/P—reserves/production (ratio)
SNG—substitute natural gas
SO_2—sulfur dioxide
SRI—Stanford Research Institute
SWU—separative work units
TCF—trillion cubic feet
TVA—Tennessee Valley Authority
USGS—U.S. Geological Survey
VLCC—very large crude carriers